EIPC

Eastern Interconnection Planning Collaborative

Eastern Interconnection Planning Collaborative
Technical Committee

Frequency Response Working Group
2022 Final Report
Public Version

February 10, 2024

Eastern Interconnection Planning Collaborative

Table of Contents

List of Tables

List of Figures

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 Working Group (FRWG) 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 2024 NERC Long-Term Reliability Assessment (LTRA).

The analysis and simulation of this study demonstrated that the EI would have sufficient system inertia over the next 5 years with the generation resource mix, load, and interchange levels and governor participation modeled. However, with the addition of non-synchronous generation and planned resource retirements, maintaining frequency in the EI is a concern which warrants continued study. 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 increased non-synchronous generation with reduced inertia, there is a need for improved frequency responsive simulation power flow models. With assistance from all FRWG members, biweekly meetings and collaborative efforts allowed the FRWG to develop, assign, and complete many tasks in support of this effort.

In total, 13 tasks which are described in Section 4 were completed. These tasks include benchmarking historical frequency events with spring light load (SLL) cases to determine how the existing generator governor models perform in response to the frequency events. Improvements to future modeling of governors is expected to supersede the need for limiting generator governor responses. The FRWG also created a list of recommended changes to improve the frequency responsiveness of the planning models for use by the EI Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG) in future model development cycles.

As with the study performed in 2020, the FRWG tested two different historical frequency events and the most severe single contingency (MSSC) for the Eastern Interconnection pulled from 2022. The two historical frequency events include the loss of 2,006 MW event from 2018 and the loss of 1,423 MW event from 2019. The EI MSSC selected for this study is the loss of 2,314 MW. The benchmarking analysis for this study resulted in converting all governor models to have deadband enabled. This decision was made with the thought process that most governors have deadband but are not setup in the MMWG cases that way, so for a frequency study they should be considered to have deadband. 5% of governors had deadband already, 74% of governors were converted to the related deadband type model, and 21% of governors that did not have deadband were converted to the TGOV1DU model.

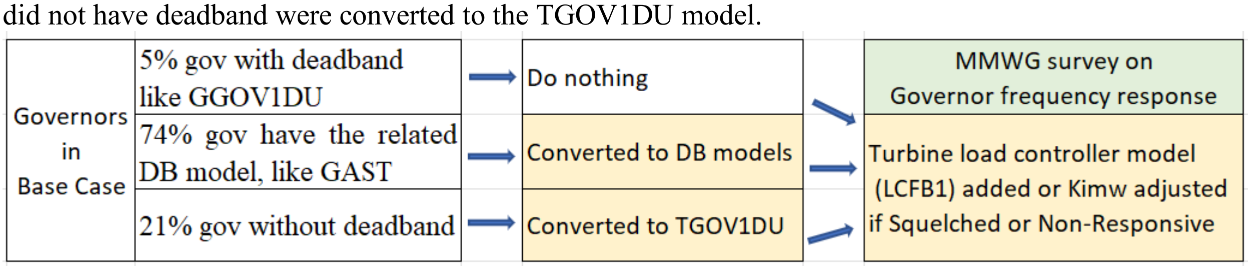


Figure 1: Governor Responsiveness in 2022 FRWG Study

This compares to approximately 45% of governors modeled as responsive in the 2018 study and 30% of governors modeled as responsive in the 2020 study. Building off the benchmark analysis, EI load was scaled to a minimum load forecast level and dispatch changes were applied to model forecasted changes in system inertia over the next 5 years. With these changes applied to the 2020 Series 2025 case, the simulated events and the selected MSSC exhibited satisfactory frequency response with a minimum nadir of 59.92 HZ. The study results are still significantly above the initial UFLS set point of 59.6 Hz.

The FRWG also tested two additional sensitivity cases that included a 20% increase in IBR penetration and a 40% increase in IBR penetration. The 10,000 MW benchmark event was used to test these cases. The simulation completed, with a frequency nadir of 59.65 Hz, in the 20% IBR penetration case. However, there were issues completing the simulation in the 40% IBR penetration case, so the 10,000 MWs was reduced to 5,000 MW in order to complete the simulation. After this change, the frequency nadir of the simulation was 59.77 Hz. The frequency nadir for both simulations is above the UFLS set point of 59.6 Hz, but due to having to reduce the trip amount in the 40% case, another study should be conducted to further study the increased IBR penetration impacts.

The results of this analysis have been shared with NERC for inclusion in the 2024 NERC LTRA. EIPC will continue to work with industry groups to implement these recommendations.

- Recommendation #1: Gross PMax Values
- Recommendation #2: Governor Modeling
- Recommendation #3: Frequency Responsive Dynamics Files
- Recommendation #4: Evaluate Frequency Response for a Low Inertia 10Y case
- Recommendation #5: Mid-day Minimum Inertia

1. Introduction

The EIPC represents an effort that draws Planning Coordinators in the EI together in a collaborative effort to perform the technical analysis of transmission planning and 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 efforts including the interconnection-wide review of the existing regional plans and development of transmission options associated with the various energy policy options.

As part of the EIPC's ongoing work to perform technical analyses of transmission planning issues, the EIPC Technical Committee established the Frequency Response Task Force (FRTF) on July 20, 2017 (later changed to the Frequency Response Working Group (FRWG) in March 2019) to take a leadership role in providing on a biannual basis the frequency response Measures 1, 2, and 4 from the Essential Reliability Services Task Force (ERSTF) Measurements Framework Report[1] for the EI for the North American Electric Reliability Corporation (NERC) Long Term Reliability Assessment (LTRA). The FRWG coordinates its work with the NERC.

The quickly evolving resource mix for the EI continues to place importance on ensuring the EI frequency response to a loss of generation events will not lead to the activation of UFLS. The scope of work outlined in this report included the 2020 study[2] recommendations of modeling of gross PMax values in the cases, accurate governor modeling in the cases, and update of frequency responsive dynamics files to library as noted in the 2020 study. The EIPC FRWG used an outside contractor, Powertech Labs, for this study, to perform benchmarking analysis, build future minimum load/low inertia case, and perform simulations used to calculate frequency response measures 1, 2, and 4.

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

[2] https://static1.squarespace.com/static/5b1032e545776e01e7058845/t/5fa9a84f3c84443d2d807e16/1604954194466/EIPC+FRWG+2020+Public+Report+-+FINAL+-+Approved+by+Ex+Com+on+10-21-20.pdf

2. Background and Purpose

The FRWG 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. The scope of this work will benchmark existing models and simulate conditions on the interconnection when generation inertia is low based on a credible generation dispatch and assumed resource mix for the timeframe being modeled. The FRWG will then use the low inertia case to test that frequency response of the system, calculate Measures 1, 2, and 4, and develop a report on its findings and recommendations.

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, which are leading to a much larger mix of inverter based resources (IBRs) associated with the retirement of synchronous resources have a potential to lower the inertia even further and 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 Under-Frequency Load Shed (UFLS) events, which would be detrimental to reliability of the system and is therefore a concern to Planning Coordinators in the EI.

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 Multiregional Model 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. Following presentation and ongoing discussions of the 2020 FRWG study recommendations, the MMWG began developing a minimum load future year case during the 2021 model library build. This additional library model has leveraged existing model building processes to better enable engineers to simulate EI frequency response to loss of generation events. As demonstrated by the benchmarking analysis from the 2018, 2020 and 2022 studies, the recommendations from the 2018 and 2020 studies to improve accuracy of governor modeling continues to be a key area for improving the models to predict EI frequency response to loss of generation events.

One focus of the FRWG effort is to establish a baseline confidence in the solutions provided by currently available frequency response models and to provide suggestions to improve those models. The FRWG's biannual studies continue to develop models that adequately represent the behavior of the system to contingencies during time periods when the impact on frequency will be the largest. The objective is 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 NERC for inclusion in the NERC LTRA report.

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.

The FRWG will continue to work with the MMWG to implement the set of recommendations from the 2020 report[Error! Bookmark not defined.] and this report to augment the current model building process to create 'study-ready' cases to calculate frequency measures and develop a procedure manual to conduct these measures on a future ongoing basis. The results of Measures 1, 2, and 4 are provided in Section 6.10.

4. Tasks

As part of this effort, the FRWG developed 13 tasks to be performed. Details for each task are shown below. Volunteers were taken and EIPC members completed 10 of the tasks. A contractor was selected to complete the other 3 tasks (Tasks 8, 9 and 10). From late 2021 through 2023, members of the FRWG, working with the contractor, completed each of these tasks.

4.1 Task 1 – Develop Procedure Manual

Develop a detailed Procedure Manual to document the process to build the low inertia case and calculate the Frequency Measures 1, 2, and 4. The Procedure Manual was also used for developing the Request for Proposal (RFP) to hire consultants to build the low inertia case with EIPC member supplied data, and perform the contingency analysis.

4.2 Task 2 – EI Inertia/Load Calculator

Work with Eastern Interconnection Data Sharing Network (EIDSN) to provide technical input regarding the dynamics data that is linked to generator status for calculation of EI inertia. Establish process with EIDSN to review updates to the dynamics data to keep the information up-to-date and accurate.

