NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Agenda
Reliability and Security Technical Committee

December 14, 2021 | 11:00 a.m.–4:30 p.m. Eastern
Virtual Meeting Via WebEx

Attendee Webex Link: Join Meeting

Call to Order

NERC Antitrust Compliance Guidelines and Public Announcement*

Introductions and Chair's Remarks

1. **Administrative items**
   a. Arrangements
   b. Announcement of Quorum
   c. Reliability and Security Technical Committee (RSTC) Membership 2020-2023*
      i. RSTC Roster*
      ii. RSTC Organization
      iii. RSTC Charter
      iv. Parliamentary Procedures*
      v. Participant Conduct Policy

Consent Agenda

2. **Minutes – Approve**
   a. September 8-9, 2021 RSTC Meeting*

Regular Agenda

3. **Remarks and Reports**
   a. Remarks – Greg Ford, RSTC Chair
      i. Subcommittee Reports*
      ii. RSTC Work Plan
   b. Report of November 4, 2021 Member Representatives Committee (MRC) Meeting and Board of Trustees Meeting – Chair Ford

4. **Nominating Subcommittee Member Election* – Approve -** Chair Ford

   Due to recently approved RSTC Charter revisions, the Nominating Subcommittee (NS) was expanded to consist of seven (7) members (the RSTC Vice-Chair and six (6) members drawing from different sectors and at-large representatives). Nominations were sought November 5-29, 2021 for the two new seats and recommended candidates were selected by the RSTC Chair in consultation with the RSTC Executive Committee. The recommended candidates are John Stephens, Sector 5

representative and Patrick Doyle, At-large representative. The terms for the two new seats will be a shortened term through February 2022 and the full Nominating Subcommittee annual nomination process will commence in March 2022.

5. **Frequency Response Annual Analysis* – Endorse –** David Till, NERC Staff

   The 2021 Frequency Response Annual Analysis is submitted to FERC on an annual basis. The analysis was developed by NERC Staff and approved by the Resources Subcommittee. This report is the 2021 annual analysis of frequency response performance for the administration and support of NERC Reliability Standard BAL-003-2 – Frequency Response and Frequency Bias Setting, effective December 1, 2020. BAL-003-2 (Phase I) revises the BAL-003-1.1 standard and process documents to include (in part) the addressing of the inconsistencies in calculation of Interconnection frequency response obligations (IFRO) due to interconnection frequency response performance changes of Point C and/or Value B; the Eastern Interconnection (EI) Resource Contingency Protection Criteria; and the frequency of nadir point limitations (prior limited to t0 to t +12).We are seeking RSTC endorsement of the report prior to the annual filing with FERC.

6. **6 GHz Task Force Scope* – Approve –** Jennifer Flandermeyer, CCC Chair

   During the September 2021 RSTC meeting, the RSTC membership was provided an overview of the *Impact of Proposed Wi-Fi Operations on Microwave Links at 6 GHz*. The membership reached a consensus that a task force should be created to investigate the reliability impacts as the 6 GHz band of the radio spectrum is widely used by a broad array of industries responsible for critical infrastructure such as electric, gas and water utilities, railroads, and wireless carriers, as well as by public safety and law enforcement officials. The proposed task force would report to the RSTC in the Mitigating Risks program area. Proposed task force members were nominated by RSTC members and the group developed a draft Scope document as well as a proposed work plan. We are seeking RSTC approval of the Scope document.

7. **RSTC Sunset Review Team Recommendations* – Approve –** Robert Reinmuller

   Per the RSTC Charter, the RSTC "will conduct a "sunset" review of each working group every year" and "review the task force scope at the end of the expected duration and at each subsequent meeting of the RSTC until the task force is retired." The RSTC Executive Committee developed a draft process and template for these reviews to be conducted prior to the December 2021 RSTC meeting.

   The process for this review included the RSTC Sponsors, in coordination with group leadership and NERC Staff Liaisons, reviewing the working group or task force deliverables and work plans to populate the information in the template. The Sunset Review Team is seeking approval of its recommendation for each working group and task force.

8. **Reliability Guidelines and Security Guidelines Triennial Review* – Approve –** Candice Castaneda, John Moura

   On January 19, 2021, the Federal Energy Regulatory Commission ("FERC") accepted the North American Electric Reliability Corporation's ("NERC") proposed approach for evaluating Reliability Guidelines, as proposed in the Five Year Assessment proceeding. Initial triennial review of existing Reliability Guidelines is due June 2023.

   NERC Staff made a preliminary recommendation for each existing Guideline to either remain a Guideline, convert to a Technical Reference Document or become a Hybrid (a Guideline and a

Technical Reference Document). Each RSTC subcommittee, working group or task force that is responsible for triennial review of an existing guideline reviewed the recommendation and determined the final disposition as well as which tranche the document should be revised within. The RSTC Review Team developed its final recommendations and is seeking RSTC approval of the tranches so that work plan items can be developed to meet the regulatory deadlines.

LUNCH BREAK – 20 MINS

9. **White Paper – Oscillation Analysis for Monitoring and Mitigation* – Approve** - Tim Fritch, SMWG | Todd Lucas, Sponsor

   Recent oscillation events, such as the January 11, 2019 forced oscillation event in Florida that interacted with a natural system mode of the Eastern Interconnection and led to propagation of the oscillation across the Interconnection, have highlighted the need for increased monitoring and consistency in the monitoring of oscillation disturbances. Some of the key recommendations from the report on the event included the need for Reliability Coordinators (RCs) and Transmission Operators (TOPs) to utilize real-time oscillation detection tools.

   The NERC Synchronized Measurement Working Group (SMWG) was requested to develop guidance on oscillation analysis methods to encourage consistency in the system quantities that are monitored for oscillation events and the respective thresholds for alarms. The detection and alarming of oscillations and their classification in a consistent manner is critical in ensuring coordinated mitigation of both local and widespread oscillation disturbances in the bulk power system. The SMWG is seeking RSTC approval of the White Paper.

10. **Event Analysis Subcommittee Membership* – Approve** – Ralph Rufrano, EAS Chair | Patrick Doyle, Sponsor

    The EAS Scope document calls for RSTC approval of its membership. The EAS has a vacancy for the NPCC Regional Industry Representative. The EAS proposes **Bill Temple** (**Avangrid**) to fill the seat and is requesting RSTC approval.

11. **RSTC Work Plan, RISC Report Recommendations and Joint FERC/NERC Cold Weather Report Recommendations* – Information** – Rich Hydzik, RSTC Vice Chair

    At the September RSTC meeting, the RISC Report recommendations were reviewed and a Tiger Team formed to review the RISC Report recommendations and the Joint FERC/NERC Cold Weather Report recommendations to create or modify RSTC work plan items to address the recommendations. The Tiger Team is providing a status update as well as a plan to coordinate with RSTC subgroups to review risks and develop mitigation activities and work plan items for future RSTC approval.

12. **EMP Working Group Update* – Information** – Aaron Shaw, EMPWG Chair | Brian Evans-Mongeon, Sponsor

    Chair Shaw will provide some of the current thinking on EMP Vulnerability Assessments as well as other EMPWG subteam's work plans. The intent of this presentation is to brief the RSTC members on the overall EMP project.

BREAK – 15 MINS

13. **Nominating Subcommittee (NS) Update* – Information –** Rich Hydzik, RSTC Vice Chair

    The NS will report on upcoming activities and timelines for At-Large nominees to fill RSTC terms ending in 2022 as well as other At-Large vacancies.

14. **Odessa Disturbance Report and Odessa Disturbance Follow-Up Document* – Approve –** Julia Matevoysan, IRPWG Vice Chair, Rich Bauer and Ryan Quint NERC Staff | Jody Green, Sponsor

    NERC Staff developed an in-depth review of the Odessa Disturbance with a report published by NERC in October 2021. Presenters will provide a detailed review of the event along with a summary of a brief white paper that was developed by the IRPWG as a follow-up to the disturbance report. That report contained a set of key findings and recommendations. The IRPWG discussed each of the key findings and recommendations in detail, and is providing a brief technical discussion and technical basis for each recommendation. Where appropriate, follow-up action items are identified. Table 1 shows the recommendations and actions needed from Chapter 3 of the NERC disturbance report on the left-hand column and the IRPWG follow-up and recommendations for each item in the right-hand column. The IRPWG has developed a follow up document with recommendations on this subject and is seeking RSTC approval.

15. **FERC - NERC - Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and the South Central United States – Information –** Dave Huff and Heather Polzin, FERC Staff, Steven Noess and Kiel Lyons, NERC Staff

    This report describes the severe cold weather event occurring between February 8 and 20, 2021 and how it impacted the reliability of the bulk electric system ("BES" or colloquially known as the grid) in Texas and the South Central United States (hereafter known as "the Event"). During the Event, extreme cold temperatures and freezing precipitation led 1,045 individual BES generating units, (with a combined 192,818 MW of nameplate capacity) in Texas and the South Central United States to experience 4,124 outages, derates or failures to start. Each individual generating unit could, and in many cases, did, have multiple outages from the same or different causes. To provide perspective on how significant the generating unit outages were, including generation already on planned or unplanned outages, the Electric Reliability Council of Texas (ERCOT) averaged 34,000 MW of generation unavailable (based on expected capacity) for over two consecutive days, from 7:00 a.m. February 15 to 1:00 p.m. February 17, equivalent to nearly half of its all-time winter peak electric load of 69,871 MW.

16. **Chair's Closing Remarks and Adjournment**

Antitrust Compliance Guidelines

I. General

It is NERC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. This policy requires the avoidance of any conduct that violates, or that might appear to violate, the antitrust laws. Among other things, the antitrust laws forbid any agreement between or among competitors regarding prices, availability of service, product design, terms of sale, division of markets, allocation of customers or any other activity that unreasonably restrains competition.

It is the responsibility of every NERC participant and employee who may in any way affect NERC's compliance with the antitrust laws to carry out this commitment.

Antitrust laws are complex and subject to court interpretation that can vary over time and from one court to another. The purpose of these guidelines is to alert NERC participants and employees to potential antitrust problems and to set forth policies to be followed with respect to activities that may involve antitrust considerations. In some instances, the NERC policy contained in these guidelines is stricter than the applicable antitrust laws. Any NERC participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NERC's antitrust compliance policy is implicated in any situation should consult NERC's General Counsel immediately.

II. Prohibited Activities

Participants in NERC activities (including those of its committees and subgroups) should refrain from the following when acting in their capacity as participants in NERC activities (e.g., at NERC meetings, conference calls and in informal discussions):

- Discussions involving pricing information, especially margin (profit) and internal cost information and participants' expectations as to their future prices or internal costs.
- Discussions of a participant's marketing strategies.
- Discussions regarding how customers and geographical areas are to be divided among competitors.
- Discussions concerning the exclusion of competitors from markets.
- Discussions concerning boycotting or group refusals to deal with competitors, vendors or suppliers.

- Any other matters that do not clearly fall within these guidelines should be reviewed with NERC's General Counsel before being discussed.

III. Activities That Are Permitted

From time to time decisions or actions of NERC (including those of its committees and subgroups) may have a negative impact on particular entities and thus in that sense adversely impact competition. Decisions and actions by NERC (including its committees and subgroups) should only be undertaken for the purpose of promoting and maintaining the reliability and adequacy of the bulk power system. If you do not have a legitimate purpose consistent with this objective for discussing a matter, please refrain from discussing the matter during NERC meetings and in other NERC-related communications.

You should also ensure that NERC procedures, including those set forth in NERC's Certificate of Incorporation, Bylaws, and Rules of Procedure are followed in conducting NERC business.

In addition, all discussions in NERC meetings and other NERC-related communications should be within the scope of the mandate for or assignment to the particular NERC committee or subgroup, as well as within the scope of the published agenda for the meeting.

No decisions should be made nor any actions taken in NERC activities for the purpose of giving an industry participant or group of participants a competitive advantage over other participants. In particular, decisions with respect to setting, revising, or assessing compliance with NERC reliability standards should not be influenced by anti-competitive motivations.

Subject to the foregoing restrictions, participants in NERC activities may discuss:

- Reliability matters relating to the bulk power system, including operation and planning matters such as establishing or revising reliability standards, special operating procedures, operating transfer capabilities, and plans for new facilities.
- Matters relating to the impact of reliability standards for the bulk power system on electricity markets, and the impact of electricity market operations on the reliability of the bulk power system.
- Proposed filings or other communications with state or federal regulatory authorities or other governmental entities.
- Matters relating to the internal governance, management and operation of NERC, such as nominations for vacant committee positions, budgeting and assessments, and employment matters; and procedural matters such as planning and scheduling meetings.

RSTC Meetings – Governance Management

Chair will state the governance management of the meeting as follows:

1. For each topic, the Chair will introduce the topic and allow for discussion.
2. At the conclusion of the discussion, the Chair will state the primary motion, and ask for first/second.
3. The Chair will then call for any additional discussion.
   - During such discussion, a secondary motion can be offered,
   - The Chair will ask for first/second, discussion/debate; the Chair will then call for a vote.
   - If the secondary motion does not receive a second or is voted down, the Chair will go back and restate the primary motion.
4. At this point, the following actions may proceed:
   - Debate on that primary motion again;
   - Another secondary motion can be offered;
   - Motion could be offered to postpone, table, etc. Management of next action will follow Steps 3 and 4.

The Chair is able to initiate a motion to end a debate.

Motions can encompass accepting minor revisions as provided during the discussions and reflected in the words of the motion.

Guiding principle is one thing at a time.

Types of Documents

Reliability & Security Guidelines

- *Formulated from best and/or optimal practices*
- *Suggested approaches or behaviors*
- *"HOW" certain objectives can be met*
- *Recommendations for how objectives "could" or "should" be accomplished*

Reference Documents, Whitepapers and Technical Reports

- *Documented technical concepts*
- *Definitions of technical terms*
- *Defined methods or approaches*
- *Can be used as justification to support "WHY" certain practices are needed*

Implementation Guidance

- *Provides examples or approaches for "HOW" Registered Entities could demonstrate compliance with Reliability Standard requirements.*
- *Used in Compliance Monitoring and Enforcement activities*

Submitted to ERO

Standard Authorization Request

- *Defines scope, reliability benefit, and technical justification for a new or modified Reliability Standard or definition.*
- *Identifies "WHAT" requirements are needed to ensure the reliable operation of the BPS*

Submitted to SC

Reliability Assessment Reports

- Independent and objective evaluations of BPS reliability conducted by the ERO
- Subgroup used to gain industry perspectives, expertise, and validation
- Requires BOT approval

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Types of Documents: Member Considerations

Reliability & Security Guidelines	*Reference Documents, Whitepapers and Technical Reports*	*Implementation Guidance*	*Standard Authorization Request*

• *ACCEPT for public comment*
  • *Is guidance needed on this topic?*
  • *Are there major flaws?*
• *APPROVE*
  • *Has the public and committee comments been sufficiently addressed?*
  • *Do you agree with the recommended guidance?*
	• *APPROVE*
	  • *Does it provide sufficient detail to support technical, security, and engineering SMEs?*
	  • *Has it been peer reviewed and supported by a technical subgroup?*
	  • *Is it foundational and/or conceptual*
	  • *Does it contain specific recommendations?*
		• *ENDORSE*
		  • *Does it provide examples or approaches on how to implement a Reliability Standard?*
		  • *Does it meet the expectations identified in the Implementation Guidance Development and Review Aid?*
			• *ENDORSE*
			  • *Is the SAR form complete?*
			  • *Does it contain technical justification?*

Reliability Assessment Reports

- ENDORSE
  - Is there general agreement with findings and recommendations?
  - Was the process followed?

RSTC Actions

- **Approve:** The RSTC has reviewed the deliverable and supports the content and development process, including any recommendations.
- **Accept:** The RSTC has reviewed the deliverable and supports the development process used to complete the deliverable.
- **Remand:** The RSTC remands the deliverable to the originating subcommittee, refer it to another group, or direct other action by the RSTC or one of its subcommittees or groups.
- **Endorse:** The RSTC agrees with the content of the document or action, and recommends the deliverable for the approving authority to act on. This includes deliverables that are provided to the RSTC by other NERC committees. RSTC endorsements will be made with recognition that the deliverable is subject to further modifications by NERC Executive Management and/or the NERC Board. Changes made to the deliverable subsequent to RSTC endorsement will be presented to the RSTC in a timely manner. If the RSTC does not agree with the deliverable or its recommendations, it may decline endorsement. It is recognized that this does not prevent an approval authority from further action.

RSTC Status Report – Electromagnetic Pulse Working Group (EMPWG)

Chair: Aaron Shaw
Vice-Chair: Rey Ramos
February 9th, 2021

- On Track
- Schedule at risk
- Milestone delayed

Purpose: The purpose of the EMPWG is to address key points of interest related to system planning, risks and assessments, modeling, and reliability impacts to the bulk power system (BPS).

Items for RSTC Approval/Discussion:

- **N/A**

Recent Activity

- Solicitation of industry volunteers in EMPWG.

Upcoming Activity

- Formally establish EMPWG team structure by March 31st
- EMP Technical Workshop by end of Q2 2021
- Exploring risks of electric fired compressor stations as it relates to fuel assurance for natural gas
- Reviewing the FERC/NERC inquiry to determine where the EGWG can provide value to meet the recommendations of the report
- Developing the 2022 EGWG Work Plan

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Expand Membership	On Track	Industry solicitation was sent out on January 21, 2021
Establish Team Structure and Nominate Team leads	On Track	EMPWG Leadership is reviewing incoming nominations received by industry.

RSTC Status Report – Event Analysis Subcommittee (EAS)

Chair: Vinit Gupta
Vice-Chair: Ralph Rufrano
December 14, 2021

- On Track
- Schedule at risk
- Milestone delayed

Purpose: The EAS will support and maintain a cohesive and coordinated event analysis (EA) process across North America with industry stakeholders. EAS will develop lessons learned, promote industry-wide sharing of event causal factors and assist NERC in implementation of related initiatives to lessen reliability risks to the Bulk Electric System.

Recent Activity

- The EAS has published a total of 12 new Lessons Learned in 2021 with 4 more currently under development
- The EMSWG completed hosting the 9th annual Monitoring & Situational Awareness Technical Conference.
- FMMTF: Two Diagrams Drafted & Two Updated in 2021

Items for RSTC Approval/Discussion:

- NPCC EAS Industry Representative Replacement – Bill Temple (Avangrid).

Ongoing & Upcoming Activities

- Ralph Rufrano (NPCC) appointed to EAS Chair
- Chris Moran (PJM) appointed to EAS Vice-Chair
- Significant progress developing EAP revisions for 2022 review as portion of complementary EA program contextual alignment. Achievement in program overarching "event" definition and draft modification of "unintended" criteria.
- Development of Lessons Learned
- FMMTF Development of Failure Mode & Mechanism Diagrams

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Pandemic Response Lessons Learned	●	Completed
Review & Input into EA Chapter of 2021 SOR	●	Completed in coordination with PAS
EAS Scope Document	●	Approved March 2,2021
Events Analysis Process Review	●	On going

RSTC Status Report – Inverter-based resource Performance Working Group (IRPWG)

Chair: Al Schriver
Vice-Chair: Julia Matevosyan

- On Track
- Schedule at risk
- Milestone delayed

Purpose: *To explore the performance characteristics of utility-scale inverter-based resources (e.g., solar photovoltaic (PV) and wind power resources) directly connected to the bulk power system (BPS).*

Items for RSTC Approval/Discussion:

- TPL-001-5 SAR for BPS-Connected IBRs
- White Paper: BPS-Connected IBR and Hybrid Plant Capabilities for Frequency Response
- White Paper: Grid Forming Technology

Recent Activity

- Reviewed latest draft and comments for white paper for Using BPS-Connected Inverter-Based Resources and Hybrid Plant Capabilities for Frequency Response
- Discussed latest draft of guideline: Reliability Guideline: EMT Modeling and Studies
- Continue work for Reliability Guideline: Recommended Approach to Interconnection Studies for BPS-Connected Inverter-Based Resources

Upcoming Activity

- *Reliability Guideline: Electromagnetic Transient Modeling and Simulations Reliability Guideline on EMT modeling and simulations of BPS-connected inverter-based resources.*
- *Reliability Guideline: Recommended Approach to Interconnection Studies for BPS-Connected Inverter-Based Resources Focused guidance on improving the study process for BPS-connected inverter-based resources, particularly with increasing penetrations of these resources and the growing complexity of performing sufficient studies to ensure BPS reliability.*

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Reliability Guideline: EMT Modeling and Studies	●	In progress
IEEE p2800 Monitoring and Support Monitor and support the activities of IEEE p2800, and provide technical expertise and input as requested.	●	In progress
Reliability Guideline: Recommended Approach to Interconnection Studies for BPS-Connected Inverter-Based Resources	●	In Progress

RSTC Status Report – Load Modeling Working Group (LMWG)

Chair: Kannan Sreenivasachar,
Vice-Chair:

- On Track
- Schedule at risk
- Milestone delayed

Purpose:
The LMWG is transitioning utilities from the CLOD model to the CMLD Composite Load Model. The CLOD model lacks the capability to model events like FIDVR, which can have significant consequences on planning decisions.

Items for RSTC Approval/Discussion:

- **Approve**: LMWG *Work Plan*

Recent Activity

- CMLD Field Test Survey Summary
- CMLD Field Test Reports
- Testing by entities with updated Motor D parameters
- EPRI initial test results on AC phasor model in PSLF
- Inclusion of CMLD model in MMWG 2021 Series Cases
- Initial Draft of Transient Voltage Response Whitepaper

Upcoming Activity

- *Testing by entities with updated Motor D parameters*
- *Post Motor Data Standard Parameters to LMWG Restricted Access Site*
- *Develop modeling treatment of "Extra Vars" based on vendor points of agreement*
- *Continue work on Phasor model*
- *Modify LMDT tool for PSS/E Version 35.0*
- *Revisions to Transient Voltage Response Whitepaper*

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Phasor Model Development	●	In progress
Evaluate Distribution-Level Impacts of Plug-in Electric Vehicle (PEV)	●	In progress
Evaluate differential equation based models for HVACs and electronic drives	●	In progress
Transient Voltage Response Whitepaper	●	In progress

RSTC Status Report – Performance Analysis Subcommittee (PAS)

Chair: Brantley Tillis
Vice-Chair: David Penney
September 16, 2020

On Track
Schedule at risk
Milestone delayed
Not started
Complete

Purpose: The PAS reviews, assesses, and reports on reliability of the North American Bulk Power System (BPS) based on historic performance, risk and measures of resilience.

Items for RSTC Approval/Discussion:

- None

Recent Activity

- September 30: Annual Commissioner-led Reliability Technical Conference

Upcoming Activity

- GADS Section 1600 data comments under review
- Continue annual metric review and proposed metrics

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Section 1600 Data Request	On Track On Track	Public comment period completed 7/31/21. Volume and content of comments will require additional time to review and address. Second round of public comments planned for 2022.
Conduct annual metric review	On Track	Second half of 2021 – review commenced
Review proposed new metrics	Not started	Second half of 2021
2022 State of Reliability Report		Commences in 2022

RSTC Status Report – Probabilistic Assessment Working Group (PAWG)

Chair: Andreas Klaube
Vice-Chair: Alex Crawford
December 15, 2021

- On Track
- Schedule at risk
- Milestone delayed

Purpose: *The primary function of the NERC Probabilistic Assessment Working Group (PAWG) is to advance and continually improve the probabilistic components of the resource adequacy work of the ERO Enterprise in assessing the reliability of the North American Bulk Power System.*

Items for RSTC Approval/Discussion:

- None

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments

Recent Activity

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- PAF was an overwhelming success in October. Nearly tripled the size as the first iteration.
- Ongoing engagement with RAS with probabilistic components of their seasonal assessments.
- Started work on the biennial ProbA process.

Upcoming Activity

- *White Paper: Probabilistic Planning for the Tails* – Plan to complete by 2023
- *2022 Probabilistic Assessment* – Both the Base Case and Scenario Case to continue work in 2022.

RSTC Status Report – Reliability Assessments Subcommittee (RAS)

Chair: Anna Lafoyiannis (11/2021)
Vice-Chair: Andreas Klaube (11/2021)
December 14-15, 2021

- On Track
- Schedule at risk
- Milestone delayed

Purpose: The RAS reviews, assesses, and reports on the overall reliability (adequacy and security) of the BPS, both existing and as planned. Reliability assessment program is governed by NERC RoP Section 800.

Items for RSTC Approval/Discussion:

Recent Activity

- RAS Members are reviewing the ERATF Energy Roadmap and will provide appropriate inputs
- RAS Meeting December 2: topics included request material revisions for the 2022 SRA and 2022 LTRA
- 2021-2022 WRA was published on November 18
- RAS Meeting November 9-10: topics included chair and vice chair elections, preparation for 2022 assessments, and strategy discussion

Upcoming Activity

- 2021 LTRA publication planned for December 21
- Development of 2022 LTRA Data and Narrative Requests

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
2021 Long-Term Reliability Assessment	●	Report planned publication on December 21
2022 Summer Reliability Assessment	●	Request materials in development

RSTC Status Report – Resources Subcommittee (RS)

- On Track
- Schedule at risk
- Milestone delayed

Chair: Greg Park
Vice-Chair: Rodney O'Bryant
December 2021

Purpose: The RS assists the NERC RSTC in enhancing Bulk Electric System reliability by implementing the goals and objectives of the RSTC Strategic Plan with respect to issues in the areas of balancing resources and demand, interconnection frequency, and control performance.

Recent Activity

- Reviewed existing RS documents and classified per RSTC guidelines
- Continue to work on items to sunset the Inadvertent Interchange Working Group
- Quarterly review of interconnection performance
- Reviewed BAL-003 SDT proposed attachments and reporting methodology

Items for RSTC Approval/Discussion:

- **Endorse and Advance**:
  - 2021 Frequency Response Annual Analysis – RS Approved
  - Reporting ACE Standard Authorization Request

Upcoming Activity

- Scheduling a Joint RS and RTOS meeting

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Support ERSWG Measures 1,2,4, and 6	●	Periodic review and consultation with NERC staff ongoing
ACE Definition SAR	●	Chair has determined advancement of SAR to RSTC is appropriate at this time
RS M6 outreach to BAs indicating a year over year decline in performance.	●	RS leadership and regional representatives are meeting with identified BAs

RSTC Status Report – Real Time Operating Subcommittee (RTOS)

Chair: Jimmy Hartmann
Vice-Chair: Tim Beach
December 2021

- On Track
- Schedule at risk
- Milestone delayed

Purpose: The RTOS assists in enhancing BES reliability by providing operational guidance to industry; oversight to the management of NERC-sponsored IT tools and services which support operational coordination, and providing technical support and advice as requested.

Recent Activity

- Task Force developed to review Reliability Coordinator Plan Reference Document
- RSTC approved new RTOS Chair and Vice-chair for the 2022-2024 term
- RTOS Approved new Executive Committee members for 2022-2024 term

Items for RSTC Approval/Discussion:

- Reliability Guideline: Cyber Intrusion Guide for the System Operator: Request approval to post for 45 day comment
- GMD Monitoring Reference Document: Request approval to post for 45 day comment
- Oscillation Analysis for Monitoring and Mitigation Whitepaper: Request RSTC Approval
- SMWG Self Evaluation Report

Upcoming Activity

- Reliability Coordinator Plan Reference Document Q2 2022

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Monitor development of common tools and act as point of contact for EIDSN.	On Track	In Progress
Frequency Monitor Reporting (Standing RTOS agenda item to discuss).	On Track	In Progress
Reliability Guideline: Cyber Intrusion Guide for System Operators (Approved by the Operating Committee on June 5, 2018)	On Track	In Progress
Reliability Coordinator Plan Reference Document	On Track	In Progress

RSTC Status Report – Supply Chain Working Group (SCWG)

Chair: Tony Eddleman
Vice-Chair: Open
December 14-15, 2021

- On Track
- Schedule at risk
- Milestone delayed

Purpose: To Identify known supply chain risks and address through guidance documentation or other appropriate vehicles. Partner with National Laboratories to address cyber security supply chain risk.

Items for RSTC Approval/Discussion:

- **N/A**

Recent Activity

- Met virtually on September 20th, October 18th and November 15th
- Issued the Supply Chain Standard Effectiveness Survey to Registered Entities
  - NERC to use the results to brief the Board on the Supply Chain Standards
- INL presented an overview of Cyber Testing for Resilient Industrial Control Systems (CyTRICS)
- Discussed the Central Repository

Upcoming Activity

- Supply Chain Standard Effectiveness Survey
  - Review results and summarize
- Periodic review of Security Guidelines
- Monitor the development of the Central Repository
- Monitor the Software Bill of Materials (SBoM) Project by CISA
- Guidance documentation on supply chain risk management issues and topics
  - Monitoring FERC, Executive Orders, DOE, and CISA for future directions

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Supply Chain Standard Effectiveness Survey	●	In Progress
Periodic Review of Supply Chain Security Guidelines	●	In Progress
Guidance documentation on supply chain risk management issues and topics	●	In Progress

RSTC Status Report
Security Integration and Technology Enablement Subcommittee (SITES)

Chair: VACANT
Vice Chair: Brian Burnett
December 14-15, 2021

- On Track
- Schedule at risk
- Milestone delayed

Purpose: To identify, assess, recommend, and support the integration of technologies on the bulk power system (BPS) in a secure, reliable, and effective manner.

Items for RSTC Approval/Discussion:

- **Accept**: *None*
- **Approve**: *None*

Recent Activity

- BES operations in the cloud whitepaper: Subgroup has been formed and initial working draft has been developed.
- Zero-trust whitepaper: Subgroup has been formed; draft is nearly complete.

Upcoming Activity

- Chair has resigned; currently seeking replacement
- BES operations in the cloud whitepaper public comment period. Date TBD.
- Zero-trust whitepaper initial draft and prep for public comment period. Date TBD.

Workplan Status *(6-month look-ahead)*

Milestone	Status	Comments
BES Operations in the Cloud	Schedule at risk	In progress Q4/2021
Zero-Trust Concepts	Schedule at risk	In progress Q4/2021
Security Integration	On Track	Planning phase Q1/2022
IT/OT Convergence	On Track	Planning phase Q1/2022
Reliability/Resilience/Security balance	On Track	Planning phase Q1/2022
Emerging Technologies	On Track	Planning phase Q1/2022
Risk Identification	On Track	Planning phase Q1/2022
Security Implementation	On Track	Planning phase Q1/2022

RSTC Status Report – System Planning Impacts from DER Working Group (SPIDERWG)

- On Track
- Schedule at risk
- Milestone delayed

Chair: Kun Zhu
Vice-Chair: Bill Quaintance
December XX, 2021

Purpose: *The NERC Planning Committee (PC) identified key points of interest that should be addressed related to a growing penetration of distributed energy resources (DER). The purpose of the System Planning Impacts from Distributed Energy Resources)SPIDERWG) is to address aspects of these key points of interest related to system planning, modeling, and reliability impacts to the Bulk Power System (BPS). This effort builds off of the work accomplished by the NERC Distributed Energy Resources Task Force (DERTF) and the NERC Essential Reliability Services Task Force/Working Group (ERSTF/ERSWG), and addresses some of the key goals in the ERO Enterprise Operating Plan.*

Items for RSTC Approval/Discussion:

- **Approval**: White Paper *Survey of DER Modeling Practices*
- **Approval**: *Reliability Guideline: Recommended Approaches for UFLS Program Design with Increasing Penetrations of DERs*
- **Endorse**: *MOD-032 SAR (with accompanying document)*
- **Endorse**: *TPL-001 SAR*

Workplan Status *(6 month look-ahead)*

See next slide

Recent Activity

- Met in October 2021 to update work products and refocus on high priority items.
- Held self-nomination period for upcoming leadership turnover in 2022.
- Held software vendor engagement in October 2021.

Upcoming Activity

- *Many deliverables targeted for RSTC action in Q1 and Q2 of 2022.*
- *Revision of Software Vendor white paper based on Software Vendor engagement.*
- *Next SPIDERWG meeting in January. Anticipated SPIDERWG milestone completion of:*
  - *Standards Review White Paper*
  - *Reliability Guideline on DER Forecasting*
  - *Technical Report on Beyond Positive Sequence*

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Work Look Ahead

- On Track
- Schedule at risk
- Milestone delayed

Workplan Status (6 month look-ahead)

Milestone	Status	Comments
C6 – NERC Reliability Standards Review	Schedule at risk	Initial draft complete. Coming to RSTC in Q1 of 2022 after MOD-032 and TPL-001 SARs.
O1 – White Paper BPS Perspectives on the DER Aggregator	On Track	Reviewing and refocusing draft to address the DER Aggregator. Title changed
S1 – Reliability Guideline: Bulk Power system Planning under Increasing Penetration of Distributed Energy Resources	On Track	Targeting RSTC request to post in Q1 or Q2 of 2022
V2 - Reliability Guideline: DER Forecasting Practices and Relationship to DER Modeling for Reliability Studies	On Track	Comment period ends November 20th. Anticipate RSTC approval in Q1 2022.
S3 – Recommended Simulation Improvements and Techniques	On Track	Beginning software vendor engagement. Requesting RSTC Review of white paper
S4b – Whitepaper: DER impacts to UVLS Programs	On Track	Drafting underway for Q2 2022 target.
S5 – Technical Report: Beyond Positive Sequence RMS Simulations for High DER Penetration Conditions	Schedule at risk	Document type changed. SPIDERWG reviewing draft
M6 – Modeling Distributed Energy Storage and Multiple Types of DERs	Schedule at risk	Drafting underway for Q2 2022 target for RSTC action.

RSTC Status Report – System Protection and Control Working Group (SPCWG)

Chair: Jeff Iler (outgoing)
Vice-Chair: Bill Crossland
Vice-Chair Elect: Lynn Schroeder
November 29, 2021

- On Track
- Schedule at risk
- Milestone delayed

Purpose: The SPCWG will promote the reliable and efficient operation of the North American power system through technical excellence in protection and control system design, coordination, and practices.

Items for RSTC Approval/Discussion:

- **Approval**: none

Recent Activity

- Developing PRC-024-3 CIG
- Developing PRC-019-2 CIG
- IBR Impact on BPS Protection Technical Report
- Developing Inter-Entity Short Circuit Paper

Upcoming Activity

- Developing 2022 Work plan
- Finalize revised scope document

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Revising Scope Document	On Track	Ongoing
Developing 2022 Work plan	On Track	ongoing
Developing PRC-024-3 SAR	Schedule at risk	Looking for a new team lead
Developing PRC-019-2 CIG	On Track	On schedule
Developing Inter-Entity Short Circuit Paper	On Track	On schedule

RSTC Status Report – Security Working Group (SWG)

Co-Chair: Brent Sessions
Co-Chair: Katherine Street
November 17, 2021

On Track
Schedule at risk
Milestone delayed

Purpose: Provides a formal input process to enhance collaboration between the ERO and industry with an ongoing working group. Provides technical expertise and feedback to the ERO with security compliance-related products.

Recent Activity

- Assessing and Reducing Risk Tech Paper Survey completed: Scope of work complete.
  - Forming new team to transition work to NIST in a new partnership (in process)
- BCSI in the Cloud TTX second draft completed, sent to team for review
- Cloud Solutions and Encrypting BCSI Implementation Guidance Paper awaiting process updates
- SWG process enhancements
  - Mapped work plan to RISC report
  - Older guidance review complete
  - Restructuring sharepoint site
  - Intake process for work tasks

Items for RSTC Approval/Discussion:

- **No Activity**

Upcoming Activity

- Determine next steps for Encryption in the Cloud IG paper
- Extranet work area reorganization and rollout (complete training and work aid)
- SWG process/procedures development
  - Document approval lifecycle flowchart
  - SITES requests process being developed
- FERC CIP-002 LL strawman IG document development, 1st draft
- Review new version of BCSI in Cloud TTX document package
- Update scope and other docs if SWG switched to subcommittee
- Map RISC report to work plan, address unmapped activities

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Complete Encryption in the Cloud Compliance Guidance	●	Complete, net endorsed 8/12/21
BCSI in the Cloud Tabletop Lessons Learned	●	2nd draft completed and submitted to review team
FERC CIP-002 WP	●	Restructuring team to address resources
SWG SP and process improvements + training	●	
Add or map workplans to RISC report	●	Draft completed

Nominating Subcommittee Member Election

Action
Approve

Summary
Due to recently approved RSTC Charter revisions, the Nominating Subcommittee (NS) was expanded to consist of seven (7) members (the RSTC Vice-Chair and six (6) members drawing from different sectors and at-large representatives). Nominations were sought November 5-29, 2021 for the two new seats and recommended candidates were selected by the RSTC Chair in consultation with the RSTC Executive Committee. The recommended candidates are John Stephens, Sector 5 representative and Patrick Doyle, At-large representative. The terms for the two new seats will be a shortened term through February 2022 and the full Nominating Subcommittee annual nomination process will commence in March 2022.

Frequency Response Annual Analysis

Action
Endorse

Summary
The 2021 Frequency Response Annual Analysis is submitted to FERC on an annual basis. The analysis was developed by NERC Staff and approved by the Resources Subcommittee. This report is the 2021 annual analysis of frequency response performance for the administration and support of NERC Reliability Standard BAL-003-2 – Frequency Response and Frequency Bias Setting, effective December 1, 2020. BAL-003-2 (Phase I) revises the BAL-003-1.1 standard and process documents to include (in part) the addressing of the inconsistencies in calculation of Interconnection frequency response obligations (IFRO) due to interconnection frequency response performance changes of Point C and/or Value B; the Eastern Interconnection (EI) Resource Contingency Protection Criteria; and the frequency of nadir point limitations (prior limited to t0 to t +12).We are seeking RSTC endorsement of the report prior to the annual filing with FERC.

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2021 Frequency Response Annual Analysis

December 2021

This report was approved by the Resources Subcommittee on November 10, 2021.

This report subject to RSTC review at the December 14-15, 2021, meeting.

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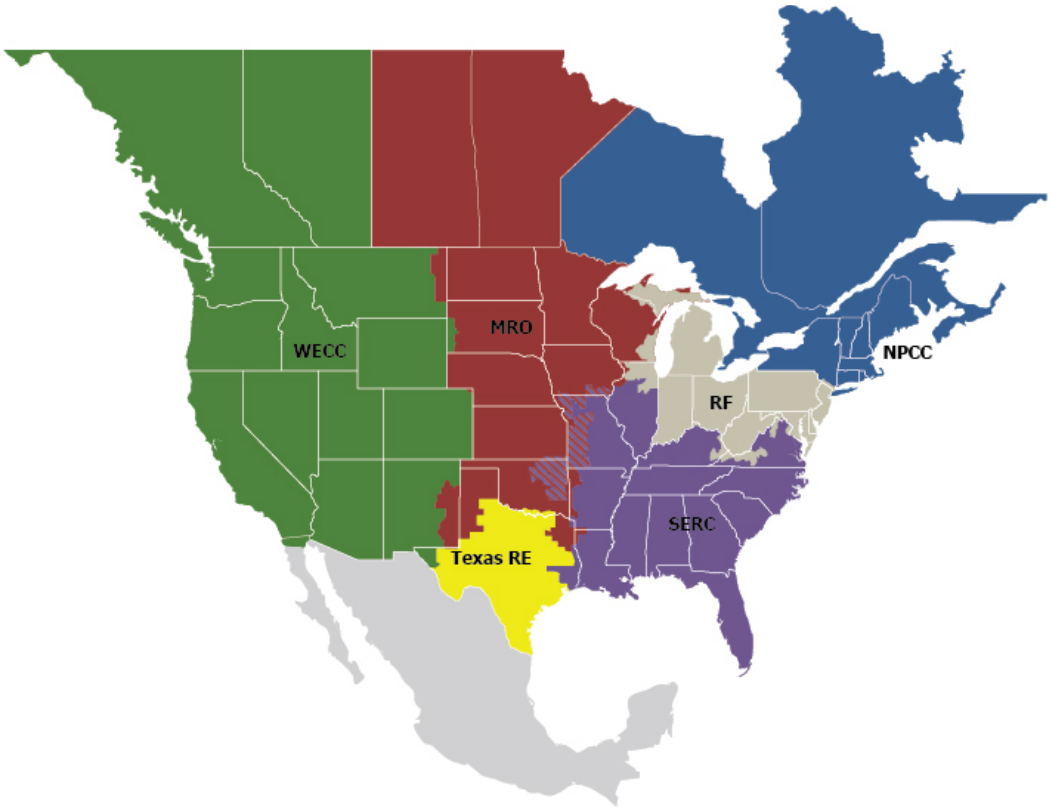
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one RE while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

Executive Summary

This report is the 2021 annual analysis of frequency response performance for the administration and support of *NERC Reliability Standard BAL-003-2 – Frequency Response and Frequency Bias Setting,*[1] effective December 1, 2020. BAL-003-2 (Phase I) revises the BAL-003-1.1 standard and process documents to include (in part) the addressing of the inconsistencies in calculation of Interconnection frequency response obligations (IFRO) due to interconnection frequency response performance changes of Point C and/or Value B; the Eastern Interconnection (EI) Resource Contingency Protection Criteria; and the frequency of nadir point limitations (prior limited to t_0 to t_{+12}).

The *2016 FRAA* stated that the "CB_R ratio in the IFRO calculation couples Point C and Value B together, resulting in IFRO trends that do not align with the intent of the standard. Improvement in Value B with no change in Point C (improving recovery phase) would result in higher obligation to be carried, essentially penalizing improved performance." This was addressed as part of the revision of the IFRO calculation in the BAL-003-2 Reliability Standard.

This report provides an update to the statistical analyses and calculations contained in the *2012 Frequency Response Initiative Report*[2] that was approved by the NERC Resources Subcommittee (RS), the technical committee that predated the Reliability and Security Technical Committee (RSTC), and accepted by the NERC Board of Trustees (Board). It is a transition report that includes some of the information from past IFRO method while fully supporting BAL-003-2 (phase I) requirements and looking ahead to further phased revisions.

This report is prepared by NERC staff[3] and contains the annual analysis, calculation, and recommendations for the IFRO for each of the four Interconnections of North America for the operating year (OY) 2022 (December 2021 through November 2022). Below are the key findings and recommendations contained in this report.

This report further includes **Appendix A**, which details the performance of respective interconnections in arresting frequency reduction for loss of generation events, most commonly referenced as Point A–C analysis. This analysis is specifically concerned with maintaining margin between the lowest event frequency and the first-level of underfrequency load shed scheme. NERC formerly presented this analysis in the annual State of Reliability report.

Key Findings

Continued Increase in CB_R Supports Changes to IFRO Calculation Effected in BAL-003-2

The ratio between CB_R is a multiplicative factor in the IFRO formulae that couples these two quantities together in the formulation of the IFRO. The original intent of the IFRO calculation was to ensure that a declining frequency nadir (as demonstrated by an increasing A–C) would result in an increase in the IFRO. However, the calculation also resulted in an increase in IFRO when Stabilizing Period performance improved (as demonstrated by a decreasing A–B) while Point C remained relatively stable when performing calculations to meet BAL-003-1. When CB_R increased and all other variables remained the same, the IFRO increased when using that calculation method. The IFRO should not penalize an Interconnection for improved performance of Value B during the Stabilizing Period. **Table 2.7** shows the year-over-year comparison of adjusted CB_R for all Interconnections and demonstrates the trend of higher CB_R values that have resulted in higher calculated IFROs. Future iterations of this report will trend BAL-003-2 calculation improvement impacts.

Table 2.8 shows a comparison of mean Value A, mean Value B, and mean Point C that is illustrative of Interconnection performance during low frequency events over the previous OY and as compared to the 2016 OY, during which the IFRO values were frozen until OY 2022. Loss of load events have been excluded from the data in **Table 2.6**. The EI and

[1] http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-003-2.pdf

[2] http://www.nerc.com/docs/pc/FRI_Report_10-30-12_Master_w-appendices.pdf

[3] Prepared by the NERC Standards and Engineering organization.

WI maintained a trend of a mean increase in Value B and a mean decrease in A–B, indicating improved performance during the Stabilizing Period of frequency events (Table 2.8). The Texas Interconnection (TI) showed no change in mean Value B and mean A–B, and the Québec Interconnection (QI) had a decrease in mean Value B and increase in mean (A-B). The EI and WI show an increase or no change in mean Point C as well as a decrease or no change in mean (A–C), indicating improved performance during the Arresting Period of frequency events. This performance data demonstrates that the increases in year-over-year CB_R that result in higher calculated IFROs are due to improved Stabilizing Period performance and not due to a decline in the performance of the Point C nadir. Between OY 2020 and OY 2021, the TI and QI showed a decreasing mean Point C and increasing mean A–C.

Resource Loss Protection Criteria Method Mitigates BPS Risk

The IFRO for each Interconnection is calculated for this report by using the respective BAL-003-2 RLPC actual value derived from 2021 Form 1, BA submissions from the Interconnection:

$$\text{IFRO} = \frac{(\text{RLPC-CLR})}{(\text{MDF}*10)} \text{ expressed as MW/0.1Hz,}$$

RLPC is a major determining factor in the calculated IFRO. Table ES.1 reflects the respective changes in Interconnection RLPC as BAL-003-2 improved IFRO calculation through use of N-2 resource loss versus BAL-003-1 use of N-1 resource loss. The change in the method of determining Resource Loss Protection Criteria (RLPC) in accordance with BAL-003-2 provides greater accuracy in determining IFRO values that will mitigate risk to the BPS.

Table ES.1: Comparison of Respective RLPCs for OY 2022

Method	Eastern (EI)	Western (WI)	Texas (TI)	Québec (QI)	Units
Under BAL-003-1	4,500	2,626	2,805	1,700	MW
Under BAL-003-2 (estimated by SDT)	3,209	2,850	2,750	2,000	MW
Under BAL-003-2 (actual reported by BAs for this report)	3,740	3,069	2,805	2,000	MW

.

Recommendation

NERC provides the following recommendation for the administration of *Standard BAL-003-2*[1] for OY 2022 (December 1, 2021, through November 30, 2022).

NERC requests that the recommended IFRO values calculated in this report in accordance with BAL-003-2 and shown in **Table ES.2** be approved for implementation in the OY 2022. NERC, in collaboration with the RS, shall continue to monitor and evaluate the impacts on BPS reliability as a result of changes in IFRO values.

Table ES.2: Recommended IFROs for OY 2022

Value	Eastern (EI)	Western (WI)	Texas (TI)	Québec (QI)	Units
MDF[4]	0.420	0.280	0.405	0.947	Hz
RLPC[5]	3,740	3,069	2,805	2,000	MW
CLR	0	0	1136	0	MW
Calculated IFRO	-890	-1,096	-412	-211	MW/0.1 Hz
Recommended IFROs[6]	-915	-1,096	-412	-211	MW/0.1 Hz

[4] The Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard, Version II, provided in the approved ballot for BAL-003-2, specifies that "MDF is the Maximum Delta Frequency for the specific interconnection as determined in the 2017 Frequency Response Annual Analysis (FRAA)".

[5] BAL-003-2, Attachment A specifies that RLPC be based on the two largest potential resource losses in an Interconnection. This value is required to be evaluated annually.

[6] BAL-003-2 requires that the EI IFRO will be stepped down to its calculated value over three years. The maximum reduction is limited to 100 MW/0.10 Hz annually.

Introduction

This report, prepared by NERC staff,[7] contains the annual analysis, calculation, and recommendations for the IFRO for each of the four Interconnections of North America for the OY 2022 (December 2021 through November 2022). This analysis includes the following information:

- Statistical analysis of Interconnection frequency characteristics for the OYs 2016 through 2020 (December 1, 2015, through November 30, 2020)
- Analysis of frequency profiles for each Interconnection
- Calculation of adjustment factors from BAL-003-2 frequency response events

This year's frequency response analysis builds upon the work and experience from performing such analyses since 2013. As such, there are several important things that should be noted about this report:

- The University of Tennessee–Knoxville FNET[8] data used in the analysis has seen significant improvement in data quality, simplifying and improving annual analysis of frequency performance, and ongoing tracking of frequency response events. In addition, NERC uses data quality checks to flag additional bad one-second data, including bandwidth filtering, least squares fit, and derivative checking.
- As with the previous year's analysis, all frequency event analysis is using subsecond data from the FNET system frequency data recorders (FDRs). This eliminates the need for the CC_{ADJ} factor originally prescribed in the *2012 Frequency Response Initiative Report*[9] because the actual frequency nadir was accurately captured.
- The frequency response analysis tool[10] is being used by the NERC Power System Analysis group for frequency event tracking in support of the NERC Frequency Working Group and RS. The tool has streamlined Interconnection frequency response analysis. The tool provides an effective means of determining frequency event performance parameters and generating a database of values necessary for calculation of adjustment factors.

This report contains numerous references to Value A, Value B, and Point C, which are defined in NERC *BAL-003-2.*[1] As such, it is important to understand the relationship between these variables and the basic tenants of primary and secondary frequency control.

The Arresting, Rebound, Stabilizing, and Recovery Periods of a frequency event following the loss of a large generation resource are shown in **Figure I.1**. Value A and Value B are average frequencies from t-16 to t-2 seconds and t+20 to t+52 seconds, respectively, as defined in NERC *BAL-003-2*. Point C is experienced within the first 20 seconds following the start of a frequency event. A Point C' value may exist if frequency falls below the original Point C nadir or Value B after the end of the 20–52 second Stabilizing Period.

[7] Prepared by the Power System Analysis and Advanced System Analytics & Modeling departments

[8] 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.

[9] http://www.nerc.com/docs/pc/FRI_Report_10-30-12_Master_w-appendices.pdf

[10] Developed by Pacific Northwest National Laboratory

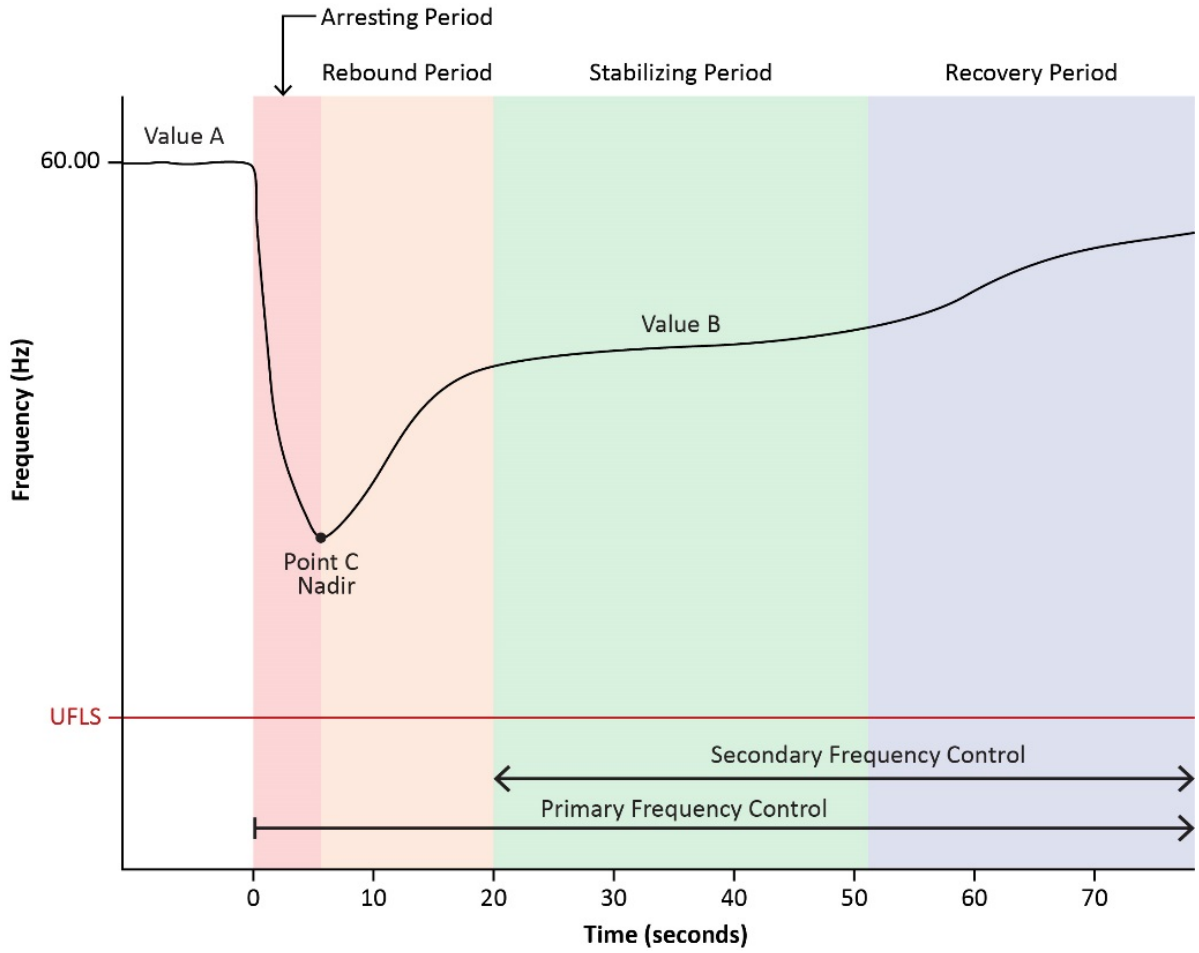


Figure I.1: Primary and Secondary Frequency Control

Primary Frequency Control: This is the action by the Interconnection to arrest and stabilize frequency in response to frequency deviations and has three time components: the Arresting Period, Rebound Period, and Stabilizing Period. These terms are defined as follows:

- **Arresting Period:** This is the time from zero (Value A) to the time of the nadir (Point C) and is the combination of system inertia, load damping, and the initial primary control response of resources acting together to limit the duration and magnitude of frequency change. It is essential that the decline in frequency is arrested during this period to prevent activation of automatic UFLS schemes in the Interconnection.
- **Rebound Period:** This includes the effects of governor response in sensing the change in turbine speed as frequency increases or declines, causing an adjustment to the energy input of the turbine's prime mover. This can also be impacted by end-user customer or other loads that are capable of self-curtailment due to local frequency sensing and control during frequency deviations.
- **Stabilizing Period:** This is the third component of primary frequency control following a disturbance when the frequency stabilizes following a frequency excursion. Value B represents the interconnected system frequency at the point immediately after the frequency stabilizes primarily due to governor action but before the contingent control area takes corrective automatic generation control action.

Chapter 1: Interconnection Frequency Characteristic Analysis

Annually, NERC staff performs a statistical analysis (as detailed in the *2012 Frequency Response Initiative Report)*[11] of the frequency characteristics for each of the four Interconnections. That analysis is performed to monitor the changing frequency characteristics of the Interconnections and to statistically determine each Interconnection's starting frequency for the respective IFRO calculations. For this report's analysis, one-second frequency data[12] from OYs 2016–2020 (December 1, 2015, through November 30, 2020) was used.

Frequency Variation Statistical Analysis

The 2021 frequency variation analysis was performed on one-second frequency data for 2016–2020 and is summarized in **Table 1.1**. This variability accounts for items like time-error correction (TEC), variability of load, interchange, and frequency over the course of a normal day. It also accounts for all frequency excursion events.

The starting frequency is calculated and published in this report for comparison and informational purposes. Starting frequencies are evaluated annually, and the analysis indicated no need to change the maximum delta frequency for OY 2022.

Table 1.1: Interconnection Frequency Variation Analysis 2016–2020

Value	Eastern	Western	Texas	Québec
Number of Samples	157,144,838	157,221,492	156,982,483	150,888,115
Filtered Samples (% of total)	99.6%	99.6%	99.4%	95.6%
Expected Value (Hz)	59.999	59.999	59.999	59.999
Variance of Frequency (σ^2)	0.00025	0.00033	0.00028	0.00041
Standard Deviation (σ)	0.01596	0.01806	0.01660	0.02032
50% percentile (median)[13]	59.999	59.999	60.003	59.998
Starting Frequency (F_{START}) (Hz)	**59.972**	**59.969**	**59.971**	**59.966**

The starting frequency is the fifth-percentile lower tail of samples from the statistical analysis, representing a 95% chance that frequencies will be at or above that value at the start of any frequency event. Since the starting frequencies encompass all variations in frequency, including changes to the target frequency during TECs, the need to expressly evaluate TEC as a variable in the IFRO calculation is eliminated.

Figure 1.1–**Figure 1.4** show the probability density function (PDF) of frequency for each Interconnection. The vertical red line is the fifth-percentile frequency; the interconnection frequency will statistically be greater than that value 95% of the time. This value is used as the starting frequency.

[11] https://www.nerc.com/docs/pc/FRI_Report_10-30-12_Master_w-appendices.pdf

[12] One-second frequency data for the frequency variation analysis is provided by UTK. The data is sourced from FDRs in each Interconnection. The median value among the higher-resolution FDRs is down-sampled to one sample per second and filters are applied to ensure data quality.

[13] Note regarding the EI median frequency is as follows: with fast time error corrections the median value is around but slightly below 60 Hz; without these corrections the median would be above 60 Hz.

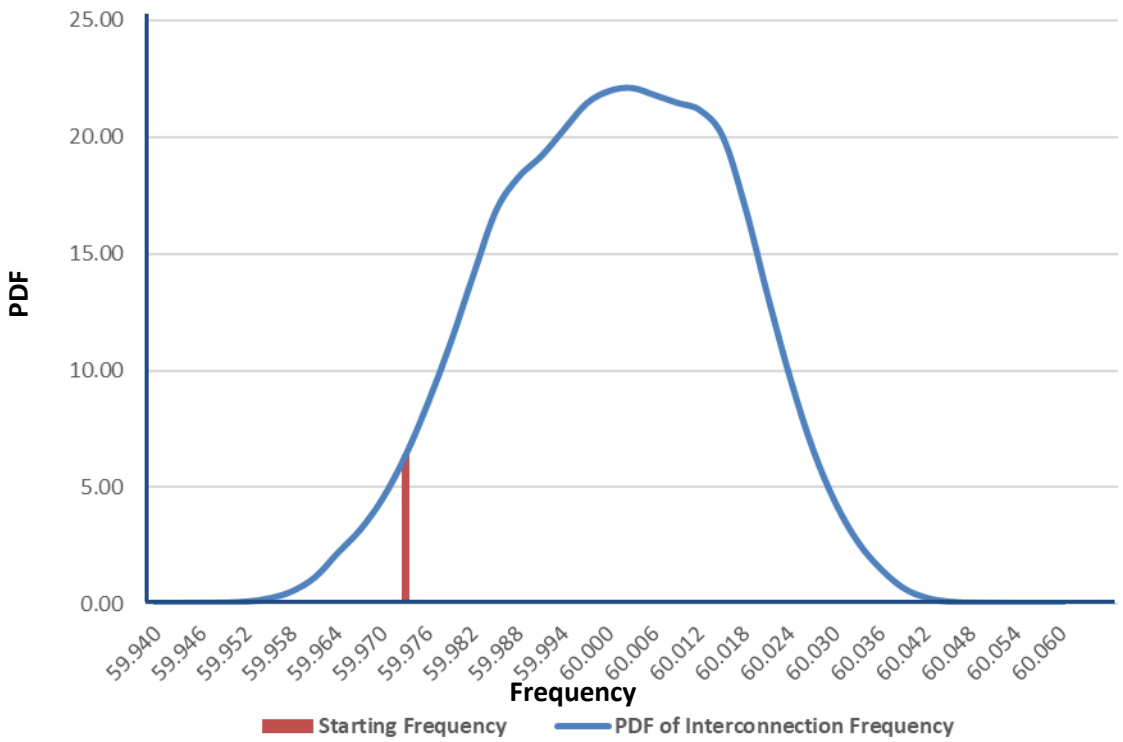


Figure 1.1: Eastern Interconnection 2016–2020 Probability Density Function of Frequency

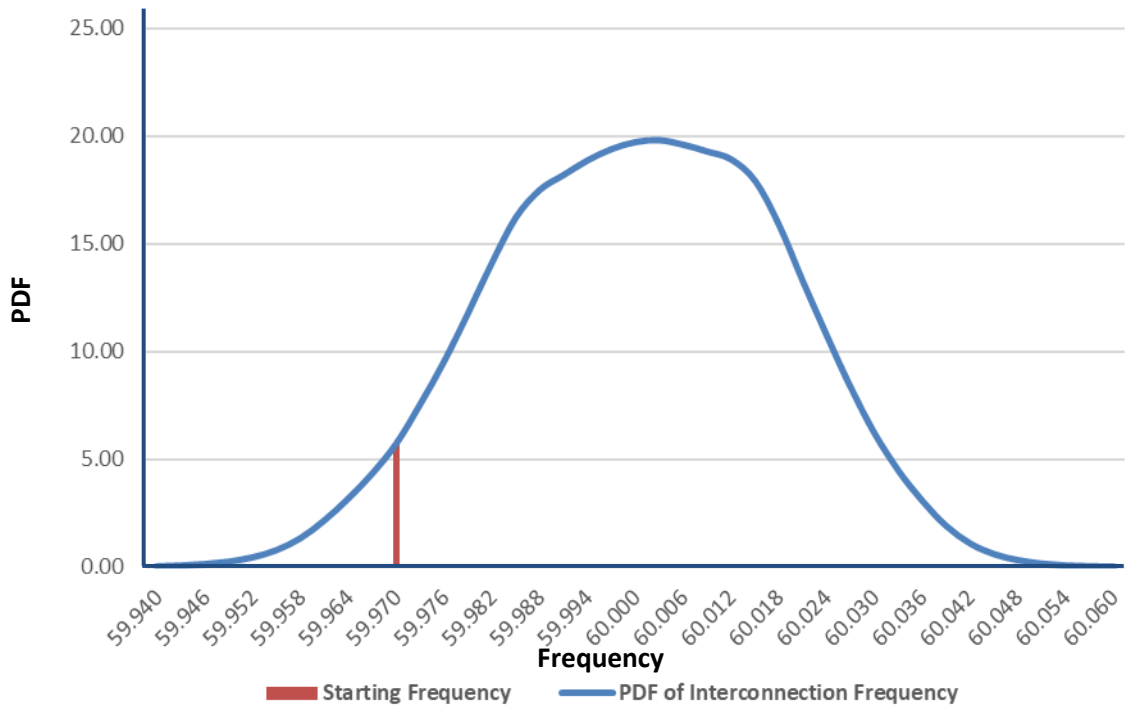


Figure 1.2: Western Interconnection 2016–2020 Probability Density Function of Frequency

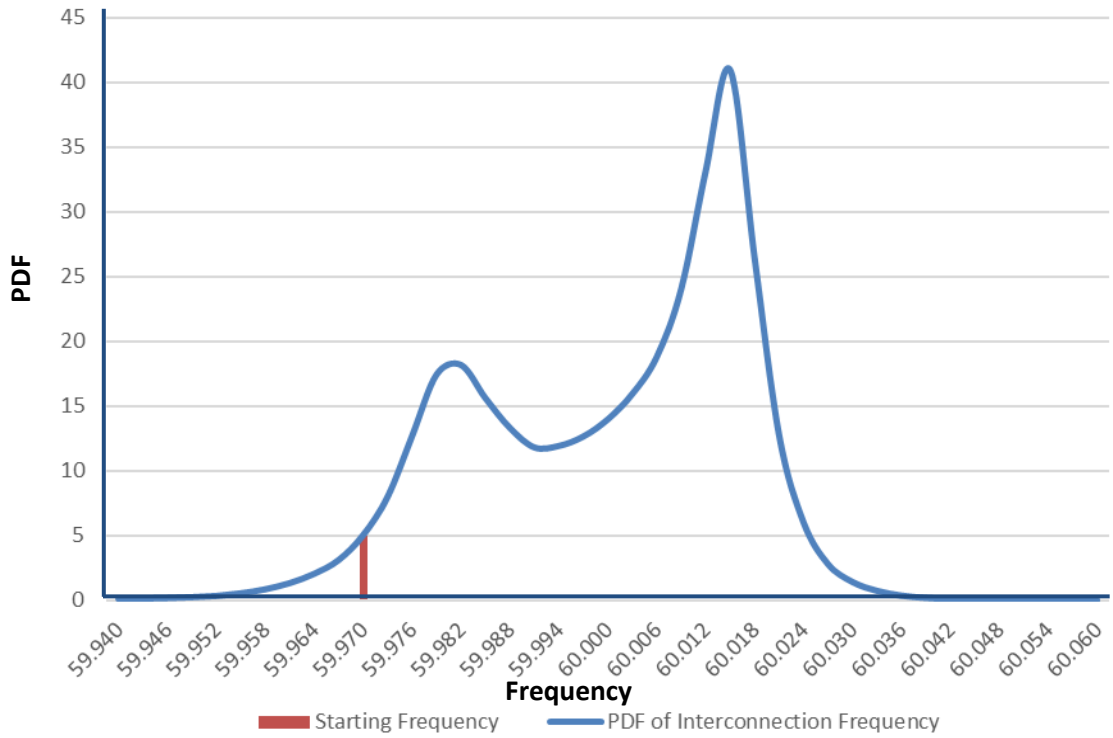


Figure 1.3: Texas Interconnection 2016–2020 Probability Density Function of Frequency

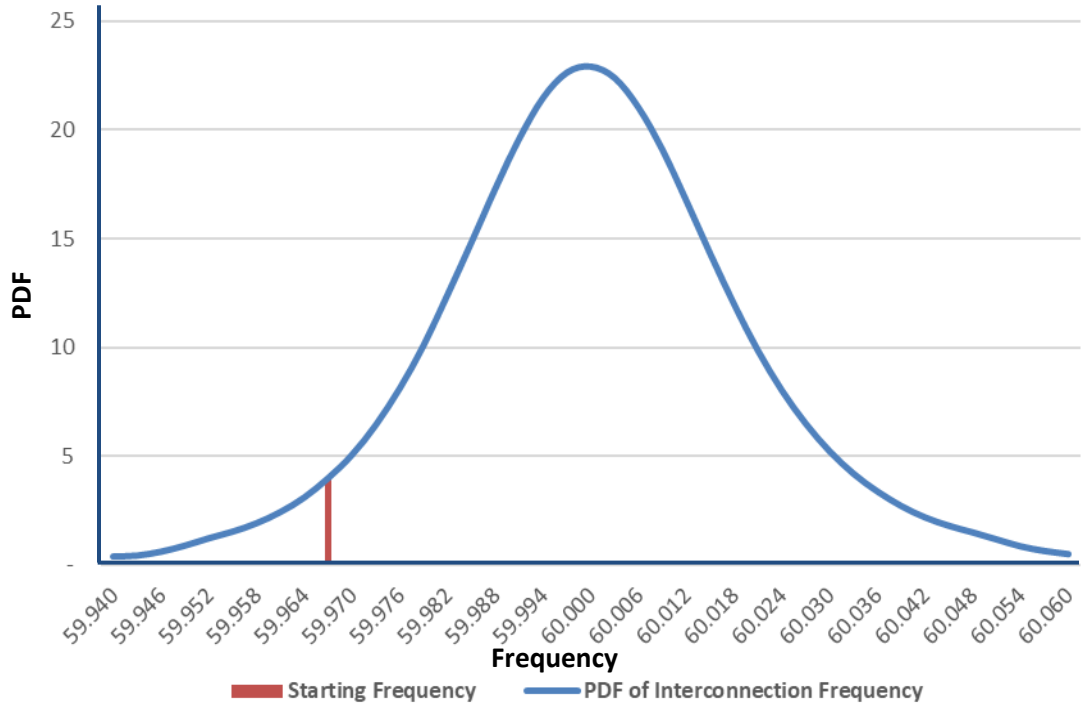


Figure 1.4: Québec Interconnection 2016–2020 Probability Density Function of Frequency

Figure 1.1–Figure 1.4 show the PDF of frequency for each Interconnection. The Interconnection frequency will statistically be greater than that value 95% of the time; this value is used as the starting frequency. Figure 1.5 shows a comparison of the PDF for all Interconnections.

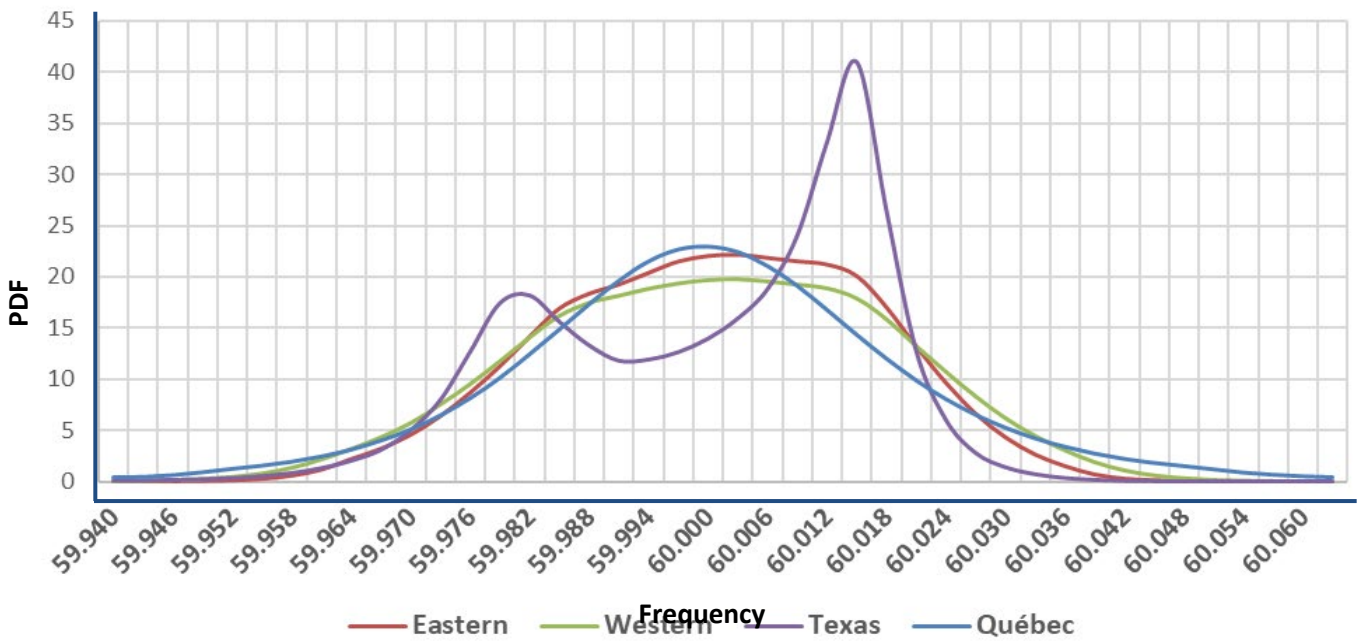


Figure 1.5: Comparison of 2016–2020 Interconnection Frequency PDFs

Variations in Probability Density Functions

The following is an analysis of the variations in probability density functions of the annual distributions of Interconnection frequency for years 2016–2020. Table 1.2 lists the standard deviation of the annual Interconnection frequencies.

Table 1.2: Interconnection Standard Deviation by Year

Interconnection	2016	2017	2018	2019	2020
Eastern	0.0157	0.0156	0.0161	0.0162	0.0163
Western	0.0190	0.0186	0.0186	0.0174	0.0176
Texas	0.0165	0.0165	0.0162	0.0165	0.0174
Québec	0.0203	0.0198	0.0203	0.0204	0.0208

In the EI, the standard deviation continued to increase in 2020 compared to 2016–2019. The standard deviation increased as well in the QI and the TI and increased slightly the WI in 2020 compared to 2019. As standard deviation is a measure of dispersion of values around the mean value, the increasing standard deviations indicate reduced concentration around the mean value and less stable performance of the interconnection frequency. Comparisons of annual frequency profiles for each Interconnection are shown in Figure 1.6–Figure 1.9.

Eastern Interconnection Frequency Characteristic Changes

The increase in standard deviation for the EI frequency characteristic in 2020 is shown in Figure 1.6. Statistical skewness (S)[14] continued to increase in 2020 (S = -0.17) as compared to 2016 and 2017 (S = -0.08 and -0.08,

[14] The skewness (S) is a measure of asymmetry of a distribution. A perfectly symmetric distribution has S=0. The sign indicates where a longer tail of the distribution is. The negatively-skewed distribution has a longer left tail, and its curve leans to the opposite direction (to the right). Algebraically, it means that the frequency values that are smaller than its mean are spread farther from the mean than the values greater than the mean or that there is more variability in lower values of the frequency than in higher values of the frequency.

respectively). NERC, in coordination with its technical committees, continues to evaluate this phenomenon and its impact (if any) on BPS reliability.

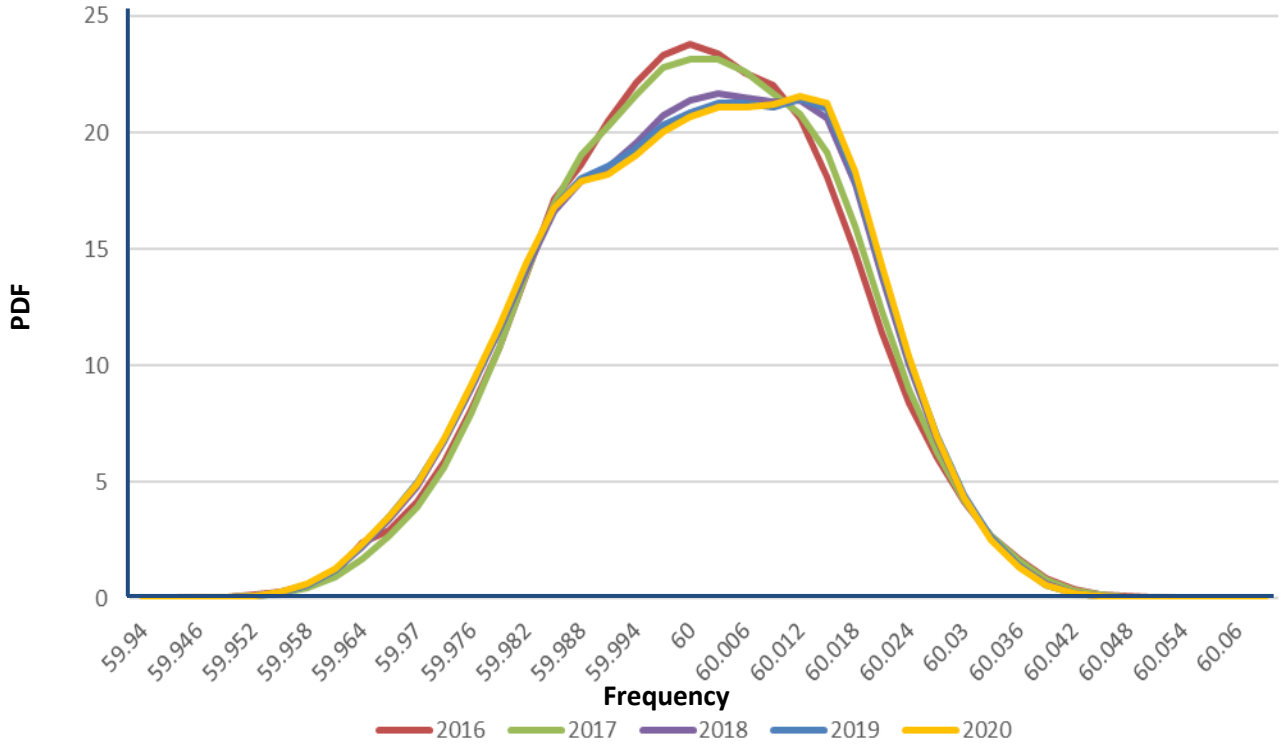


Figure 1.6: Eastern Interconnection Frequency Probability Density Function by Year

Western Interconnection Frequency Characteristic Changes

There was an observable change in the frequency distribution for the WI in 2020 that includes some skewness, as shown in **Figure 1.7**.

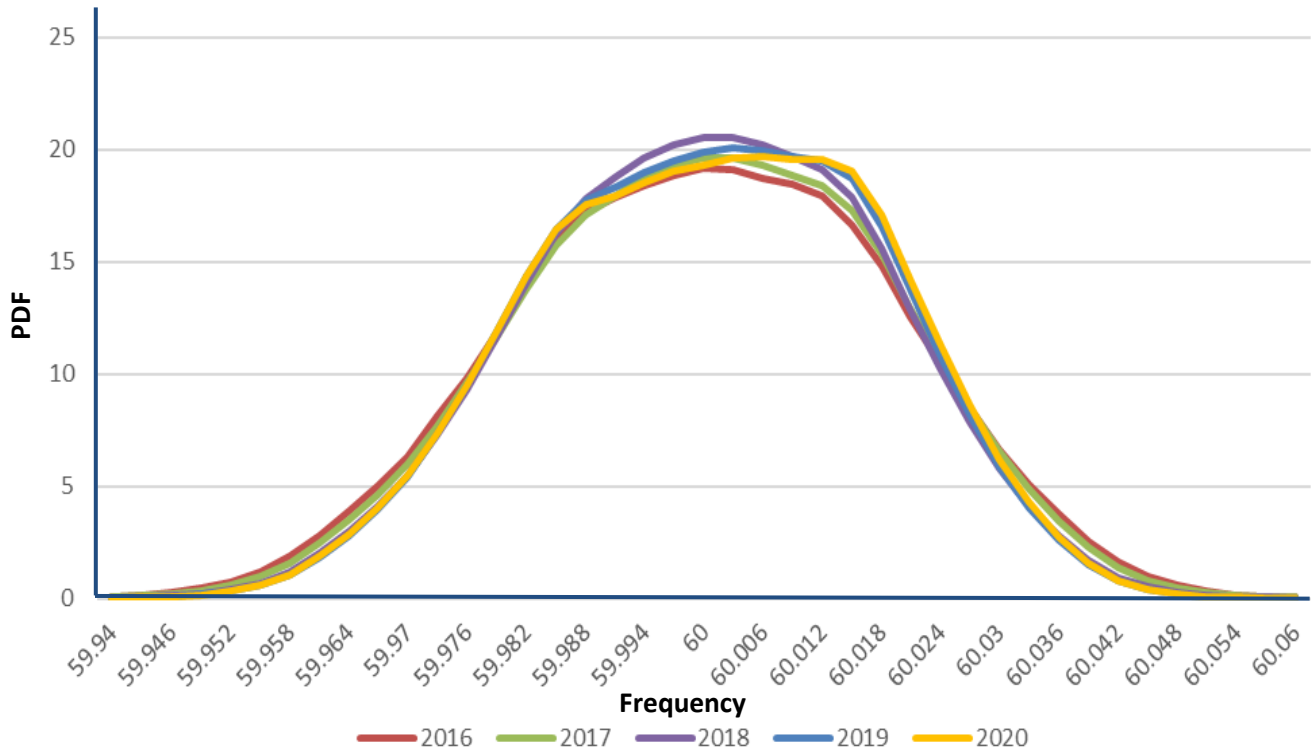


Figure 1.7: Western Interconnection Frequency Probability Density Function by Year

Texas Interconnection Frequency Characteristic Changes

Standard TRE BAL-001[15] went into full effect in April 2015 and caused a dramatic change in the probability density function of frequency for ERCOT in 2015 and 2016. This standard requires all resources in ERCOT to provide proportional nonstep primary frequency response with a ±17 mHz dead-band. As a result, when any time frequency exceeds 60.017 Hz, resources automatically curtail themselves. That has resulted in far less operation in frequencies above the dead-band since all resources, including wind, are backing down. It is exhibited in **Figure 1.8** as a probability concentration around 60.017 Hz. Similar behavior is not exhibited at the low dead-band of 59.983 Hz because most wind resources are operated at maximum output and cannot increase output when frequency falls below the dead-band.

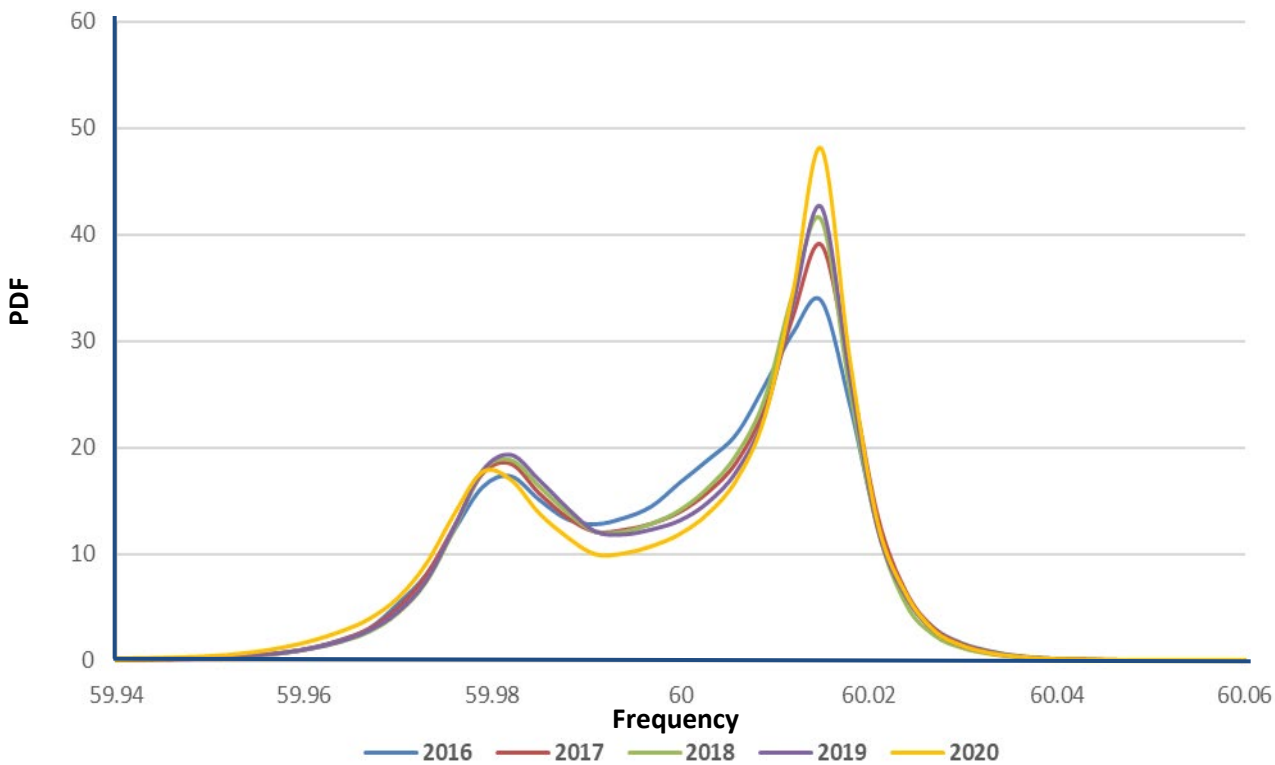


Figure 1.8: Texas Interconnection Frequency Probability Density Function by Year

[15] http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-001-TRE-1.pdf

Québec Interconnection Frequency Characteristic Changes

There were no observable changes in the shape of the distribution for the QI as shown in **Figure 1.9**.

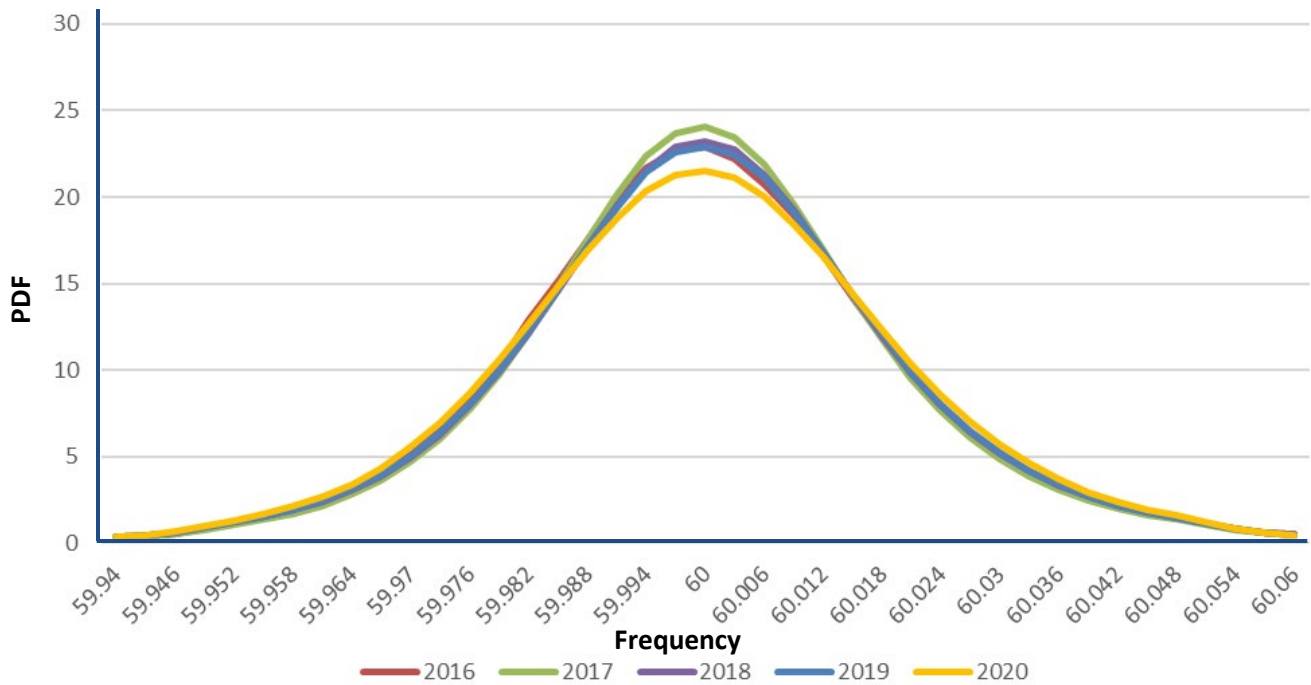


Figure 1.9: Québec Interconnection Frequency Probability Density Function by Year

Chapter 2: Determination of Interconnection Frequency Response Obligations

With this report, the calculation of the IFROs is determined by recently approved BAL-003-2. Previously, the calculation involved a multifaceted process that employed statistical analysis of past performance; analysis of the relationships between measurements of Value A, Point C, and Value B; and other adjustments to the allowable frequency deviations and resource losses used to determine the recommended IFROs. Refer to the *2012 Frequency Response Initiative Report* for additional details on the development of the IFRO and the adjustment calculation methods.[16] This report includes information that serves to transition from the old to the new method.