4.3 Task 3 – Formalize EI Inertia Calculation Script

Using python, create a script from the 2022 study to calculate the equivalent system inertia using the MMWG spring light load (SLL) power flow cases. The code was revised and made more user friendly for this year's study. 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)

4.4 Task 4 – Implement 2020 Recommendations with MMWG

Based on the 2020 FRWG report[Error! Bookmark not defined.], work with the MMWG to implement recommendations 1 through 3 from the report. Those recommendations were modeling of gross PMax values in the cases, accurate governor modeling in the cases, update of frequency responsive dynamics files to library.

4.5 Task 5 – Select Historical Low Inertia and Frequency Events

Using the MISO Parallel Flow Visualizations data (the pre-cursor to the upcoming EIDSN calculator described in Task 2), select the minimum inertia time from the last 3 years (2020-2022).

Using historical FNET[3] data, select 2 historical events which had recorded frequency excursions that coincide with the MMWG 2021 Spring Light Load (SLL) model. The frequency events will be used to benchmark the frequency response of the latest MMWG 2020 library case.

4.6 Task 6 – Collect Historical Dispatch Data Associated with the Low Inertia and Frequency Events

Based on the dates selected for the historical low inertia and frequency events, each Planning Coordinator will collect the unit dispatch for those dates. This historical dispatch will be used to identify the overall resource mix and type of generation (including pumped storage as negative generation) participating in the primary frequency response for the Eastern Interconnection and sub-regions during the times selected.

4.7 Task 7 – Select the Most Severe Single Contingency (MSSC) and the Largest 10-year Historical Event for the EI

To capture the trend of frequency response in the EI, the Planning Coordinators will test three (3) different contingencies. The first is the largest historical event within the past 10 years (2013-2022). The second event will be the most severe single contingency (MSSC) for the EI. The FRWG will use the documented criteria to establish the MSSC and each Planning Coordinator will submit their region's MSSC. The final event will be a 10,000 MW benchmark test to test the EI margin until the under-frequency load shedding threshold of 59.6 Hz[4]. Following more detailed review of the 2018 study which used 59.5 Hz as the threshold for UFLS within the EI, the 2022 study used a UFLS threshold of 59.6 Hz for the EI after changes related to the merging of FRCC into SERC.

4.8 Task 8 – Benchmark Historical Frequency Event

Conduct a benchmark comparison of the historical frequency event and the 2021 spring light load MMWG case from the 2020 library with a focus on identifying the resource mix and amount of generation participating in the frequency response. Specific unit to unit mapping between the historical and MMWG cases is not necessary to achieve similar inertial response between the recorded frequency event and the simulated event.

4.9 Task 9 – Create Low Inertia 5-Years-Out Case

Using the data submitted in Task 5 and any changes to the dynamics model from the benchmarking in Task 7, modify the future 5-years-out MMWG 2025 spring light load case so that it represents an expected future minimum load, low inertia case. Verify that the dynamics case will initialize and solve for the timeframe of primary frequency response for resource contingencies identified in Task 6.

---

[3] 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 FDRs 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] FRCC has historically used a UFLS threshold of 59.7 Hz for local system conditions. Since joining SERC in 2019, FRCC proposed modifying the PRC-006-SERC-02 to align the historical UFLS schemes used in FRCC with the thresholds specified in the standard. The SERC UFLS standard currently in the draft phase, proposes a change in the highest set point for UFLS to be set to 59.6 Hz.

4.10 Task 10 – Calculate Frequency Measures 1, 2, and 4

Simulate the frequency response of the EI to postulated resource contingencies and plot frequency versus time for each contingency selected in Task 6. Collect other pertinent information from the dynamics simulations needed to develop a detailed report on the results of the frequency response tests.

4.11 Task 11 – Write a Comprehensive Report

Write a report to document the findings of the effort. The report includes detailed information on the efforts performed by members of the FRWG and references the detail of the results of the Frequency Measures 1, 2, and 4.

4.12 Task 12 – Outreach to Other Interconnections

Communicate with other interconnections and NERC. The purpose of this task is to understand how the other interconnections are developing the same information. Results from the FRWG work will be shared with other interconnections.

4.13 Task 13 – Create a Sensitivity for Fast Frequency Response Capability of Inverter Baser Resources and Loads

Through discussions at the FRWG meetings, it was decided that an incremental look at increased IBR presence in the planning cases could have a beneficial effect in restoring frequency following a disturbance on the grid. It was decided that increasing IBR penetration by 20% and 40% would provide a good starting point for this sensitivity.

5. Schedule

The FRWG met as a whole monthly at virtual meetings on WebEx format. The timeline for each task and specific milestones are shown in Table 5-1.

Table 5-1: Milestone Timeline

	2021 Q1	2021 Q2	2021 Q3	2021 Q4	2022 Q1	2022 Q2	2022 Q3	2022 Q4	2023 Q1	2023 Q2	2023 Q3	2023 Q4
Task 1												
Task 2												
Task 3												
Task 4												
Task 5												
Task 6												
Task 7												
Task 8												
Task 9												
Task 10												
Task 11												
Task 12												
Task 13												

6. Results of Each Task

EIPC members completed tasks 1-7. Due to the amount of time required for tasks 8-10, it was decided to solicit bids for the work to be done by contractors. Several bids were received and, following evaluation by the FRWG, Powertech Labs (PLI) was chosen to complete these tasks. The results of the work performed by PLI on tasks 8-10 is briefly described in this section.

The EIPC FRWG 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.

6.1 Task 1 – Develop Procedure Manual

A detailed Procedure Manual was developed to document the process to build low inertia case and calculate the Frequency Measures 1, 2, and 4. The Procedure Manual was also used for developing the Request for Proposal (RFP) to hire consultants to build the low inertia case with EIPC member supplied data.

6.2 Task 2 – EI Inertia/Load Calculator

EIPC FRWG met with Eastern Interconnection Data Sharing Network (EIDSN) to discuss providing technical input regarding the dynamics data that is linked to generator status for calculation of EI inertia. The EIDSN board has approved the FRWG to have access to real time EI Inertia data and are developing the process for accessing the real time EI Inertia calculations in 2024.

6.3 Task 3 – Formalize EI Inertia Calculation Script

The FRWG updated the inertia calculation python script to calculate the equivalent system inertia of the two MMWG cases. Updates include adding wind provided inertia to the calculation. The following are changes for each revision. Rev 5 is final and was provided to the consultant for use in building the models for this study:

Rev 1 : 2019/10/10 - turned each model into a separate function to speed up script

Rev 2 : 2019/10/16 - added offline and gnet inertia values, removed R from spreadsheets

Rev 3 : 2019/10/16 - added additional gen and gov models, added check for PLL for Type 3 WTG, added area to errors

Rev 4 : 2019/11/01 - added load totals to summary tab of results

Rev 5 : 2019/11/25 - excluded Type 3 WTGs from system total inertia calculation and flagged in the "Error" sheet as "Skipped (Type 3 or Type 4 WTG)", fixed fetching the user model GEWTG2 inertia that is given by its turbine module GEWTT1, updated the T_{rate} based on the information in the generator model added several user models (HYGOV4, CIMTSS and GWPM27) for system total inertia calculation

Rev 6: 2021/10/13 – Added option to select PSSE Version 33 or 34 - This is to make sure the script works with 2025 MMWG case which is in version 34. Added SITGTU1 governor model. Added GENTPJ1 model (was GENTPJU1 in PSSE V33)

6.4 Task 4 – Implement 2020 Recommendations with MMWG

The following reflect the EIPC FRWG recommendations for improving the simulation study results of the MMWG base cases. More detail on each recommendation is provided in section 7.

The 3 recommendations from the 2020 report are:
Recommendation #1: Gross PMax Values
Recommendation #2: Governor Modeling
Recommendation #3: Frequency Responsive Dynamics Files

6.5 Task 5 – Select Historical Low Inertia and Frequency Events

A minimum inertia time from 2018-2020 was selected. The FRWG agreed to select 4/21/2019 3:28:00. This event was based on NERC Resources Subcommittee (RS) data that records the EI inertia and system load throughout time. The inertia from 4/21/2019 is in Table 6-2 below.

Table 6-2: EI Inertia

	Time	EI Inertia (MVA-s)	Delta from Prev
Min Inertia	4/21/2019 3:28 AM	1,096,360	7.61%

Two historical frequency response events were also selected. The event times are shown in Table 6-3. The FNET plots for each event are shown in Figures 6-2 and 6-3.

Table 6-3: Historical Frequency Events

Event ID	Local Time
EI_2018-03-14_123810	03-14-2018 08:38:10
EI_2019-02-23_205652	02-23-2019 15:56:52

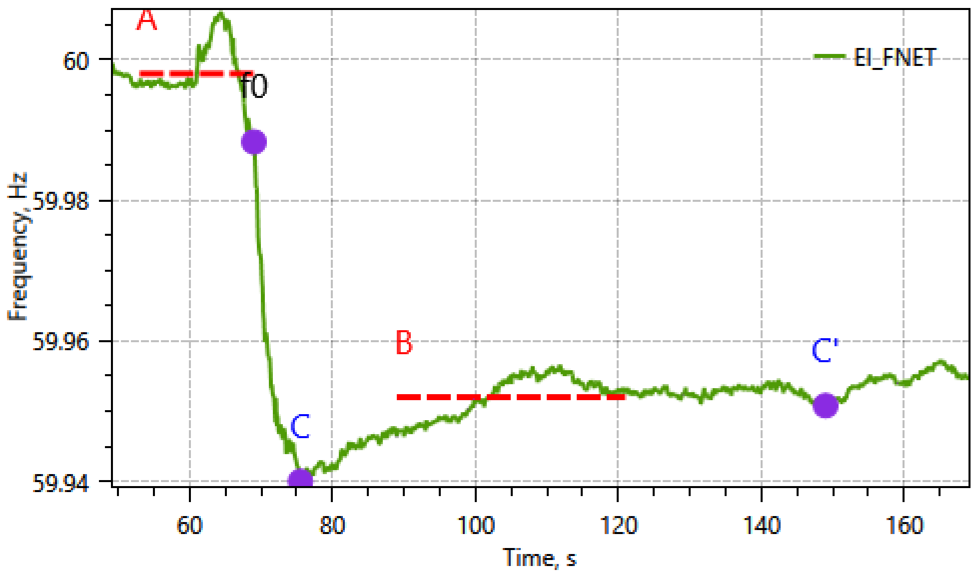


Figure 6-2: EI FNET March 14, 2018 Frequency Event Raw Data Plot (Event 1)

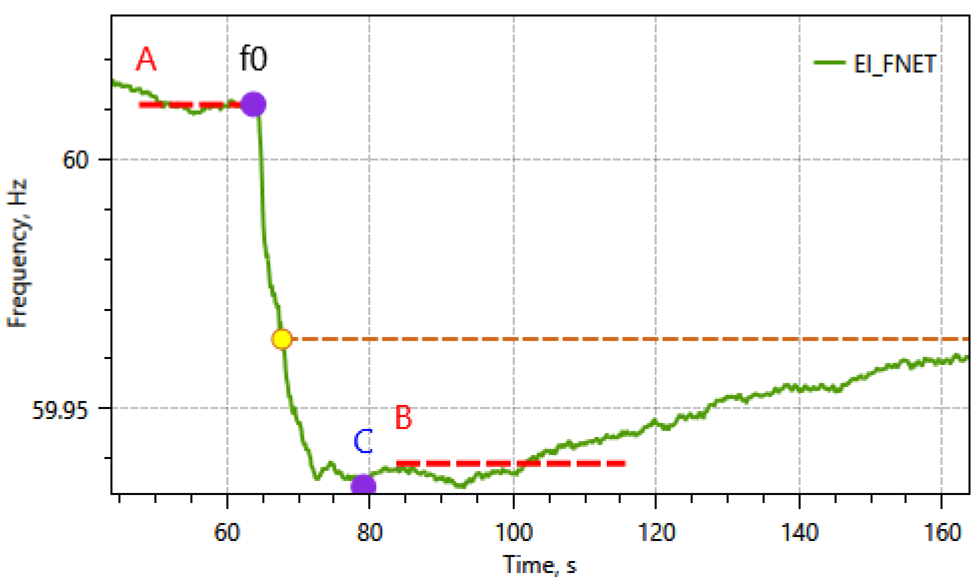


Figure 6-3: EI FNET February 23, 2019 Frequency Event Raw Data Plot (Event 2)

6.6 Task 6 – Collect Historical Dispatch Data Associated with the Low Inertia and Frequency Events

Based on the dates selected in Task 5, each PC collected and submitted the unit dispatch for their area. Digital Fault Recorder (DFR) or Phasor Measurement Unit (PMU) data was used and the equivalent system inertia was calculated. FRWG 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 separated into 9 categories (nuclear, coal, natural gas CC, natural gas simple cycle, hydro, wind, solar, pumped storage, and other. 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 minimum inertia event on 4/21/2019 are shown in Table 6-4 below.

Table 6-4: Historical Resource Mix by Type Min Inertia 04/21/2019 03:28:00 AM

Nuclear	Coal	NG CC	NG SC	Hydro	Wind	Solar	Other	Pump
33%	19%	23%	5%	5%	13%	0%	3%	-1%

6.7 Task 7 – Select the Most Severe Single Contingency (MSSC) and the Largest 10-year Historical Event for the EI

The largest event in 10 year history was selected. It is the event where 2,398 MW of generation was lost. This event was on 4/17/2013.

The MSSC was selected from the submitted events by EIPC member regions. This event is where 2,314 MW is lost.

The final benchmark is a 10,000 MW benchmark test to determine the EI margin until the under-frequency load shedding threshold of 59.6 Hz[4].

6.8 Task 8 – Benchmark Historical Frequency Event

PLI performed Tasks 8, 9 and 10. For Task 8, the FRWG provided PLI with MMWG 2020 Series dynamic base cases, Python script, and stability model files. PLI used these files to create the cases. PLI conducted a benchmark comparison of two of the frequency events chosen in Task 5. The two events had similar load levels to the 2021SLL library case. PLI used PSS/E version 34.6 to simulate the events. Generation adjustments were made to the cases to simulate the actual dispatch for the two events. For each simulation, PLI provided parameters and frequency response plots to compare the actual events to the simulations. The MMWG cases were provided as the base case. The main objective with the benchmark cases is to identify the correct deadband value to be used for the rest of the analysis conducted during this study.
For event #1, 60-second simulations are conducted with different deadbands as well as MMWG case. The simulation results are presented in Figure 6-4.

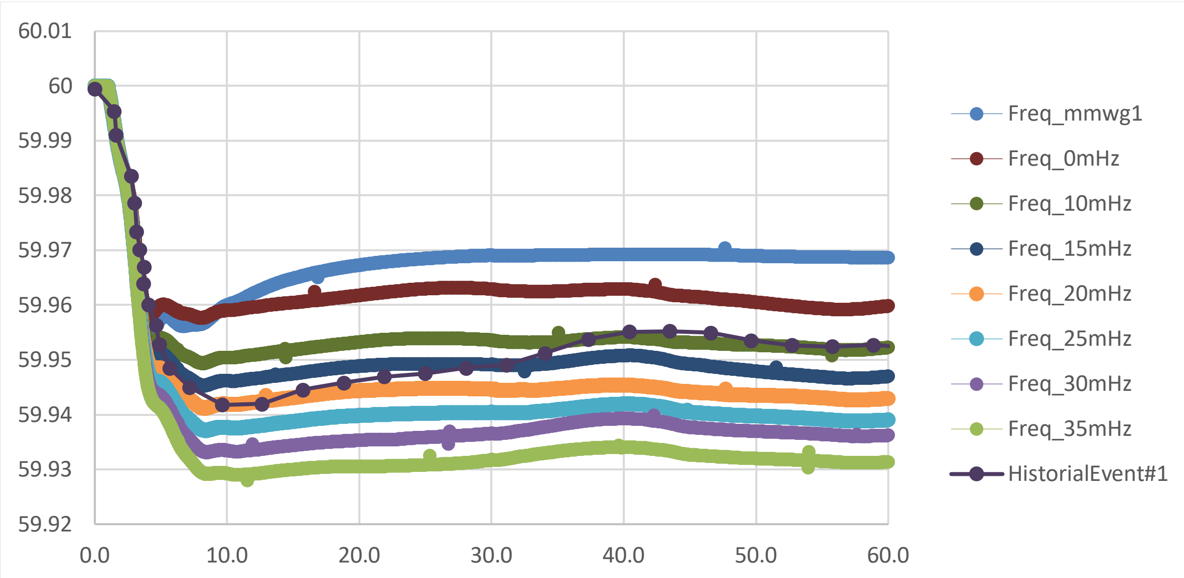


Figure 6-4: Dynamic Simulation for Event #1 with Different Deadband

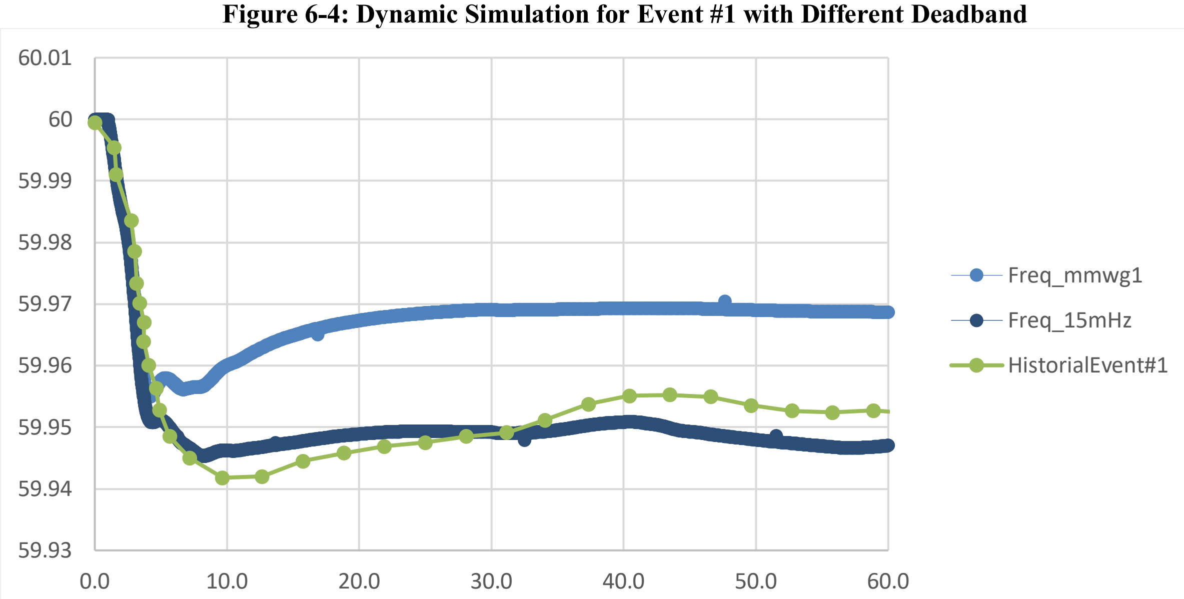


Figure 6-5: Dynamic Simulation for Event #1 with 15 mHz Deadband

The total inertia of event #1 base case is close to the inertia in historical event #1. From the simulation, it is shown that the frequency response with 15 mHz deadband shows the closest performance compared to the historical event #1, therefore 15 mHz deadband is selected for the rest of frequency response study events.