Tenets of IFRO

The IFRO is the minimum amount of frequency response that must be maintained by an Interconnection. Each Balancing Authority (BA) in the Interconnection is allocated a portion of the IFRO that represents its minimum annual median performance responsibility. To be sustainable, BAs that may be susceptible to islanding may need to carry additional frequency-responsive reserves to coordinate with their UFLS plans for islanded operation.

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

- A frequency event should not activate the first stage of regionally approved UFLS systems within the Interconnection.
- Local activation of first-stage UFLS systems for severe frequency excursions, particularly those associated with delayed fault-clearing or in systems on the edge of an Interconnection, may be unavoidable.
- Other frequency-sensitive loads or electronically coupled resources may trip during such frequency events as is the case for PV inverters.
- It may be necessary in the future to consider other susceptible frequency sensitivities (e.g., electronically coupled load common-mode sensitivities).

UFLS is intended to be a safety net to prevent system collapse due to severe contingencies. Conceptually, that safety net should not be utilized for frequency events that are expected to happen on a relatively regular basis. As such, the resource loss protection criteria were selected in accordance with BAL-003-2 to avoid violating regionally approved UFLS settings.

Interconnection Resource Loss Protection Criteria

BAL-003-2 introduced the Interconnection RLPC to replace the Resource Contingency Protection Criteria used previously. It is based on resource loss in accordance with the following process.

NERC requests BAs to provide their two largest resource loss values and their largest resource loss due to an N-1 or N-2 RAS event. This facilitates comparison between the existing Interconnection RLPC values and the RLPC values in use. This data submission allows NERC to complete the calculation of the RLPC and IFRO.

BAs determine the two largest resource losses for the next operating year based on a review of the following items:

- The two largest balancing contingency events due to a single contingency identified by using system models in terms of loss measured by megawatt loss in a normal system configuration (N-0) (an abnormal system configuration is not used to determine the RLPC.)
    - The two largest units in the BA area, regardless of shared ownership/responsibility

[16] http://www.nerc.com/docs/pc/FRI_Report_10-30-12_Master_w-appendices.pdf

- The two largest Remedial Action Scheme (RAS) resource losses (if any) that are initiated by single (N-1) contingency events

The BA provides these two numbers determined above as Resource Loss A and Resource Loss B in the FR Form 1.

The BA should then provide the largest resource loss due to RAS operations (if any) that is initiated by a multiple contingency (N-2) event (RLPC cannot be lower than this value). If this RAS impacts more than a single BA, one BA is asked to take the lead and sum all resources lost due to the RAS event and provide that information.

The calculated RLPC should meet or exceed any credible N-2 resource loss event.

The host BA (or planned host BA) where jointly-owned resources are physically located should be the only BA to report that resource. The full ratings of the resource, not the fractional shares, should be reported.

Direct-current (dc) ties to asynchronous resources (e.g., dc ties between Interconnections, or the Manitoba Hydro Dorsey bi-pole ties to their northern asynchronous generation) should be considered as resource losses; dc lines like the Pacific DC Intertie, which ties two sections of the same synchronous Interconnection together, should not be reported. A single pole block with normal clearing in a monopole or bi-pole high-voltage dc system is a single contingency.

Calculation of IFRO Values

The IFRO is calculated using the RLPC (Table 1 from BAL-003-2):

$$\text{IFRO} = \frac{(\text{RLPC-CLR})}{(\text{MDF}*10)} \text{ expressed as MW/0.1Hz}$$

As specified in the Procedure for ERO Support of Frequency Response and Frequency Bias setting Standard, "MDF is the Maximum Delta Frequency for the specific interconnection as determined in the 2017 Frequency Response Annual Analysis (FRAA)." The BAL-003-2 revision alleviated the adverse impacts of an improving CB_R.

The IFRO for each Interconnection is calculated in this report in **Table 2.5**, and it should be noted that the calculated value for the EI IFRO is estimated by BAL-003-2 to be stepped down over three years with a reduction of IFRO not to exceed -100 MW/0.10 Hz per year in accordance with BAL-003-2. Collected RLPC data exceeded the estimate at the time BAL-003-2 balloted, and EI IFRO should meet the actual calculated value in only two operating years as a result. That determines the difference between the calculated EI IFRO in **Table 2.5** and the recommended IFRO shown in **Table ES.2** and **Table 2.9**.

Determination of Adjustment Factors

The CB_R detailed in this section is no longer used in the IFRO method but is still calculated and published in this report for comparison and informational purposes.

Adjustment for Differences between Value B and Point C (CB_R)

All the calculations in the IFRO are based on avoiding instantaneous or time-delayed tripping of the highest set point (step) of UFLS either for the initial nadir (Point C) or for any lower frequency that might occur during the frequency event. However, as a practical matter, the ability to measure the tie line and loads for a BA is limited to supervisory control and data acquisition (SCADA) scan rates of one to six seconds. Therefore, the ability to measure frequency response at the BA level is limited by the SCADA scan rates available to calculate Value B. To account for the issue of measuring frequency response as compared with the risk of UFLS tripping, an adjustment factor (CB_R) is calculated from the significant frequency disturbances selected for BAL-003-1 OYs 2015 through 2019 that capture the relationship between Value B and Point C.

Sub-Second Frequency Data Source

Frequency data used for calculating all the adjustment factors used in the IFRO calculation comes from the "FNet /GridEye system" hosted by UTK and the Oak Ridge National Laboratory. Six minutes of data is used for each frequency disturbance analyzed, one minute prior to the event and five minutes following the start of the event. All event data is provided at a higher resolution (10 samples per second) as a median frequency from the five most perturbed FDRs for that event.

Determination of C-to-B Ratio

The evaluation of data to determine the C-to-B ratio (CB_R) to account for the differences between arrested frequency response (to the nadir, Point C) and settled frequency response (Value B) is also based on a physical representation of the electrical system. Evaluation of this system requires investigation of the meaning of an intercept. The CB_R is defined as the difference between the predisturbance frequency and the frequency at the maximum deviation in postdisturbance frequency (A–C) divided by the difference between the predisturbance frequency and the settled postdisturbance frequency (A–B):

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

A stable physical system requires the ratio to be positive; a negative ratio indicates frequency instability or recovery of frequency greater than the initial deviation. The CB_R adjusted for confidence shown in **Table 2.1** should be used to compensate for the differences between Point C and Value B. For this analysis, BAL-003-2 frequency events from OYs 2016–2020 (December 1, 2015, through November 30, 2020) were used.

Table 2.1: Analysis of Value B and Point C (CB_R)

Interconnection	Number of Events Analyzed	Mean	Standard Deviation	95% Confidence	CB_R Adjusted for Confidence
Eastern	125	1.159	0.177	0.026	1.185
Western	110	2.092	0.764	0.121	2.213
Texas	114	1.833	0.569	0.088	1.921
Québec	217	4.689	1.432	0.161	1.550

The EI historically exhibited a frequency response characteristic that often had Value B below Point C, and the CB_R value for the EI has been below 1.000. In those instances, the CB_R had to be limited to 1.000. However, the calculated

CB_R in this year's analysis[17] indicates a value above 1.000, so no such limitation is required. This is due in large part to the improvement made to primary frequency response of the Interconnection through the continued outreach efforts by the NERC RS and the North American Generator Forum.

The QI's resources are predominantly hydraulic and are operated to optimize efficiency, typically at about 85% of rated output. Consequently, most generators have about 15% headroom to supply primary frequency response. This results in a robust response to most frequency events exhibited by high rebound rates between Point C and the calculated Value B. For the 211 frequency events in their event sample, QI's CB_R value would be two to four times the CB_R values of other Interconnections. Using the same calculation method for CB_R would effectively penalize QI for their rapid rebound performance and make their IFRO artificially high. Therefore, the method for calculating the QI CB_R was modified, limiting CB_R.

The QI has an operating mandate for frequency responsive reserves to prevent tripping the 58.5 Hz (300 millisecond trip time) first-step UFLS for their largest hazard at all times, effectively protecting against tripping for Point C frequency excursions. The QI also protects against tripping a UFLS step set at 59.0 Hz that has a 20-second time delay that protects the Interconnection from any sustained low-frequency Value B and primary-frequency response withdrawals. This results in a Point C to Value B ratio of 1.5. To account for the confidence interval, 0.05 is then added, making the QI CB_R equal 1.550.

Adjustment for Primary Frequency Response Withdrawal (BC'_{ADJ})

At times, the actual frequency event nadir occurs after Point C, defined in BAL-003-1 as occurring in the T+0 to T+12 second period during the Value B averaging period (T+20 through T+52 seconds) or later.[18] This lower nadir is symptomatic of primary frequency response withdrawal or squelching by unit-level or plant-level outer loop control systems. Withdrawal is most prevalent in the EI.

To track frequency response withdrawal in this report, the later-occurring nadir is termed Point C', which is defined as occurring after the Value B averaging period and must be lower than either Point C or Value B.

Primary frequency response withdrawal is important depending on the type and characteristics of the generators in the resource dispatch, especially during light-load periods. Therefore, an additional adjustment to the maximum allowable delta frequency for calculating the IFROs was statistically developed. This adjustment is used whenever withdrawal is a prevalent feature of frequency events.

The statistical analysis is performed on the events with C' value lower than Value B to determine the adjustment factor BC'_{ADJ} to account for the statistically expected Point C' value of a frequency event. These results correct for the influence of frequency response withdrawal on setting the IFRO. **Table 2.2** shows a summary of the events for each Interconnection where the C' value was lower than Value B (averaged from T+20 through T+52 seconds) and those where C' was below Point C for OYs 2016 through 2020 (December 1, 2015, through November 30, 2020).

Table 2.2: Statistical Analysis of the Adjustment for C' Nadir (BC'_{adj})

Interconnection	Number of Events Analyzed	C' Lower than B	C' Lower than C	Mean Difference	Standard Deviation	BC'ADJ (95% Quantile)
Eastern	125	42	16	0.006	0.004	0.007
Western	110	70	1	N/A	N/A	N/A
Texas	114	60	1	N/A	N/A	N/A
Québec	217	35	20	-0.017	0.023	-0.008

[17] The same was true for the 2016 analysis.

[18] BAL-003-2 redefines Point C to occur within T+20 seconds.

Only the EI had a significant number of resource-loss events where C' was below Point C or Value B for those events. The 20 events detected for QI and 1 event for WI are for load-loss events; this is indicated by the negative values for the mean difference and the BC'_{ADJ}. The adjustment is not intended to be used for load-loss events.

Although one event with C' lower than Point C was identified in the TI, it does not warrant an adjustment factor; only the adjustment factor of 7 mHz for the EI is necessary. Of the 125 frequency events analyzed in the EI, there were 42 events that exhibited a secondary nadir where Point C' was below Value B and 16 events where Point C' was lower than the initial frequency nadir (Point C). These secondary nadirs occur beyond 52 seconds after the start of the event,[19] within the time frame for calculating Value B, so a BC'_{ADJ} is only needed for the EI; no BC'_{ADJ} is needed for the other three Interconnections. This will continue to be monitored moving forward to track these trends in C' performance.

Low-Frequency Limit

The low-frequency limits to be used for the IFRO calculations (**Table 2.3**) should be the highest step in the Interconnection for regionally approved UFLS systems. These values have remained unchanged since the *2012 Frequency Response Initiative Report*.

Table 2.3: Low-Frequency Limits (Hz)

Interconnection	Highest UFLS Trip Frequency
Eastern	59.5
Western	59.5
Texas	59.3
Québec	58.5

The highest UFLS set point in the EI is 59.7 Hz in SERC-Florida Peninsula (FP), which was previously FRCC, while the highest set point in the rest of the Interconnection is 59.5 Hz. The SERC-FP 59.7 Hz first UFLS step is based on internal stability concerns and is meant to prevent the separation of the FP from the rest of the Interconnection. SERC-FP concluded that the IFRO starting point of 59.5 Hz for the EI is acceptable in that it imposes no greater risk of UFLS operation for an Interconnection resource loss event than for an internal SERC-FP event.

Protection against tripping the highest step of UFLS does not ensure generation that has frequency-sensitive boiler or turbine control systems will not trip, especially in electrical proximity to faults or the loss of resources. Severe system conditions might drive the combination of frequency and voltage to levels that present some generator and turbine control systems to trip the generator. Similarly, severe rates-of-change occurring in voltage or frequency might actuate volts-per-hertz relays; this would also trip some generators, and some combustion turbines may not be able to sustain operation at frequencies below 59.5 Hz.

Inverter-based resources may also be susceptible to frequency extremes. Laboratory testing by Southern California Edison of inverters used on residential and commercial scale PV systems revealed a propensity to trip at about 59.4 Hz, about 200 mHz above the expected 59.2 Hz prescribed in IEEE Standard 1547 for distribution-connected PV systems rated at or below 30 kW (57.0 Hz for larger installations). This could become problematic in the future in areas with a high penetration of inverter-based resources.

[19] The timing of the C' occurrence is consistent with outer-loop plant and unit controls, causing withdrawal of inverter-based resource frequency response.

Credit for Load Resources (CLR)

The TI depends on contractually interruptible (an ancillary service) demand response that automatically trips at 59.7 Hz by under-frequency relays to help arrest frequency declines. A CLR is made for the resource contingency for the TI.

The amount of CLR available at any given time varies by different factors, including its usage in the immediate past. NERC performed statistical analysis on hourly available CLR over a two-year period from January 2019 through December 2020, like the approach used in the *2015 FRAA* and in the *2016 FRAA*. Statistical analysis indicated that 1,136 MW of CLR is available 95% of the time. Therefore, a CLR adjustment of 1,136 MW is applied in the calculation of the TI IFRO as a reduction to the RLPC.

ERCOT Credit for Load Resources

Prior to April 2012, ERCOT was procuring 2,300 MW of responsive reserve service, of which up to 50% could be provided by the load resources with under-frequency relays set at 59.70 Hz. Beginning April 2012, due to a change in market rules, the responsive reserve service requirement was increased from 2,300 MW to 2,800 MW for each hour, meaning load resources could potentially provide up to 1,400 MW of automatic primary frequency response.

Determination of Maximum Allowable Delta Frequencies

Because of the measurement limitation[20] of the BA-level frequency response performance, IFROs must be calculated in "Value B space." Protection from tripping UFLS for the Interconnections based on Point C, Value B, or any nadir occurring after Point C, within Value B, or after T+52 seconds must be reflected in the maximum allowable delta frequency for IFRO calculations expressed in terms comparable to Value B.

Table 2.4 shows the calculation of the maximum allowable delta frequencies for each of the Interconnections. All adjustments to the maximum allowable change in frequency are made to include the following:

- Adjustments for the differences between Point C and Value B
- Adjustments for the event nadir being below Value B or Point C due to primary frequency response withdrawal measured by Point C'

Table 2.4: Determination of Maximum Allowable Delta Frequencies

Value	EI	WI	TI	QI	Units
Starting Frequency	59.972	59.969	59.971	59.966	Hz
Minimum Frequency Limit	59.500	59.500	59.300	58.500	Hz
Base Delta Frequency	0.472	0.469	0.671	1.466	Hz
CB_R[21]	1.185	2.213	1.921	1.550	Hz
Delta Frequency (DF_{CBR})[22]	0.398	0.212	0.349	0.946	Hz
BC'_{ADJ}[23]	0.007	N/A	N/A	-0.008	-
Calculated Max. Allowable Delta Frequency	0.391	0.212	0.349	0.954	Hz

[20] Due to the use of 1–6 second scan-rate data in BA's EMS systems to calculate the BA's Frequency Response Measures for frequency events under BAL-003-1

[21] Adjustment for the differences between Point C and Value B

[22] Base Delta Frequency/CB_R

[23] Adjustment for the event nadir being below the Value B (EI only) due to primary frequency response withdrawal.

Table 2.4: Determination of Maximum Allowable Delta Frequencies					
Value	EI	WI	TI	QI	Units
Max. Delta Frequency Per Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard	0.420	0.280	0.405	0.947	Hz

Calculated IFROs

Table 2.5 shows the determination of IFROs for OY 2022 (December 2021 through November 2022) under standard BAL-003-2 as well as under BAL-003-1 based on a resource loss equivalent to the recommended criteria in each Interconnection. The maximum allowable delta frequency values have already been modified to include the adjustments for the differences between Value B and Point C (CB_R), the differences in measurement of Point C using one-second and subsecond data (CC_{ADJ}), and the event nadir being below the Value B (BC'_{ADJ}).

Table 2.5: Initial Calculation of Operating Year 2022 IFROs					
Value	Eastern	Western	ERCOT	Québec	Units
Resource Loss Protection Criteria	3,740	3,069	2,805	2,000	MW
Credit for Load Resources	N/A	N/A	1136	N/A	MW
Calculated IFRO Using BAL-003-1 Method					
Starting Frequency	59.972	59.969	59.971	59.966	Hz
Calculated Max. Delta Frequency	0.391	0.212	0.349	0.954	Hz
Calculated IFRO using Calculated 2021 MDF	-957	-1096	-412	-210	
Calculated IFRO Using BAL-003-2 Method (2017 MDF)					
Max. Delta Frequency Per Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard	0.420	0.280	0.405	0.947	Hz
Calculated IFRO using 2017 MDF	-890	-1,096	-412	-211	MW/0.1 Hz
Recommended IFRO					
IFRO per Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard	-915[24]	-1096	-412	-211	MW/0.10 Hz

Comparison to Previous IFRO Values

The IFROs were first calculated and presented in the *2012 Frequency Response Initiative Report*. Table 2.6 compares the current IFROs and their key component values to those presented in the *2016 FRAA* report.

[24] EI IFRO decrease is limited to 100 MW/0.10 Hz annually from previous values. Calculated value without consideration of the limitation is -890 MW/0.10 Hz.

Table 2.5: Interconnection IFRO Comparison						
Value	**OY 2021 In Use[25]**	**OY 2021 Calc.[26]**	**OY 2022 Calc.[27]**	**2021 Calc. to 2022 Calc. Change**	**OY 2021 In Use to 2022 Calc. Change**	**Units**
Eastern Interconnection						
Starting Frequency	59.974	59.973	59.972	-0.001	-0.002	Hz
Max. Allowable Delta Frequency	0.443	0.418	0.420	0.002	-0.023	Hz
Resource Loss Protection Criteria	4,500	4,500	3,740	-760	-760	MW
Credit for Load Resources	0	0	0	0	0	MW
Absolute Value of IFRO	**1,015**	**1,092**	**890**	-202	-125	MW/0.1 Hz
Western Interconnection						
Starting Frequency	59.967	59.967	59.969	0.002	0.002	Hz
Max. Allowable Delta Frequency	0.292	0.248	0.280	0.032	-0.012	Hz
Resource Loss Protection Criteria	2,626	2,626	3069	443	443	MW
Credit for Load Resources	0	120	0	-120	0	MW
Absolute Value of IFRO	858	1,010	**1,096**	86	238	MW/0.1 Hz
Texas Interconnection						
Starting Frequency	59.966	59.971	59.971	0	0.005	Hz
Max. Allowable Delta Frequency	0.411	0.377	0.405	0.028	-0.006	Hz
Resource Loss Protection Criteria	2,750	2,750	2,805	55	55	MW
Credit for Load Resources	1,181	1,209	1,136	-73	-45	MW
Absolute Value of IFRO	**381**	**409**	**412**	3	31	MW/0.1 Hz
Québec Interconnection						
Starting Frequency	59.969	59.967	59.966	-0.001	-0.003	Hz
Max. Allowable Delta Frequency	0.948	0.946	0.947	0.001	-0.001	Hz
Resource Loss Protection Criteria	1,700	1,700	2,000	300	300	MW
Credit for Load Resources	0	0	0	0	0	MW
Absolute Value of IFRO	**179**	**180**	**211**	31	32	MW/0.1 Hz

[25] Calculated in the 2015 FRAA report. Average frequency values were for OYs 2012 through 2014.
[26] Calculated in the 2019 FRAA report. Average frequency values were for OYs 2015 through 2018.
[27] Calculated in the 2020 FRAA report. Average frequency values were for OYs 2015 through 2019.

Key Findings

Continued Increase in CB_R Supports Changes to IFRO Calculation Effected in BAL-003-2

Analysis of the characteristics of the IFRO calculations in response to trends in frequency response performance have identified inconsistencies in the IFRO calculation that have been identified and discussed, beginning with the *2016 FRAA*. The following findings are important to highlight. Although BAL-003-2 has addressed these inconsistencies, and a Standard Drafting Team continues the effort further, the explanation of these inconsistencies remains in this report as a transition between methods:

> The ratio between CB_R is a multiplicative factor in the IFRO formulae that couples these two quantities together in the formulation of the IFRO. The original intent of the IFRO calculation was to ensure that a declining frequency nadir (as demonstrated by an increasing A–C) would result in an increase in the IFRO. However, the calculation also resulted in an increase in IFRO when Stabilizing Period performance improved (as demonstrated by a decreasing A–B) while Point C remained relatively stable when performing calculations to meet BAL-003-1. When CB_R increased and all other variables remained the same, the IFRO increased when using that calculation method. The IFRO should not penalize an Interconnection for improved performance of Value B during the Stabilizing Period. **Table 2.7** shows the year-over-year comparison of adjusted CB_R for the Interconnections and demonstrates the trend of higher CB_R values that have resulted in higher calculated IFROs. Future iterations of this report will trend BAL-003-2 calculation improvement impacts.

Table 2.6: Year over Year Comparison Adjusted CB_R

Interconnection	OY2016	OY2019	OY2020	OY2021	OY2022	Difference OY2022–OY2016
Eastern	1.052	1.134	1.148	1.152	1.185	0.133
Western	1.598	1.879	2.004	2.009	2.213	0.615
Texas	1.619	1.774	1.826	1.835	1.921	0.302
Québec	1.55	1.55	1.55	1.55	1.55	0

Resource Loss Protection Criteria (RLPC)

The IFRO for each Interconnection is calculated for this report with the respective BAL-003-2 RLPC actual value derived from the BA submissions of 2021 Form 1 for each Interconnection, represented below:

$$\text{IFRO} = \frac{\text{(RLPC-CLR)}}{\text{(MDF*10)}} \text{ expressed as MW/0.1Hz}$$

RLPC is a major determining factor in the calculated IFRO. **Table ES.1** reflects the respective changes in Interconnection RLPC as BAL-003-2 improved IFRO calculation through use of N-2 resource loss versus BAL-003-1 use of N-1 resource loss.

Table 2.8 shows a comparison of mean Value A, mean Value B, and mean Point C that is illustrative of Interconnection performance over the previous OY and as compared to the 2016 OY when the IFRO values were frozen. Loss of load events have been excluded from the data in **Table 2.8**. The EI and WI maintained the trend of an increase in mean Value B and a decrease in the mean (A–B), indicating improved performance during the Stabilizing Period of frequency events. The TI showed no change in mean Value B and mean (A-B), and The QI had a decrease in mean Value B and increase in mean (A–B). The EI and WI show an increase or no change in mean Point C as well as a decrease or no

change in mean (A–C), indicating improved performance during the Arresting Period of frequency events. This performance data demonstrates that the increases in year-over-year CB_R that result in higher calculated IFROs are due to improved Stabilizing Period performance and not due to a decline in the performance of the Point C nadir. The TI and QI showed decreasing mean Point C and increasing mean (A-C).

Table 2.7: Year over Year Comparison Value A, Value B, and Point C (Loss of Load Events Excluded)

Value	OY2016	OY2021	OY2022	Difference OY2022–OY2016	Difference OY2022–OY2021
Eastern Interconnection					
Mean Value A (Hz)	59.998	59.999	59.999	0.001	0.000
Mean Value B (Hz)	59.947	59.953	59.954	0.006	0.001
Mean Point C (Hz)	59.947	59.949	59.949	0.002	0.000
Mean A–B (Hz)	0.051	0.046	0.045	-0.005	-0.001
Mean A–C (Hz)	0.051	0.050	0.050	-0.001	0.000
Western Interconnection					
Mean Value A (Hz)	60.000	59.995	59.995	-0.005	0.000
Mean Value B (Hz)	59.923	59.934	59.936	0.011	0.002
Mean Point C (Hz)	59.887	59.887	59.890	0	0.003
Mean A–B (Hz)	0.077	0.061	0.059	-0.016	-0.002
Mean A–C (Hz)	0.112	0.108	0.105	-0.004	-0.003
Texas Interconnection					
Mean Value A (Hz)	59.996	59.997	59.997	0.001	0.000
Mean Value B (Hz)	59.889	59.918	59.918	0.029	0.000
Mean Point C (Hz)	59.840	59.865	59.863	0.025	-0.002
Mean A–B (Hz)	0.107	0.079	0.079	-0.028	0.000
Mean A–C (Hz)	0.156	0.132	0.134	-0.024	0.002
Québec Interconnection					
Mean Value A (Hz)	60.003	60.003	60.004	0	0.001
Mean Value B (Hz)	59.843	59.876	59.870	0.033	-0.006
Mean Point C (Hz)	59.433	59.533	59.522	0.1	-0.011
Mean A–B (Hz)	0.160	0.127	0.133	-0.033	0.006
Mean A–C (Hz)	0.570	0.469	0.482	-0.101	0.013

Recommended IFROs for OY 2022

Consistent with the requirements of BAL-003-2, the IFRO values shown in **Table 2.9** for OY 2022 (December 2021 through November 2022) are recommended as follows:

Table 2.8: Recommended IFROs for OY 2022

Value	EI	WI	TI	QI	Units
MDF[28]	0.420	0.280	0.405	0.947	Hz
RLPC[29]	3,740	3,069	2,805	2,000	MW
CLR	0	0	1136	0	MW
Calculated IFRO	-890	-1096	-412	-211	MW/0.1 Hz
Recommended IFRO[30]	-915	-1096	-412	-211	**MW/0.1 Hz**

[28] The Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard, Version II provided in the approved ballot for BAL-003-2 specifies that "MDF is the Maximum Delta Frequency for the specific Interconnection as determined in the 2017 Frequency Response Annual Analysis (FRAA)".

[29] BAL-003-2, Attachment A specifies that RLPC be based on the two largest potential resource losses in an interconnection. This value is required to be evaluated annually.

[30] BAL-003-2 requires that the EI IFRO will be stepped down to its calculated value over three years. The maximum reduction is limited to 915 MW/0.10 Hz annually.

Chapter 3: Dynamics Analysis of Recommended IFROs

Because the IFROs for the EI, WI, and TI have only upon issue of this report been changed as governed by BAL-003-2, additional dynamic validation analyses were not done for this report.

Refer to the dynamics validation in the *2017 FRAA*[31] report for details. No analysis was performed for the QI.

Further supporting dynamic studies accompanied the development and filing of BAL-003-2.

[31] https://www.nerc.com/comm/OC/Documents/2017_FRAA_Final_20171113.pdf

Appendix A: Statistical Analysis of A–C Frequency Response

2016–2020 Statistical Trend Summary

Interconnection	2016–2020 Statistical Time Trend
	A–C Frequency response
Eastern	Stable (Neither decreasing nor increasing)
Texas	Stable (Neither decreasing nor increasing)
Québec	Stable (Neither decreasing nor increasing)
Western	Improving (increasing)

Eastern Interconnection

Eastern IFRM (A–C): 5-Year Data and Annual Datasets

Table A.1: Descriptive Statistics for Eastern Interconnection IFRM (A–C)

Operating Year (OY)	Number of Events	Mean Frequency Response	Standard Deviation	Median	Minimum	Maximum
2016–2020	**306**	**2,137**	**625**	**2040**	**961**	**4,615**
2016	61	2,243	550	2205	1,227	3,511
2017	80	1,974	566	1,844	961	3,611
2018	74	2,217	665	2,136	1,080	3,773
2019	56	2,105	594	1,886	1,174	3,721
2020	35	2,204	776	1,982	1,136	4,615

Eastern IFRM (A–C): Annual Distributions and Year-to-Year Changes

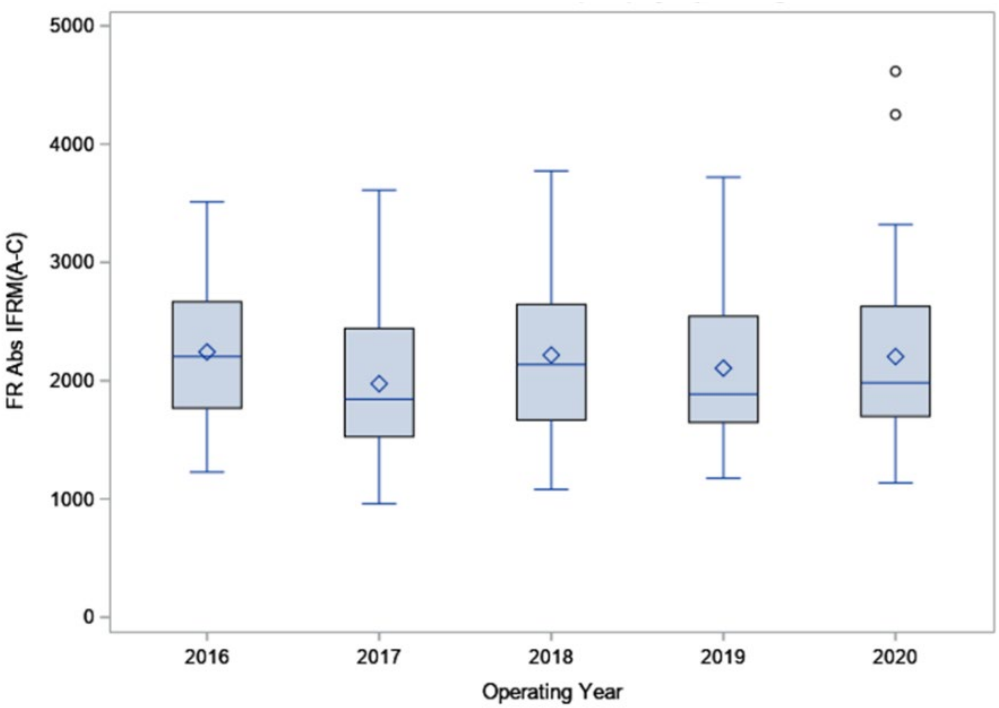


Figure A.1: Box Plots[32] of Eastern IFRM (A–C) Distribution by Operating Year 2016–2020

The 2020 mean Interconnection frequency response performance measure (IFRM) (A–C) was the third highest (and the third lowest) over the five years. Statistical tests found that the 2020 mean IFRM (A–C) was statistically similar to the other four years (in **Figure A.2** their means are connected with the 2020 mean by either a blue bar or a red bar).

[32] A box and whisker plots illustrate annual distributions as follows: The boxes enclose the interquartile range with the lower edge at the first (lower) quartile and the upper edge at the third (upper) quartile. The horizontal line drawn through a box is the second quartile or the median. The lower whisker is a line from the first quartile to the smallest data point within 1.5 interquartile ranges from the first quartile. The upper whisker is a line from the third quartile to the largest data point within 1.5 interquartile ranges from the third quartile. The data points beyond the whiskers represent outliers, or data points more than or less than 1.5 times the upper and lower quartiles, respectively. The diamonds represent the mean.

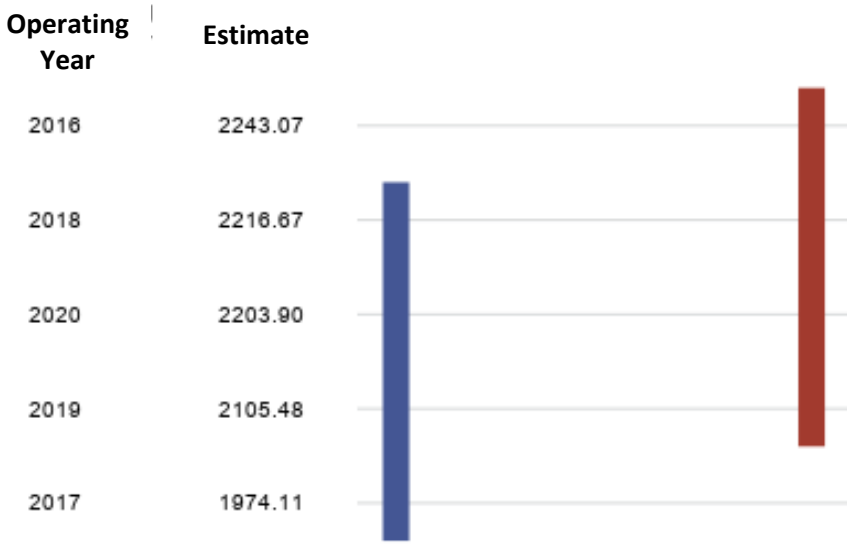


Figure A.2: Duncan Test for Eastern IFRM (A-C) Mean for Operating Years 2016–2020

Eastern IFRM (A-C): Time Trend[33]

In the EI, a linear regression line (a trend line for the IFRM (A–C) mean) shown in **Figure A.3** has a positive slope which is not statistically significant (p-value=0.96). This result implies that it is extremely likely that the positive slope of the trend line may have occurred simply by chance. This leads to the inference that from 2016–2020, the IFRM (A-C) in the EI has been neither decreasing nor increasing as measured by the mean.

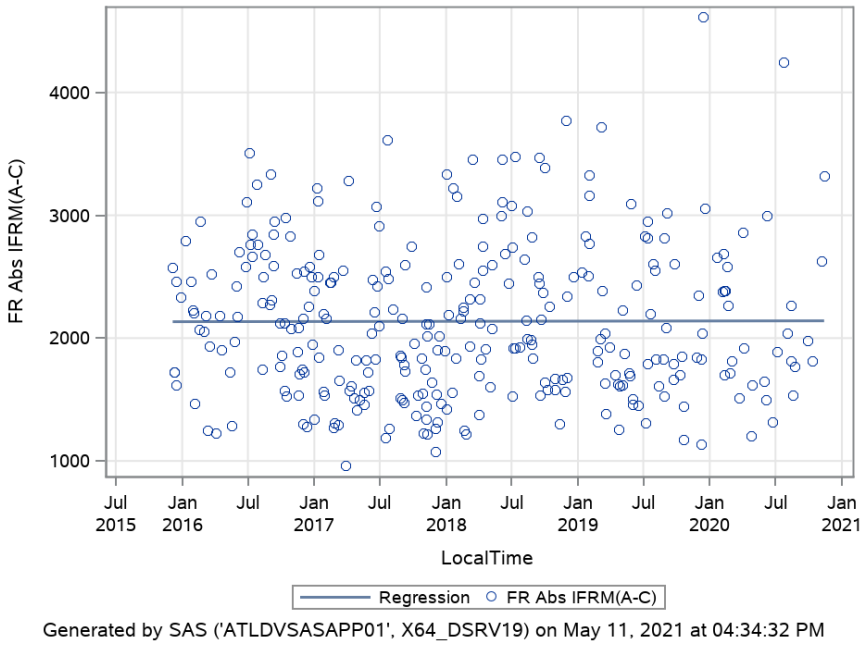


Figure A.3: Eastern IFRM (A–C) Scatter Plot and Time Trend Line for Mean IFRM (A–C) in 2016–2020

[33]The time trend analysis uses a dataset for the 2016–2020 operating years. Performance of IFRM (A-C) and its changes in time are studied by investigating relationships between IFRM (A–C) data and the explanatory variable time. A scatter plot is completed by a linear regression line that represents changes of the mean IFRM (A–C). A significance of a linear regression is tested at the significance level of 0.05. This analysis is repeated for each Interconnection.

Texas Interconnection

Texas IFRM (A–C): 5-Year Data and Annual Datasets

Table A.2: Descriptive Statistics for Texas Interconnection IFRM (A–C)						
Operating Year (OY)	Number of Events	Mean Frequency Response	Standard Deviation	Median	Minimum	Maximum
2016–2020	**223**	**476**	**101**	**467**	**268**	**1,040**
2016	50	467	91	466	268	728
2017	49	452	70	455	272	585
2018	38	506	128	479	350	1,040
2019	41	495	124	492	285	872
2020	45	470	86	448	326	646

Texas IFRM (A–C): Annual Distributions and Year-to-Year Changes

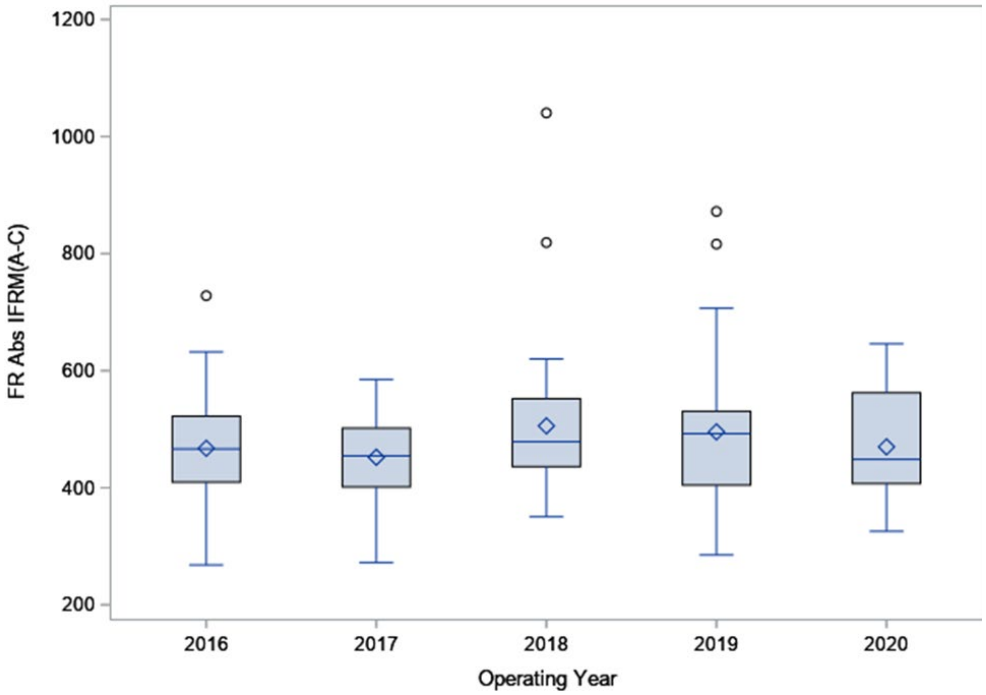


Figure A.4: Box Plots of Texas IFRM (A-C) Distribution by Operating Year 2016–2020

The 2020 Mean IFRM (A–C) was the third highest (and lowest) over the five years. Statistical tests found that the 2020 Mean IFRM (A–C) was statistically similar to the other four years (in **Figure A.5** the means are connected with the 2020 Mean by either a blue bar or a red bar).

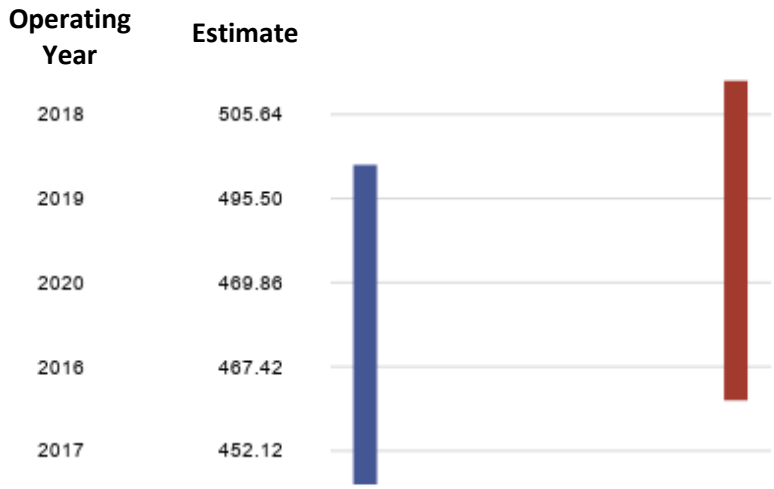


Figure A.5: Duncan Test for Texas IFRM (A–C) Mean for Operating Years 2016–2020

Texas IFRM (A-C): Time Trend

In the TI, a linear regression line (a trend line for the IFRM (A-C) mean) shown in **Figure A.6** has a positive slope which is not statistically significant (p-value=0.22). This result implies that it is likely that the positive slope of the trend line may have occurred simply by chance. It leads to the inference that from 2016–2020, the IFRM (A-C) in the TI has been neither decreasing nor increasing as measured by the mean.

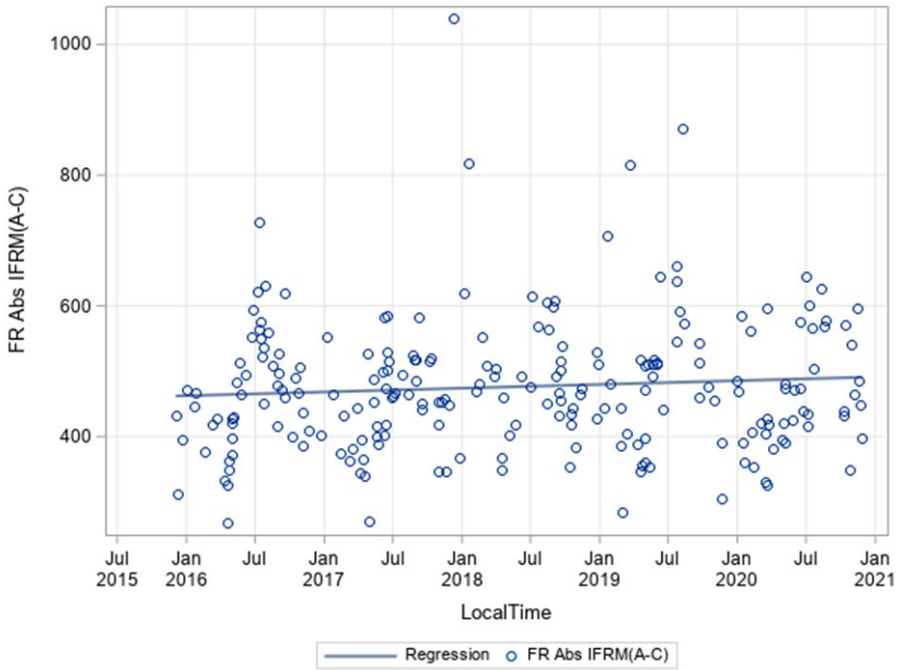


Figure A.6: Texas IFRM (A-C) Scatter Plot and Time Trend Line for Mean IFRM (A–C) in 2016–2020

Québec Interconnection

Québec IFRM (A–C): 5-Year Data and Annual Datasets

Table A.3: Descriptive Statistics for Québec Interconnection IFRM (A–C)						
Operating Year (OY)	**Number of Events**	**Mean Frequency Response**	**Standard Deviation**	**Median**	**Minimum**	**Maximum**
2016–2020	**311**	**133**	**30**	**127**	**54**	**292**
2016	47	138	30	140	76	242
2017	73	123	24	122	86	213
2018	82	134	27	127	86	267
2019	57	141	40	134	76	292
2020	52	129	28	127	54	197

Québec IFRM (A-C): Annual Distributions and Year-to-Year Changes

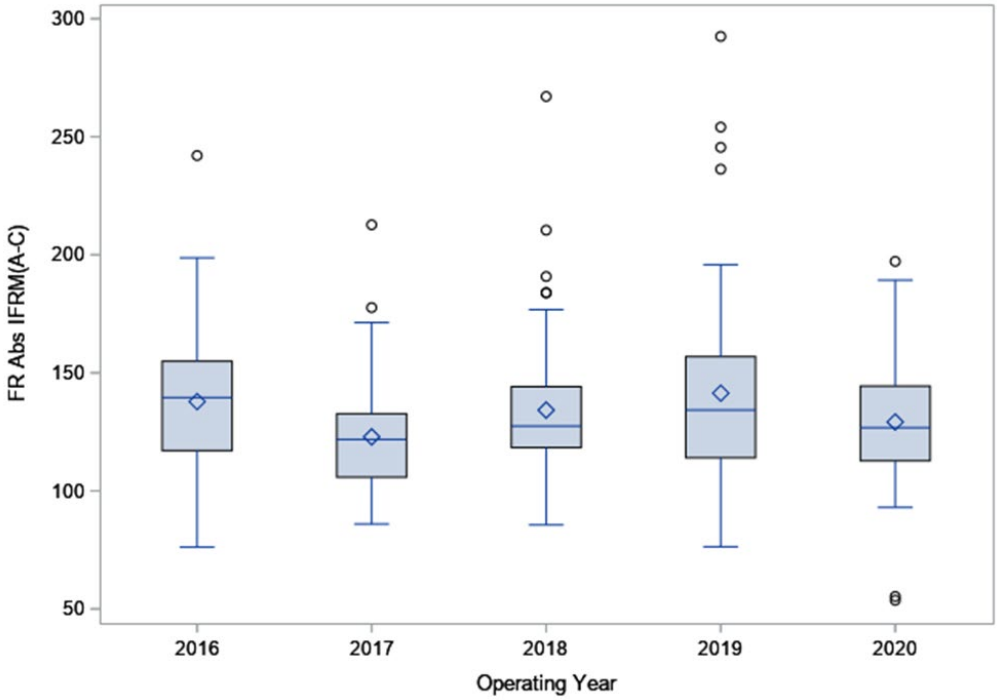


Figure A.7: Box Plots of Québec IFRM (A–C) Distribution by Operating Year 2016–2020

The 2020 Mean IFRM (A–C) was the second lowest over the five years. Statistical tests found that the 2020 Mean IFRM (A–C) was statistically similar to 2016, 2017, and 2018 and statistically significantly lower than the 2019 (the best year)—no bar connects the 2020 Mean and the 2019 Mean in **Figure A.8**.

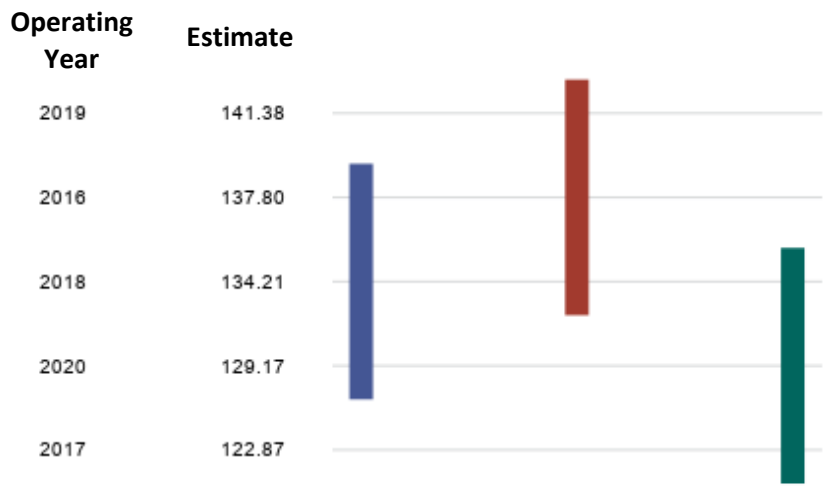


Figure A.8: Duncan Test for Québec IFRM (A–C) Mean for Operating Years 2016–2020

Québec IFRM (A-C): Time Trend

In the QI, a linear regression line (a trend line for the IFRM (A–C) mean) shown in **Figure A.9** has a negative slope which is not statistically significant (p-value=0.50). This result implies that it is likely that the negative slope of the trend line may have occurred simply by chance. It leads to the inference that from 2016–2020, the IFRM (A–C) in the QI has been neither decreasing nor increasing as measured by the mean.

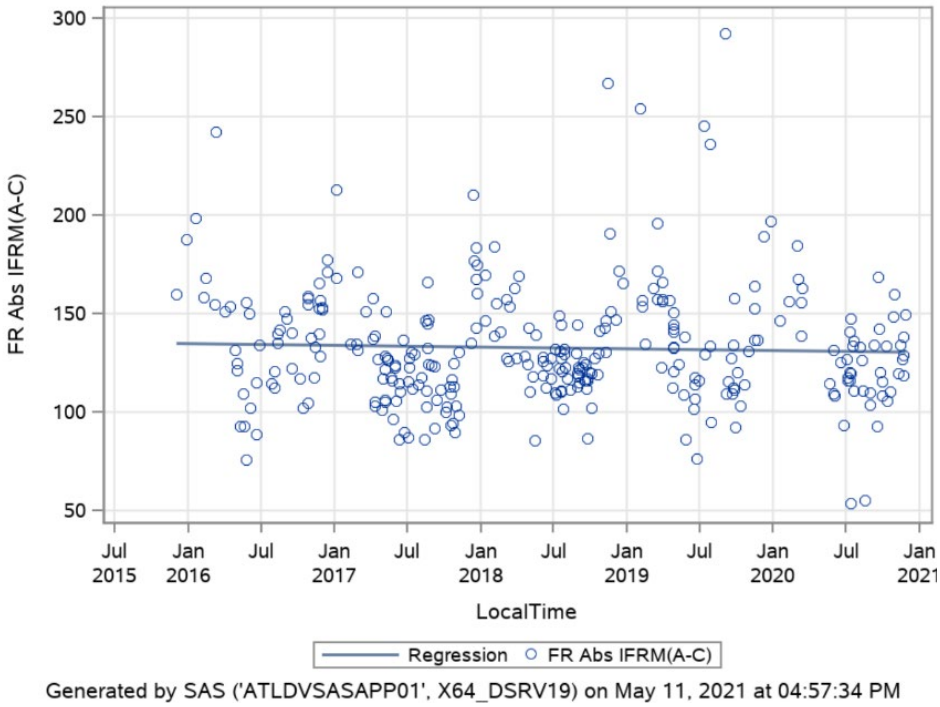


Figure A.9: Québec IFRM (A-C) Scatter Plot and Time Trend Line for Mean IFRM (A-C) 2016–2020

Western Interconnection

Western IFRM (A–C): 5-Year Data and Annual Datasets

Table A.4: Descriptive Statistics for Western Interconnection IFRM (A–C)						
Operating Year (OY)	Number of Events	Mean Frequency Response	Standard Deviation	Median	Minimum	Maximum
2016–2020	**200**	**867**	**228**	**841**	**373**	**1,737**
2016	47	827	177	804	525	1,375
2017	41	881	255	898	373	1,580
2018	43	840	180	847	419	1,179
2019	37	856	275	832	408	1,737
2020	32	955	245	978	381	1,649

Western IFRM (A–C): Annual Distributions and Year-to-Year Changes

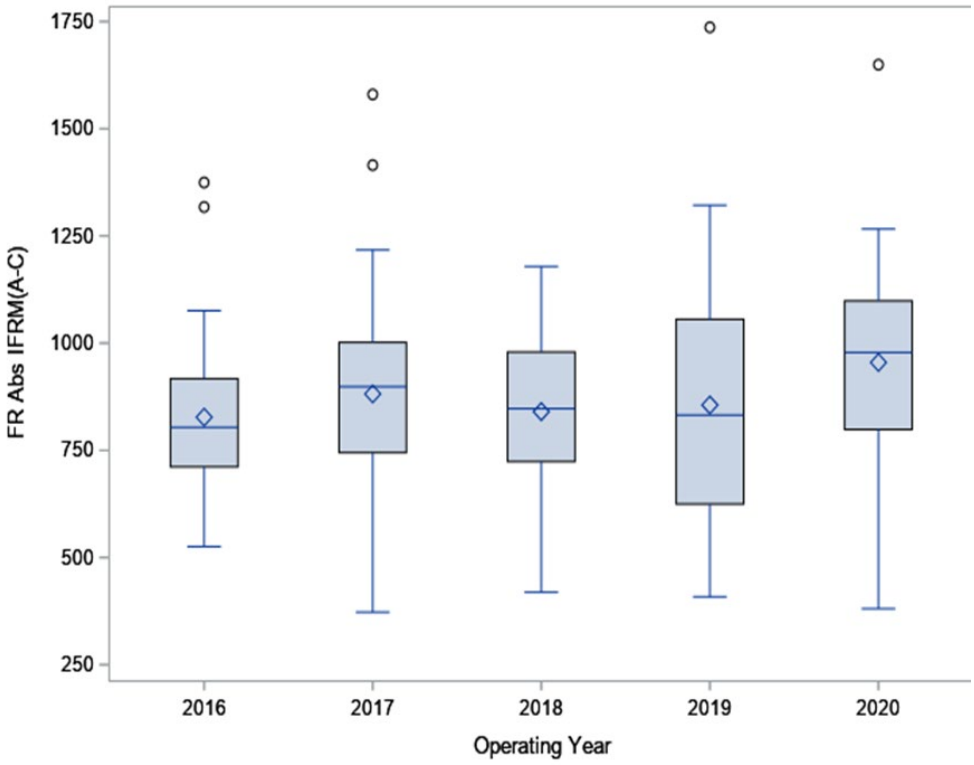


Figure A.10: Box Plots of Western IFRM (A–C) Distribution by Operating Year 2016–2020

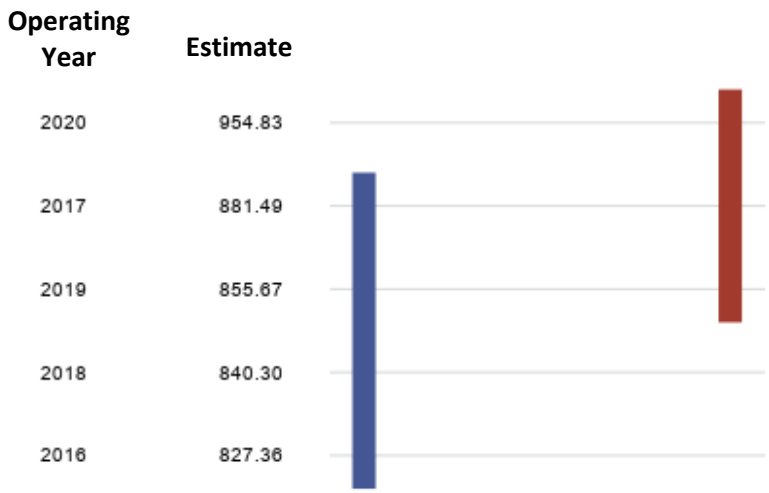


Figure A.11: Duncan Test for Western IFRM (A–C) Mean for Operating Years 2016–2020

The 2020 Mean and Median IFRM (A–C) were the highest over the five years. Statistical tests indicate that the 2020 mean was statistically significantly better than in 2016 and 2018 and statistically similar to 2017 and 2019.

Western IFRM (A-C): Time Trend

In the WI, a linear regression line (a trend line for the IFRM (A-C) mean) shown in **Figure A.12** has a positive slope which is statistically significant (p-value=0.04). This result implies that it is unlikely that the positive slope of the trend line may have occurred simply by chance. This leads to the inference that from 2016–2020, the IFRM (A–C) as measured by the mean has been increasing at the annual average rate of 21.2 MW/Hz*0.1.

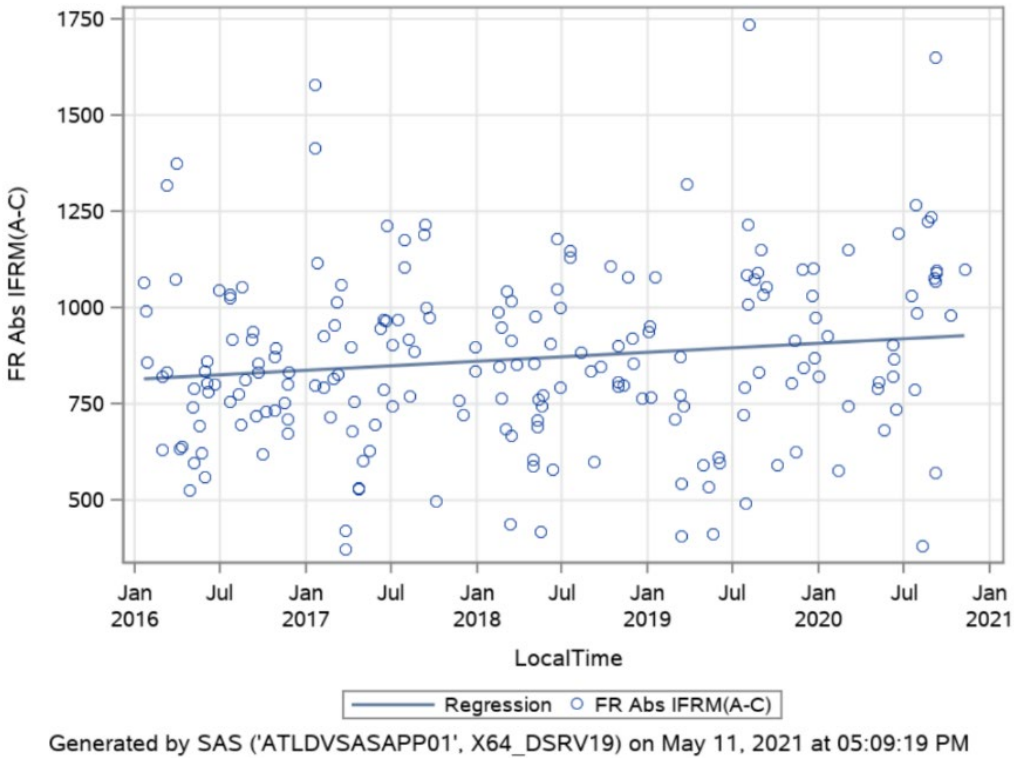


Figure A.12: Western IFRM (A–C) Scatter Plot and Time Trend Line for Mean IFRM (A–C) in 2016–2020

6 GHz Task Force Scope

Action
Approve

Summary
During the September 2021 RSTC meeting, the RSTC membership was provided an overview of the *Impact of Proposed Wi-Fi Operations on Microwave Links at 6 GHz*. The membership reached a consensus that a task force should be created to investigate the reliability impacts as the 6 GHz band of the radio spectrum is widely used by a broad array of industries responsible for critical infrastructure such as electric, gas and water utilities, railroads, and wireless carriers, as well as by public safety and law enforcement officials. The proposed task force would report to the RSTC in the Mitigating Risks program area. Proposed task force members were nominated by RSTC members and the group developed a draft Scope document as well as a proposed work plan. We are seeking RSTC approval of the Scope document.

6 GHz Task Force Scope

Purpose

In 2020, a consortium of electric industry associations published a report on the Impact of Proposed Wi-Fi Operations on Microwave Links at 6 GHz. The 6 GHz band of the radio spectrum is widely used by a broad array of industries responsible for critical infrastructure such as electric, gas and water utilities, railroads, and wireless carriers, as well as by public safety and law enforcement officials. Those industries rely on the 6 GHz band to operate their equipment and is a main source of primary communications for voice and data, and in-some cases back-up communications, during emergencies and disasters. The report identifies impacts to electric power operations. Additional follow-on work by EPRI and various affected stakeholders have shown—through testing--impacts to their critical electric infrastructure communications due to increased congestion and interference on the 6GHz wireless communication band. As adoption of the new technology increases, the risk to BPS operations may increase.

Activities

The Reliability and Security Technical Committee (RSTC) oversees the 6 GHz Task Force (6GTF).

The 6 GHz Task Force will provide recommendations to the NERC RSTC as follows:

1. Determine scope of issue (e.g., limited to 6 GHz, relationship to other telecommunications items, etc.)
2. Gather information related to risk of harmful interference in the 6 GHz spectrum.
    a. Identify penetration and Bulk Power System users relying on 6 GHz.
    b. Reach to industry for input on potential readiness issues (e.g., trade associations, membership organization, compliance forums, registered entities, etc.).
    c. Initiate or request industry information related to current harmful interference experience.
    d. Identify potential mitigation strategies.
3. Evaluate options for industry outreach.
4. Develop suggested recommendations related to the issue.

Deliverables

The 6 GHz Task Force will develop the following:

1. Impact Assessment to effectively assess communication disruption risks in operations of the Bulk Power System.
    a. Representative group of utilities perform critical circuit identification voluntarily for pilot activities and feasibility development. Recommended focus on Hub locations or non-Hub locations that are critical to grid operations.

2. Recommendations for the development of tools/guides to enhance operational awareness about harmful interference to communications information. Some of the information needed for situational awareness is captured below.

a. Work with radio manufacturer(s) to assess what performance reports and alarms are available from the radio. In addition, assessment should include how the radios interface with respective Network Management Systems (NMS). Information sharing for industry if possible.
b. Work with their equipment manufacturers to determine next steps needed to detect interference for information sharing, if practicable.
c. Develop method for standardized reporting of identified harmful interference.

3. Information that can be used for a range of audiences that describe potential emerging risks and possible solutions to address these risks. This information may include educational materials, workshops, webinars, or other beneficial platforms.
   a. Several resources are available publicly to further demonstrate the problem and anticipated outcomes. Design effective way to share information (FAQ, resource library, one-stop shop, etc.).
      i. Southern's Test Report (Insert Link).
   b. Guidance for entities to provide options for methods to test for harmful interference.
   c. Host webinar to raise industry awareness and increase recognition that Wi-Fi6E interference will have detrimental effects on the Licensed 6GHz fleet for all companies.

4. Recommendations related to the GridEx V Executive Tabletop Recommendation on 6 GHz to facilitate work with the telecommunications sector to consider interdependencies.
   a. Utilities should document critical communications facilities as part of their grid restoration plans.
   b. Work with telecommunication providers to understand broader communication industry restoration priorities.
   c. Incorporate any other identified and related communication network recommendations as deemed necessary or logical for the scope of the task force.

5. Other tasks as deemed appropriate.

Materials developed could include technical reference documents, guidelines, alerts, and other educational materials to support industry efforts for preparedness.

Members, Structure, and Roles and Responsibilities

The 6 GHz Task Force includes members who have technical or policy level expertise in the following areas:

- Telecommunications networking
- Reliability Coordination
- Transmission Operations
- Generation Operations
- Electric and infrastructure operations
- Communications Policy

The 6 GHz Task Force will consist of a chair and vice chair appointed by the RSTC leadership. NERC staff will be assigned as Coordinator(s). Decisions will be consensus-based of the membership, led by the chairs and staff Coordinator(s). Any minority views may be included in an addendum.

Reporting and Duration

The 6 GHz Task Force will report to the NERC RSTC. All work products will be approved by the NERC RSTC. The group will submit a work plan to the RSTC following its inception and will develop the deliverables outlined.

Meetings

The group is expected to meet as necessary via conference calls to execute the deliverables outlined in the near-term timeframe. Further work and continued necessity for meeting will be evaluated once deliverables have been delivered and approved.

Appendix A: Roles and Responsibilities

Table A.1: 6GHz TF RACI (Responsible, Accountable, Consulted, Informed)

Description	RSTC Sponsor	6 GHz TF Chair	6 GHz TF Vice Chair	Sub-Team Lead	Sub-Team Member	NERC Staff (Secretary)	NERC Staff (Support)	6 GHz TF Member	6 GHz TF Observer
Organize monthly/quarterly 6 GHz TF Meetings	I	A, R	A, R	I	I	C	I	C	I
Organize Sub-team meetings	I	A	A	A, R	C	C	I	I	I
Coordinate Sub-team activities, ensure completion of Sub-team tasks	I	I	I	A	R	I	I	I	I
Administrative review of products completed	C	A	A	R	C	C	I	I	I
Drive RSTC review/acceptance process	C	A, R	A, R	C	C	C	I	I	I
Perform sub-team tasks	N/A	I	I	A	R	I	I	I	I
Coordinate with other working groups	I	A, R	A, R	C	C	I	I	I	I
Meet with 6 GHz TF chair/vice chair for status, problem-solving	C	C	C	A, R	C	I	I	N/A	N/A
POC for 6 GHz TF for industry groups	C	A, R	A, R	C	I	I	I	I	I
Problem-solve for delivery dates	I	C	C	A, R	R	C	I	I	I
Maintain extranet site	I	A, R	A, R	A, R	R	I	I	I	I
Send out and collect calls for volunteers	I	A, R	A, R	C	C	C	C	I	I
Drive continuous improvement for 6 GHz TF processes	C	A, R	A, R	R	C	C	C	C	I
Endorse 6 GHz TF products	C	A, R	A, R	C	I	C	I	I	I
Provide 6 GHz TF Scope Guidance	A	R	R	C	C	I	I	I	I
Provide daily guidance to sub-teams	N/A	A	A	R	C	I	I	I	I
Extranet design changes, tools	I	A, R	A, R	C	C	I	I	I	I
Manage project input process	C	A, R	A,R	C	C	I	I	I	I
Maintain and monitor work processes	I	A	A	R	C	C	I	I	I
Approve 6 GHz TF Work Plan	C	A	A	R	C	C	I	I	I
Manage mailing lists and overall SharePoint environment (extranet)	N/A	A	A	C	C	C	R	I	I

Appendix B: Version History

Table B.2: 6 GHz TF Scope Version History			
Date	**Page**	**Description**	**Version**
12/14/2021	All	Draft 6 GHz TF Scope Approved by the RSTC	0.1

RSTC Sunset Review Team Recommendations

Action
Approve

Summary
Per the RSTC Charter, the RSTC "will conduct a "sunset" review of each working group every year" and "review the task force scope at the end of the expected duration and at each subsequent meeting of the RSTC until the task force is retired." The RSTC Executive Committee developed a draft process and template for these reviews to be conducted prior to the December 2021 RSTC meeting.

The process for this review included the RSTC Sponsors, in coordination with group leadership and NERC Staff Liaisons, reviewing the working group or task force deliverables and work plans to populate the information in the template. The Sunset Review Team is seeking approval of its recommendation for each working group and task force.

Reliability Guidelines and Security Guidelines Triennial Review

Action
Approve

Summary
On January 19, 2021, the Federal Energy Regulatory Commission ("FERC") accepted the North American Electric Reliability Corporation's ("NERC") proposed approach for evaluating Reliability Guidelines, as proposed in the Five Year Assessment proceeding. Initial triennial review of existing Reliability Guidelines is due June 2023.

NERC Staff made a preliminary recommendation for each existing Guideline to either remain a Guideline, convert to a Technical Reference Document or become a Hybrid (a Guideline and a Technical Reference Document). Each RSTC subcommittee, working group or task force that is responsible for triennial review of an existing guideline reviewed the recommendation and determined the final disposition as well as which tranche the document should be revised within. The RSTC Review Team developed its final recommendation**s** and is seeking RSTC approval of the tranches so that work plan items can be developed to meet the regulatory deadlines.

RSTC: Reliability Guidelines and Security Guidelines

Identification Number (RG/SG-3DigitCategory-ApprovalMMYY-Version) (Alpha added after MMYY if more than one approved on same day)	Guideline Title (Security Guideline: NAME OF GUIDELINE)	Reliability Guideline, Reference Document or hybrid combo RG/RD?	Category/ Topic	Lastest Approval Date	Next Review Due Date	Subgroup	Priority/Tranche	No. Pages	Notes
RG-OPS-1211-3	Reliability Guideline: Generating Unit Operations During Complete Loss of Communications	RG	Operations	12/11/2018	12/10/2021	EAS	1	19	
RG-SPC-0918-1	Reliability Guideline: BPS-Connected Inverter-Based Resource Performance	RG	Resource Performance	9/12/2018	9/11/2021	IRPWG	1	98	Changed from Tranche 3 to Tranche 1 base on review due date
RG-SPC-0919-1	Reliability Guideline: Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources	RG	Transmission Planning	9/13/2019	9/12/2022	IRPWG	1	52	Changed from Tranche 3 to Tranche 1 base on review due date
RG-MOD-0317-1	Reliability Guideline: Developing Load Model Composition Data	HYBRID	Transmission Planning	3/10/2017	3/9/2020	LMWG	1	34	Put in Tranche 1 based on review due date
RG-BAL-1217-1	Reliability Guideline: Inadvertent Interchange	RG	Balancing	12/13/2017	12/12/2020	RS	1	9	Currently under revision for December 2021 approval
RG-BAL-0619-2	Reliability Guideline: Primary Frequency Control	RG	Balancing	6/4/2019	6/3/2022	RS	1	34	
RG-ENA-1217-1	Reliability Guideline: Gas and Electrical Operational Coordination Considerations	RG	Energy Assurance	12/13/2017	12/12/2020	RTOS	1	14	Put in Tranche 1 based on review due date
RG-OPS-0618-1	Reliability Guideline: Cyber Intrusion Guide for System Operators	RG	Operations	6/25/2018	6/24/2021	RTOS	1	3	Currently under revision for December 2021 approval
SG-SCH-1220-1	Security Guideline: Supply Chain Procurement Language	SG	Supply Chain	12/15/2020	12/15/2023	SCWG	1	3	Consider whether or not to combine all SC Guidelines into a single one.
SG-CYB-1013-1	Security Guideline: Control Systems Electronic Connectivity	SG	Cyber	10/28/2013	10/27/2016	SWG	1	26	Tranche 1 based on review due date
SG-PHY-1013-1	Security Guideline: Physical Security Response	SG	Physical	10/28/2013	10/27/2016	SWG	1	16	Tranche 1 based on review due date
SG-PHY-0319-1	Security Guideline: Physical Security Considerations at High Impact Control Centers	SG	Physical	3/5/2019	3/4/2022	SWG	1	13	Tranche 1 based on review due date
SG-PHY-0619-1	Security Guideline: Reliability Assessments and Resiliency Measures for Extreme Events	SG	Physical	6/5/2019	6/4/2022	SWG	1	22	Tranche 1 based on review due date

Agenda Item 9
Reliability and Security
Technical Committee Meeting
December 14, 2021

White Paper – Oscillation Analysis for Monitoring and Mitigation

Action
Approve

Summary
Recent oscillation events, such as the January 11, 2019 forced oscillation event in Florida that interacted with a natural system mode of the Eastern Interconnection and led to propagation of the oscillation across the Interconnection, have highlighted the need for increased monitoring and consistency in the monitoring of oscillation disturbances. Some of the key recommendations from the report on the event included the need for Reliability Coordinators (RCs) and Transmission Operators (TOPs) to utilize real-time oscillation detection tools.

The NERC Synchronized Measurement Working Group (SMWG) was requested to develop guidance on oscillation analysis methods to encourage consistency in the system quantities that are monitored for oscillation events and the respective thresholds for alarms. The detection and alarming of oscillations and their classification in a consistent manner is critical in ensuring coordinated mitigation of both local and widespread oscillation disturbances in the bulk power system. The SMWG is seeking RSTC approval of the White Paper.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Recommended Oscillation Analysis for Monitoring and Mitigation

Synchronized Measurement Working Group

November 2021

RELIABILITY | RESILIENCE | SECURITY

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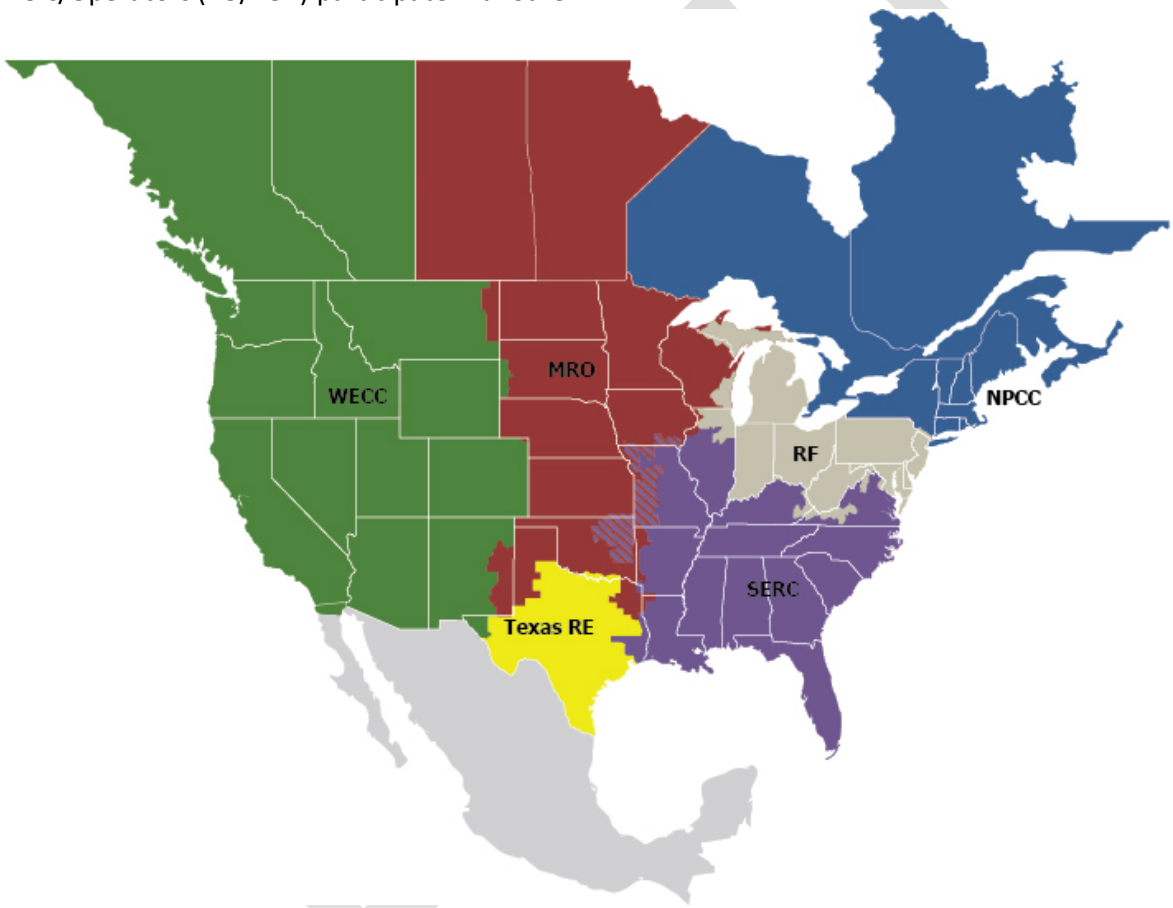
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one RE while associated Transmission Owners/Operators (TO/TOP) participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

Executive Summary

Recent oscillation events, such as the January 11, 2019, forced oscillation event in Florida that interacted with a natural system mode of the Eastern Interconnection and led to propagation of the oscillation across the Interconnection, have highlighted the need for increased monitoring and consistency in the monitoring of oscillation disturbances. Some of the key recommendations from the report[1] on the event included the need for Reliability Coordinators (RCs) and Transmission Operators (TOPs) to utilize real-time oscillation detection tools. RCs and TOPs should have real-time oscillation detection tools in place to identify when oscillations are occurring and determine if the oscillations are limited locally within their footprint or are more widespread. Equally important is to be able to distinguish between forced oscillations, poorly damped natural system modes, or scenarios where forced oscillations may be propagating across a wider area due to resonance conditions. In addition, there was a recognition that RCs should improve their communication with RCs in the event of widespread oscillation disturbances in BPS and when operating procedures could be an effective means of ensuring this coordination upon the identification of an oscillation.

The NERC Synchronized Measurement Working Group (SMWG) was also requested to develop guidance on oscillation analysis methods to encourage consistency in the system quantities that are monitored for oscillation events and the respective thresholds for alarms. The detection and alarming of oscillations and their classification in a consistent manner is critical in ensuring coordinated mitigation of both local and widespread oscillation disturbances in BPS.

In addition, it is also important to identify what kind of operator actions are necessary for different kind of oscillations. These actions can range from locating the source of forced oscillations to reducing power transfers across major transmission paths. Actions can also include making topological changes to improve damping of widespread natural system oscillations or combinations of those actions if there is interaction of the forced oscillations with natural system modes that results in propagation across the Interconnection.

The following are key findings and recommendations of this white paper:

- For monitoring of inter-area or natural oscillations, various methods exist that can utilize ambient or post-disturbance data to determine the system modes that are significant. These assessments are recommended to be done annually or based on significant changes in the system. After identifying the significant modes, additional analyses can be performed to determine the locations where the modes are observable and the respective thresholds for alarming or operator action based on damping and the energy of the modes. In addition, analyses using powerflow cases and the associated dynamic models can be utilized to validate the modeling of the observed significant modes and to determine what mitigation actions might be effective in improving the damping of those modes.
- Forced oscillations can be detected using various methods that utilize thresholds established by prior analyses to differentiate between sustained forced oscillations and normal ambient changes in system conditions. Once the forced oscillations are detected, various methods exist to determine the locations from where the forced oscillations originate.
- Under certain conditions, forced oscillations can propagate across an Interconnection due to resonance with a natural system mode. Mitigation of such wide spread oscillations can require a combination of mitigation actions ranging from locating and eliminating the source of the oscillation to taking actions to reduce the impacts across the system by improving the damping of the impacted system mode.

[1] Lesson Learned: Interconnection Oscillation Disturbances: https://www.nerc.com/pa/rrm/ea/Lessons Learned Document Library/LL20210501_Interconnection_Oscillation_Disturbances.pdf

- Mitigation of local and widespread oscillation disturbances and their impact requires effective tools and coordination between RCs and TOPs to determine the type of oscillation and the appropriate mitigation actions.

Introduction

The SMWG, formerly the Synchronized Measurement Subcommittee, has provided well-accepted guidance on what oscillations are, why they occur, and what are the various tools to monitor them. Various previously published reports on Interconnection oscillation analyses[2] and forced oscillation events[3] provide recommendations on what Reliability Coordinators (RC) and TOPs should do to monitor oscillations, emphasizing the need to coordinate and develop tools. Monitoring of oscillations requires the setup and configuration of real-time tools that require a certain level of analyses and preparation to determine the quantities for monitoring, what should be their respective thresholds for alarms, and the respective operator actions.

The analysis that is required can vary depending on whether a tool is being set up to monitor a natural inter-area oscillation or a forced oscillation. The levels at which operator actions are necessary to intervene and mitigate for any potential reliability impacts of oscillations can also vary based on the type and location of oscillation. RCs and TOPs are in the process of developing operating procedures to supplement the monitoring of oscillations. These operating procedures contain specific actions for operators to follow during critical oscillatory conditions. Model-based simulations provide an opportunity to determine required mitigation actions for consistency in developed operating procedures and mitigation plans.

This white paper addresses two distinct types of power system oscillations, natural and forced and is divided into five distinct chapters:

- **Chapter 1** addresses inter-area electromechanical oscillations. These oscillations are often referred to as natural oscillations because they arise from the dynamics inherent to any power system. A system's inter-area modes of oscillation govern the periodic exchange of energy between generators in different parts of the system. Natural oscillations can take on different forms depending on how the system's dynamics are excited: ambient oscillations resulting from continuous perturbation by random load changes and ringdown oscillations caused by an impulsive disturbance, such as a generator tripping off-line.
- **Chapter 2** addresses forced oscillations, which are the response of a system to a particular periodic input, such as a generator with a steam valve cycling on and off continuously.
- **Chapter 3** discusses the case where a forced oscillation becomes observable across a wide area.
- **Chapter 4** provides recommended guidelines for operators to address wide-area oscillations.
- **Chapter 5** discusses examples of existing practices by RCs and operators.

In summary, the chapters of this white paper aim at providing a framework of methods to do the following:

- Conduct natural-mode-related and forced oscillation analysis by using examples to illustrate what is normal and what is not
- Determine quantities to be monitored and quantify their boundaries and how to implement these boundaries as monitoring thresholds in tools
- Determine and validate mitigation actions and establish distinction between local and system issues

[2] Interconnection Oscillation Analysis: https://www.nerc.com/comm/PC/SMSResourcesDocuments/Interconnection_Oscillation_Analysis.pdf
[3] Eastern Interconnection Oscillation Disturbance: https://www.nerc.com/pa/rrm/ea/Documents/January_11_Oscillation_Event_Report.pdf

Chapter 1: Inter-Area Electromechanical Oscillations

As demonstrated by the *2019 Interconnection Oscillation Analysis Reliability Assessment* [4] different Interconnections have different known modes. In fact, there are a large number of modes, but they can be reduced to only a handful that are dominant, important, and observable and actually have a noticeable effect on electrical signal dynamics of the system. This reduction usually leads to roughly a half dozen or so modes in each Interconnection (depending on grid size and complexity) that are worth understanding and tracking. Some of the commonly known modes are shown in **Table 1.1**, which demonstrates the differences between the Interconnections and the expected Hz range for these oscillations.

Table 1.1: Major Modes in Various Interconnections

Interconnection	Mode Name	Mode Frequency Range (Hz)
Eastern	N–S	0.16–0.22
	NW–S	0.29–0.32
	NE–NW–S	0.23–0.24
Texas	N–SE	0.62–0.73
Western	North-South A (NSA)	0.20–0.30
	North-South B (NSB)	0.35–0.45
	East-West A (EWA)	0.35-0.45
	British Columbia (BC)	0.50-0.72
	Montana	0.70-0.90

The next section provides a summary of known methods that help determine the following:

- The modes of significance in an Interconnection that are recommended to be monitored, for a given system topology and operating condition, typically appear as consistent peaks in the signal spectrum (see **Figure 1.1**). When mode monitoring algorithms (both ringdown and ambient measurement-based) are used, the estimated modes tend to form clusters (as shown in **Figure 1.2**) over time or across multiple signals on a complex plane. In addition, significant modes tend to have much higher pseudo modal energy[5] compared to all other estimated modes from the same measurement window. This can be verified by looking at curve fitting errors from a small subset of the estimated modes.
- Methods for determining the effective mitigation actions should be used to increase damping of the determined modes.
- Methods for determining the measurements should be used to monitor the significant modes.

[4] Interconnection Oscillation Analysis: https://www.nerc.com/comm/PC/SMSResourcesDocuments/Interconnection_Oscillation_Analysis.pdf
[5] Trudnowski, Daniel J., John W. Pierre, Ning Zhou, John F. Hauer, and Manu Parashar. "Performance of three mode-meter block-processing algorithms for automated dynamic stability assessment." IEEE Transactions on Power Systems 23, no. 2 (2008): 680–690.