The total inertia of historical event #2 is not available, but it is less than the historical event #1 according to the recorded frequency response. Event#2 base case, which is developed from event#1 base case, has similar inertia to event #1 base case. It might not match the historical event #2, therefore only 15 mHz, which is selected from event#1, has been tested for event #2 simulation, and the simulation results are presented in the Figure 6-6.

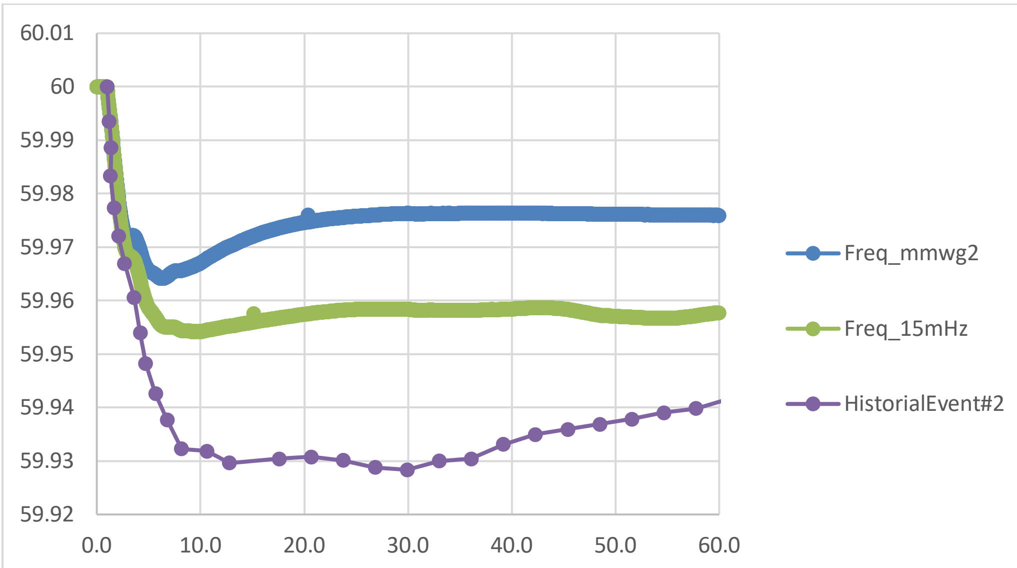


Figure 6-6: Dynamic Simulation for Event #2 with 15 mHz Deadband

6.9 Task 9 - Low Inertia 5-Year-Out Case

PLI developed the low inertia 5-year out case using the MMWG 2020 Series 2025 SLL case. During the model build process, it was discovered that a number of units had been reduced to negative load equivalents. Subsequent to discussions with the MMWG model builder, a revised case was produced in December 2019 which included the full dynamic models for these units. The MMWG Base Case 2 was used again to develop this case. The FRWG members provided the generation mix, load, and interchange levels to PLI projected to occur in 2025 in IDV or Python script. Some of the member areas had a large discrepancy in generation and load between the 2025 Spring Light Load Case and the Low Inertia 5-year study case. This is due to transitioning from “light load” model assumptions to “minimum load” model assumptions consistent with a low inertia case. The information provided included power flow and dynamic modeling changes. Once provided, PLI merged all the files and applied the changes to the 2025 SLL Base Case and tested it. The case was initialized and tested. The historic events (03/10/2019 01:01:45 and 03/15/2019 20:39:02) were simulated. Calculated parameters are shown in Tables 6-5.

Table 6-5: Comparison Results of the 5-Year Out Cases: 2023 vs 2025

Case Year	Case 2023	Case 2025	% Change from case 2023 to 2025
Total System's Synchronous Inertia (MVA-s)	1,476,166	1,371,179	-7%
Total Non-synchronous Generation Dispatched (Pgen [%])	9.4%	17.9%	90%
Total Synchronous Generation Dispatched (Pgen [%])	90.6%	82.1%	-9%
Total DC Tie-Line Imports (MW)	3,123	2	-100%
Total System Load (MW)	247,574	274,244	11%

*All quantities are shown for the main island in the case (2025).
** Case 2023 refers to the 2020 FRWG study that used the 2018 MMWG series and Case 2025 refers to this study that used the 2020 MMWG series

Based on the overview in Table 6, the reduction in inertia is reasonable given the increase in non-synchronous generation.

6.10 Task 10 – Calculate Frequency Measures 1, 2, and 4

Figure 6-15 includes a sample frequency response plot from the ERSTF report[1] which shows how frequency response is calculated and frequency deviation due to generation loss. Values A, B, and C are each described in Figure 6-15.

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.

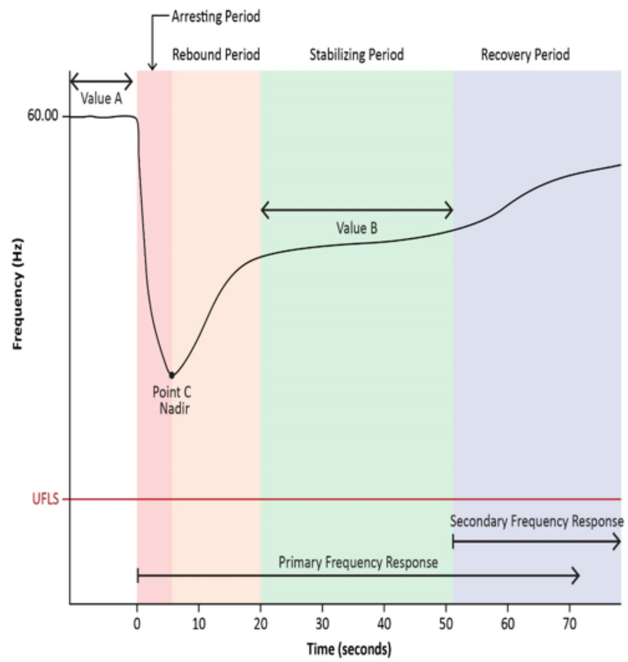


Figure 6-7: Frequency Response Data Point Explanations

PLI simulated the frequency response of the EI to postulated resource contingencies. Other pertinent information from the dynamic simulations needed was also collected. Frequency versus time was plotted for each contingency defined in Task 7.

The frequency values were modeled in a manner consistent with the methodology utilized by FNET. PLI 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.

The following plots are generated through PSSPLT and show Frequency on the y-Axis and Time on the x-axis. The starting point, or '0' value show in the figures is where f = 60Hz. The scale of frequency change is shown on the right side of each plot.

MSSC Trip Event

The simulation results for the MSSC are shown in Figure 6-8. It is noted from the figure that the frequency nadir of the event (Point C) is approximately 59.93 Hz, occurring at about 7.6 sec after the initiation of the event, ROCOF0.5 is 29.0 mHz/s, and Primary Frequency Response (Value B) is about 59.94Hz. The frequency nadir is well above the UFLS triggering threshold which was set to 59.6 Hz for the study.