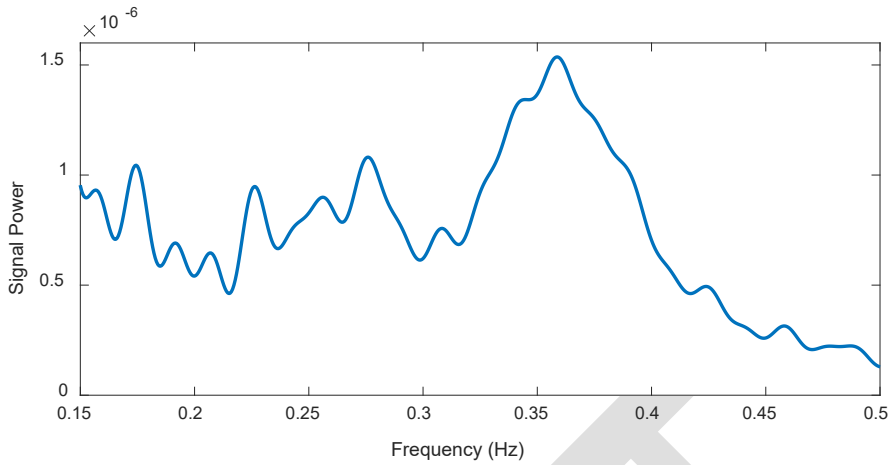


Figure 1.1: Estimate of the Spectral Content of the Frequency Signal

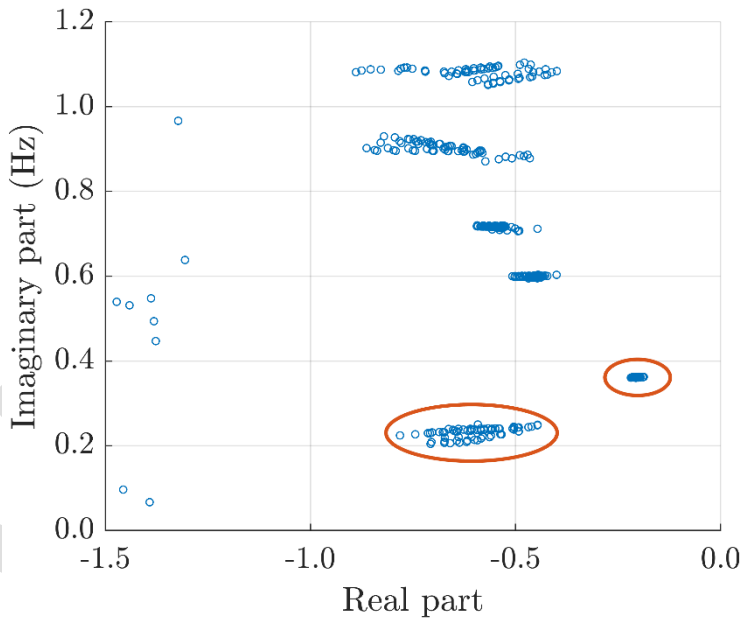


Figure 1.2: Example of clusters formed by eigenvalue estimates

1.1 Interconnection-Wide Analysis to Determine Significant Modes

This section provides a framework of known small-signal stability analysis methods to determine the inter-area modes of significance, input data, and any other information required to do these analyses. Guidance is also provided on the recommended frequencies of these studies. The *2019 Interconnection Oscillation Analysis*[6] report presented various types of oscillation analysis techniques for modal identification. In addition, more comprehensive details on these methods are available in the IEEE Power and Energy Society (PES) developed technical report: *Identification of Electromechanical Modes in Power Systems.*[7] Several of the methods described in this section have been deployed in commercial tools and deployed by system operators. Examples are provided in **Chapter 5**.

These methods fall into three main categories:

[6] Interconnection Oscillation Analysis: https://www.nerc.com/comm/PC/SMSResourcesDocuments/Interconnection_Oscillation_Analysis.pdf

[7] IEEE Task Force on Identification of Electromechanical Modes, *Identification of Electromechanical Modes in Power Systems, IEEE Technical Report PES-TR15*, June 2012 (http://resourcecenter.ieee-pes.org/pes/product/technical-publications/PESTR15).

Ringdown Methods: These are used to analyze natural oscillations that result from large disturbances on the BPS. These methods can be utilized with phasor measurement data or simulated data from offline powerflow dynamic simulations. The post-disturbance trajectories of relevant power system states, or sometimes combinations of statements, are commonly referred to as "ringdowns." Analysis of ringdowns provides valuable insight into the frequency, damping ratio, and shape of the system's inter-area modes of oscillation. It can also serve as a useful tool in model validation (i.e., ensuring that the modal characteristics of real-time or planning base cases match those of the actual system). There are various algorithms and methods employed for modal analysis of disturbance data that are distinct from the techniques used to analyze ambient data.

Ambient Methods: These are used to analyze signals during normal, steady-state conditions where the primary excitation to the system is random load changes. These methods are typically in real-time tools or offline tools for analysis of phasor measurement data. They can be used to track the frequency, damping ratio, shape of specific modes of oscillation, or to identify periods of low damping in any mode. They can also be used to analyze ambient periods surrounding disturbance data to provide validation for ringdown methods.

Eigenvalue Analysis Method: This method can be implemented by using powerflow cases along with the associated dynamic data to determine the modes that exist in a system. The mode frequency, damping and associated mode shape, controllability, and participation factor of participating generators can be determined. The method can be utilized on offline powerflow base-cases used for transmission planning and operational planning studies or with real-time state estimator snapshots.

Table 1.2 shows a summary of the methods along with the type of data or model where the methods are applicable.

Table 1.2: Methods for Modal Analysis

Data Type	Ringdown Methods	Ambient Methods	Eigenvalue Analysis
Synchrophasor Data (Ambient Data)		X	
Synchrophasor Data (Post-Disturbance Data)	X		
Powerflow Base-Cases (Offline Planning Models or Real-Time State Estimator Snapshots) with associated dynamic data	X		X

The results of the analyses will help to determine the modes that are important from a monitoring perspective. The modes are typically defined by a frequency and a mode shape that lists the participating generators and the respective areas in the mode. The analysis also provides the damping[8] of the respective modes that can vary significantly based on system operating conditions and generator controller configurations. These methods are summarized in **Table 1.3** for a quick comparison of the approaches and data requirements.

[8] Modes are often represented as complex numbers in rectangular form: $\lambda = \sigma + j\omega$. A mode's frequency is given by $f = \frac{\omega}{2\pi}\ Hz$ and its damping ratio is often expressed in percent as $\zeta = \frac{-\sigma}{\sqrt{\sigma^2+\omega^2}} \times 100\%$. A system maintains small-signal stability as long as all of its modes have a positive damping ratio.

Table 1.3: Ringdown and Ambient Methods		
Name of Method	**Algorithm**	**Data required**
Prony Methods[9]	• Estimates damped sinusoidal components in a linear system response • Expressing the system outputs as linear combinations of fundamental sinusoidal modal components • Singular Value Decompositions (SVDs) for handling the measurement noise and for reducing the computational burden	Post-Disturbance Data
Eigensystem Realization Algorithm[10]	• Singular value decomposition of a matrix whose entries are samples of the system impulse response (Hankel matrix) • Using the decomposition, a reduced linear system realization is computed (i.e., the system state matrices)	Post-Disturbance Data
Matrix Pencil[11]	• Compute a pseudo-inverse of a matrix using an SVD technique (This also includes a built-in filter for leaving out noise related phenomena in the SVD formulation.)	Post-Disturbance Data
Variable Projection (VARPRO)[12]	• General nonlinear least-squares optimization technique	Post-Disturbance Data
Hankel Total Least Squares (HTLS)[13]	• Formulate a Hankel matrix from the observed Phasor Measurement Unit (PMU) measurements of the event • Use a Total Least Squares approach for evaluating the eigenvalues again using a SVD computation	Post-Disturbance Data

[9] D. J. Trudnowski, J. M. Johnson and J. F. Hauer, "Making Prony analysis more accurate using multiple signals," in IEEE Transactions on Power Systems, vol. 14, no. 1, pp. 226-231, Feb. 1999.

[10] J. J. Sanchez-Gasca, "Identification of power system low order linear models using the ERA/OBS method," in IEEE PES Power and Systems Conference and Exposition, 2004.

[11] Guoping Liu, J. Quintero and V. M. Venkatasubramanian, "Oscillation monitoring system based on wide-area synchrophasors in power systems," 2007 iREP Symposium - Bulk Power System Dynamics and Control - VII. Revitalizing Operational Reliability, Charleston, SC, 2007, pp. 1–13.

[12] A. R. Borden and B. C. Lesieutre, "Variable Projection Method for Power System Modal Identification," in IEEE Transactions on Power Systems, vol. 29, no. 6, pp. 2613–2620, Nov. 2014.

[13] J. J. Sanchez-Gasca and J. H. Chow, "Computation of power system low-order models from time domain simulations using a Hankel matrix," in IEEE Transactions on Power Systems, vol. 12, no. 4, pp. 1461–1467, Nov. 1997.

Table 1.3: Ringdown and Ambient Methods		
Name of Method	**Algorithm**	**Data required**
Yule Walker[14]	• Method operates by first estimating the autocovariance sequence of the measured data • It then fits a model that describes the relationship between the autocovariance sequence at different lag values • The parameters of this model are associated with a rational polynomial whose poles correspond to the power system's electromechanical modes • An extension allows the parameters of electromechanical modes and forced oscillations to be identified simultaneously[15]	Ambient synchrophasor measurements
Least Squares[16]	• Fits a model that describes the current measurement in terms of past measurements and the current random input • This model parameterized as a rational polynomial whose poles correspond to the power system's electromechanical modes • An extension allows the parameters of electromechanical modes and forced oscillations to be identified simultaneously[17]	Ambient synchrophasor measurements
Frequency Domain Decomposition[18]	• Power spectral density (PSD) functions of the ambient measurements are first estimated in the frequency domain • Singular value decomposition (SVD) then used to combine and extract the principal singular values of the multiple PSD estimates	Ambient synchrophasor measurements

[14] R. W. Wies, J. W. Pierre and D. J. Trudnowski, "Use of ARMA block processing for estimating stationary low-frequency electromechanical modes of power systems," in IEEE Transactions on Power Systems, vol. 18, no. 1, pp. 167–173, Feb. 2003, doi: 10.1109/TPWRS.2002.807116.
[15] U. Agrawal, J. Follum, J. W. Pierre and D. Duan, "Electromechanical Mode Estimation in the Presence of Periodic Forced Oscillations," in IEEE Transactions on Power Systems, vol. 34, no. 2, pp. 1579–1588, March 2019.
[16] N. Zhou, J. W. Pierre, D. J. Trudnowski and R. T. Guttromson, "Robust RLS Methods for Online Estimation of Power System Electromechanical Modes," in IEEE Transactions on Power Systems, vol. 22, no. 3, pp. 1240–1249, Aug. 2007.
[17] J. Follum, J. W. Pierre and R. Martin, "Simultaneous Estimation of Electromechanical Modes and Forced Oscillations," in IEEE Transactions on Power Systems, vol. 32, no. 5, pp. 3958–3967, Sept. 2017.
[18] Guoping Liu and V. Venkatasubramanian, "Oscillation monitoring from ambient PMU measurements by Frequency Domain Decomposition," 2008 IEEE International Symposium on Circuits and Systems, Seattle, WA, 2008, pp. 2821–2824.

Table 1.3: Ringdown and Ambient Methods		
Name of Method	**Algorithm**	**Data required**
	• Local peaks among the singular values to correspond to frequencies of system modes and oscillations observed in the data • Modal properties estimated by analyzing these principal singular values near the peak frequencies	
Stochastic subspace identification (SSI)[19]	• Formulate the PMU measurements as outputs of a linear system being excited by unknown random load fluctuations, modeled as independent white noise inputs. • Essential features of the linear system model describing the power system can then be estimated	Ambient synchrophasor measurements
Eigenvalue Analysis	• QR-based methods for complete eigenvalue decomposition • Arnoldi-based methods for partial eigenvalue decomposition • Provides information on observability, controllability, and participation factor of generators along with frequency and damping ratio of respective modes	Powerflow Case and Dynamic Data

The recommendation is to perform these analyses on a regular basis after events by using the post-mortem analysis methods and by using the powerflow base cases and associated dynamic data on a seasonal or yearly basis. Significant system changes can also be used as triggers for performing these analyses, such as the following:

- Changes in system
- Retirement of generation facilities
- Changes in power system injection points due to an increase in renewable resources penetration or generation dispatch patterns and inverter-based resource
- Other significant changes in generation dispatch patterns

In addition, the modes can also be validated by using post-mortem analysis through planned signal tests in the Interconnection. The annual Chief Joseph Brake insertion test in the Western Interconnection (WI) is an example of a signal test allowing the validation and update of some of the known modes.

[19] S. A. Nezam Sarmadi and V. Venkatasubramanian, "Electromechanical Mode Estimation Using Recursive Adaptive Stochastic Subspace Identification," in IEEE Transactions on Power Systems, vol. 29, no. 1, pp. 349–358, Jan. 2014

1.1.1 Commonalities on Interconnection Oscillation Analysis using Modal Analysis of Ringdowns

This section presents an example of modal analysis performed using power system data collected during a disturbance, either observed or simulated. The ringdown method is used as an example. The intent of this section is to discuss concepts that are generally applicable to all ringdown methods. The notion of curve fitting is central to modal analysis of ringdowns. In broad terms, curve fitting is the process of specifying a model whose output provides the best fit to measured data under some mathematical criteria. The model identified by a curve-fitting routine can then be used to extract information about the resonant properties of the system. Specifically, the identified model permits estimation of the eigenvalues and eigenvectors of a linearized representation of the system dynamics that correspond to a particular operating point. For studying electro-mechanical oscillations, measurements of rotor speed, bus frequency, and intertie active power flows provide useful input data.

A crucial step in any curve fitting procedure is to specify the structure of the model being fit to the data. For power system applications, common choices include autoregressive models and discrete-time state-space models. Often, choosing a specific model structure helps to determine which algorithm is best suited to the problem. For instance, Prony's method identifies an autoregressive model to determine the coefficients of the characteristic polynomial. In contrast, the Eigensystem Realization Algorithm identifies a discrete-time state-space model. Often (but not always), autoregressive models are used for single-channel analysis whereas state-space models are inherently multi-channel. In this context, "single-channel" refers to the analysis of one ringdown while "multi-channel" refers to the simultaneous analysis of multiple ringdowns.

Data Collection and Pre-Processing

In general, it may not be possible to analyze all of the modes of interest by using data collected for a single disturbance. The reason for this limitation is that a given disturbance may not excite all of the modes, or it may not excite them enough to permit estimation with the desired accuracy. For example, following a Chief Joseph Brake insertion in the WI, it may be possible to estimate the frequency and damping of the North-South B mode but not the East-West A mode. When characterizing dynamic models, this limitation can be mitigated by simulating multiple disturbances that originate from various points in the system. The data for each simulated disturbance can then be used to estimate a subset of the system modes.

Modal analysis may be performed by using data collected during a wide variety of disturbances; however, special considerations arise in the case of transient disturbances during which the operating point of the system may move from one equilibrium to another. For example, following the loss of a transmission line, the active power transfer on the remaining ac lines may change. If these power transfer measurements are used as inputs to a modal analysis framework, the dc offset corresponding to the post-disturbance power flow must be subtracted from the original signal. In the case of generator trips, the trajectories of rotor speeds and bus frequency measurements contain considerable low-frequency content that lies below the range of the electromechanical modes. It is generally desirable to remove this very low frequency component of the system response to better highlight oscillatory phenomena. This may be done by forming pairs of relative signals that represent the difference in bus frequency (or rotor speed) measured at two different points in the system. If an estimate of a particular mode is sought, these pairs may be selected based on knowledge of its shape. Alternatively, the center-of-inertia frequency (or speed) may be subtracted from each individual frequency (or speed) signal. This is a useful technique when the mode shapes are not known in advance. If the subsequent deviations after detrending the data are small, scaling (or normalizing) the data may improve numerical performance, if it is done in a consistent manner.

In order to get the best possible results from any modal analysis technique, care must be taken in collecting and preparing the input data. When analyzing data collected from actual disturbances, it is often beneficial to use a lowpass filter to mitigate the impact of high-frequency measurement noise and/or process noise. When circumstances allow, as in a posteriori analysis, high-order finite impulse response filters are preferred because they can be designed with a linear phase response, preserving a constant group delay across the entire frequency band.

The corner of this lowpass filter should be placed such that the oscillatory phenomena of interest falls firmly within the passband. This step may be omitted when analyzing simulated data arising from real-time or planning base cases when noise is not present.

To maximize the accuracy of mode frequency estimates, the input data may be resampled via a combination of anti-aliasing and decimation. A useful rule-of-thumb is to set the sampling rate of the input data to approximately 10 times the highest frequency of interest. For example, if the highest mode frequency of interest is 1 Hz, this would imply a sampling rate in the range of 10–12 sps (samples per second). During this process, the sampling rate of the original data should also be taken into account. Resampling generally yields the best results when the final sampling rate is an integer factor of the original rate. For instance, if the original data is sampled at 60 sps, it would be advisable to resample the data at 10 or 12 sps, as opposed to 11 sps. Choosing the final sampling rate in this way obviates the need to upsample (i.e., interpolate, the original data, which is not advisable in modal analysis applications). Before downsampling the original data, it must be passed through an anti-aliasing (lowpass) filter that limits its bandwidth to satisfy the Nyquist-Shannon sampling theorem. For example, if 60 sps data is going to be resampled at 12 sps, the stopband of the anti-aliasing filter should begin at 6 Hz. As with noise reduction filters, high-order linear phase finite impulse response filters are preferred for this application where possible.

Curve Fitting Sensitivities

Most curve fitting algorithms for modal analysis are designed to operate on the so-called "free response" of the system (i.e., the period in which the input or forcing function has gone to zero). Thus, the position of the curve-fitting window must be aligned with the free response for best accuracy. For example, if the system stimulus is a dynamic brake insertion, the left endpoint of the curve-fitting window should be placed no sooner than the instant when the brake is removed. In general, it is a good practice to allow some additional time to elapse, perhaps 0.5–1s, to ensure that the dynamics within the curve-fitting window correspond to the free response. In special circumstances where the forcing function is known (such as probe testing), this rule for positioning the curve-fitting window may be relaxed; however, the analysis algorithm may require modification. The positioning of the right endpoint of the curve-fitting window is equally important. A useful rule-of-thumb is that the duration of the window should be approximately 3–4 cycles of the lowest oscillation of interest if possible. For example, if the lowest mode frequency of interest is 0.25 Hz, this would imply a curve fitting window length of approximately 12–16 s. A caveat is that the window should not include flat or nearly flat signal content. This is an indication that the system has reached a new steady state that is not helpful in characterizing its dynamics and that the right endpoint must be placed no later than the final data sample.

There are multiple ways to quantify a curve-fitting error, some of which depend on whether the analytical formulation is single-channel or multi-channel in nature. Two commonly employed approaches are the ℓ_2-norm and the closely related mean squared error (MSE). Both methods correspond to so-called least-squares error minimization. In the single-channel case, the ℓ_2-norm is given by

$$f(z,\tilde{z}) = \sqrt{\sum\nolimits_{k\in\mathcal{K}} (z_k - \tilde{z}_k)^2},$$

Where z_k the input data, and $\tilde{z}_k$ the output of the model. Here k denotes the sample index and $\mathcal{K}$ the set of points in the analysis window. Similarly, the mean squared error is defined as

$$f_{\text{mse}}(z,\tilde{z}) = \frac{1}{|\mathcal{K}|}\sum\nolimits_{k\in\mathcal{K}} (z_k - \tilde{z}_k)^2,$$

Where $|\mathcal{K}|$ is the total number of samples in the window. These methods may be extended to the multi-channel case by summing over not only time but also the various signal channels. This type of least-squares minimization is implicit in many algorithms, such as Prony's method and dynamic mode decomposition (DMD).

When curve-fitting routines are used for modal analysis, attention must be paid not only to the fitting error but also to the estimates of the eigenvalues and eigenvectors derived from the results. These estimates are sensitive to various factors, including (but not limited to) the model order, the position of the curve-fitting window, and the value of any additional parameters. Many algorithms, such as Prony's method, require the user to specify the model order, or the number of poles, as an input. As discussed above, the user must also specify the position and duration of the curve-fitting window. Furthermore, optimization-based curve fitting routines may utilize additional parameters, such as constants allowing the user to trade-off between various terms in a multi-objective optimization formulation. All of these user-specified inputs have an impact on both the curve fitting error and the mode estimates returned by the algorithm.

When performing modal analysis of ringdowns, it is generally advisable to sample the space of possible input parameter combinations. For example, an input parameter combination may comprise a given model order, analysis window, and trade-off parameter value. At the start of the procedure, a set of possible combinations is defined that spans some portion of the space of interest. Then, the results of analysis are recorded for each combination that creates a collection of mode estimates. Eigenvalue estimates may be categorized first according to their position in the complex plane and then according to the corresponding eigenvectors. This process produces clusters of eigenvalue estimates in the complex plane, each that roughly takes the form of an ellipse. Categorizing estimates based on the eigenvectors helps to distinguish modes that are close to one another in the complex plane but have different shapes. Likewise, categorizing mode estimates purely in terms of their frequency and damping is insufficient because their mode shapes may be different. For example, the North-South B mode and the East-West A mode reside at very similar frequencies in the WI; however, they have different mode shapes. Final mode estimates may be derived by averaging individual estimates that have been confirmed to have the same shape.

Examples

This subsection presents practical examples stemming from modal analysis of a simulated Chief Joseph Brake insertion in the WI. To generate this simulated data, the dynamic brake was inserted at the 5s mark for a duration of 0.5s. In these examples, the inputs to the curve fitting routine were bus frequency measurements recorded at 26 points distributed geographically throughout the system. Each bus frequency was calculated by using a backward difference derivative approximation applied to the voltage angle. To model the effect of a bandlimited sensor, the output of the derivative approximation was then passed through a first-order lowpass filter. Modal analysis was performed by using an optimization-based, multi-channel curve-fitting algorithm. As with ERA, this method identifies a reduced-order state-space model that can then be fed into eigen analysis routines.

Figure 1.3 shows the frequency deviation (from nominal) measured at Nicola, British Columbia, and Genesee, Alberta. The dashed traces show the measured state trajectories, and the colored traces show the output of the model constructed by the algorithm. In this case, the curve-fitting window begins at the 6.5s mark and is 12s in length.

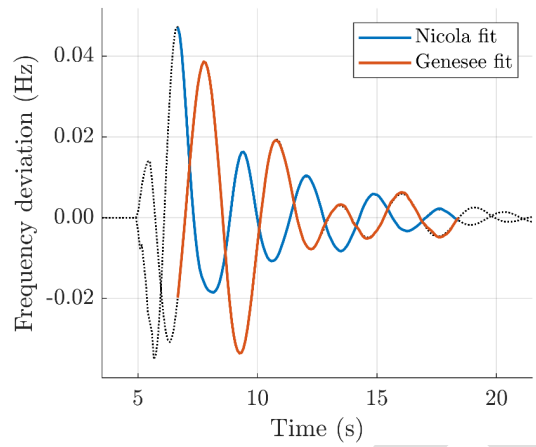


Figure 1.3: Example Curve Fit

Figure 1.4 shows the frequency difference measured between Nicola and Genesee. As explained above, computing the frequency difference between two points can make modal analysis easier by cancelling out common mode behavior. The dashed trace shows the relative frequency itself, and the colored traces show the two dominant modal components of the ringdown, the North-South A and B (NSA and NSB) modes. This decomposition can be performed by solving for the minimum-norm solution to an overdetermined system of linear equations as in Prony's method.

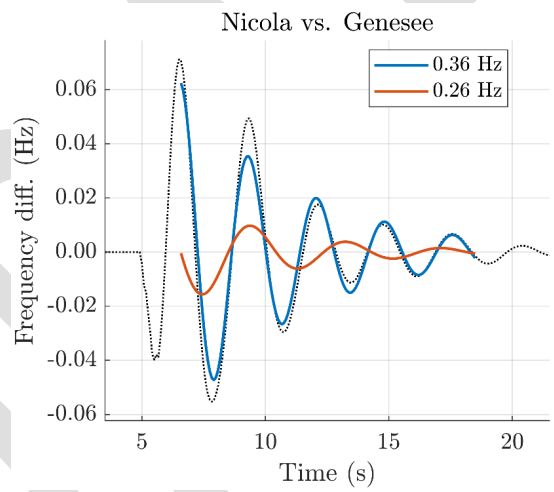


Figure 1.4: Decomposition of the Relative Frequency

The curve fitting procedure was repeated for 64 unique combinations of input parameters that spanned eight different analysis windows and eight values of a trade-off parameter used in the optimization. **Figure 1.2** shows the eigenvalue estimates generated using this approach. The orange ellipses highlight the estimates of the North-South A and B Modes generated from this disturbance. As discussed above, after the estimates were clustered according to their position in the complex plane, the eigenvectors were checked to ensure that all of the estimates within a given ellipse had matching mode shapes. In general, the variance associated with mode frequency estimates is lower than the variance associated with damping estimates. Furthermore, it is generally true that the variance associated with damping estimates increases as the true damping of the underlying mode increases. For this disturbance, the North-South B mode may be estimated with a higher degree of confidence than the North-South A mode because the variance is lower in both dimensions.

Figure 1.5 shows the shape of the North–South A mode overlaid on a map of the WI. Likewise, **Figure 1.6** shows the shape of the North–South B mode. Recall that mode shapes correspond to the right eigenvectors of the linearized state matrix. The shape of a mode provides information about how observable it is in a particular state or at a particular location. The shape also provides information about the phase of the oscillation, which can be used to determine which complexes of generators (or other components) are oscillating against one another. In the maps, the area of each marker is proportional to the magnitude of the entry of the right eigenvector corresponding to state measured at that location. Likewise, the arrow emanating from the center of each marker shows the precise phase of the oscillation. The color gradient indicates which states are oscillating against one another, as delineated in the key. This analysis is useful in verifying that the modal properties of dynamic models used in operations and planning match those of the actual system.

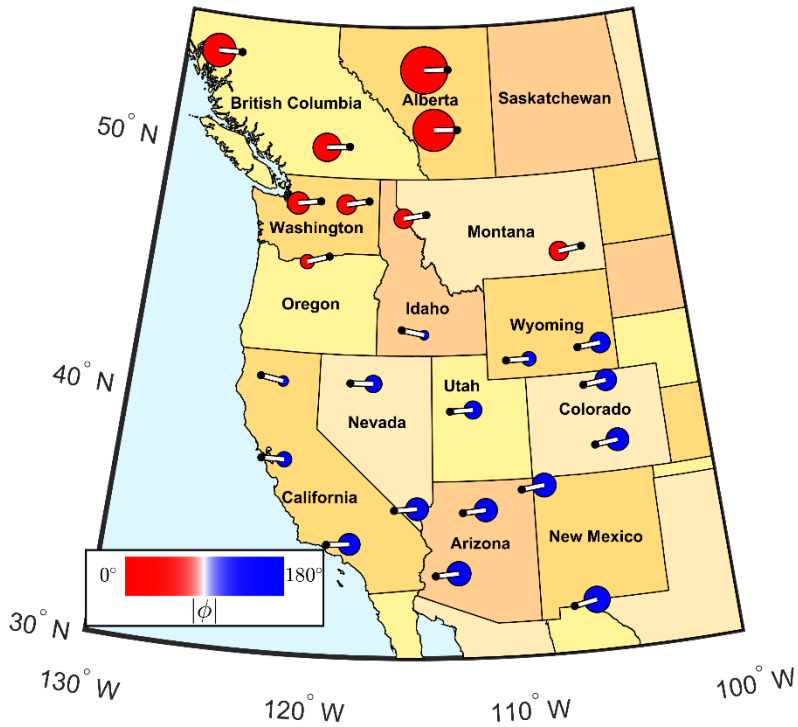


Figure 1.5: Map of the Shape for the 0.26 Hz North-South A mode

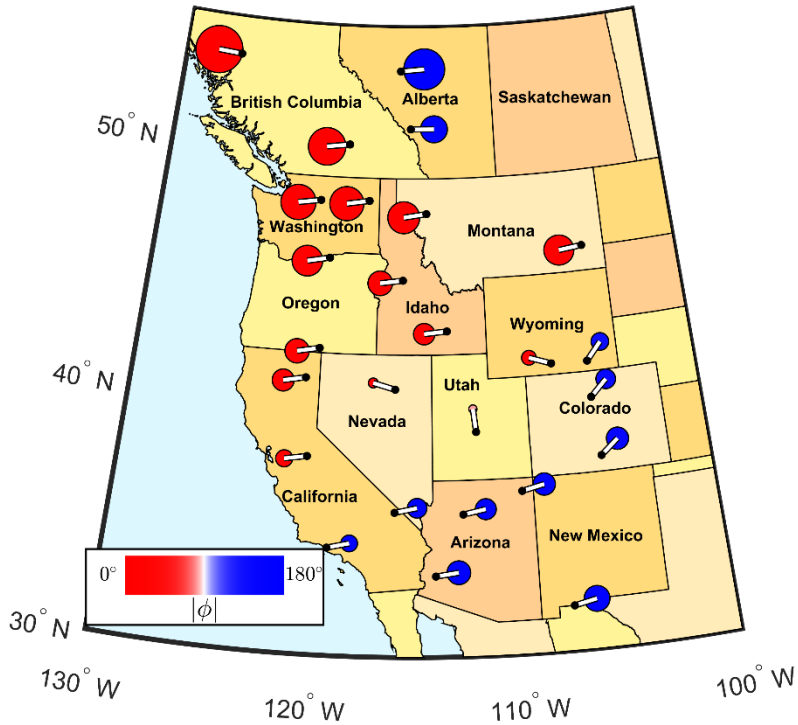


Figure 1.6: Map of the Shape for the 0.36 Hz North–South B mode

1.1.2 Commonalities on Interconnection Oscillation Analysis using Modal Analysis

This section describes ambient analysis techniques and the commonalities between them. The fundamental assertion behind modal analysis of ambient data is that the power system's dynamics are continuously excited by random load changes. Through proper analysis, the results of this excitation can be observed in synchrophasor data even during ambient conditions.

A measurement of frequency from a PMU during ambient conditions is plotted in **Figure 1.7**. Modal oscillations are not apparent from visual inspection, but the impact of the system's modes is present in the signal's random variation. To better see this, consider the estimate of the signal's frequency-domain spectrum in **Figure 1.8**. This estimate was generated by analyzing 30 minutes of data, including the 60 seconds in **Figure 1.7**, by applying a method based on the Discrete Fourier Transform (DFT). Note the spectrum's peak near 0.35 Hz. This peak corresponds to the well-known North-South B mode in the WI.

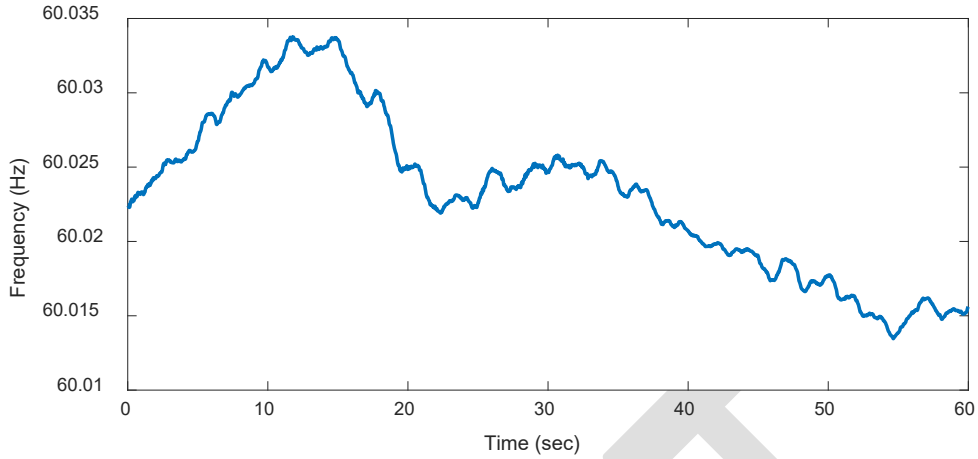


Figure 1.7: Plot of Frequency Measurements from a PMU during Ambient Conditions

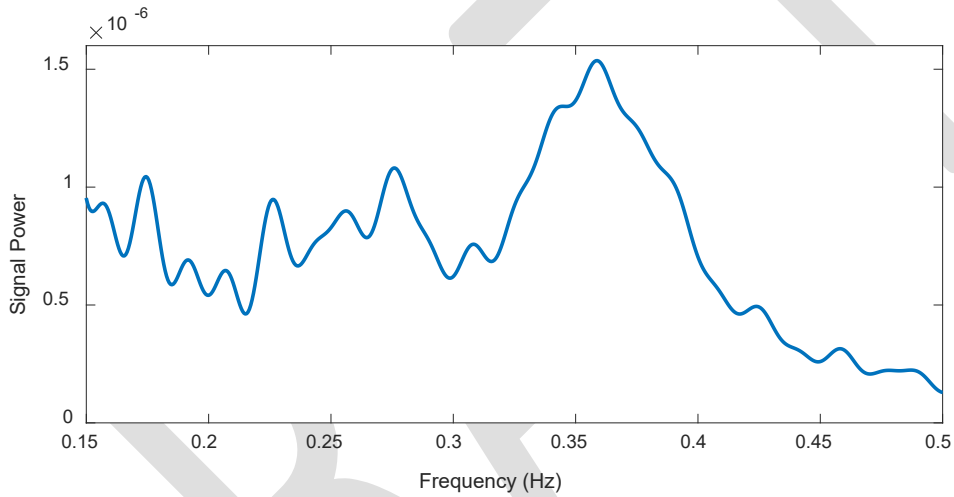


Figure 1.8: Estimate of the Spectral Content of the Frequency Signal

The observability of modes in the frequency-domain spectra of PMU measurements forms the basis for several ambient modal analysis algorithms. The Least Squares and Yule-Walker algorithms used in mode meters are actually spectral estimation methods. The methods determine model parameters to estimate the spectrum. These models can then be evaluated to extract estimates of the system's modes. Similarly, the fast frequency domain decomposition (FFDD) algorithm used in oscillation monitoring tools is based on estimation of power spectrum densities from all available PMU measurements. Further details are provided in **Section 2.1.2**.

Ambient algorithms were primarily developed to provide improved situational awareness to system operators in real-time environments. They can also be useful tools for identifying modes that need to be monitored. Ambient algorithms can be applied to historic data to obtain mode estimates that are updated regularly, even at one-minute intervals. This approach provides a much more granular view of each mode's behavior than can be obtained with transient analysis. Ambient analysis can also be used to understand how modes change during different loading conditions, system topologies, and seasons. This information can be critical in understanding of which modes need to be monitored and what conditions may lead to poor system damping.

1.2 Determination of Mitigation Actions

In addition to monitoring, operators would need guidance on how to mitigate inter-area oscillations. It is important to determine and validate mitigation actions in a consistent manner. These actions are developed ahead of time in

operational planning studies and summarized in operating guides. There are two main model-based methods to determine and validate mitigation actions that can be included in the operating guidelines provided to operators:

- Eigenvalue analysis with powerflow cases and associated dynamic data
- Ringdown analysis with simulated disturbances on powerflow base cases and associated dynamic data

1.2.1 Eigenvalue Analysis with Powerflow Base Cases to Determine Mitigation Actions

Powerflow cases along with the associated dynamic data provide an opportunity to determine the significant modes along with their damping. The global positioning system (GPS) coordinates of the generating resources in the powerflow cases can help to establish the geographical mode shapes in addition to determining the participating generators in the various modes. Additionally, eigenvalue analysis also provides information on the controllability of participating generators for each mode. Using this information can help identify generators that have more control over a specific mode and therefore help with identifying strategies to improve damping ratio of that mode, such as tuning of Power System Stabilizers (PSS) of generators having high controllability for a mode to improve the damping ratio of that specific mode. This approach can be applied to both offline powerflow cases used for transmission and operational planning purposes and with real-time powerflow cases that utilize the state estimation solution and real-time conditions. The model-based approach to determine the mitigation actions provides some advantages:

- It allows for real-time validation of the provided mitigation approaches in operating guidelines provided to operators when used with real-time powerflow cases and the associated dynamic data.
- It allows testing different strategies such as varying transfers along major transmission corridors, varying topology conditions, such as status of transmission lines or series capacitors or generation redispatch.
- It allows testing the impact of contingencies on the damping of the significant modes. This can provide situational awareness to operators of the impact of contingencies when the damping of the monitored modes is below the critical levels for a sustained period.

The basic approach in this method is to calculate the eigenvalues within a certain frequency and damping range. It is recommended to pick a frequency range of 0.1 to 0.95 Hz to capture all possible inter-area modes and make the damping range large enough to capture the known significant modes. It is also recommended to filter out all modes that have a damping of more than 25% to focus on the modes of interest that show lower damping. Once a known significant mode is identified, mode tracing can be utilized to trace the impact of transfer across a path and variation of other topological conditions or equipment status, such as PSS on the damping of the known significant mode. This allows the development of guidelines for operators when developing mitigation actions for reducing damping of the monitored modes.

Figure 1.9 and **Figure 1.10** are examples of eigenvalue analysis performed by using the above approach in with the Small Signal Analysis Tool (SSAT) on the real-time state estimator snapshots along with the associated dynamic models at RC West. Mapping the GPS coordinates to each of the resources allows the development of the mode shape plots. This allows the validation of the mode shapes with state estimator cases when the damping and energy of the monitored modes reaches critical levels.

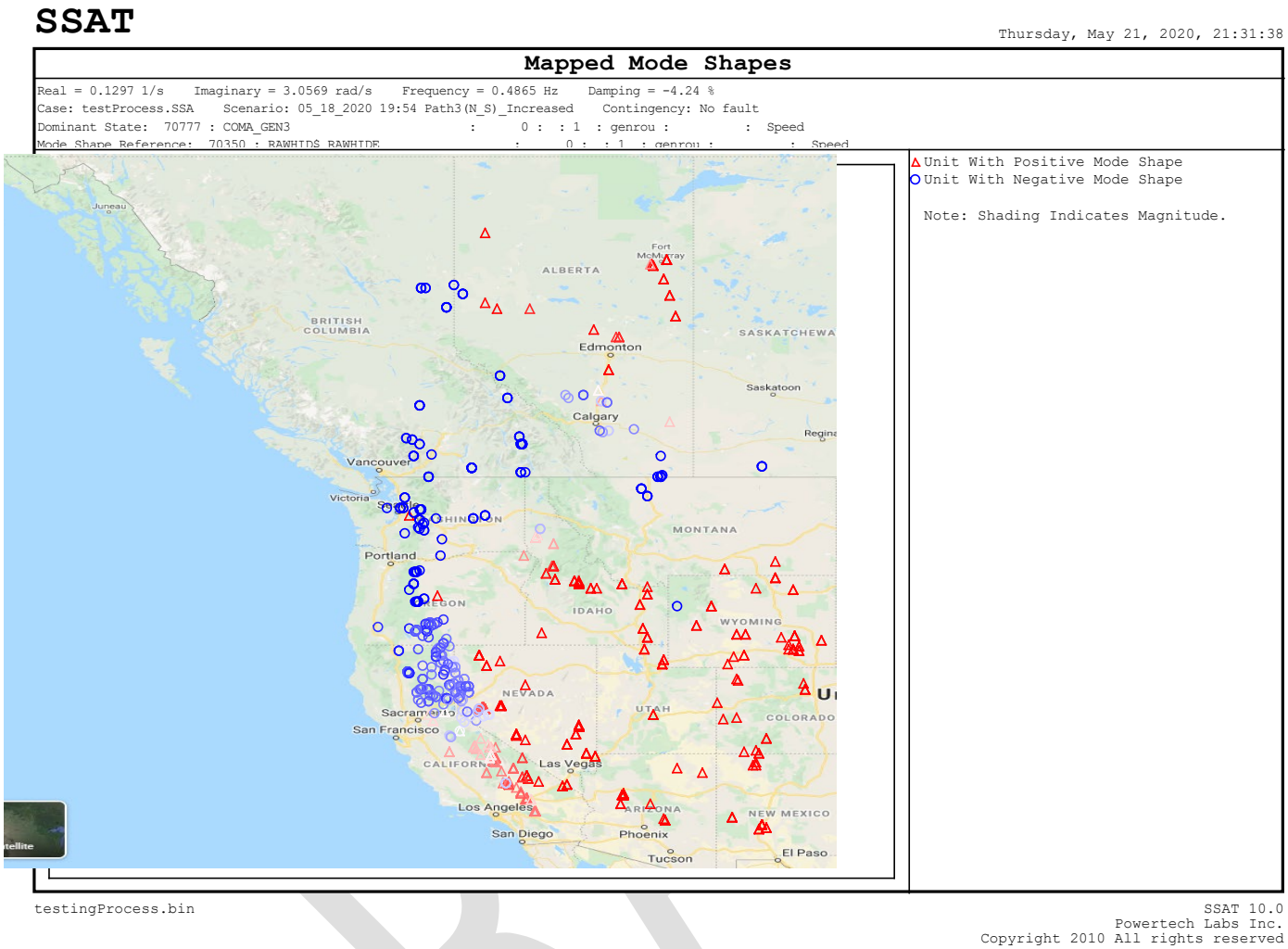


Figure 1.9: Mode Frequency Damping and Shape Estimated Using Eigenvalue Analysis

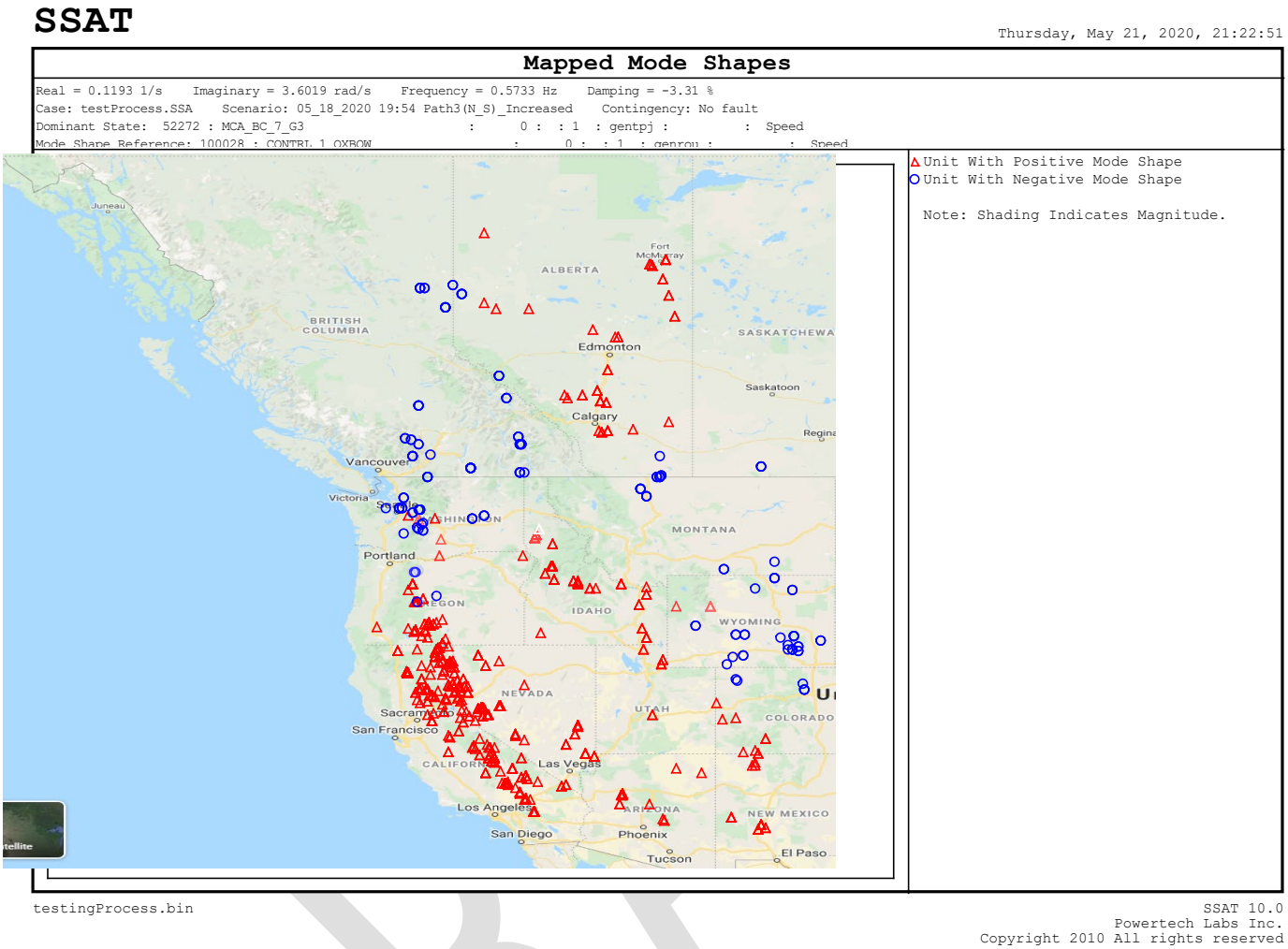


Figure 1.10: Mode Frequency Damping and Shape Estimated Using Eigenvalue Analysis

1.2.2 Ringdown Analysis with Powerflow Base Cases to Determine Mitigation Actions

Utilizing ringdown analysis with powerflow base cases using simulated disturbances is very similar to the earlier described process to determine the various modes and their associated frequencies and shapes. The proposed mitigation actions, such as change in interface MW transfer levels or change in topological conditions, would be simulated in the powerflow base cases and the ringdown analysis would be repeated to determine if there is change in the damping of the mode being tracked while also ensuring that the mode shape is more or less constant. This iterative process helps to determine and validate mitigation actions.

1.3 Monitored Quantities Informed by Analysis

Monitoring the modes of significance requires determining which synchrophasor data that should be utilized in tools to monitor the modes. Various quantities can be used, such as voltage angle pairs, voltages, or flows. It is important for system operators to monitor modes in a consistent manner. This section provides guidance on which quantities can be selected.

While the number of PMU measurements are limited, all the system variables' dynamics, to some extent, are affected by each mode. This means that measurements of electrical quantities, to some extent, will contain information on

the modes that can be extracted/estimated for analysis and tracking purposes. This does not mean that all measurements are the same when it comes to tracking modes; some measurement points are affected by certain modes more than others are and have more unique properties that are useful for the process of tracking the stability of each mode. For example, the answer is to use signals that make the mode(s) of interest highly and easily observable and therefore easy to track when trying to track a particular mode and decide whether to use voltage, power, or frequency signals. For inter-area mode estimation/tracking, angle-pair derivative signals are a great choice because they consist of two individual PMU voltage angle measurements from different grid locations that, with proper signal choice and setup, produce a single signal that amplifies a single mode's presence and ideally attenuates all other modes. As mentioned before, this makes the tracking of individual dominant modes much easier. There are many methods for modal analysis and signal selection. Below is just one example of the process of choosing signals for a mode meter setup.

Consider the following frequency trend lines at different substations spread out through the WI over a one-hour duration in **Figure 1.11**.

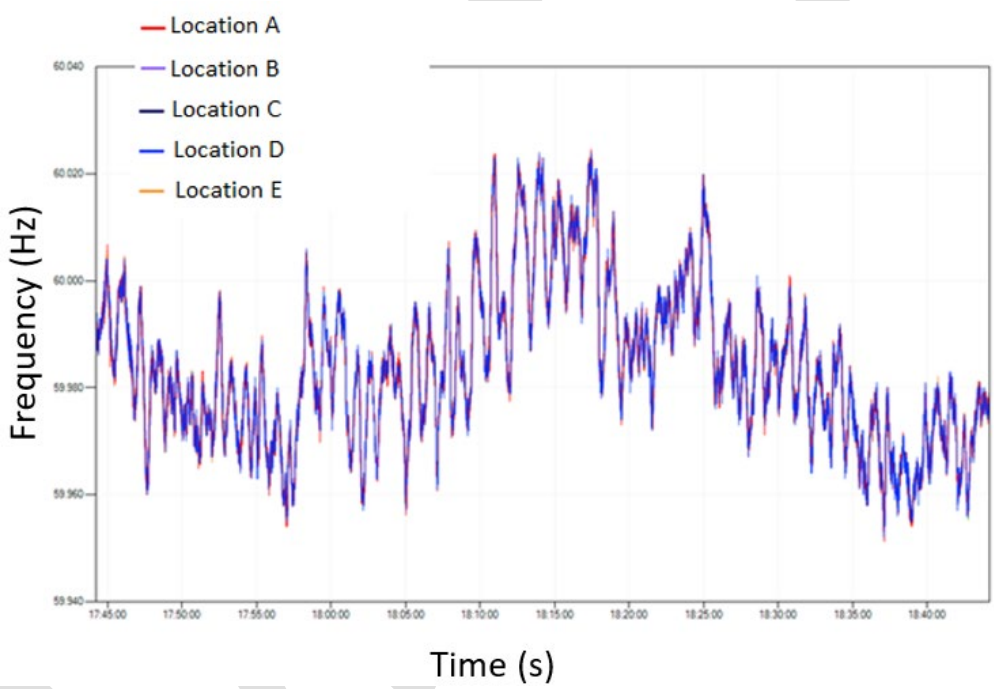


Figure 1.11: Sample Frequency Trend in the WI

At first glance, this looks like a 60 Hz frequency signal with some random ambient noise. In truth, this represents that the modes are manifesting themselves onto the frequency signal measurements at each location, but they are not apparent in the waveforms. If the signal's spectra are plotted, their energy as a function of frequency can help identify dominant modes. **Figure 1.12** conveys that dominant modes truly exist with their frequencies characterized by broad peaks.

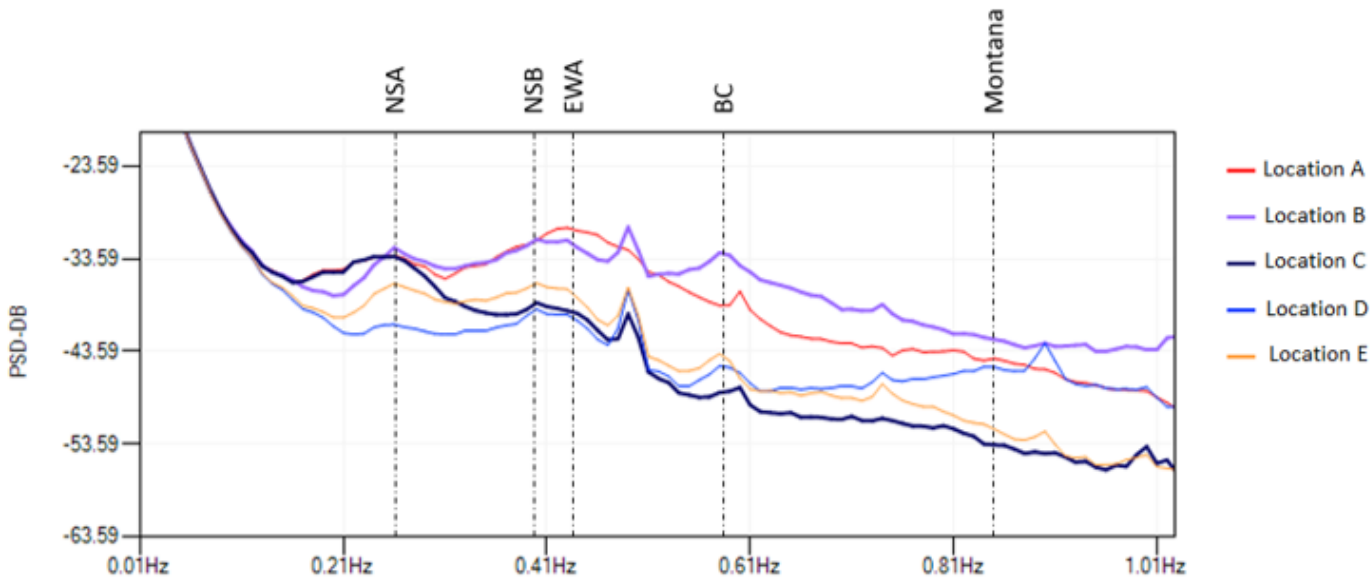


Figure 1.12: Mode Observability at different PMU locations

Upon close inspection, it becomes clear that certain modes only manifest themselves (or show themselves) in certain locations on this signal set. For example, the frequency signal spectrum at Location D shows that the Montana mode is observable in Location D's frequency signal spectrum but not in Location C's frequency signal spectrum. In addition, some locations' frequency signal spectrum (like Location A) show one mode overpowering all other modes by a considerable amount that dominates the modal contribution to the observable dynamics of the frequency signal at that location (e.g., East-West A Mode (EWA) for Location A).

From this sort of analysis, one can also extract one more piece of information, the "phase." Spectral analysis of the modes on a particular signal set at different PMU locations not only indicates what modes manifest themselves at each location for the given signal type of the signal set for each mode but also reveals the phase at one location relative to one another location when the mode ideally "shows itself" at both locations. Because the modes are linear ordinary differential equation (ODE) solutions, they are oscillatory and cause system variables to also oscillate to some extent in harmony or anti-harmony with one another. That means all of the interactions of system variables for each mode can be described by a set of sine and cosine waves that have magnitude and phase values describing their relationship to one another. The phase can be anywhere between 0 to +/-180 degrees. Essentially, the phase shows how a location's signal measurements interact with each other when under the influence of a single given mode. Locations with a phase near 0 degrees apart from one another are "in-phase." However, locations with a phase near 180 degrees apart from one another are "out-of-phase." Locations with a phase near 90 degrees apart from one another are "uncorrelated."

To put this concept into practice, consider the example scenario below. According to the power spectrum in the previous section, Location C and E are grid locations where the NSA mode clearly presents itself (~0.25Hz). According to the mode phase data shown in **Figure 1.13**, Location E is nearly -180 degrees "out-of-phase" with Location E, (approx. -157 degrees).

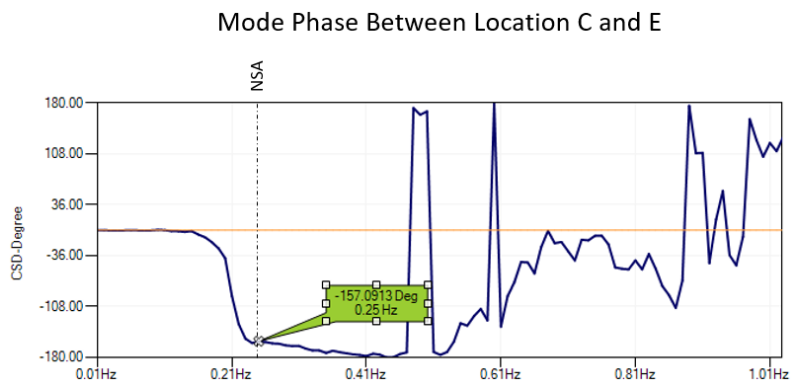


Figure 1.13: Example of Mode Phase between Two Locations

By taking the phase and mode energy data from the estimated power spectrums, a "mode shape" plot describes how all of the signals that are being influenced by the mode are related to one another. To visually show this, imagine a PMU at locations A and C that shows the ideal frequency signals of 60 Hz when suddenly the NSA mode becomes unstable and negatively damped. Consequently, a near-0.25 Hz oscillation starts to build and, due to the locations' relative mode phase as the signal at Location C swings up, the signal at Location E does exactly the opposite as shown in **Figure 1.14**. This is an example of an "inter-area oscillation" caused by an unstable and negatively damped mode.

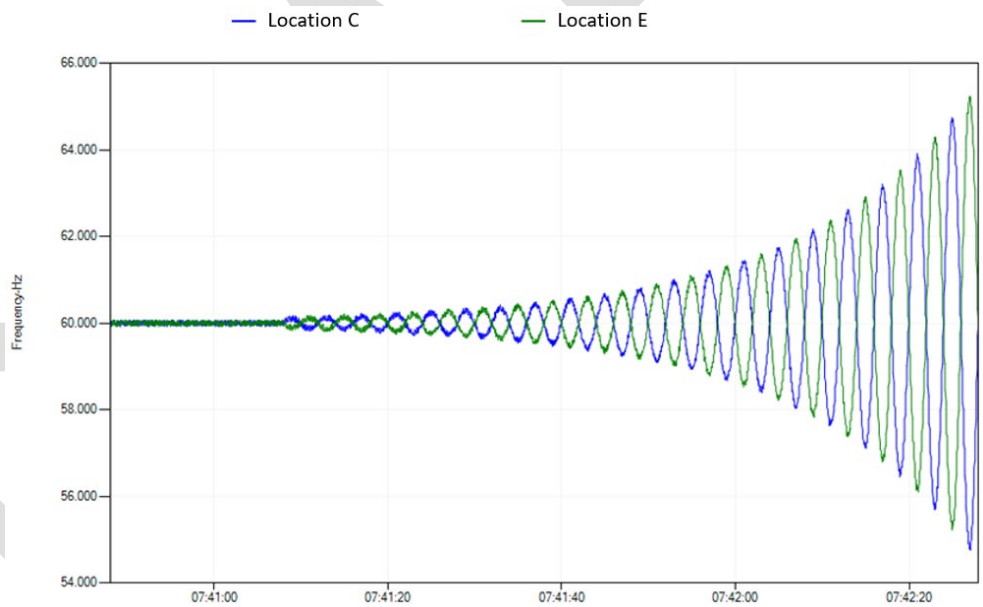


Figure 1.14: Example of Frequency at Different Locations during an Inter-area Oscillation

Since both signals exhibit the mode and have a relative mode phase near 180 degrees, these two signals can be used in a special way to gain an advantage for tracking a mode with a mode meter. Shown again in **Figure 1.15** are the sample estimated power spectrums of the frequency signals at Location C and E.

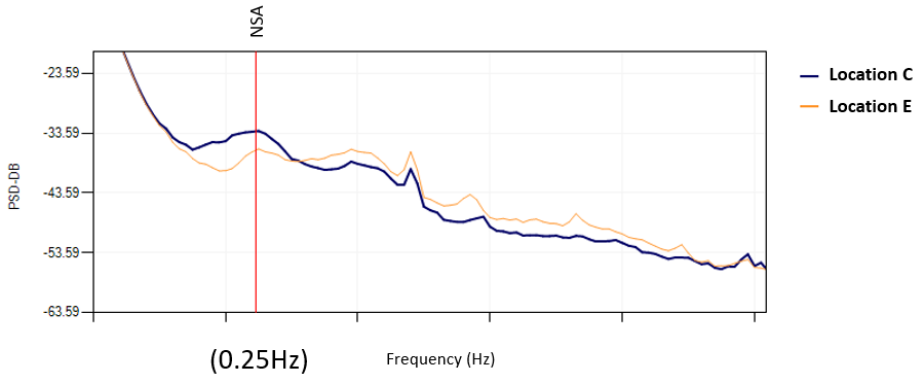


Figure 1.15: Sample Estimated Power Spectrums of Frequency Signals

By subtracting these two frequency (or numerical derivative of PMU voltage angle signal) signals at Locations E and E, creating a differential "angle pair" signal, we can see that the new signal makes the NSA mode "pop-out" as shown in **Figure 1.16** by attenuating common properties and amplifying differing properties in the Location C and E frequency signals.

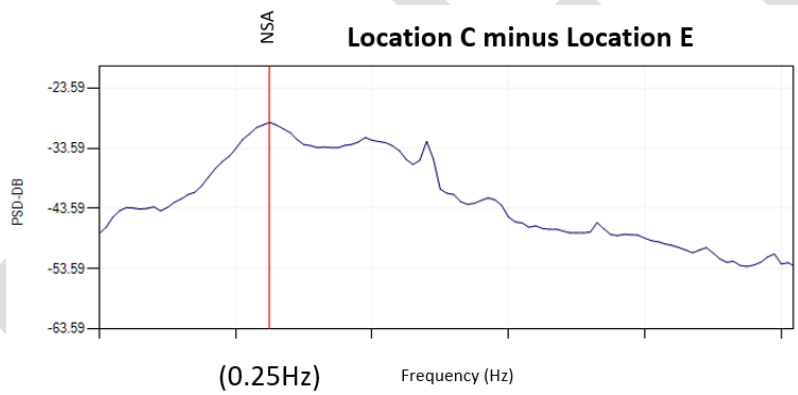


Figure 1.16: Sample Angle Pair Differential Pair Signal for North-South A Mode

As seem above, using the angle-pair differential signals can provide an effective to monitor a given mode in mode-meters. Therefore, it can more easily calculate and estimate frequency and damping ratio of a given mode if the system is in ambient conditions. If we do the same procedure over a large set of signals, we can better determine an acceptable input signal for a given mode meter. See example in **Figure 1.17**.

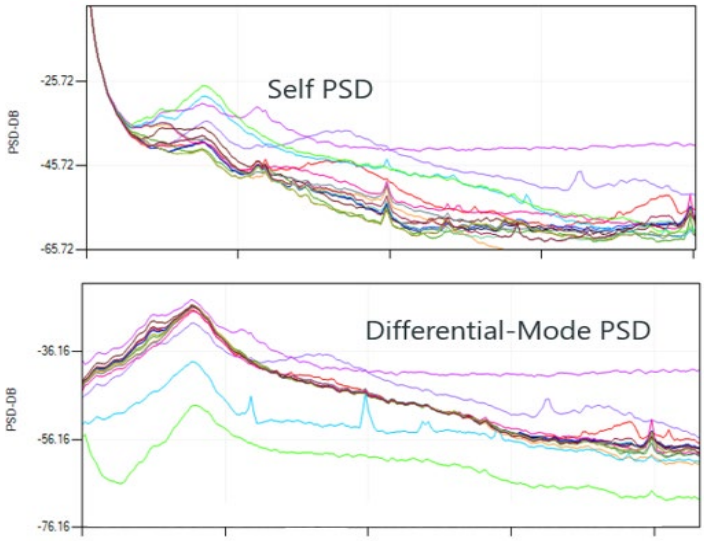


Figure 1.17: Sample Self and Differential Spectrums for Multiple Signals

So far, this paper has discussed a maximum of two signals. If two dominant modes are close in-terms of natural frequency, it might be necessary to either add more input signals to create a more unique output signal that distinguishes the two close modes or change the signal type since all signal types exhibit different network mode shapes. By utilizing the gain properties of differential and common signals, a unique signal for a given mode can be created that provides the best input to a given mode meter for a given set of available PMUs. For example, the sum of active power flows in two lines interconnecting Mexico to the rest of Central America is used to monitor and control unstable modal activities for opening the interconnection between Guatemala and El Salvador when unstable operating condition is detected.[20]

1.3.1 Thresholds for Damping and Energy

Simulation studies and review of historical mode estimates can help determine how much a contingency or credible set of contingencies can reduce a particular mode's damping ratio. This information can then be used to select alert and alarm thresholds to ensure that a sufficient stability margin is maintained in precontingency conditions to preserve stability in post-contingency. Offline studies are helpful to determine thresholds, but additional margins should be included to account for unforeseen contingencies and system conditions. Though alert and alarm thresholds should be based on studies, a damping ratio below 5% typically warrants investigation while corrective action is likely necessary if the damping ratio falls below 3%. The mode estimate should be validated before taking action to ensure that the low damping estimate is not the result of poor data quality, the presence of forced oscillations, or normal variation in the estimate. Offline modal baseline analysis can help determining the threshold for modal energy in different operating conditions.[21] Peak energy levels in the signal spectrum for a mode in a normal operating condition can be used to set the thresholds for energy.[22] As discussed next, mode shape and system conditions can also be evaluated to validate mode estimates.

[20] Espinoza, José Vicente, Armando Guzmán, Fernando Calero, Mangapathirao V. Mynam, and Eduardo Palma. "Wide-area protection and control scheme maintains Central America's power system stability." In 39th Annual Western Protective Relay Conference. 2012.
[21] Trudnowski, Daniel J., and Ferryman, Tom, Modal baseline Analysis of the WECC system for the 2008/9 Operating Season, Technical Report, September 2010
[22] Donnelly, Matt, Dan Trudnowski, James Colwell, John Pierre, and Luke Dosiek. "RMS-energy filter design for real-time oscillation detection." In 2015 IEEE Power & Energy Society General Meeting, pp. 1–5. IEEE, 2015.

1.3.2 Monitoring Mode Shape

In addition to monitoring the mode frequency and damping, it is also recommended that tools be set up to monitor the mode shapes of the various monitored modes. This will allow operators to validate that the mode where damping and energy are reaching critical levels is the same for which operators have been provided operating guidance.

1.3.3 Monitoring System Conditions

The system conditions identified for increasing damping and reducing the energy of the monitored modes should be monitored along with the damping, energy, and the mode shape. This is to ensure that system conditions are contributing to the damping and the energy of the monitored modes that reach critical levels where the next contingency can cause instability. Therefore, path flows, topology conditions (such as line status, series capacitor status, generator status) should be monitored along with damping and energy of the modes.

Chapter 2: Forced Oscillations

One among the many challenges faced by the electric power industry is the presence of forced oscillations in the power system grid and determining the source location of these forced oscillations in real-time. The existence of these oscillations is increasing as the grid characteristics change with the addition of wind, solar, and distributed technologies both on grid and behind the meter. Many oscillations have been observed in the power system over the past couple of years[23] across the North American system. Possible root-causes for forced oscillations include the following:

- Malfunctioning equipment
- Control systems with incorrect settings
- Control systems with faulty designs
- Incorrect power system stabilizer settings and governor control settings
- Incorrect dc converter station settings
- Cyclic load

The occurrence of these oscillations can be persistent or intermittent and with low energy or high energy. The presence of these oscillations may lead to undesired operation of the power system, including equipment tripping that causes further stress on the system. Therefore, the early detection and mitigation of oscillations in real-time is crucial to ensuring reliable operation of the grid.

Knowing that an oscillatory event exists in the system is the first step in the proposed methodology. In the past, many oscillation events went by unnoticed due to an inability to detect oscillations using supervisory control and data acquisition (SCADA) measurements. Synchrophasors provide the resolution necessary to capture oscillations and provide real-time alarms for oscillations that are sustained on the system. This information is important for the operators to avoid further stress and outages in the system that may degrade system reliability.

The following are different methods for detecting forced oscillations and the respective quantities that should be monitored in these methods and how the alarm thresholds should be set up for these monitored quantities. Where applicable, baselining techniques are also provided to help determine the thresholds at which forced oscillations warrant immediate mitigation or further investigation.

2.1 Forced Oscillation Detection Methods

Examples of methods available to detect forced oscillations are described below.

2.1.1 Detection Method 1: Energy Bands Monitoring Approach

Detection of oscillations in the power system requires not only identifying the existence of oscillatory signatures in the real-time measurements but also defining the thresholds to be used to differentiate oscillatory signatures from ambient changes in the measurements. Key metrics of power system oscillations can be monitored and analyzed to define the severity of oscillations and therefore establish the detection criteria. The main parameters for power system oscillations are as follows:

- **Oscillation Frequency:** Rate of change of fluctuations seen in the signal over time
- **Oscillation Energy:** indicator of severity of oscillation (high energy oscillations require operator attention)
- **Damping:** Indicator of the sustainability of oscillation over time

[23] Reliability Guideline: Forced Oscillation Monitoring & Mitigation - https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_Forced_Oscillations_-_2017-07-31_-_FINAL.pdf

Oscillation Frequency

It has been observed from oscillations forced on the system that similar devices lead to oscillations relatively close in frequency. Therefore, monitoring the oscillation frequency can be an indicator of type of oscillation (e.g., inter-area, local, control system problems, Flexible Alternating Current Transmission System (FACTS) device settings). In this approach, the frequency spectrum is divided in multiple bands where each band of frequency is used to indicate a common root-cause of the oscillation. Through observation of previous oscillation events and correlating the frequency to the identified root-cause, four bands of oscillations are defined corresponding to various types of oscillations. The oscillation frequency bands are useful to indicate the most likely cause of the oscillation. Frequency band details along with common causes are shown in the **Table 2.1**.

Table 2.1: Frequency Bands of Oscillations and Likely Causes

Frequency Band	Likely Cause of Oscillations
0.01–0.15 Hz	Governor, plant controller, automatic generation control
0.15–1 Hz	Electromechanical inter-area and local plant oscillations
1–5 Hz	Local plant modes, intra-plant modes, local generator control oscillations, excitation controls, dc circuit controls
>5 Hz	Torsional oscillations, sub-synchronous oscillations, fast acting controllers

Oscillation Energy

Amplitude is the most direct indicator of the severity of an oscillation at a particular frequency. When frequency bands are considered, the energy in each band can be monitored as a proxy for amplitude. Oscillations with high peak-to-peak amplitudes will result in high energy within their frequency band. Oscillations can be monitored by alerting or alarming when the energy in a band exceeds predefined thresholds. Monitoring energy in a band[24] can be more practical than estimating the amplitude of individual oscillations because oscillations may have time-varying frequencies and be accompanied by harmonics in the same frequency band.

Oscillation Damping

Oscillations are a part of every power system and can be observed every day while monitoring the dynamics of the system; however, sustained oscillations can cause reliability issues if not managed carefully. For this reason, it is important to distinguish oscillations that are normal from the ones that are of a potential concern. The damping of an oscillation is the indicator of the sustainability of oscillations over time. Highly damped oscillations dissipate quickly, meaning that the oscillation is observed over a short period before dissipating, while lower damped oscillations sustain for longer periods. Therefore, monitoring oscillations sustainability can be performed through monitoring damping or calculating oscillation continuity over time, as explained in the following sections.

This sets the stage for monitoring the oscillations in real-time. For effective real time oscillation monitoring, it is important to do the following:

- Establish frequency bands for oscillation monitoring:
  - What frequency bands to configure for monitoring?
- Establish thresholds for minimum energy:
  - At what level is an oscillation identified and detected?

[24] Real Time Dynamics Monitoring System – Electric Power Group: http://www.electricpowergroup.com/rtdms.html

In order to establish the parameters for real time oscillation monitoring, periodic analysis and baselining of key power system metrics is required to establish the proper oscillation thresholds for monitoring. The thresholds are usually system-specific and depend on the normal behavior of the power system. To identify the monitoring parameters, it is realistic to baseline the power system oscillations from a rich source of archived high-resolution phasor data. This requires mining historical phasor data to search for oscillations and gather the prerequisites required to monitor in real time. Phasor data mining studies would reveal both known and unknown oscillations. The unknown oscillations can be added to the bucket of known oscillations for additional monitoring until mitigation actions are executed to terminate the oscillations. The key steps in baselining study are as follows:

1. Access to archived phasor data
2. Data conditioning (filtering and conditioning, eliminating bad measurements)
3. Establishing mining criteria (Frequency bands, Energy, Oscillation period)
4. Scanning data and identifying events that meet mining criteria
5. Reviewing and interpreting mining results to identify types of oscillations
6. Preparing recommended parameters for real time oscillation monitoring—frequency bands, energy thresholds, damping, and key monitoring locations.

The basic requirement for data mining is high-resolution phasor data across the system from multiple locations for a minimum of three months to tabulate different oscillations based on the availability of events. The study can be extended to additional months to extend the research of new additional oscillations. The process could also be made iterative with a relatively short baseline study period to establish low thresholds and utilize prolonged periods of adjusting/increasing thresholds while learning of the system oscillatory properties.

The data mining process includes the following:

1. Scan through phasor data, detect low damped oscillations, and record the associated damping and energy value
2. Calculate statistics for each oscillation identified, including pattern of occurrence, highest energy value with timestamp, and PMU measurement
3. Record baseline oscillation characteristics: location, minimum energy level, and frequency band for additional monitoring in real-time

Data Analysis Procedure

The analysis procedure for establishing oscillations alarm thresholds steps are as follows:

1. Assess the quality of the phasor data using PMU quality flags. This step identifies the bad or unusable data (as indicated by the PMUs), which was then removed from the baselining analysis.
2. Identify additional bad data (not indicated by PMUs) using range check and stale check filters. The data dropouts in the communication links are eradicated in this step. Additionally, engineering judgment can be used to identify voltage signals that show significant deviations from the respective base voltages.
3. Perform oscillation analysis or the remaining good data. This step identifies oscillation in the data set and categorizes the events by location, severity, duration, and count to provide an event library for use in the study. Visual inspection of detected events and validation of oscillation energy detected through peak-peak oscillation variation is helpful in this step to eradicate false events.
4. Establish the oscillation alarm thresholds by calculating the oscillation energy in each frequency band for the dataset during ambient conditions. The average energy for each signal can be used to establish the suggested alarm thresholds for the bands.

Detection Procedure and Methodology

All available frequency, voltage magnitude, current magnitude, and voltage phase angle signals are to be initially used to mine for oscillation events. Bad data is to be removed prior to mining by using PMU quality flags, range check filters, and stale check filters. Oscillation events are detected based upon event filters listed in **Table 2.2** below.

Table 2.2: Example Oscillations Mining Criteria

Event Filter Type	Filter Value	Description
Oscillation Frequency (Hz)	>= 0.1 Hz	An oscillation frequency filter is used to retain oscillation events above a certain oscillation frequency.
Duration (minutes)	>= 1 Minute	An oscillation event filter is used to retain sustained oscillations above certain duration.
Energy	> 3 times Standard Deviation	An oscillation energy filter is used to detect the significant energy in the oscillation.

Establishing Alarm Thresholds

The oscillation energy is calculated in each frequency band during ambient conditions for each of the four oscillation bands. When oscillations occur in a signal, the oscillation energy for that signal increases, indicating the existence of oscillatory signature in the signal. The mean energy and standard deviation for each signal in each of the oscillation bands is calculated to establish the suggested alarm thresholds. It is suggested that two levels of alarm threshold be established per the formulae below in **Table 2.3**. This method ensures that only significant oscillation events trigger alarms in real-time and provides multiple levels of alarms to differentiate oscillations requiring monitoring from the ones requiring mitigation. These thresholds should be evaluated using the data analysis approach described earlier on a regular basis to ensure that all significant oscillations are detected and alarms for insignificant oscillations are kept to a minimum.

Table 2.3: Example Criteria to Establish Alarm Threshold

Alarm Level (Each Band)	Alarm Threshold (Each Band)
Level-1 (Less Severe)	Mean Energy of Ambient Data Set+(3×Standard Deviation of Ambient Data Set)
Level-2 (More Severe)	Mean Energy of Ambient Data Set+(4×Standard Deviation of Ambient Data Set)

Detecting and Identifying Local-Area Oscillations

Forced Oscillations can be either localized to a small footprint in the Interconnection, or wide-area, resulting in multiple regions swinging against each other. Depending on the oscillation spread, the methods that are currently available to detect and identify the source may vary. Therefore, it is important to identify whether the oscillations detected are local oscillations or inter-area in nature.

Determining whether an oscillation is local or inter-area can be achieved by answering the following questions:

- What frequency band is generating the oscillation alarm? Is the oscillation frequency detected by the oscillation detector close to one of the system modal frequencies?
- Is my PMU coverage spread-out across the system? If so, is the pattern of alarms widespread across most PMUs or is it localized to a specific geographical area? Are the other entities in the Interconnection observing similar alarms?

The first indicator of local oscillations is the range of oscillation frequency. Based on the ranges defined in **Table 1.1**, if an oscillation is detected and is sustained for a period[25], an alarm will be generated from a specific band for each PMU that detects the high-energy oscillations. Referring to **Table 1.1**, local oscillations mostly reside in Band-2 or Band-3, with oscillation frequencies in the range of 0.15 -1 Hz and 1-5 Hz respectively. Oscillation alarms can be validated by observing the oscillation energy of the band at the PMU that generated the alarm. The energy trend should be increasing to exceed the alarming threshold, indicating the existence of an oscillation in that frequency band. Further validation can be done by observing the trend of the metric, which is used by the Oscillation Detection Module (ODM) to perform calculations at the PMU locations.

Secondly, local-area oscillations are contained to a specific geographical footprint and are detected by PMUs nearby the oscillation source. Therefore, only the PMUs relatively close to the source should detect and alarm for the event. That said, detection at the individual PMU level depends not only on the oscillation energy seen by the PMU but also on the alarm levels associated with the oscillation detection for the PMU. Hence, depending on the severity of the oscillation observed from different PMU locations, some PMUs relatively close to the oscillation might not alarm for the oscillation if the energy does not exceed the defined thresholds.

2.1.2 Detection Method 2: Detection of Sustained Oscillations of Any Type

Undamped oscillations can occur in power systems either from the presence of sustained oscillations related to natural power grid dynamics (stable limit cycles) or from the introduction of forced oscillations from external sources, such as from rough zone related vortex oscillations or from control failures. Thus, algorithms initially intended to detect poorly damped modal oscillations can also be used to detect sustained forced oscillations. Subsequent analysis would be needed to distinguish whether the underlying cause of the low damping is related to poor damping of natural modes or from the presence of external forced oscillations. This is important to ensure proper application of the appropriate mitigation measures, either improving a mode's damping (**Section 1.2**) or locating and disabling the forced oscillation's source (**Section 2.2**).

Multi-dimensional methods are effective for implementing this approach since they can point to oscillations present in any of the PMU signals included in the analysis. This includes algorithms, such as the FFDD and fast stochastic subspace identification (FSSI). Specifically, a FFDD that is based on estimation of power spectrum densities from all available PMU measurements is very effective in detecting sustained oscillations.

The FFDD first estimates a net energy estimate for the system in the frequency domain, called the Complex Mode Identification Function (CMIF),[26,27] from all the available signals for each frequency value of interest. Then the local peaks in CMIF can be shown to be the dominant system modes and oscillations that are observable in the PMU data at that time in the system. Then using the shape of the CMIF near the local peaks, the FFDD associates a damping estimate for each of the peaks.

In this sense, sustained oscillations can be easily distinguished by the presence of sharp peaks in the CMIF estimate, and correspondingly, the damping estimates associated with sustained oscillation frequencies can be shown to be near zero. Therefore, the FFDD based approach can directly detect the presence of any sustained or forced oscillation in the frequency range of interest and only the oscillations that have significant energy compared to the other natural modes in the CMIF estimate are selected for detection. Therefore, the method is self-calibrating, in this sense, and does not require any baselining studies. Moreover, the FFDD directly provides the mode shape or oscillation shape

[25] Waiting period is configurable and can be set to dynamically change depending on event severity. Waiting period ensures filtering of transients and post-events ringdown behavior of the system.

[26] H. Khalilinia, L. Zhang and V. Venkatasubramanian, "Fast Frequency-Domain Decomposition for Ambient Oscillation Monitoring," in *IEEE Transactions on Power Delivery*, vol. 30, no. 3, pp. 1631–1633, June 2015

[27] G. Liu and V. Venkatasubramanian, "Oscillation monitoring from ambient PMU measurements by frequency domain decomposition", *Proc. IEEE ISCAS*, pp. 2821–2824, May 2008

directly from the power spectrum matrix as part of the FFDD estimation procedure, and the shape can be useful in understanding the nature and potential source of the sustained oscillation.

The FFDD was tested extensively at Peak Reliability as part of the Forced Oscillation Detection and Source Locator (FODSL) that used PMU based FFDD for oscillation detection and SCADA based engines for source location using generator MW and MVAR SCADA outputs. The FFDD was monitoring over a thousand current magnitude and MW power signals and was very effective at detecting hundreds of sustained oscillation events at Peak Reliability. The FFDD has been implemented as an action adapter into openPDC and has been tested at several other utilities in North America and in Europe. **Figure 2.1**shows an Illustration of FFDD estimates showing a forced oscillation event that occurred on September 5, 2015.

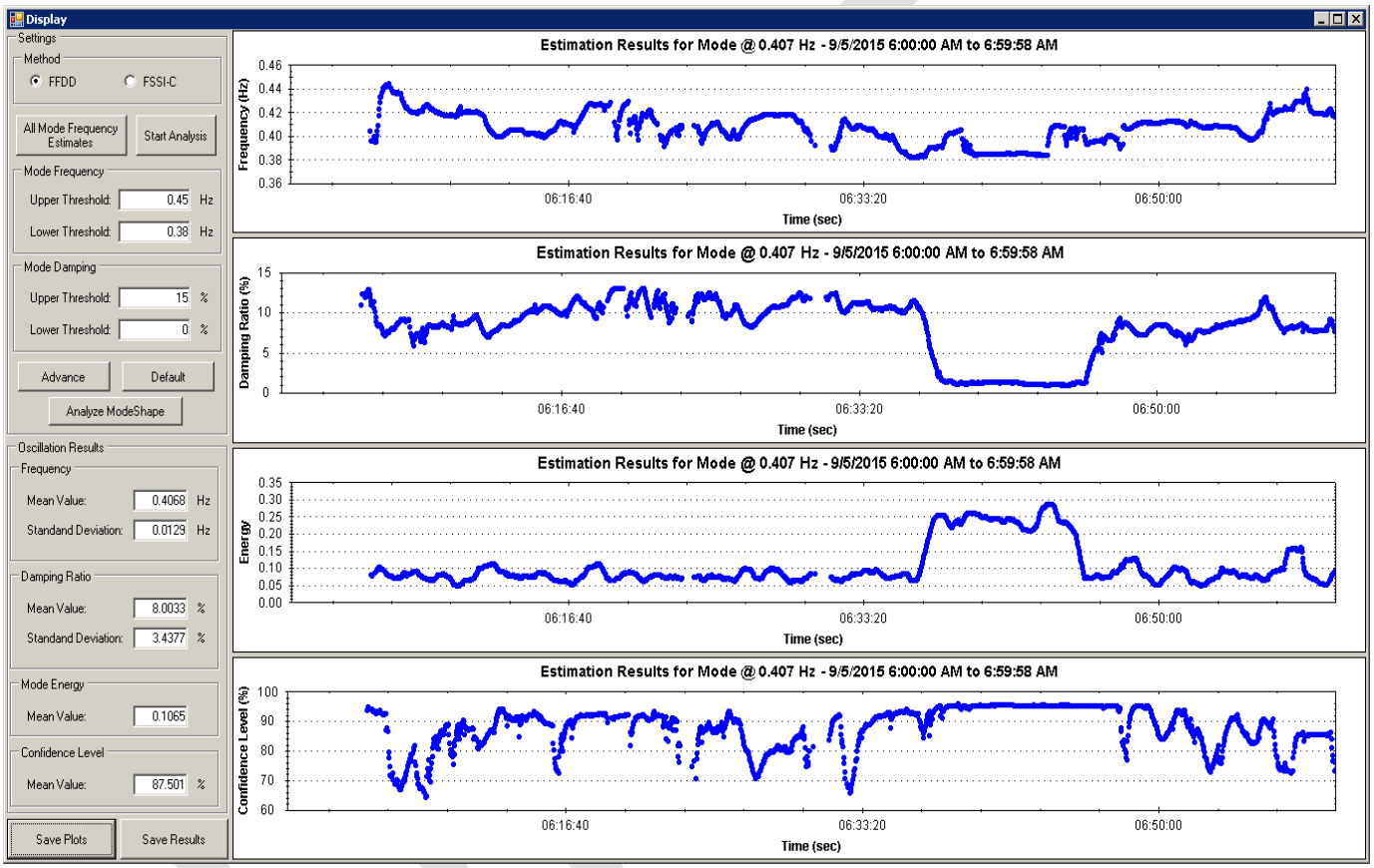


Figure 2.1: Illustration of FFDD Estimates Showing a Forced Oscillation Event that Occurred on September 5, 2015

2.1.3 Detection Method 3: Mode Frequency Band Monitoring Method

Interactions of different plants and controllers in power systems can result in small or large oscillations in the system. For a stable system, oscillations should decay by the passage of time. In an unstable system, oscillations can grow to dangerous levels where remedial actions are needed to mitigate the adverse effects of the oscillations.

Oscillations appear in power systems in different situations. One of the types of oscillations is forced oscillations (which are due to continuous cyclical excitation) as opposed to ambient oscillations (which are caused by white noise excitation). Forced oscillations can jeopardize the stability of the system when the amplitude of these oscillations is large or when these oscillations interact with system poorly-damped natural modes and the magnitude of the oscillations increases.

Power Dynamic Extraction (PDX)

Power Dynamics Extraction (PDX)[28] analysis method processes power system PMU signals to determine the presence of oscillatory components or system modes and their key parameters. For each oscillatory component, PDX determines these key parameters: frequency, damping ratio, mode shape, and amplitude of the mode. PDX down-samples the input signals with any sampling frequency to 10 Hz. The algorithm uses autoregressive model to obtain characteristics of the modes. PDX processing is applied to a window of the most recent data, and the dynamic characteristics of the system are derived for that time window. The analysis is updated at regular intervals. There are two variations of the algorithm:

- PDX-1 uses a short window (3 minutes) and updates every 5 seconds. This window is used for alarming as it can respond quickly to changes in amplitude and damping ratio.
- PDX-2 uses a longer window (more than 20 minutes) and updates every 20 seconds. This window gives more accurate and stable results. This could be used for model validation or for comparing different cases of well damped modes.

Mode Bands Management

In order to track modes in the frequency range of interest, mode bands should be defined. For example, a range may be constructed to contain a single persistently occurring low frequency mode. Defining effective mode boundaries is facilitated by collecting prior PDX1 and PDX2 processed data. Histograms containing large timespans of data (up to three days) can then be used to decide initial mode boundaries.

Alarms and Alerts

For each frequency band and each signal, some thresholds for estimated modes characteristics can be set for alarms and alerts. Damping ratio and amplitude thresholds are the most important limits. Alerts or alarms are issued when the damping ratio of a mode is below the threshold and the amplitude is larger than the threshold. There is another threshold by means of which the modes with small amplitudes are removed from alarming, regardless of their damping ratio. Similar threshold for damping ratio exists, very well-damped modes with high damping ratios are excluded from alarming regardless of the amplitude. Hysteresis limits can be set for alert and alarm events by requiring the threshold breach to persist for a defined period of time (in seconds) before an alert or alarm event is triggered.