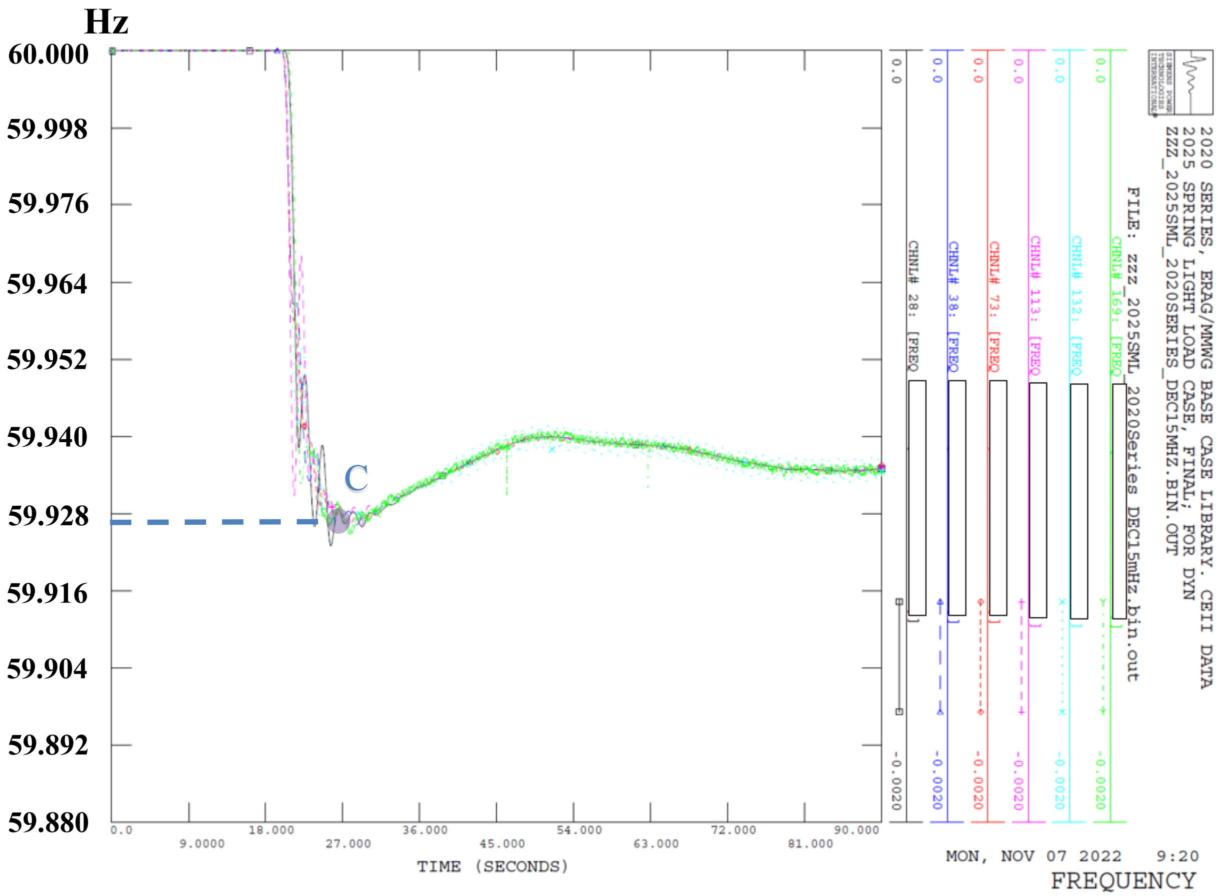


Figure 6-8: Frequency Response Following MSSC

The Largest 10-Year Event

The simulation results for the Largest 10-Year Event is shown in Figure 6-9. It is noted from the figure that the frequency nadir of the event (Point C) is approximately 59.92 Hz occurring at about 8.4 sec after the initiation of the event, ROCOF0.5 is -51.4 mHz/s, and Primary Frequency Response (Value B) is about 59.94 Hz. The frequency nadir is well above the UFLS triggering threshold which, per discussion with FRWG, was set to 59.6 Hz in the Study.

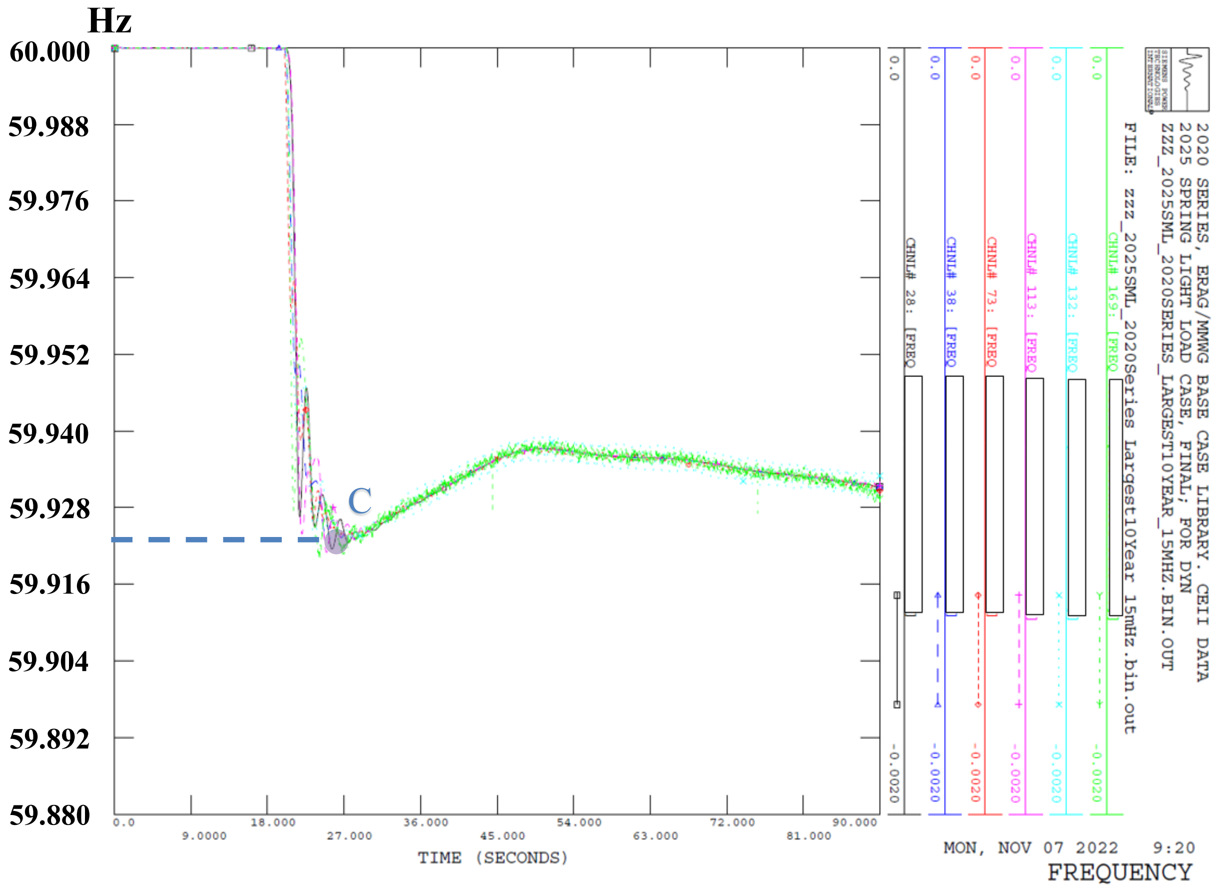


Figure 6-9: Frequency Response Following the Largest 10-Year Generation Trip Event

10,000 MW Benchmark Test

The frequency response following the 10,000 MW Benchmark test is shown in Figure 10. It is noted from the figure that the frequency nadir of the event (Point C) is approximately 59.70 Hz occurring at about 8.6 sec after the initiation of the event, ROCOF0.5 is -168.3 mHz/s, and Primary Frequency Response (Value B) is about 59.76 Hz. The frequency nadir is above the UFLS triggering threshold 59.6 Hz.

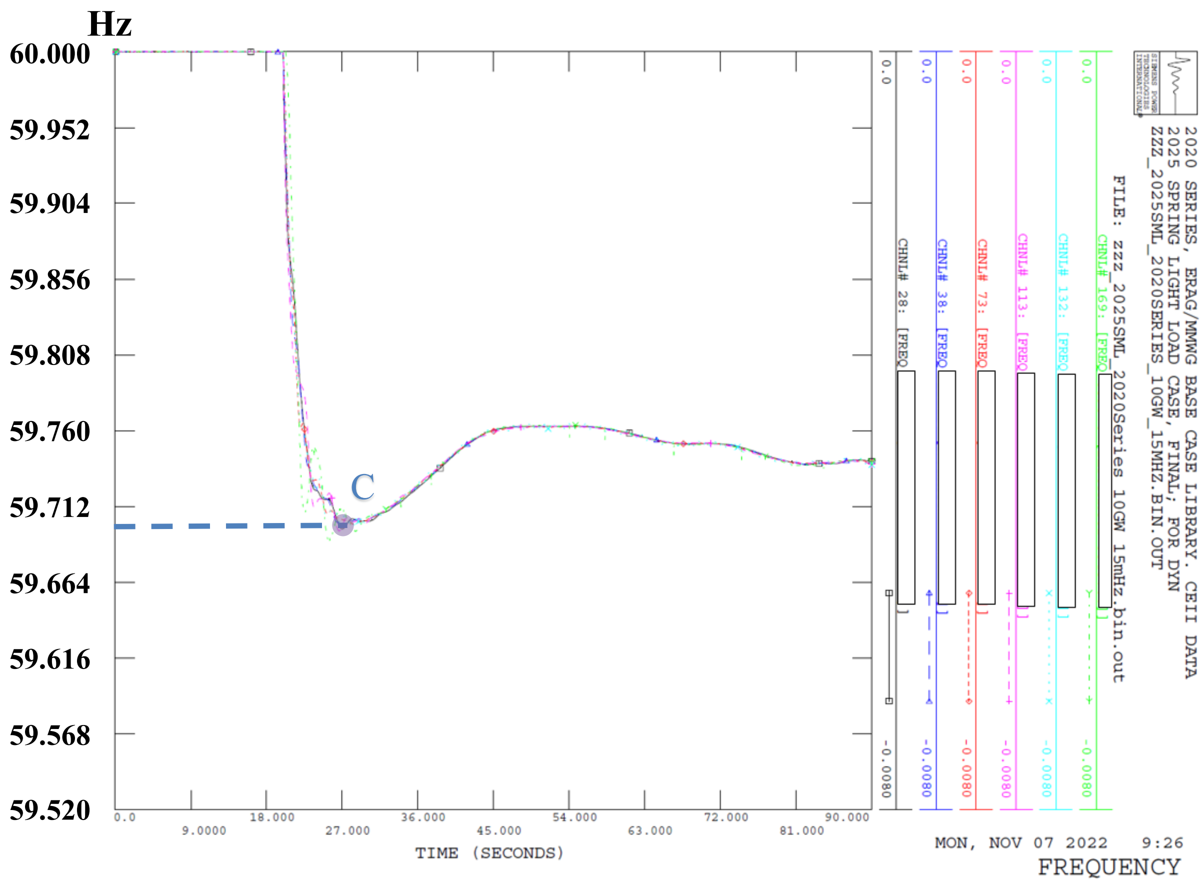


Figure 6-10: Frequency Response for the 10,000 MW Benchmark Test

Calculation of Measures and Sensitivity Analysis

Table 6-6 shows the calculated Frequency Measure 1, i.e., Synchronous Inertial Response (SIR), as well as other system parameters for both the benchmarking case and the 5-year out case. Table 6-7 shows the calculated Frequency Measure 2 for each resource contingency event simulated in the 5-year out case, including initial frequency deviation and the ROCOF during the first 0.5 second following the initiation of the event. The average frequency values from multiple frequency channels spread across the EI were used to calculate Measure 4 for each generation loss event simulation. Table 6-8 shows the calculated Frequency Measure 4 including frequency performance ratios and time measures.