Sustained Oscillation Detection

Any type of sustained oscillation, such as natural near zero damping mode or forced oscillation, can be detected by PDX method. These types of sustained oscillations are detected and presented by a near zero damping ratio mode by the PDX engine. However, for an appropriate mitigation plan, further analysis and investigation are required to understand whether the sustained oscillation is the result of a zero damping natural mode or a forced oscillation.

In the following simulation example, the understudy system is ESCA60 and a forced oscillation with the frequency of 0.5 Hz is injected to the system from a generator at Douglas substation. In **Figure 2.2**, it can be seen that a poorly-damped oscillation with the frequency of about 0.5 Hz is identified and an alarm is issued for this oscillation.

[28] PhaorPoint, GE Digital: https://www.ge.com/digital/applications/transmission/phasorpoint

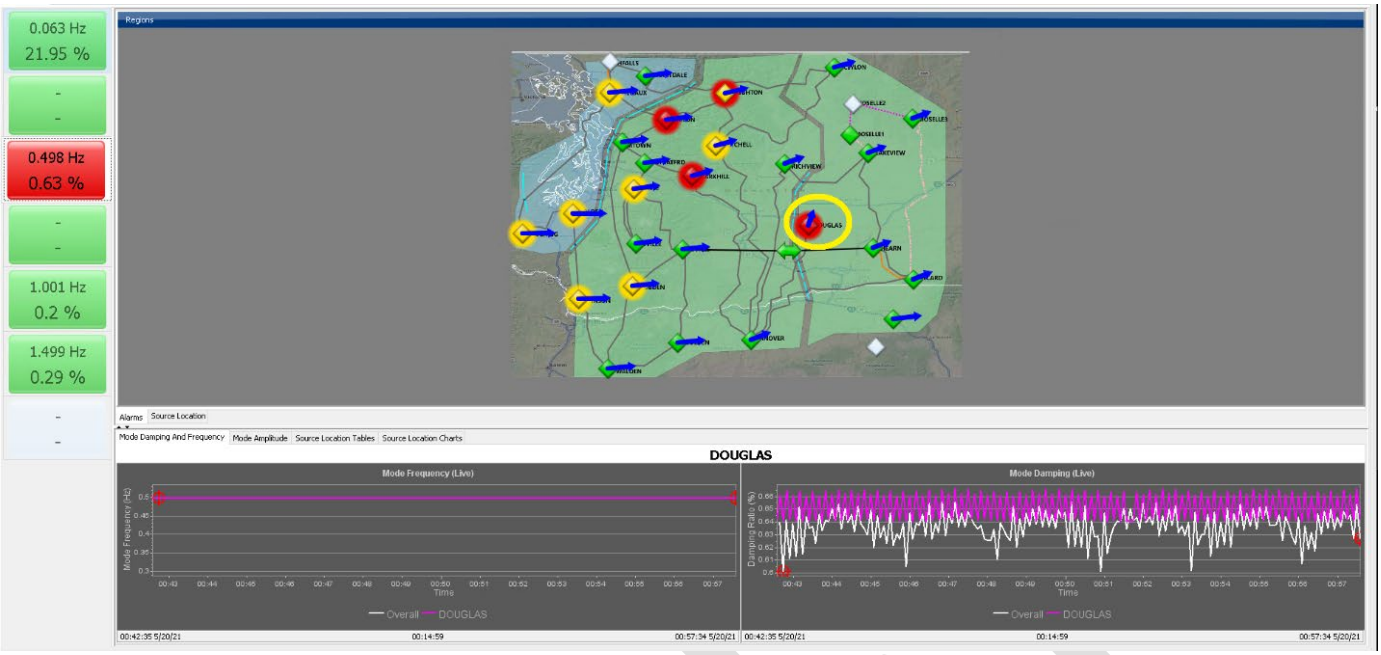


Figure 2.2: Identification of Forced Oscillation and Triggering an Alarm by PDX Method

From estimated modes, it can be seen that there are poorly-damped oscillations at 1 Hz and 1.5 Hz. These oscillations, which are harmonics of the forced oscillation at 0.5 Hz, are other indications of the presence of forced oscillation in the system. PDX could identify the forced oscillation and its harmonics that helps operators to validate the presence of forced oscillation and distinguish forced oscillation from system inter-area electromechanical oscillation.

As can be seen in **Figure 2.2**, the alarm is issued only for the estimated poorly-damped oscillation at 0.5 Hz (the estimate that corresponds to the main forced oscillation) and not for the 1 Hz and 1.5 Hz (harmonics). **Figure 2.3** illustrates the estimated damping ratio and amplitude (at the location of source) for 0.5 Hz oscillation along with the alarms and alerts thresholds. Both time plots and locus plot show that the estimated damping ratio and amplitude are in the alarm zone. In contrast, alarms or alerts are not triggered for harmonics at 1 Hz and 1.5 Hz despite their near zero damping ratio. **Figure 2.4** shows the time plots and the locus plot of estimated damping ratio and amplitude (at the location of source) for the oscillation at 1 Hz. As is evident in **Figure 2.4**, for the estimated oscillation at 1 Hz, the amplitude is below the alert and alarm thresholds.

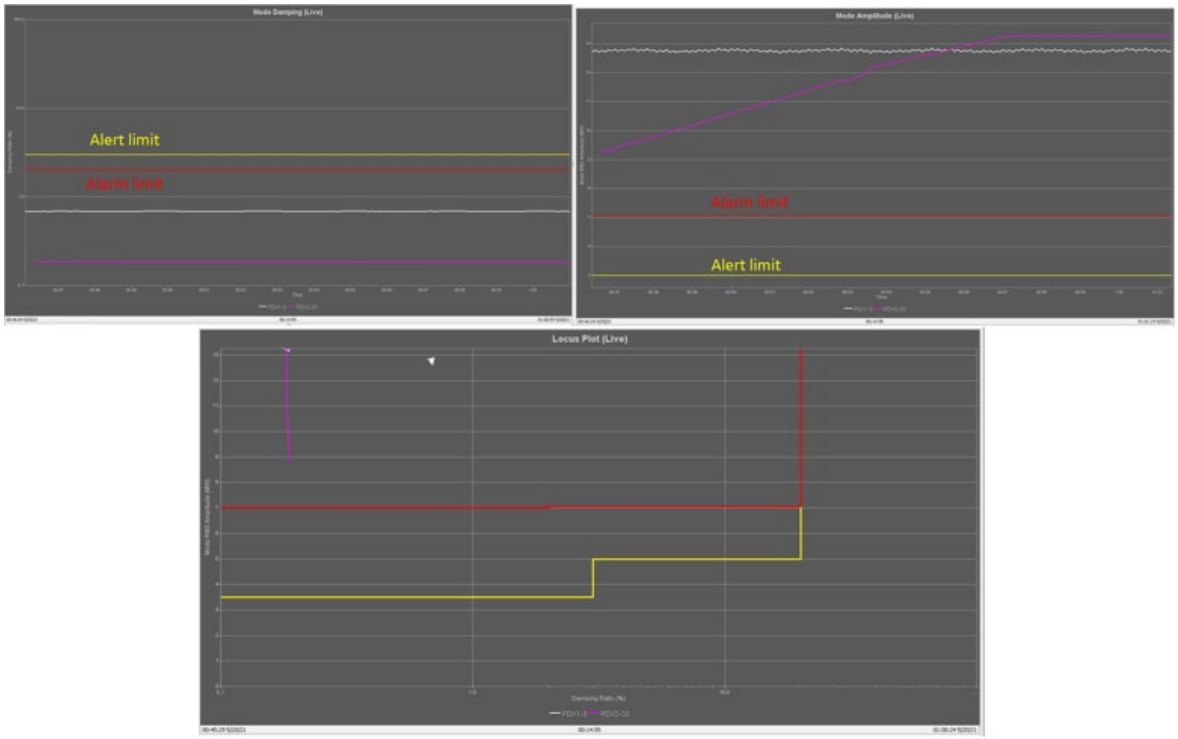


Figure 2.3: Example of Estimated Damping Ratio and Amplitude of Forced Oscillations

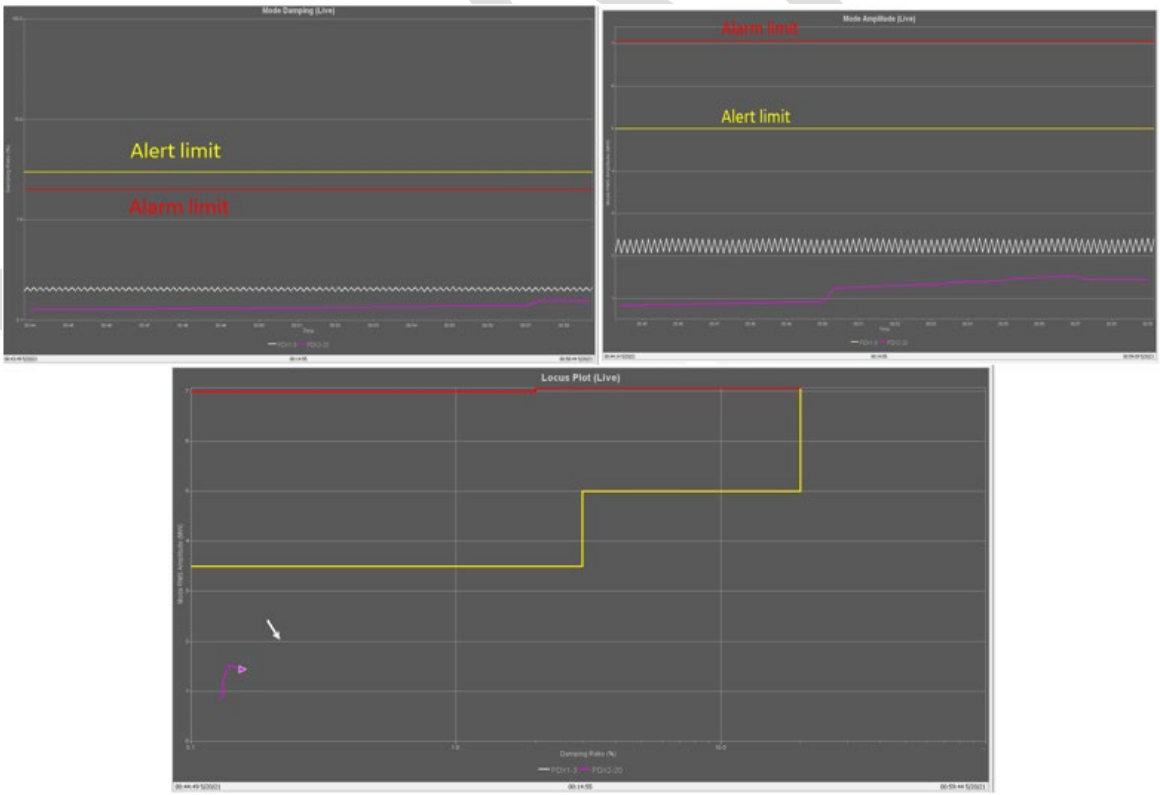


Figure 2.4: Time Plot and Locus Plot of Estimated Damping Ratio and Amplitude of the Harmonic of Forced Oscillation at 1 Hz Along with Alarm and Alert Limits

2.2 Determination of Oscillation Source

Determining the location of the source of forced oscillations can be challenging especially when the oscillation is widespread or there may not be sufficient PMU coverage to locate the exact source. For example, a RC may only be monitoring BPS level synchrophasor data, which would be utilized for alarming the operators. However, the RCs can always coordinate with the impacted TOPs to determine the source. The impacted TOPs would have a more granular view as they would be monitoring more synchrophasor data specific to the respective TOP area. In scenarios where the synchrophasor data itself is scarce, the available synchrophasor data can help to locate the local area from the oscillations originate; however, determining the exact source location would require further review of SCADA data and coordination and communication with the impacted TOPs, Balancing Authorities, and Generator Owners (GO).

When synchrophasor or telemetered data are available, the following methods help to determine the exact source location of forced oscillations or the local regions from where the oscillations originate.

2.2.1 Local Forced Oscillations

Figure 2.5 shows an example of a local forced oscillation where the source of the oscillation can be easily traced to a single location. The unit causing the oscillation may exist either at the location shown on the operator dashboard or may be in the underlying system connected to the location with the alarm if the operator dashboard does not have every location shown since synchrophasor data may not be available from every generator location. This gives the impacted RC and TOP a starting point to coordinate to determine the source.

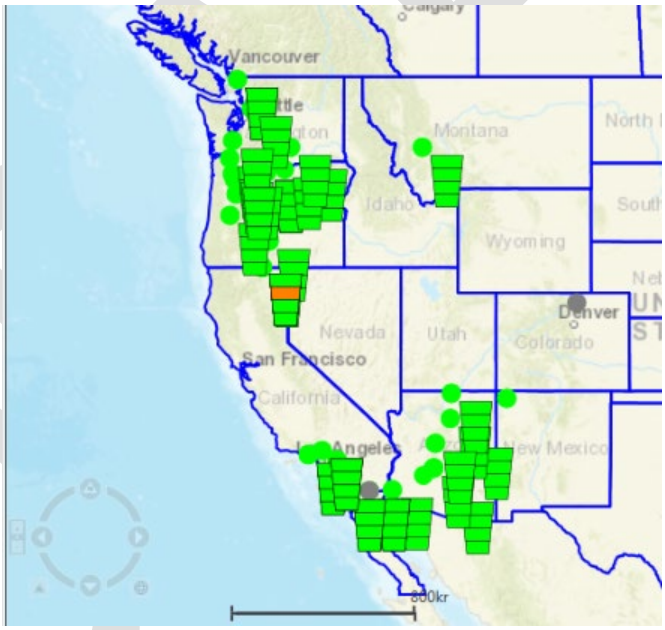


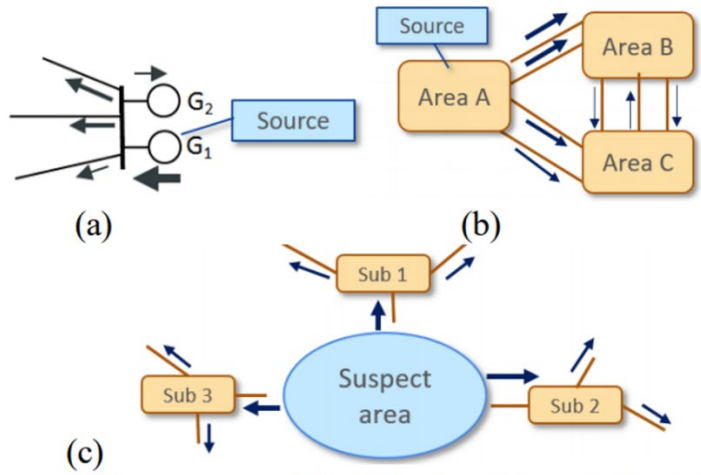
Figure 2.5: Example of Local Forced Oscillation

2.2.2 Forced Oscillations Impacting a Wide Area

When forced oscillations are observable over a wider area, location of the oscillation source can be more challenging. In certain cases, an oscillating unit can cause another unit to oscillate, which makes it difficult to pinpoint the suspect unit. The following methods help to locate oscillation sources when the forced oscillation is observable over a wider area.

Dissipating Energy Method

The method is based on tracing the flow of transient dissipating energy through the power system network (Maslennikov & Litvinov, 2020). By tracing the flow of energy back to its source, the equipment generating the oscillation is identified. When synchrophasor data is available at sufficient number of units, the method can point to the exact source of oscillation; the source will have the unique characteristic of dissipating energy flowing out of the generator. Similarly, when sufficient synchrophasor data does not exist at the terminals of generator, the suspect area can be localized by utilizing synchrophasor data from line flows. Examples of the interpretation of dissipating energy flow (DEF) results are presented in **Figure 2.6**. This method was developed and is in use at ISO New England.



The use cases of the DE pattern interpretation (a) PMU monitors POI of a power plant, (b) PMU monitor tie-lines between areas, (c) localization of suspect area non-observable by PMUs

Figure 2.6: Use Cases of the Dissipation Energy Method

Source Location Using the Phase of Oscillation

For the oscillation source location (OSL), voltage angle measurements are used to identify the PMU in the substation or region that is the closest to the sources of oscillations. This is achieved by analysing the phase of oscillations in the voltage angles from around the system. A leading phase indicates less damping contribution and the source is the location with the lowest damping contribution.[29]

Figure 2.7 shows an example of an oscillation source location map. As is evident, the source is identified and shown by the yellow circled area in the map.

[29] Al-Ashwal, N., D. Wilson, and M. Parashar. "Identifying sources of oscillations using wide-area measurements." *Proceedings of the CIGRE US National Committee 2014 grid of the future symposium, Houston*. Vol. 19. 2014.

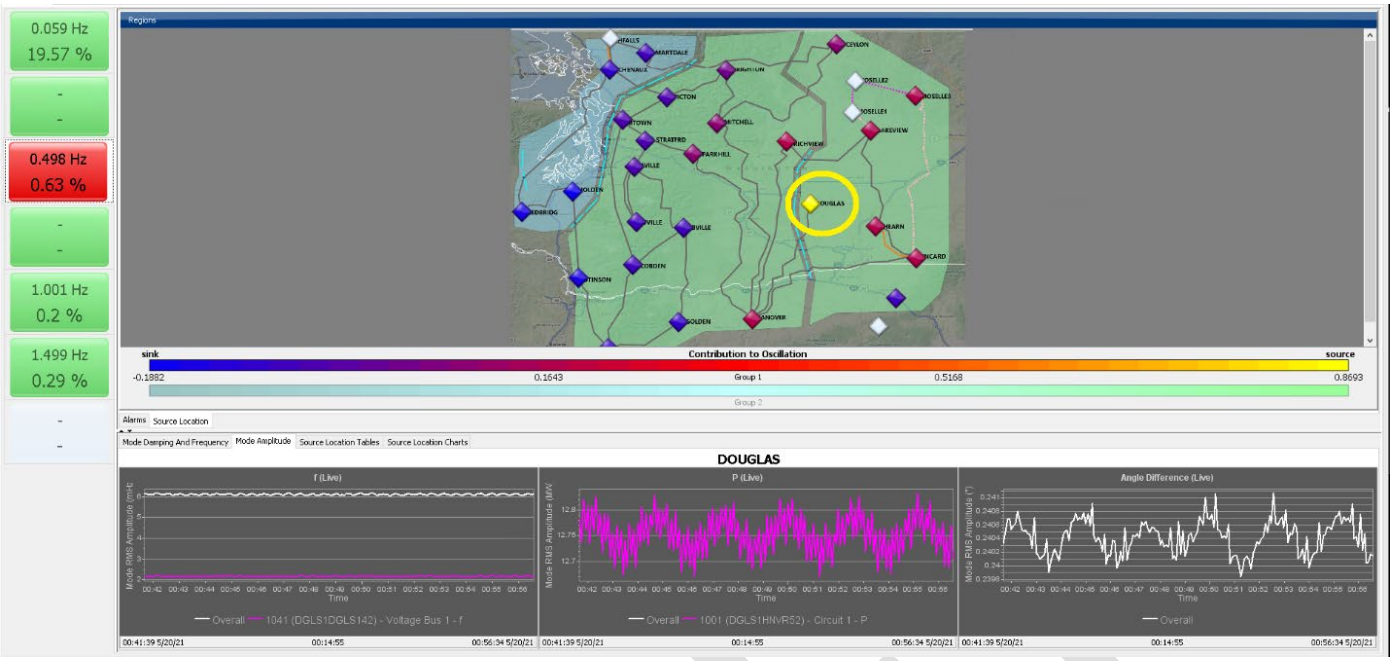


Figure 2.7: Identification of the Source of Forced Oscillation

SCADA Data Based Source Location

SCADA data can also be used to detect potential oscillation locations through the use of generator MW and MVAR telemetered data. SCADA data is easily available and, despite the lower resolution, SCADA data can help to point to the potential sources of oscillation based on the magnitude of the oscillation. This was one of the methods deployed at Peak Reliability for identifying sources of oscillation and validated with generator operators (GO) for real events.[30]

Other Oscillation Source Location Methods

Several other oscillation location methods have been developed to identify source locations under various imperfect signal conditions and practical event scenarios. These include a method[31] that combines dissipated energy flow (DEF) with a dynamic state estimator (DSE), a machine-learning pattern recognition (ML-PR) method[32] that uses DEF results as inputs, and a cross power spectral density (CPSD) based method.[33]

[30] Source Location of Forced Oscillations Using Synchrophasor and SCADA Data, https://pdfs.semanticscholar.org/97a8/48ae894edec07f462ccefe89db54a93ebf52.pdf

[31] Combined Dissipated Energy Flow Method, https://www.naspi.org/sites/default/files/2021-10/D3S8_02_estevez_fiuba.pdf

[32] Machine-LearningPpattern Recognition method, https://www.naspi.org/sites/default/files/2021-10/D3S8_03_zheng_ge_20211007_0.pdf

[33] Cross Power Spectral Density based Method, https://www.naspi.org/sites/default/files/2021-10/D3S8_04_osipov_rpi_20211007_0.pdf

Chapter 3: Forced Oscillations Causing Inter-Area Oscillations

This section addresses the phenomenon that lead to widespread impact of forced oscillations due to resonance conditions involving system modes. Also described is an example of how model-based simulations can be utilized to observe the impact of widespread oscillations during resonance conditions.

3.1 Conditions that Lead to this Phenomenon

A forced oscillation whose frequency is the same or very close to the frequency of an inter-area mode can lead to resonance that can potentially cause amplification of the oscillation across an Interconnection. Three major conditions are necessary for the resonance effect to be high:[34] [35]

- The forced oscillation frequency should be at or near a system mode frequency.
- The system mode should be poorly damped.
- The source is near a strong participation location of that system mode, such as the distant ends of the system mode. The distant end locations are the strongest participants in the system mode.

The forced oscillation event of January 11, 2019, had two of the above conditions leading to a high resonance effect. The frequency of the forced oscillation was exactly matching one of the inter-area modes at 0.25 Hz and the source was near a strong participation location. The natural system mode was well damped; however, the oscillation amplified in magnitude across the Interconnection. Oscillations higher in magnitude than the source (Florida) oscillation magnitude were observed in the Northeastern area and the rest of the Interconnection of tie-line flows leading to impact on automatic generation control operations.

3.2 Testing Possible Mitigations

Appendix A provides an example of how the impact of the January 11, 2019, forced oscillations can be determined by using model-based simulations and how possible mitigation plans can be determined for utilization in guidance provided to operators.

Since wide-area resonant forced oscillations can be simulated in dynamic analysis, the effect of various plant controls and operator actions can also be tested; see the following examples:

- Switching AVRs to manual mode
- Generation redispatch
- Curtailing power transfers
- Commissioning more PSS

The first step to the testing is to modify the load flow and dynamic cases accordingly and then perform eigenvalue analysis to determine whether the frequency of oscillation or damping of the mode being studied has been changed. Secondly, the forced oscillation should be simulated in dynamic analysis to validate changes in damping and to demonstrate any changes in the oscillation amplitude.

[34] S. Arash Nezam Sarmadi, Vaithianathan Venkatasubramanian, Armando Salazar, "Analysis of November 29, 2005 Western American Oscillation Event", *Power Systems IEEE Transactions on*, vol. 31, no. 6, pp. 5210–5211, 2016.

[35] S. A. N. Sarmadi and V. Venkatasubramanian, "Inter-area resonance in power systems from forced oscillations", *IEEE Trans. Power Syst.*, vol. 31, no. 1, pp. 378–386, Jan. 2016.

Chapter 4: Guidelines for Addressing Wide-Area Oscillations

This section addresses the analyses, tools, and procedures that RCs/TOPs need during a wide-area oscillation event. To begin, approaches for distinguishing between a natural and forced oscillation are described in **Section 4.1**. In the relatively rare case where the oscillation is due to a poorly damped inter-area electromechanical mode, the mitigation actions developed with methods described in **Section 1.2** should be implemented. If the oscillation is identified as forced, the second step is to determine if action should be taken; guidelines for making this determination are described (**Section 4.1**) then followed by a discussion of potential mitigation actions and their validation. The section concludes with a summary of the tools and procedures needed within and across RCs/TOPs footprints to enable the previously described analyses and actions.

4.1 Determining if an Oscillation is Natural or Forced

As described previously, forced oscillations become widespread when they excite one or more of a power system's inter-area electromechanical modes. For this to occur, the frequency of the forced oscillation must be similar to the frequency of the system mode. Thus, when a sustained oscillation occurs in the frequency range of electromechanical modes, it may not be immediately apparent whether the oscillation is forced or natural. The appropriate responses to natural and forced oscillations differ, so it is important to either classify the oscillation as forced or natural before taking action or ensure control and operator responses are appropriate for either type of oscillation. Currently, many of the entities operating grids are doing neither because methods for classifying sustained oscillations are not yet widely available in commercial tools. Additionally, sustained oscillations from inter-area electromechanical modes are uncommon because the operating conditions leading to these oscillations are typically identified and addressed in planning studies. Though relatively uncommon, sustained inter-area electromechanical modal oscillations do occur and pose a significant threat to reliable system operation.

One readily observable difference between natural and forced oscillations that is widely agreed upon is the presence of harmonics. Forced oscillations are often accompanied by harmonics due to the periodic nature of the driving input. For example, a 0.25 Hz oscillation may be accompanied by harmonics at 0.75 Hz, 1.25 Hz, etc. The appearance of harmonics is a clear indication of a forced oscillation because inter-area electromechanical modes do not possess harmonics. Some commercial tools may provide frequency estimates for each of an oscillation's harmonics. Others may enable spectral analysis so that the harmonics can be picked out by examining a plot. However, not all forced oscillations have harmonics and they may be too small to detect if they do. Thus, harmonics are an important characteristic to consider are not sufficient to make the distinction in all cases. **Figure 4.1** shows SSI estimates during a forced oscillation event that shows the presence of harmonics as zero damping oscillation estimates and as sharp peaks in the power spectrum plot. The forced oscillation at 0.28 Hz leads to harmonic peaks at 0.56 Hz, 0.84 Hz, and 1.12 Hz in the power spectrum plot (in the lower right side) and as 0.56 Hz, zero damping oscillation estimates in the mode estimation table (in the center).

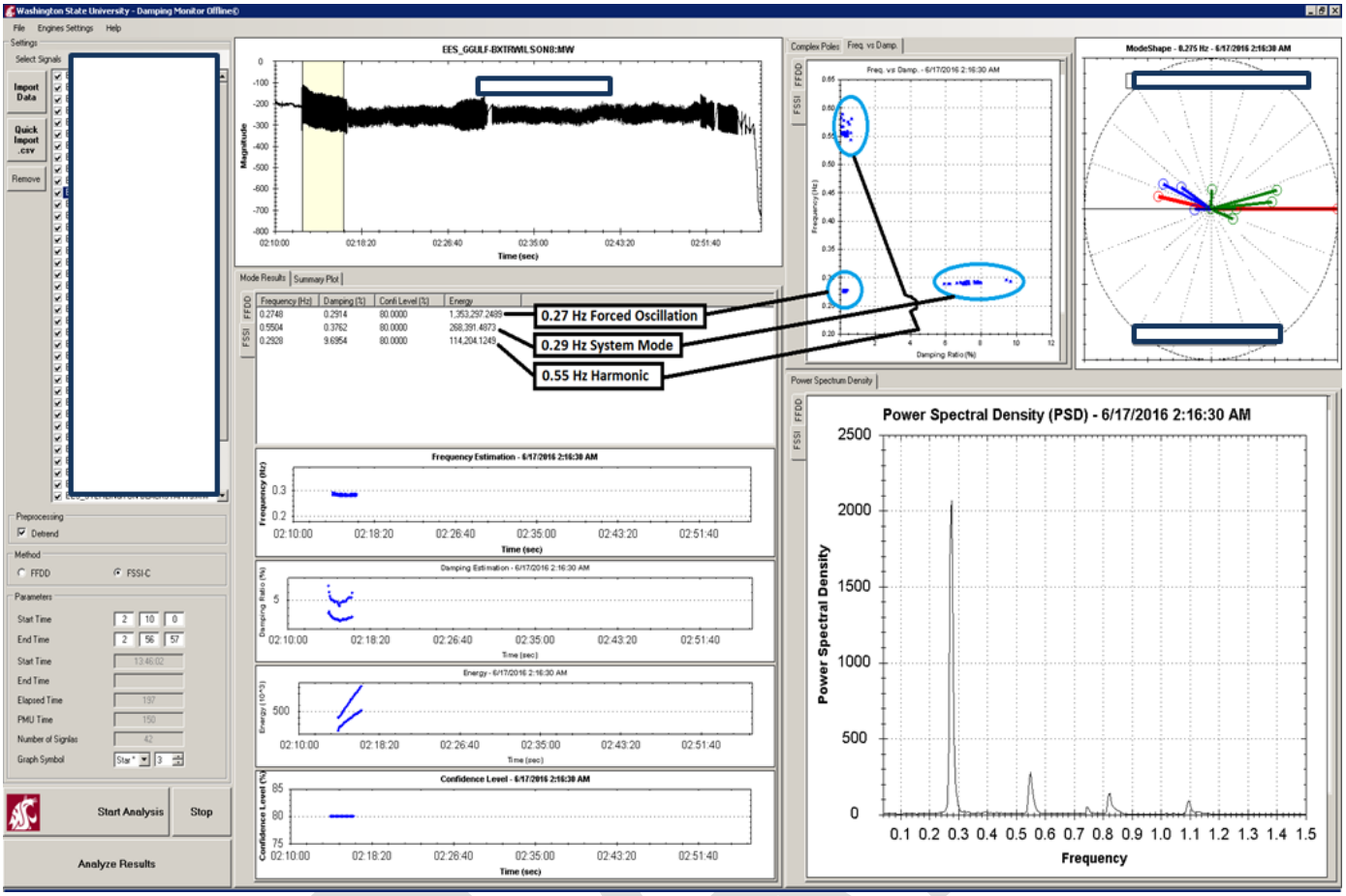


Figure 4.1: Example of Harmonics Present as Zero Damping Oscillation Estimates

The methods used to continuously monitor inter-area electromechanical modes described in **Section 1.1.2** can also help determine if an oscillation is natural or forced. These tools offer situational awareness that can help a well-trained engineer or operator understand what type of event is occurring. Forced oscillations are often (but not always) blue-sky events because they can be caused by a single piece of equipment. In contrast, poorly damped inter-area modal oscillations are often (but not always) associated with high stress conditions and/or multiple contingencies. Monitoring tools can provide an early warning of modes headed towards instability. If sustained oscillations occur following a progressive decline in a mode's damping, the oscillation is likely natural. If a sustained oscillation occurs under low-stress conditions apart from contingencies, there is a greater chance that it is forced. These are not hard and fast rules, but they can help operation staff interpret their tools appropriately.

In addition, some oscillation monitoring tools are capable of tracking forced oscillations and relatively well-damped electromechanical modes of oscillation simultaneously. If only the sustained oscillation is found at the frequency of the known electromechanical mode, there is increased likelihood that poor mode damping is leading to the oscillation. However, if the sustained oscillation and the known mode with sufficient damping are both identified, the sustained oscillation is most likely forced and has been observed before in RC operations.[36] Again, this approach requires training to help operations staff interpret results. Such approaches will be necessary while commercial tools that explicitly classify sustained oscillations as natural or forced are developed.

[36] H. Zhang, J. Ning, H. Yuan and V. Venkatasubramanian, "Implementing Online Oscillation Monitoring and Forced Oscillation Source Locating at Peak Reliability," 2019 North American Power Symposium (NAPS), 2019, pp. 1-6

4.2 Mitigating Actions

Once an oscillation is detected, a decision about whether to take mitigating actions must be made. Defining thresholds to determine if an oscillation is a reliability threat requiring action is a nontrivial task, but the key parameter is the oscillation's amplitude. Offline dynamic studies and reviews of relay settings can be used to set well-informed thresholds. In addition, regular investigation of oscillatory events can build an institution's understanding of how oscillations of various amplitudes, durations, and frequencies may impact reliability. As much as possible, oscillation scenarios should be studied in advance through the use of measurements and models to determine appropriate action.

When a wide-area oscillation occurs, effective communication among RCs/TOPs can help maintain system reliability by ensuring that only well-coordinated and effective mitigation actions are performed. Local oscillations can typically be addressed by an RC/TOP acting alone, but if the oscillation is observed throughout an RC/TOP footprint, coordination should begin quickly. Transmission operators should contact their RC, and RCs should reach out to neighboring RCs. In this way, the affected portion of the Interconnection can be quickly identified.

Any oscillation observed across an RC/TOP footprint warrants coordination. This coordination is important even when the source is readily apparent and the oscillation is not large enough to threaten reliability within the RC/TOP footprint from which it is originating. Due to the system's dynamics, a forced oscillation may be larger in far off areas of the system. RCs in those areas need to know that the source has been identified, and the RC/TOP from which it is originating needs to adjust their response if reliability of other portions of the grid are threatened. Even oscillations too low in energy to impact system reliability may be indicative of malfunctioning or misoperating equipment. When oscillations are found to originate from a power plant, RCs/TOPs can help the power plant operator maintain reliable and safe operation by communicating with them.

With coordination efforts in place, mitigation measures can be enacted effectively. Inter-area modal oscillations should be mitigated based on the results of studies as discussed in **Section 1.2**. If the mode of oscillation is unknown, reducing flows along tie-lines may reduce system stress and improve stability. In the case of wide-area forced oscillations, the most effective mitigation measure is to identify and disable the forcing input. Disabling the input does not necessarily mean that equipment needs to be taken offline. Certain areas of operation, such as the rough zone on hydro units, may lead to oscillations. In some cases, unintended control interactions leading to oscillations can also be mitigated by adjusting an operating point. Whether the mitigating action is simply adjusting an operating point or tripping a power plant offline, the source must first be identified. Methods for identifying the source of an oscillation were discussed in **Section 2.2**.

When a severe oscillatory event occurs and reliability is threatened, a potential action is to increase the damping of the excited electromechanical mode. This action can be performed while searching for the oscillation's source, which should be the primary action of all impacted RCs/TOPs. As listed previously, the three conditions leading to widespread forced oscillations are as follows:

- Proximity of the frequencies of the forced oscillation and an electromechanical mode of oscillation
- Low damping of an electromechanical mode with similar frequency
- Controllability of an electromechanical mode with similar frequency at the source of the forced oscillation

Of these three conditions, only the damping of the electromechanical mode can be effectively adjusted by RCs/TOPs through changes in the system's operating point. Increasing the damping ratio of a mode excited by a forced oscillation will not fully address the forced oscillation, which will continue until its source is disabled. However, increasing the damping ratio of the excited mode will reduce the forced oscillation's amplitude in other parts of the system that participate in the mode.

To implement this approach, studies must be conducted ahead of time to identify the operating conditions, such as flow along transmission corridors that can be adjusted to improve the damping of each mode. When a forced oscillation occurs near the frequency of a system mode, the measures designed for that mode can be implemented to improve damping. In many cases, these actions will be similar or identical to those designed to mitigate natural oscillations due to poor system damping, as described in **Section 1.2**.

Chapter 5: Examples of Oscillation Monitoring Implemented by RCs and TOPs

In this chapter, overviews of existing tools and procedures that RCs and TOPs have put into place are discussed. PMUs and the oscillation monitoring tools provided to system operators for situational awareness of concerns that could make a 15-minute impact on BPS equipment or operational decisions should be evaluated for NERC CIP applicability

5.1 Bonneville Power Administration

Implementation and Operating Experience with Oscillation Detection - Application at Bonneville Power Administration,[37] Synchrophasor Technology at BPA: From Wide-Area Monitoring to Wide-Area Control,[38] and Reliability Guideline: Forced Oscillation Monitoring & Mitigation[39] provide an overview of the oscillation applications in use at Bonneville Power Administration (BPA). BPA's oscillation detection application has been deployed in the BPA control room since 2013, and it operates by monitoring PMU measurements for increased energy. This monitoring is performed for four frequency bands as described in **Section 2.1**. When a signal's energy exceeds the threshold, it is indicated on a geographical map in red as in **Figure 1.3**. An example where the oscillation is detected across a wide area is displayed in **Figure 5.1**. These displays provide operators with an initial indication of how widespread the oscillation is and what its type may be based on the frequency band. Once a detection is displayed, the operator can click on specific locations to obtain more detailed information as shown in **Figure 5.2** and **Figure 5.3**.

The BPA established operating procedures to accompany their oscillation detection application in 2016. If an alarm is issued for a single location, the system operator contacts the local operator or field staff to investigate further. If the alarm is issued for multiple locations, the oscillation is considered widespread. Depending on the situation, the RC may be contacted to identify the cause and develop a course of action. Potential operator actions, governed by BPA's operating procedures, include inserting series capacitors, inserting transmission lines that are out of service for voltage control, moving generation to increase system inertia, and curtailing schedules.

[37] Implementation and Operating Experience with Oscillation Detection - Application at Bonneville Power Administration: http://cigre-usnc.org/wp-content/uploads/2016/10/Kosterev.pdf

[38] Synchrophasor Technology at BPA: From Wide-Area Monitoring to Wide-Area Control: https://www.bpa.gov/Doing Business/TechnologyInnovation/Documents/2017/SYNCHROPHASORS AT BPA Nov 2017.pdf

[39] Reliability Guideline: Forced Oscillation Monitoring & Mitigation: https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_Forced_Oscillations_-_2017-07-31_-_FINAL.pdf

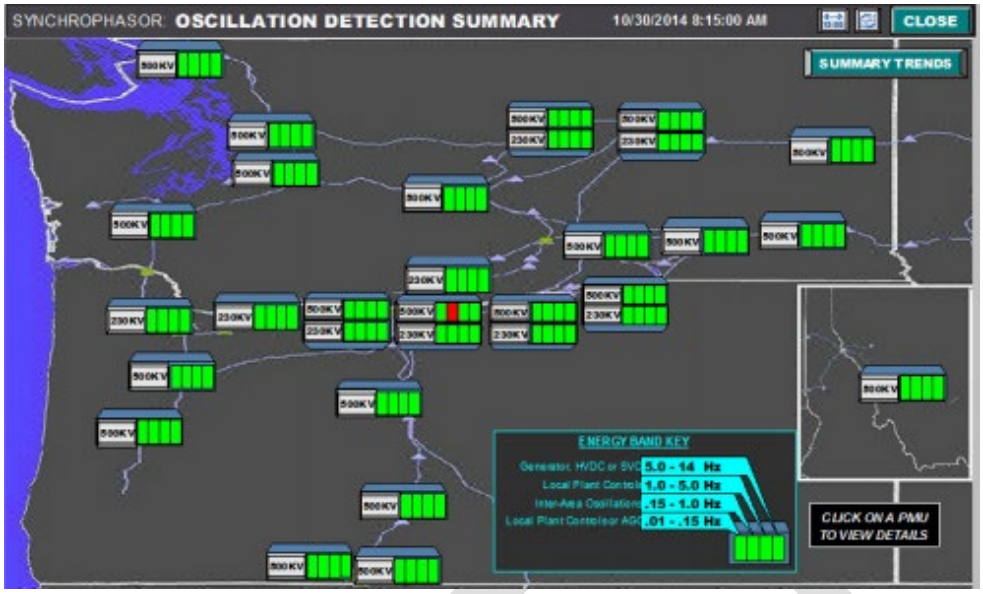


Figure 5.1: Control Room Display Indicating a Localized Oscillation in Band 2

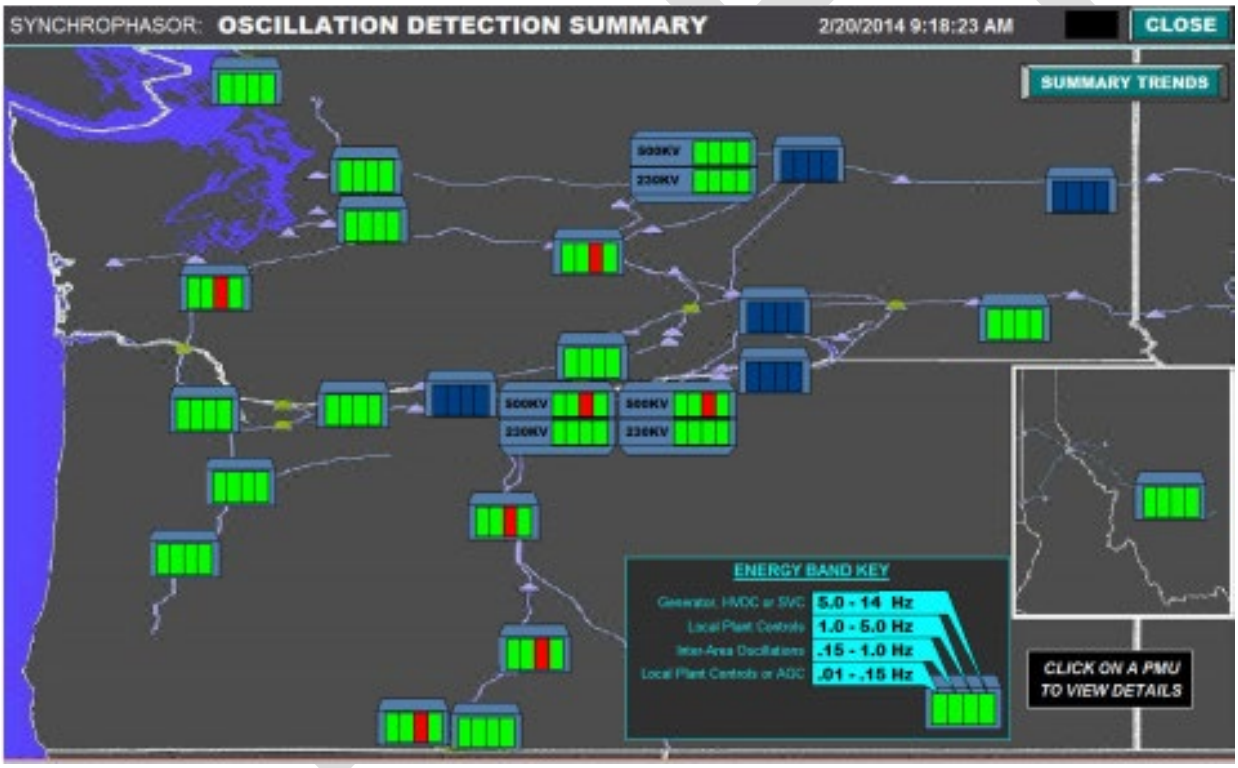


Figure 5.2: Control Room Display Indicating a Wide-Area Oscillation in Band 3

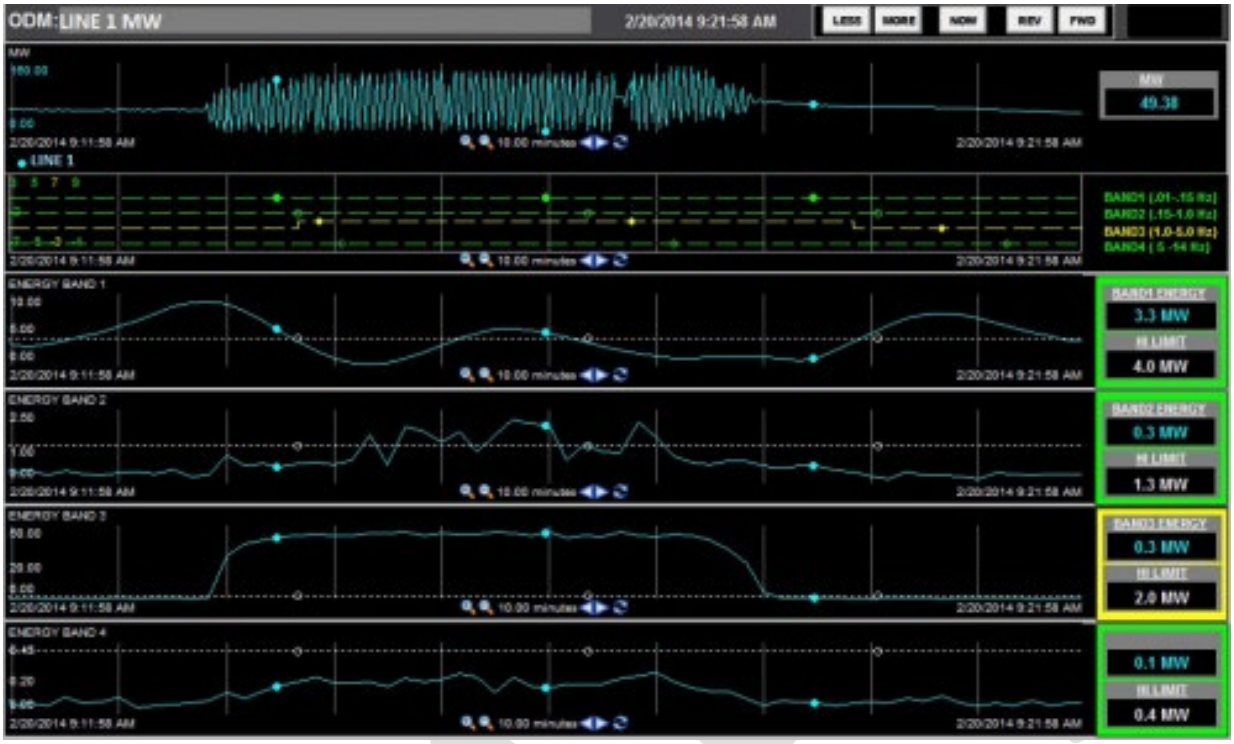


Figure 5.3: Control Room Display Providing Additional Information About a Band 3 Oscillation Alarm

BPA has also deployed a mode meter application to provide continuous tracking of known system modes. By regularly updating estimates of mode damping, the application could potentially be used to provide an early warning of inter-area oscillation problems due to high system stress; alarming and operating procedures are under development. The concept for a composite alarm that accounts for damping ratio estimates, power flows on major interfaces, and phase angle differences is displayed in **Figure 5.4**. Power flow and angle difference values have been removed from the figure.