Table 6-6: Frequency Measure 1: Synchronous Inertial Response (SIR)

Case #	Case Name	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	Benchmarking Case (2021 Spring Light Load)	1,719,381	13.27%	86.73%	193	301537.5
2	Low Inertia 5-Year Out	1,376,393	17.90%	82.10%	2	274,244

Table 6-7: Frequency Measure 2 for Resource Contingency Events Tested

Event #	Event Name	Initial Frequency Deviation (Hz) within First 0.5 Second)	Rate of Change of Frequency ($ROCOF_{0.5}$) (mHz/s)
1	Most Severe Single Contingency Event	-0.0145	-29.0
2	Largest 10-Year Generation Trip Event	-0.0257	-51.4
3	Benchmark 10,000 MW Event	-0.0842	-168.3

Table 6-8: Frequency Measure 4 for Resource Contingency Events Tested

Event #	Event Name	Frequency Performance Ratios				Time Measures			
		A:B (MW/0.1Hz)	A:C (MW/0.1Hz)	C:B	C':C	t_C-t_0 (s)	$t_{C'}$-t_C (s)	$t_{C'}$-t_0 (s)	Time to UFLS (s)
1	Most Severe Single Contingency Event	3754.4	3153.1	1.19	NaN*	7.65	NaN*	NaN*	13.80
2	Largest 10-Year Generation Trip Event	3732.9	3113.4	1.20	NaN	8.40	NaN	NaN	7.78
3	10,000 MW Benchmark Test	4191.7	3400.1	1.23	NaN	8.61	NaN	NaN	2.38

* The frequency simulation event did not exhibit absolute minimum frequency value (C'); i.e. the frequency after 52 seconds did not fall below either Point C or average Value B. Hence, there are no Point C' and its associated frequency and time measures in the frequency simulation.

Results of this study are found in Table 6-9. Comparisons to the 2020 study is in Table 6-10 and 6-11 below.

Table 6-9: Summary of Resource Contingency Events Simulations

Event/Mitigation	Gen Loss (MW)	Inertia Dropped *	Point C - Nadir (Hz)	Time C (sec)	Point B (Hz)	$ROCOF_{0.5}$ (mHz/sec)
MSSC	2,314	0.84%	59.93	7.6	59.94	-29.0
Largest 10-Year Gen Trip Event	2,398	0.70%	59.92	8.4	59.94	-51.4
10,000 MW Benchmark Test	10,160	3.40%	59.7	8.6	59.76	-168.3

* System Inertia of the 5-Year Out Case before the Event: 1,376,393 MVA-s (Frequency Measure 1)

Table 6-10: Comparison of the 5-Year Out Cases: 2023 vs 2025

Study Case	5-Year Out Case (2023 Spring Light Load) for 2020 Study	5-Year Out Case (2025 Spring Light Load) for this (2022) Study	% Change from 2023 to 2025
Case Year	2023	2025	
Total System's Synchronous Inertia (MVA-s)	1,476,166	1,376,393	-7%
Total Non-synchronous Generation Dispatched (Pgen [%])	9.4%	17.9%	90%
Total Synchronous Generation Dispatched (Pgen [%])	90.6%	82.1%	-9%
Total DC Tie-Line Imports (MW)	3,123	2	-100%
Total System Load (MW)	247,574	274,244	11%

* The 2023 case used the 2018 MMWG series and 2025 Case used the 2020 MMWG series

Table 6-11: Comparison with 2020 Frequency Response Study Findings

Event/Mitigation	Study Year	Gen Loss (MW)	Point C - Nadir (Hz)	Point B (Hz)	$ROCOF_{0.5}$ (mHz/sec)
MSSC	2020	2,299	59.89	59.91	-42.59
	2022	2,314	59.93	59.94	-29.0
	Change (%)	0.648%	0.067%	0.05%	-46.862%
Largest 10-Year Gen Trip Event	2020	3,853	59.82	59.86	-52.91
	2022	2,398	59.92	59.94	-51.4
	Change (%)	-60.676%	0.167%	0.133%	-2.937%

6.11 Task 11 – Write a Comprehensive Report

This internal report has been written to document the process and findings of the FRWG's efforts.

6.12 Task 12 – Outreach to Other Interconnections

The chair of the FRWG has been on regular conference calls with NERC to discuss submission of results for the ERSTF Measures 1, 2, and 4 for the 2024 LTRA.

6.13 Task 13 – Create a Sensitivity for Fast Frequency Response Capability of Inverter Baser Resources and Loads

Based on Task #3, two new sensitivity cases were created with an incremental penetration of 20% and 40% grid following inverter-based generation. The total system MW and other parameters of the system are listed in the table 6-12. Table 6-13 shows the change in conventional/renewable dispatch for the 20% and 40% sensitivity cases, as well as the reduction in inertia.

Table 6-12: Power flow parameters of the case 2025SML

Total On-line Gen in Main Island	262,488 MW

Total Inc Room of Renewable Gen	69,734 MW
20% Increase (MW)	52,498 MW
40% Increase (MW)	104,995 MW
Total Number of Renewable Gen	1,699
Number of Renewable Gen Having Inc Room	1,619

Table 6-13: Inertia Comparison for Base Case, 20% and 40% IBR Penetration

	Base Case	20% IBR Penetration	40% IBR Penetration
Total Generation (MW)	287,473	287,473	287,473
Total Generation (MW) (Main Island)**	262,488	262,488	262,488
IBR Penetration increase (MW)	0	52,498	104,995
Conventional (MW)	239,520	187,022	134,525
Renewable (MW)	47,953	100,451	152,948
% Renewable	16.68%	34.94%	53.20%
Online Inertia (MVA/S)	1,713,937.7	1,068,654	689,005.7
Reduction in Inertia (%)	0.00%	36.03%	59.20%

** This is the MW value from the Main Island in EI. Does not include WECC/ERCOT/Islanded generators/some of MH behind the DC tie.

When creating the sensitivity cases, the area interchanges of the base case are retained. The power flow solution parameters are the same as solving MMWG power flows.

For the renewable generators added, the dynamics models (REECA1 / REGCA1 / REPCA1) are added to the dynamics data with the typical parameters.

6.13.1 20% Renewable Scenario

The largest generation trip event of the benchmark 10,000 MW tested in Task #3 was used to simulate the frequency response in 20% Renewable scenario.

The frequency response following this event is shown in Figure 6-11. It is noted from the figure that the frequency nadir of the event (Point C) is approximately 59.65 Hz occurring at about 6.5 sec after the initiation of the event, ROCOF0.5 is -196.0 mHz/s, and Primary Frequency Response (Value B) is about 59.74 Hz. The frequency nadir is above the UFLS triggering threshold 59.6 Hz. The frequency measurement index are listed in Table 6-14.

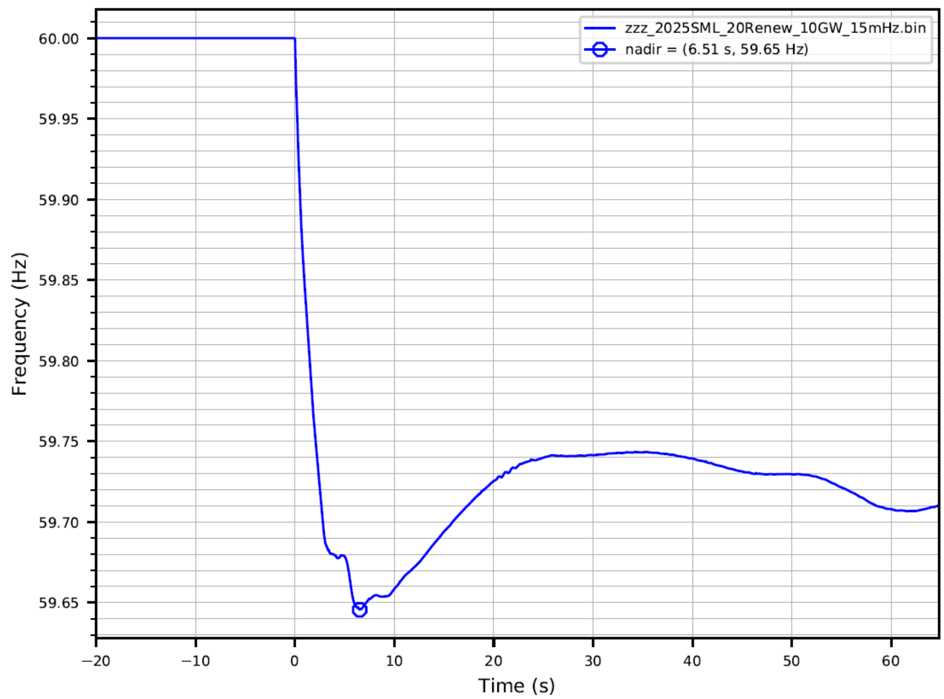


Figure 6-11: Dynamic Simulation for 10,000 MW Event in 20% Renewable

Table 6-14: 20% Renewable Frequency Measurement Index _10GW

Machine Trip (MW)	Starting Freq. (Hz)	Value A (Hz)	Value B (Hz)	Point C (Hz)	Point C' (Hz)	FA-FB (Hz)	FA-FC (Hz)	Freq. Resp. (Current) (MW/0.1Hz)	Freq. Resp. (nadir) (MW/0.1Hz)
10160.13	60	60	59.74	59.65	59.71	0.26	0.35	3862.41	2866.64

Time C (sec)	Time C' (Sec)	Time C'-C (Sec)	ROCOF_05 (mHz/Sec)	Time to UFLS (Sec)	C/B	C'/C	FC'-FA (Hz)
6.51	61.6	55.09	-196.04	2.04	1.35	0.83	-0.29

6.13.2 40% Renewable Scenario

The largest generation trip event of the benchmark 10,000 MW was used to simulate the frequency response in 40% Renewable scenario; however the network doesn't converge when tripping the units. Therefore, the generation trip event is changed from 10,000 MW to 5000 MW.

Although TYSL converges, PSS/E crashed at the time about 6 second. According to the final report on MMWG dynamic model build, the model 'WTDTA1" is removed from the simulation.

With these changes mentioned above, 10,000MW generation trip event still crashed at approximately 20.5s. It is suspected that the issues might be caused by some user-defined model. 5,000 MW generation trip event was successfully simulated, and the simulation result is shown in Figure 6-12. It is noted from the figure that the frequency nadir of the event (Point C) is approximately 59.77 Hz occurring at about 6.05 sec after the initiation of the event, ROCOF0.5 is

-125.07 mHz/s, and Primary Frequency Response (Value B) is about 59.74 Hz. The frequency nadir is above the UFLS triggering threshold 59.6 Hz. The frequency measurement index is listed in Table 6-15.

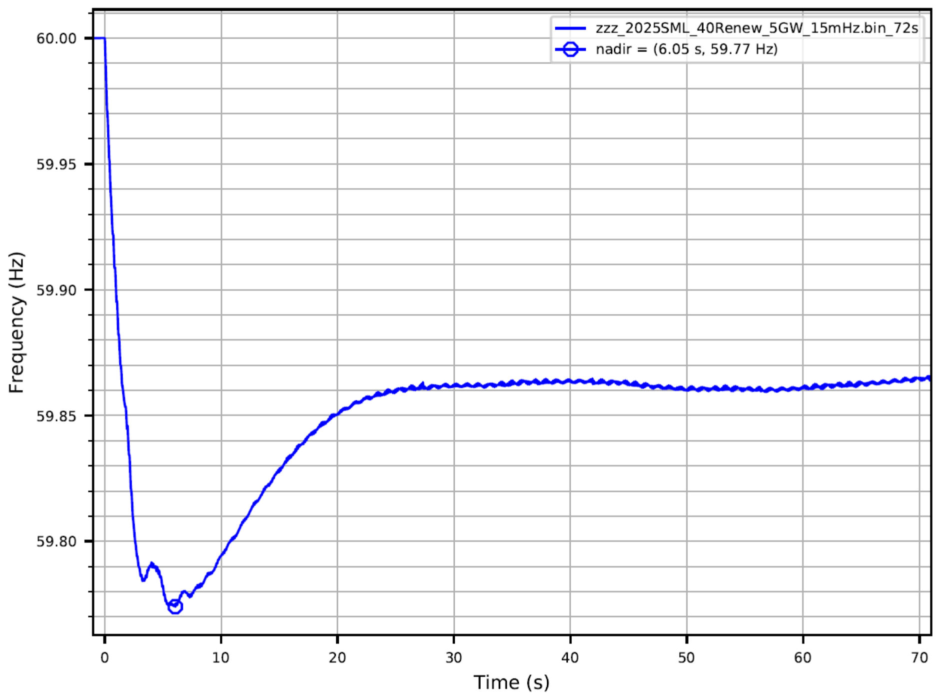


Figure 6-12: Dynamic Simulation for 5,000 MW Event in 40% Renewable

Table 6-15: 40% Renewable Frequency Measurement Index _5000MW

Machine Trip (MW)	Starting Freq. (Hz)	Value A (Hz)	Value B (Hz)	Point C (Hz)	Point C' (Hz)	FA-FB (Hz)	FA-FC (Hz)	Freq. Resp. (Current) (MW/0.1Hz)	Freq. Resp. (nadir) (MW/0.1Hz)
5211.51	60	60	59.86	59.77	59.86	0.14	0.26	3754.26	2306.42

Time C (sec)	Time C' (Sec)	Time C'-C (Sec)	ROCOF_05 (mHz/Sec)	Time to UFLS (Sec)	C/B	C'/C	FC'-FA (Hz)
6.05	56.82	50.77	-125.07	3.2	1.63	0.62	-0.14

6.13.3 Renewable Penetration Conclusions

According to the simulation results mentioned above, the following conclusions are obtained:

1. With an incremental penetration of 20% grid following inverter-based generation and 10,000 MW generation trip, the system lowest frequency (Nadir) is 59.65 Hz which is higher than UFLS triggering threshold 59.6 Hz.

2. With an incremental penetration of 40% grid following inverter-based generation and 5,000 MW generation trip, the system lowest frequency (Nadir) is 59.77 Hz which is higher than UFLS triggering threshold 59.6 Hz.

6.13.4 Suggestions for Future Case Development

When creating the cases with incremental penetration of the inverter-based renewable generation, it should be ensured that there is enough reactive power support in the system. Otherwise, the power flow and simulation TYSL are hard to converge.

For the user-defined models, they should be fully tested with different bus voltage and generation real power and reactive power outputs. When building MMWG models, it was noticed that some user defined models work only when V/P/Q are near the nominal values. Therefore, the bus voltages and MW outputs and MVAr outputs should be tested from lowest values (Vlolimit, Pgmin, Qgmin) to highest values (Vhilimit, Pgmax, Qgmax). It is not enough to test the models just with nominal voltage and nominal power outputs. This extra testing would be most effective if conducted during the interconnection process.

7. Recommendations

The following reflect the EIPC Frequency Response Working Group's (FRWG) recommendations for improving the simulation study results of the MMWG base cases. The EIPC FRWG 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. The base case benchmarking analysis performed for this study included looking at the sensitivity of adjusting governor deadband. The results of this sensitivity analysis shown in figures 6-4, 6-5, and 6-6 points to the deadband of the governor units as having a significant impact to overall frequency response. Given the need to adjust the deadband for the governors in the benchmark event case in order to match the measured frequency response of recorded events, validating governor deadband will need to be addressed by industry as noted in Recommendation #2 from the 2020 Study. Additional outreach to industry groups such as the North American Transmission Forum (NATF) and the North American Generation Forum (NAGF) with a focus on improving governor modeling should continue.

One of the previous action items of the EIPC FRWG was to look into the development of dynamic load models, specifically composite load models, to determine if they would be an appropriate means of modeling the frequency responsiveness of loads. This was not addressed during this study due to insufficient data for analysis, but could be looked at for the next frequency response study.

The first three recommendations remain the same as the 2020 study. The MMWG has taken steps to improve the model quality with these recommendations, but it remains an iterative process and these items should continue to be looked at in future studies.

A new component for this study was to include an incremental IBR penetration case where 20% and 40% increased IBR penetration is studied. There were significant issues getting a 40% increased IBR penetration case to run the same faults that were studied with the benchmark cases. Future studies should look at what value of IBR penetration begins to impact the faults in the benchmark case, as well as look at how grid-forming IBRs could assist with some of the issues seen.

Recommendation #1: Gross PMax Values

The MMWG should emphasize to model 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. PMAX should always be greater than or equal to PMIN. *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

[5] Multiregional Modeling Working Group (MMWG) Procedural Manual, Version 25, dated March 12, 2020.

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 EI 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.

Recommendation #2: Governor Modeling

The MMWG should emphasize 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 for generator model data submissions. 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[6] 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.[7] In general, the validated models resulting from the MOD-027 effort would be expected to include dead band.

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 T_{rate} (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] NERC Reliability Standard MOD-027-1, Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions.

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 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[8] (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 separate dyr file concept is already being used for the complex load models provided for the MMWG annual updates.

Recommendation #4: Evaluate Frequency Response for a low inertia 10 year out case

The FRWG should consider evaluating the frequency response of Eastern Interconnection for a 10-year out case.

The penetration of inverter-based DERs as well as the penetration of utility-scale IBRs like offshore wind are significantly increasing in the next 10 years. The 5 year out scenario that the FRWG considered in this study did not show any significant degradation in frequency response. Based on the results of this study, studying a 10 year out case going forward can give us more valuable information and make sure the EI has sufficient inertia with the expected DERs and IBRs modeled in our system. Identifying any concerns ten years in advance will also allow for more time to implement operational or system design changes to address frequency response issues.

Recommendation #5: Mid-day minimum inertia

The FRWG should collect the projected resource mix and load for a mid-day low inertia condition along with the night time low inertia condition for a future case

Many FRWG member areas in the Eastern Interconnection are starting to see a daytime minimum condition that has significantly lower inertia than a nighttime minimum condition. FRWG has been studying a nighttime minimum condition for the low inertia 5 year out case so far, since the historical minimum inertia for EI has occurred at night time. However, with the penetration of DERs and IBRs we expect to see a shift in the minimum inertia conditions at both night time and mid-day conditions. The

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

mid-day conditions could be worse for frequency response due to less synchronous generators in the resource mix. It is prudent to collect data (resource mix/system load) at both mid-day and nighttime conditions to be aware of the trend in the minimum inertia. Further, this will help FRWG make a decision on whether to transition to studying a mid-day low inertia condition instead of a nighttime low inertia condition in the future.

8. Conclusion

The analysis and simulation of this study demonstrated that the EI would have sufficient system inertia over the next 5 years with the generation resource mix, load, and interchange levels and governor participation modeled. However, with the addition of non-synchronous generation and planned resource retirements, maintaining frequency in the EI is a concern which warrants continued study. The EIPC 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 simulation power flow models. The newly added incremental IBR penetration component of this study showed that the MW value dropped during fault testing had to be reduced in the 40% increased IBR penetration case, leading to a need to study where the increased IBR penetration begins to impact system frequency. Similar to previous studies, this report details information on the updated technical analysis, model modifications, and simulations performed by members of the EIPC FRWG, with the assistance of PLI , to assess the NERC ERSWG forward looking frequency Measures 1, 2, and 4 for the EI for inclusion in the 2024 NERC LTRA.

In total, 13 tasks which are described in Sections 4 and 6 were completed. Through completion of the tasks, the EIPC FRWG was able to benchmark historical low inertia and frequency events and visually compare the results to the actual measurements. The three frequency events that were benchmarked include generation losses of 2,314 MW (MSSC), 2,398 MW (Largest Generator 10-Year Trip), and a 10,000 MW benchmark event. Results of the simulations are shown in Figure 6-8; Figure 6-9; and Figure 6-10. The testing of an appropriate deadband value for the governors for each simulation is shown in Figure 6-4. Comparison of the Measure 1, 2, and 4 calculations between the 2020 and 2022 studies in tables 6-6, 6-7 and 6-8 show a decrease in total load and an increase in non-synchronous generation. The change in total load was driven by an increased focus on modeling minimum system load in the 2022 study along with decreasing forecasted minimum load levels. Coupled with an increase in planned non-synchronous generation, this resulted in a decrease in total system inertia for this study. The changes have resulted in a lower frequency nadir for all simulations. Continued focus on this minimum load/low inertia condition will be necessary to forecast the earliest possible onset of UFLS triggered for the future planned system based on historical events.

While improvements to future modeling of governors is expected to supersede the need for limiting generator governor responses, this study has shown that continued improvement is still needed in this area. The benchmarking analysis performed for this study demonstrated the frequency response sensitivity to changes in governor modeling is greater than changes in total system inertia at the current resource mix levels. The FRWG will continue to follow the improvement in accuracy of governor models as described in recommendation 2 and the implementation of the NERC standard MOD-027.

The FRWG tested three different frequency events on a forward looking 2025SLL power flow case from the 2020 MMWG series. The events included the EI's MSSC of 2,314 MW, the largest EI frequency event of the last 10 years of 2,398 MW and a 10,000 MW benchmark event. With governor deadband set to 15 mHz, generation dispatch changes similar to the lowest observed EI inertia, and future changes to synchronous generation expected in the next 5 years, all three frequency events exhibited satisfactory frequency response with a minimum nadir of 59.70 Hz and are still far away from the initial UFLS set point of 59.6 Hz.

For the new 20% IBR penetration sensitivity case, the model exhibited satisfactory frequency response following a 10,000 MW generation trip. The system lowest frequency (Nadir) is 59.65 Hz which is higher than UFLS triggering threshold 59.6 Hz. However, with the 40% IBR penetration sensitivity case, there were issues running a 10,000 MW event. It is believed that a combination of low reactive power support and some of the user-written models could have played a part in this issues with this case. In order to complete the study, the event was reduced to a 5,000 MW generation trip. With this event, the system lowest frequency (Nadir) is 59.77 Hz which is higher than UFLS triggering threshold 59.6 Hz. Further analysis will be required as IBR penetration increases to determine the need for grid-forming IBRs.

The results of the analysis will be submitted for inclusion in the 2024 NERC LTRA. While the MMWG has included a minimum load case for the 2023 model build process, the first three recommendations for improvements to the MMWG case building process have been maintained and the FRWG will work with the MMWG and other industry groups to implement those recommendations. The fourth recommendation would require development of a new 10Y Light load / low inertia case, so continued coordination with MMWG would be required to determine the feasibility of this recommendation.

- Recommendation #1: Gross PMax Values
- Recommendation #2: Governor Modeling
- Recommendation #3: Frequency Responsive Dynamics Files
- Recommendation #4: Evaluate Frequency Response for a Low Inertia 10Y case
- Recommendation #5: Mid-day Minimum Inertia

The FRWG would like to thank all members from the Planning Coordinators for their effort and participation to successfully complete the assigned tasks. The FRWG would also like to thank PLI Company for their exemplary work in compiling necessary data and completing the simulations used in the completion of this study. Following review of the study results with NERC, the next steps for the FRWG will be to work with the TC and determine the next scope of work for the FRWG going forward.

Appendix A: 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.

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

   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.

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

   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.

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

   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).

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

In the EI, 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 EI, 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.

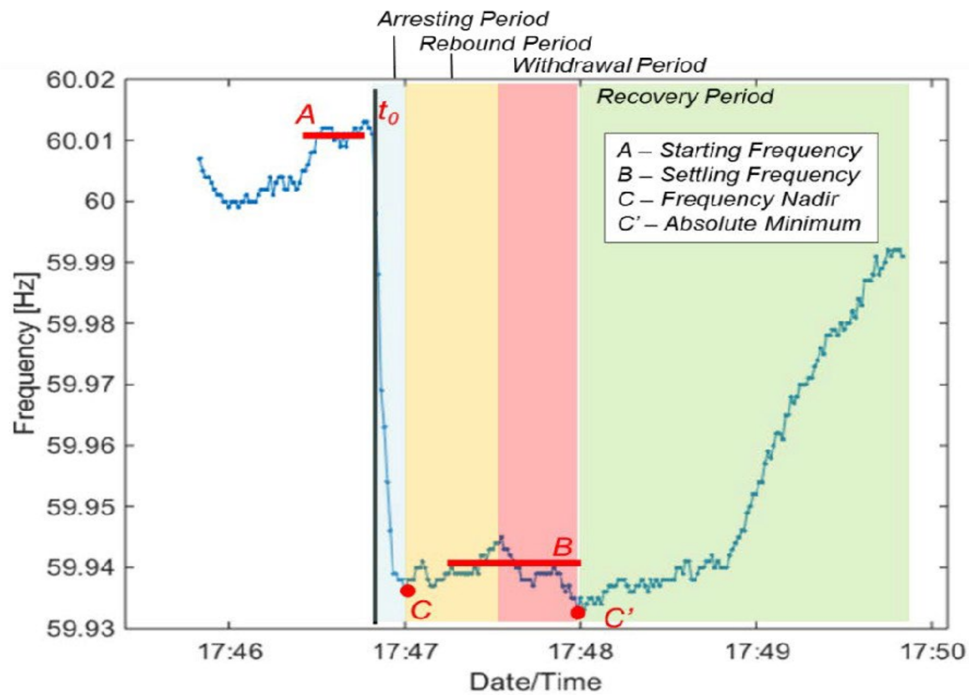
5. <u>Time-based Measures</u> are used to capture the speed in which inertial and primary frequency response as well as governor withdrawal are occurring. These Measures can be trended year to year to identify trends in the rate of change of frequency decline and whether the governor withdrawal phenomena are trending toward improvement or further degradation. These Measures include:

a. **<u>tC-t0 Measure</u>** 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. **<u>tC'-tC Measure</u>** 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. **<u>tC'-t0 Measure</u>** 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 EI, it is observed that the minimum frequency level (C' value) due to governor response withdrawal generally occurs 59–78 seconds after an event.

Examples of the proposed frequency response Measures are provided in Appendix A. 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.


Arresting Period
Rebound Period
Withdrawal Period
Recovery Period
A – Starting Frequency
B – Settling Frequency
C – Frequency Nadir
C' – Absolute Minimum
A
B
C
C'
t_0
Frequency [Hz]
60.02
60.01
60
59.99
59.98
59.97
59.96
59.95
59.94
59.93
17:46
17:47
17:48
17:49
17:50
Date/Time