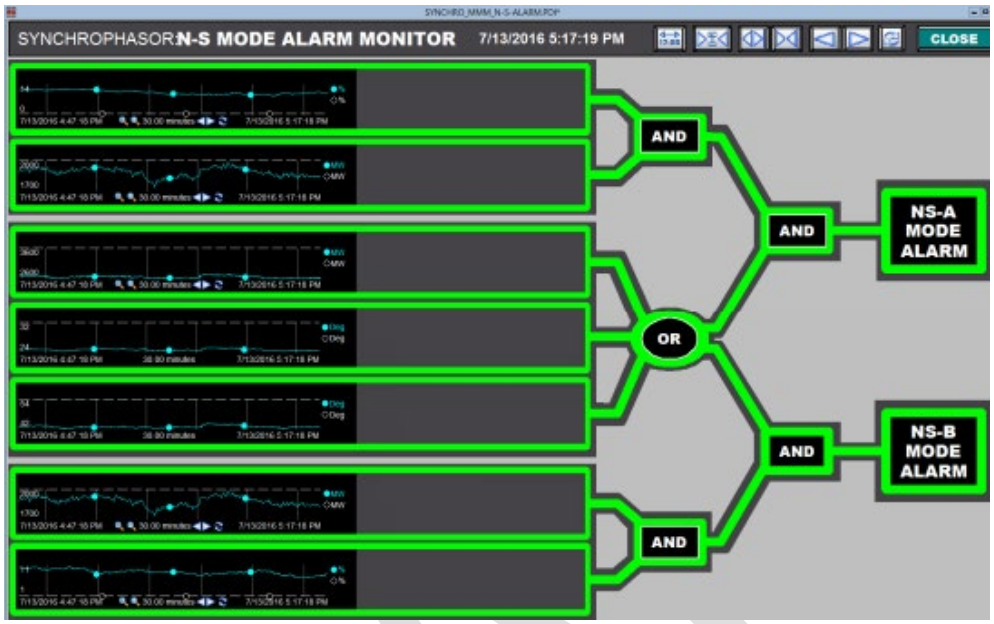


Figure 5.4: Example of a composite Alarm for Monitoring of Modes

5.2 ISO New England (ISO-NE)

Reliability Guideline: Forced Oscillation Monitoring & Mitigation[40] and ISO New England Experience in Locating the Source of Oscillations Online[41] provide an overview of oscillation applications in use at ISO-NE. ISO-NE uses the GE PhasorPoint application to detect and characterize oscillations between 0.05 Hz and 4 Hz. This frequency range is split into sub-bands that utilize their own threshold for alerts and alarms based on the magnitude and damping of the oscillations. When a sustained oscillation of significant magnitude is detected, ISO-NE follows a similar procedure regardless of whether the oscillation is natural or forced. The key objective of this procedure is to identify the oscillation's source.

ISO-NE utilizes the online OSL application to process events. The OSL application is based on the DEF method and has processed over 1,000 oscillatory events. As mentioned earlier, the equipment generating the oscillation is identified by tracing the flow of energy back to its source. Tie-lines between ISO-NE and neighboring system operators are also monitored so that ISO-NE can determine if an oscillation is coming from outside of their territory. The OSL's pattern recognition module converts the DEF in the network into a text message identifying a specific generator, power plant, or area as the containing the source of oscillation. The pattern recognition compares the energy flow with a set of pre-defined topology-based energy flow templates for all potential oscillation sources that could be uniquely identified based on system observability with PMU measurements.

[40] Reliability Guideline: Forced Oscillation Monitoring & Mitigation: https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_Forced_Oscillations_-_2017-07-31_-_FINAL.pdf

[41] S. Maslennikov and E. Litvinov, "ISO New England Experience in Locating the Source of Oscillations Online," in IEEE Transactions on Power Systems, vol. 36, no. 1, pp. 495-503, Jan. 2021

ISO-NE developed an alarm notification service to deliver the PhasorPoint and OSL results by e-mail and text messaging. An example e-mail is displayed in **Figure 5.5**.

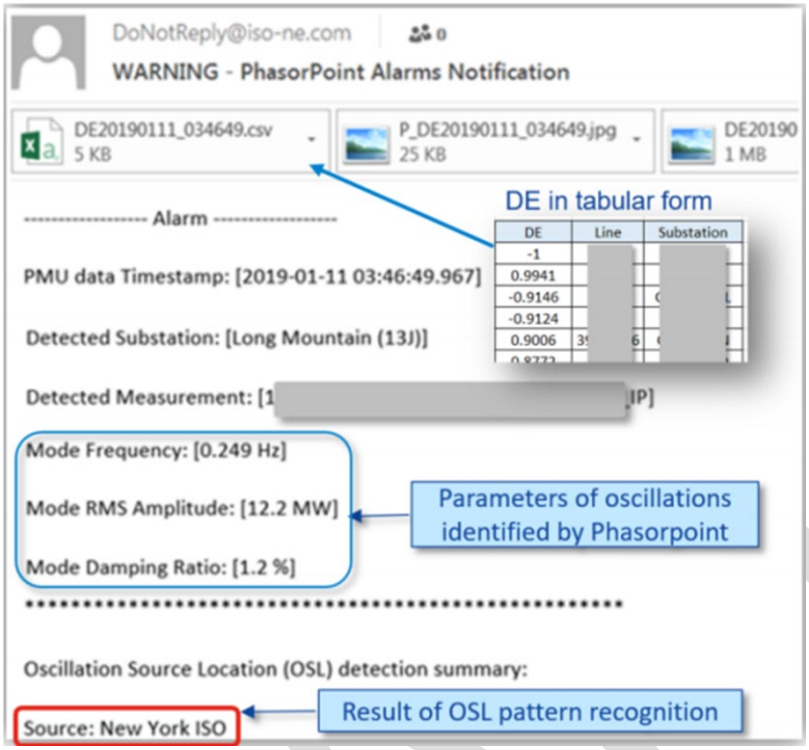


Figure 5.5: Example E-Mail from the Alarm Notification Service Detailing the Characteristics and Source of an Oscillation

E-mails from the alarm notification service are automatically generated and sent to ISO-NE control room staff and operation support engineers. If a specific power plant or generator is identified as the source, an e-mail is also sent to that generator's personnel and the local control center overseeing the generator. If the oscillation has a large magnitude, ISO-NE operational staff communicates with the operator of the source generator to apply remedial actions online. Potential mitigating measures include disconnecting the source generator from the network, adjusting the generator's MW output, or changing its control mode. If the oscillation is small, the mitigation process is shifted offline. Mitigation is again based on communication between ISO-NE personnel and the source generator's operator/owner. There is no formal distinction between a "large" and "small" oscillation at ISO-NE, but any persistent oscillation with a magnitude above the power system's ambient noise is investigated.

5.3 Oklahoma Gas & Electric (OG&E)

Reliability Guideline: Forced Oscillation Monitoring & Mitigation[42] provides an overview of the tool and procedures developed at OG&E to address oscillations in a concentrated portion of their transmission system associated with increasing wind generation resources. In recent years, the tool's use has extended to monitor low frequency oscillations related to inter-area modes. The application's oscillation detector is based on the magnitude of the Fast Fourier Transform (FFT), which is proportional to the amplitude and duration of the oscillation. The user interface shown in **Figure 5.6** allows the user to specify the detection threshold and the frequency range of interest.

[42] Reliability Guideline: Forced Oscillation Monitoring & Mitigation: https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_Forced_Oscillations_-_2017-07-31_-_FINAL.pdf

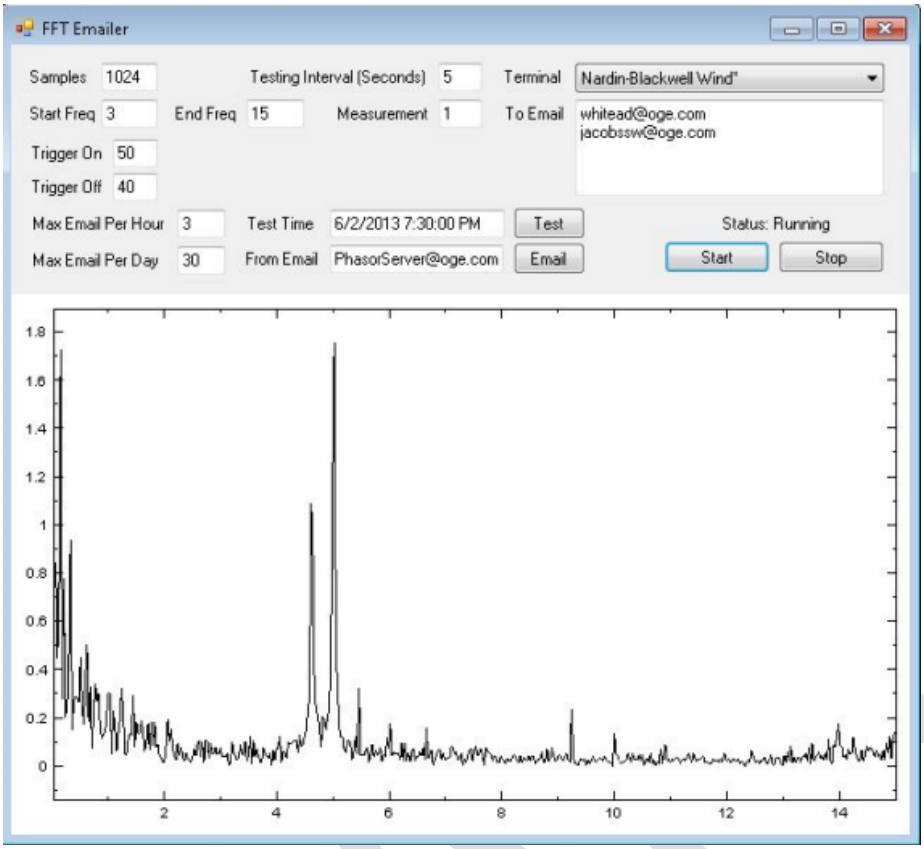


Figure 5.6: OG&E's Oscillation Detection Tool

When an oscillation is detected, the application automatically sends an e-mail like the one in **Figure 5.7** to operations support engineers. If further investigation reveals that mitigation action is necessary, the operations support engineers contact the transmission control center and recommend a mitigation strategy.

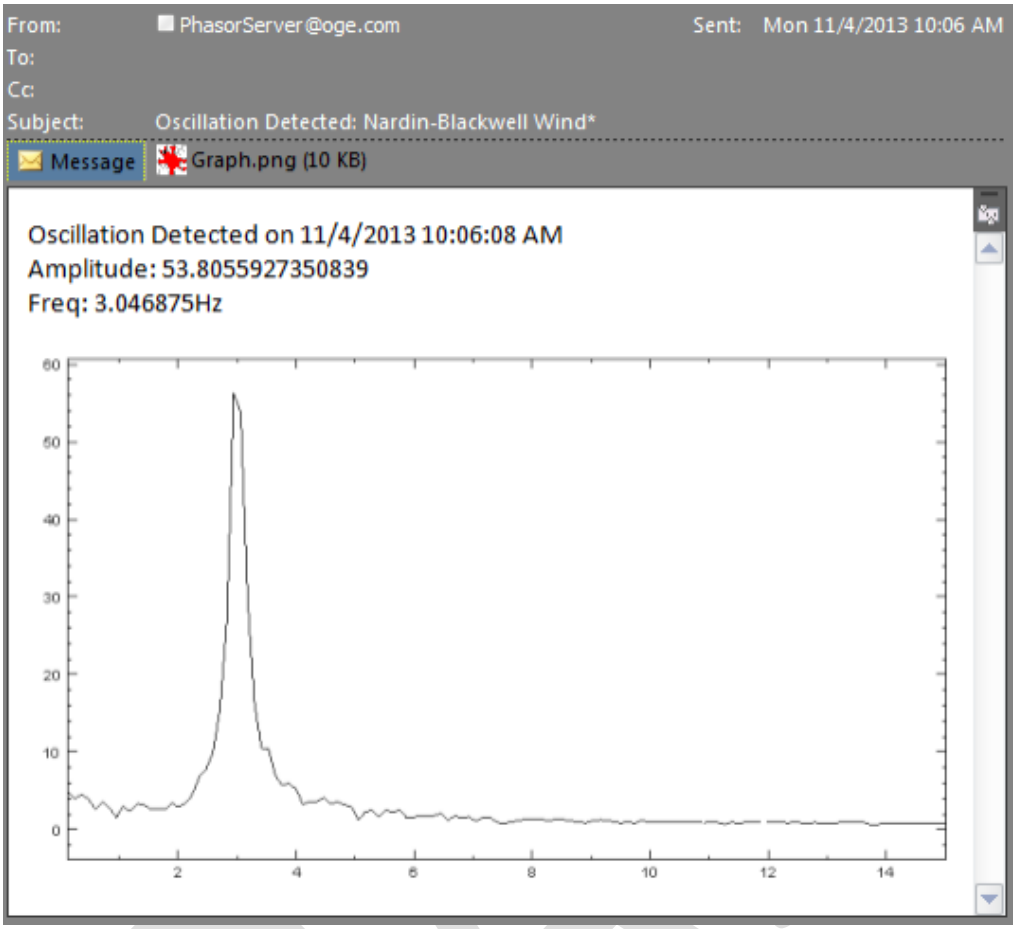


Figure 5.7: E-Mail Automatically Generated by OG&E's Oscillation Detection Tool

5.3 Peak Reliability Coordinator

Reliability Guideline: Forced Oscillation Monitoring & Mitigation[43] and Implementing Online Oscillation Monitoring and Forced Oscillation Source Locating at Peak Reliability[44] provide an overview of the oscillation applications used at Peak Reliability before its wind-down. These applications included both oscillation monitoring and source localization capabilities. Dominant inter-area modes of oscillation were monitored by analyzing PMU data in a mode meter application. This application provided updated frequency and damping ratio estimates every 10 seconds, much like the BPA tool described in a previous section. In addition, a PMU-based oscillation monitor was used to detect any high-energy oscillation, whether natural or forced. In addition, the frequencies, damping and energy levels, and mode shapes of inter-area modes and oscillations were estimated by analyzing hundreds of PMU signals using the FFDD, and the estimates were updated every 10 seconds.

Once an oscillation with a low damping ratio was detected with the FFDD, the source of the oscillation was identified using a SCADA-based application. SCADA measurements provided observability at many more power plants than was possible with PMU data. SCADA measurements also provide observability at generator level. SCADA measurements were collected asynchronously and updated at Peak every 10 seconds, restricting detailed oscillation analysis. Instead, the source localization application operated by identifying locations where measurements changed

[43] Reliability Guideline: Forced Oscillation Monitoring & Mitigation https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_Forced_Oscillations_-_2017-07-31_-_FINAL.pdf

[44] H. Zhang, J. Ning, H. Yuan and V. Venkatasubramanian, "Implementing Online Oscillation Monitoring and Forced Oscillation Source Locating at Peak Reliability," *2019 North American Power Symposium (NAPS)*, 2019, pp. 1-6

significantly at the onset of the oscillation. In many cases, the generator exhibiting a significant change comparing to ambient condition (per ranking of normalized indices) was successfully identified as the source.

Results from the oscillation source localization application were automatically routed to network application engineers for review. After validating the results through further offline studies, engineers communicated with the corresponding entity system operator and generation plant operator to identify causes and implement mitigating actions.

5.4 RC West

RC West utilizes the Electric Power Group Real Time Dynamic Monitoring System (RTDMS) for monitoring of forced and natural oscillations. The monitoring of oscillations is supplemented with an RC operating guideline that provides guidelines to the operators for the following three scenarios:

- Forced oscillations
- Inter-area oscillations
- Forced oscillations causing Inter-area oscillations

The forced oscillation monitoring is accomplished using the ODM that monitors oscillations in the four energy bands at various locations across the RC West footprint. **Figure 5.8** and **Figure 5.9** show examples of forced oscillations observed over a wide area and a local area. **Figure 5.10** and **Figure 5.11** show examples of forced oscillations observed online flows and bus voltages.

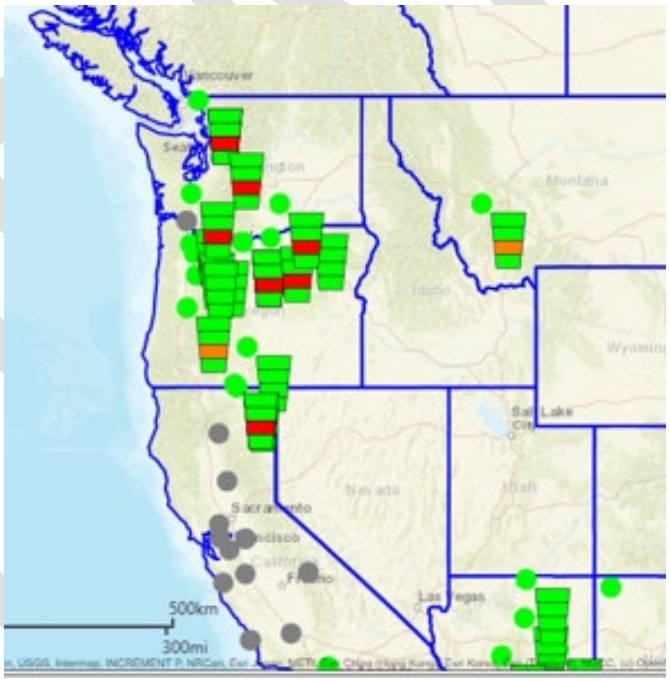


Figure 5.8: Wide-Area Forced Oscillations

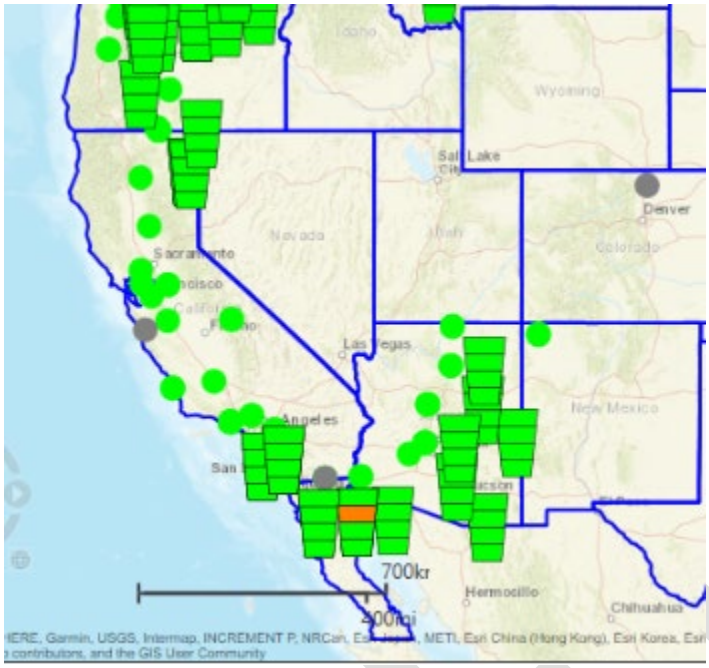


Figure 5.9: Local Forced Oscillations

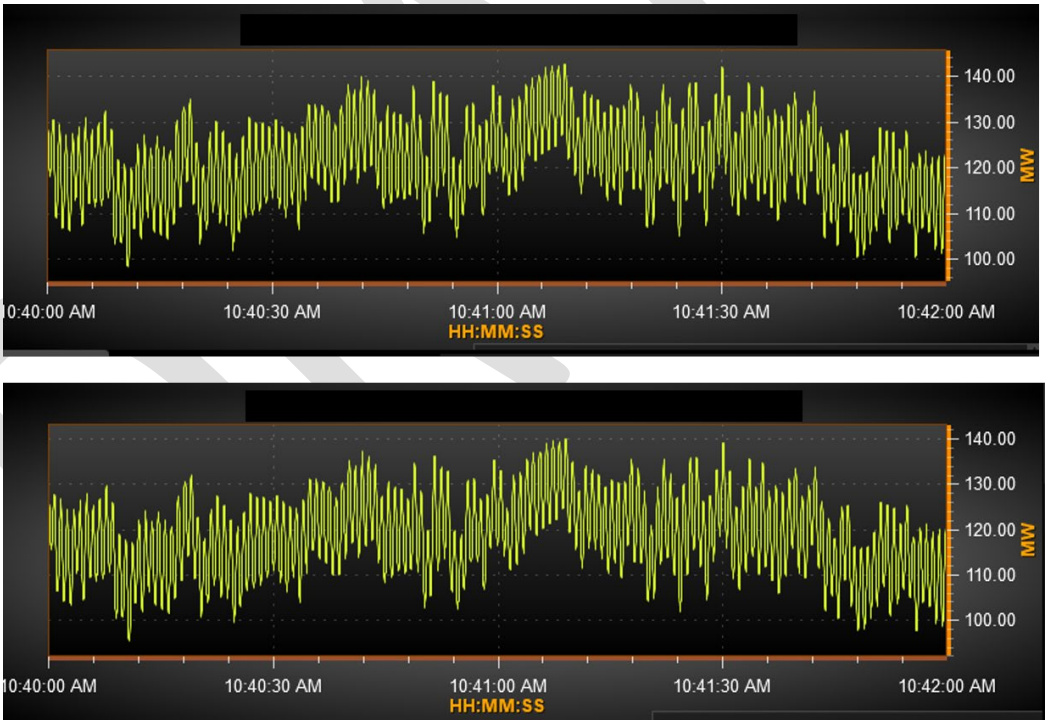


Figure 5.10: Forced Oscillations Observed on Line Flows

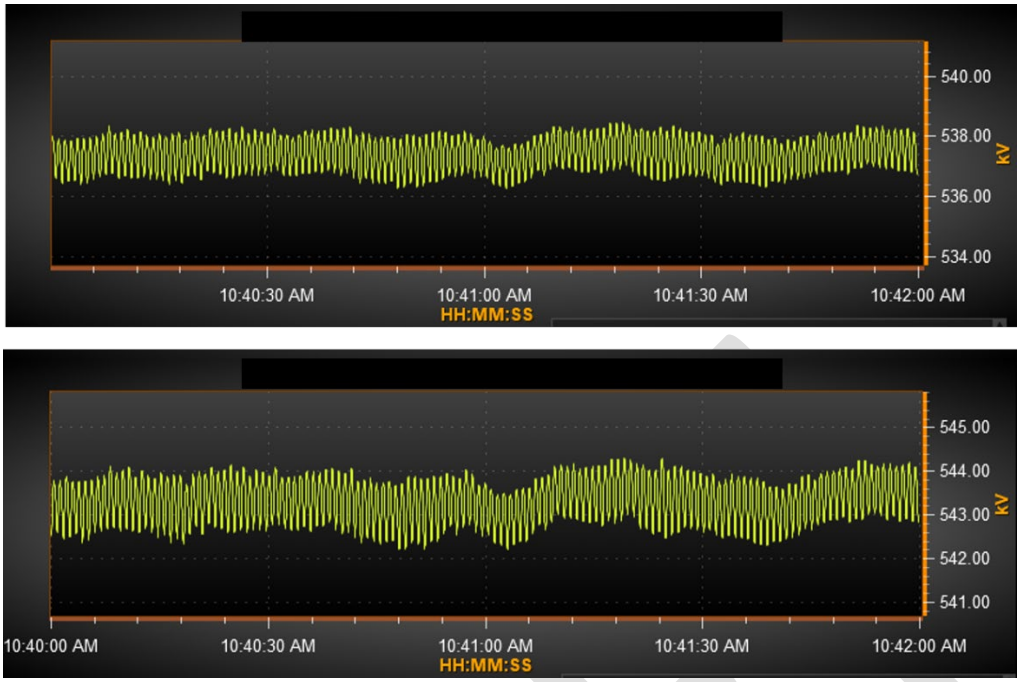


Figure 5.11: Forced Oscillations Observed on Voltages in RC West

In addition to monitoring forced oscillations, the RTDMS setup at RC West also monitors the five significant modes in the WI as shown in **Figure 5.12**: . Operators have been provided guidelines on path flows, or generators, relevant to each of these modes that can be utilized to increase damping in the event we have low sustained damping on any of these monitored modes.

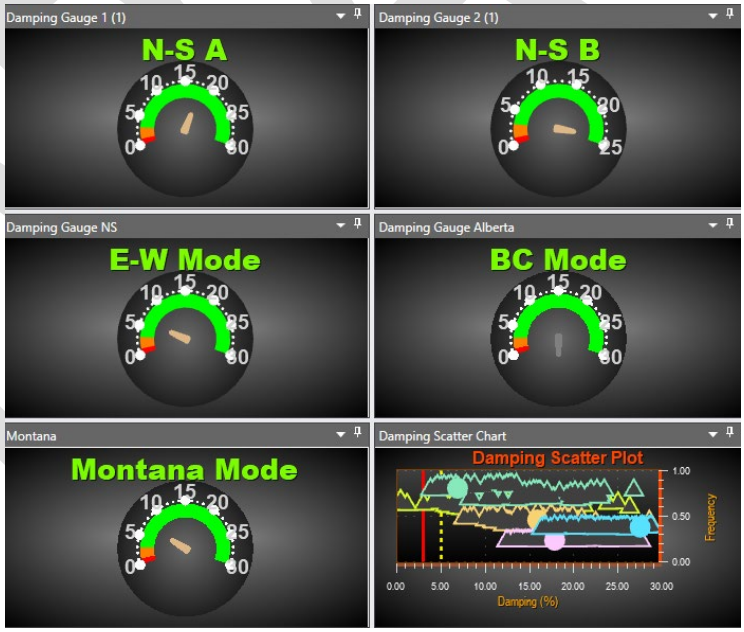


Figure 5.12: Mode Meter Monitoring

The mitigation actions for increasing damping of the modes are validated by performing SSAT analysis with real-time state estimation cases that are used along with the dynamic data applicable for the season. RC West has a running real-time transient stability analysis setup that provides the framework to perform small-signal stability analysis with the same input data from state estimation and dynamic data that is used for the transient stability analysis. The SSAT

analysis, as described in **Section 1.2.1**, allows operators to determine and validate relevant path flows or status of equipment and generators that can be adjusted to mitigate observed sustained low damping on any of the monitored modes.

5.5 Southwest Power Pool (SPP)

SPP uses PMU technology and Electric Power Group RTDMS for real-time non decision-making oscillation monitoring to ensure wide-area situational awareness of Interconnection electrical signal dynamics. SPP utilizes the ODM and mode meter engines within RTDMS to extract grid dynamics information for the purposes.

ODM is used to agnostically monitor for manifested oscillations via the use of a sliding root mean square (RMS) window. An increase in signal dynamics directly translates to an increase in the RMS value. Therefore, if an oscillation occurs on a signal measurement, ODM detects this by comparing the real-time RMS value to a pre-set RMS threshold value. If the current RMS value stays above the pre-set threshold for a minimum amount of time (e.g., 60 or 120 seconds), operators are alerted of the possible oscillation event. The pre-set thresholds are set so that they represent an increase in signal dynamics above typical ambient conditions. This information can be extracted by performing statistical analysis on raw and post-processed signals and making a decision that suffices the needs of the end user. Several methods can be used (e.g., 3sigma above mean or more slightly advanced items like Dual-Dirac fitting). If there is an oscillation present and ODM detects it, internal SPP software will alert operators who then use RTDMS displays to assess the situation, such as oscillation location, signal type, oscillation frequency, and oscillation magnitude. From there, RCs will contact entities or other RCs to communicate the detection of the event. **Figure 5.13** and **Figure 5.14** shows an example of a real-time WI forced oscillation from 2019 that showed up in SPP's RTDMS system.

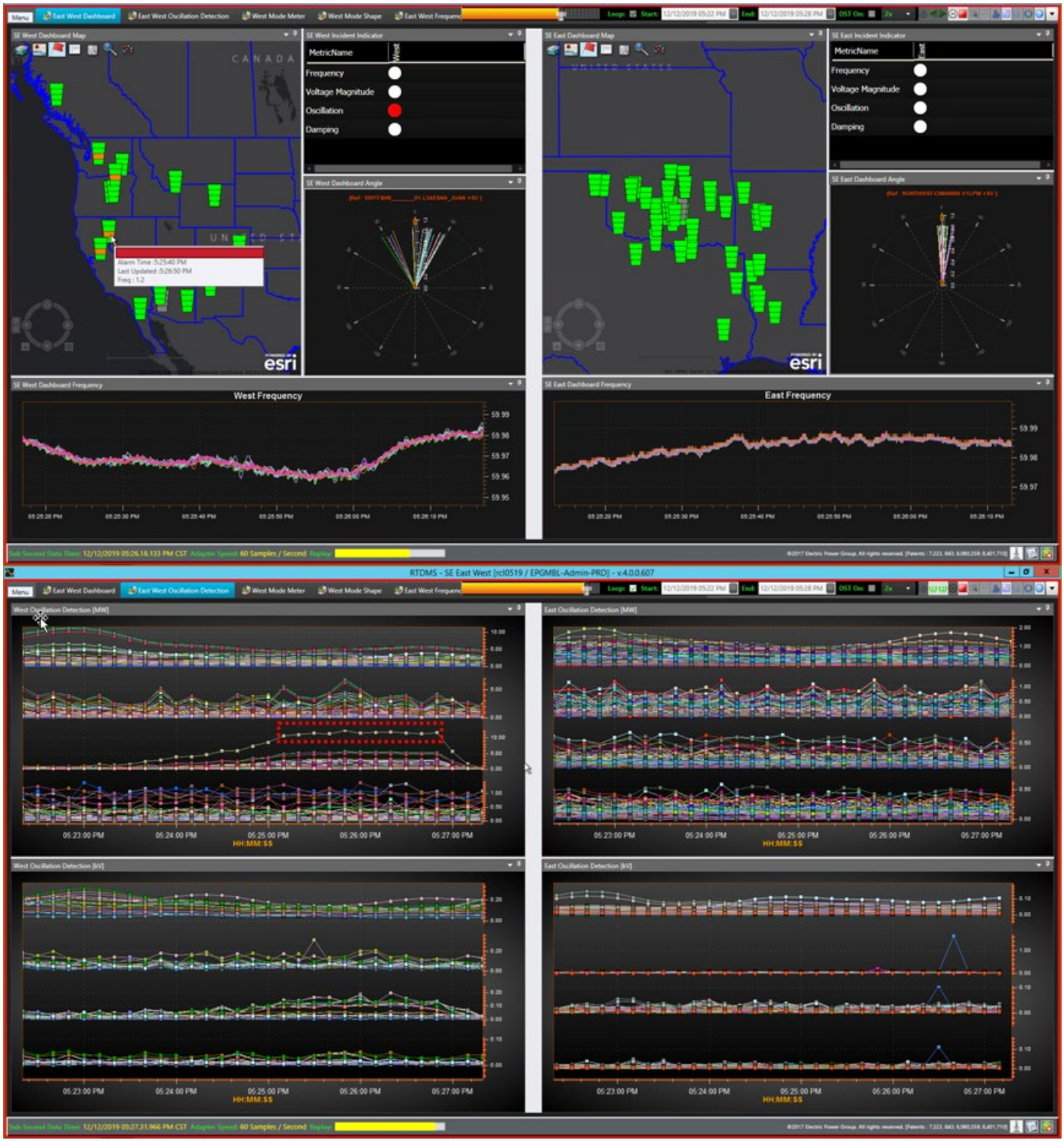


Figure 5.13: Forced Oscillation Observation in SPP

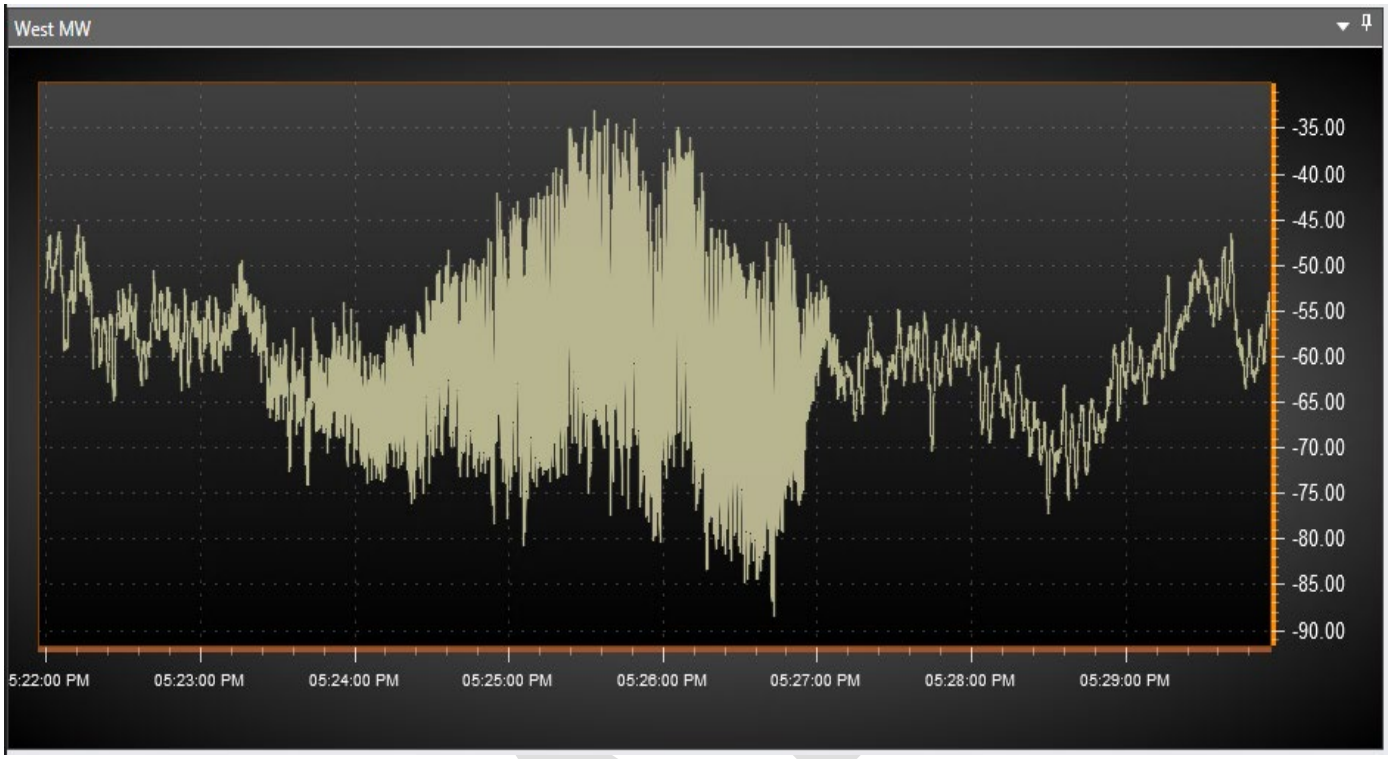


Figure 5.14: Forced Oscillation Observed on Line-Flows in SPP

On the other side of the spectrum, a mode meter is used to assess the current stability of known inter-area modes. The main outputs are the estimated damping ratio of the mode and the energy level of the composite signal used as an input to mode meter (SPP currently uses single angle pair composite signals). To assess the stability of the mode, only damping ratios are estimated and monitored in real-time. If the damping ratio of a mode drops below 3%, internal SPP software notifies the operator(s) of a potentially weakened mode. **Figure 5.15** shows an example of SPP's west mode meter display, showing the real-time states of the five main WI modes.

Figure 5.15: Mode Monitoring in SPP

SPP also uses the energy values in addition to damping ratio as a quasi-ODM for detecting system oscillations pertaining to a particular system mode. This can only be done with very careful signal choices for mode meter inputs. The basic premise is that current mode meters (not just in RTDMS) typically do not work well when a forced oscillation is happening and, in that event, will generally have damping ratio estimates drop dramatically and artificially to low levels (e.g., 0% to 3%). While there are currently fixes in place, this artifact can be exploited to our advantage. By coupling a low damping ratio percent with an energy threshold (like ODM, above typical ambient conditions), a mode meter can help operators and shift engineers assess whether there is an oscillation happening that pertains to a particular system mode whether that be an unstable mode causing growing oscillations or a case where a natural mode resonance happens. In both cases, estimated damping ratios drop and energy levels rise. **Figure 5.16** is an example conveying the concept as well as a real-use case. In addition, mode shapes are also plotted as another indicator to operators that a power system oscillation pertaining to a particular system mode is in effect.

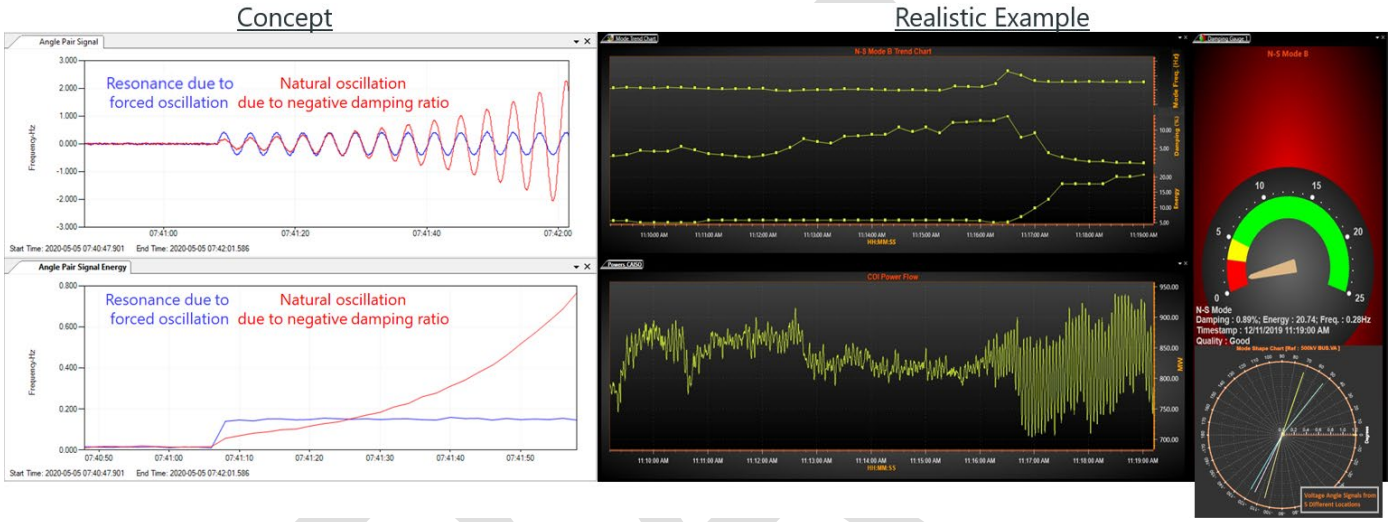


Figure 5.16: Mode Monitoring

5.6 American Electric Power (AEP)

Since early 2018, AEP has used PMU based applications for online oscillation analysis and offline event studies. Installed and maintained by AEP's protection and control team, field PMU units will stream high sampling data to an enhanced Phasor Data Concentrator (ePDC), which is a data repository. An ePDC will then dispatch PMU data streams to PhasorPoint in which real-time monitoring is enabled and alarms are generated and transmitted to energy management system (EMS) side. **Figure 5.17** illustrates the configuration of AEP's PMU system.

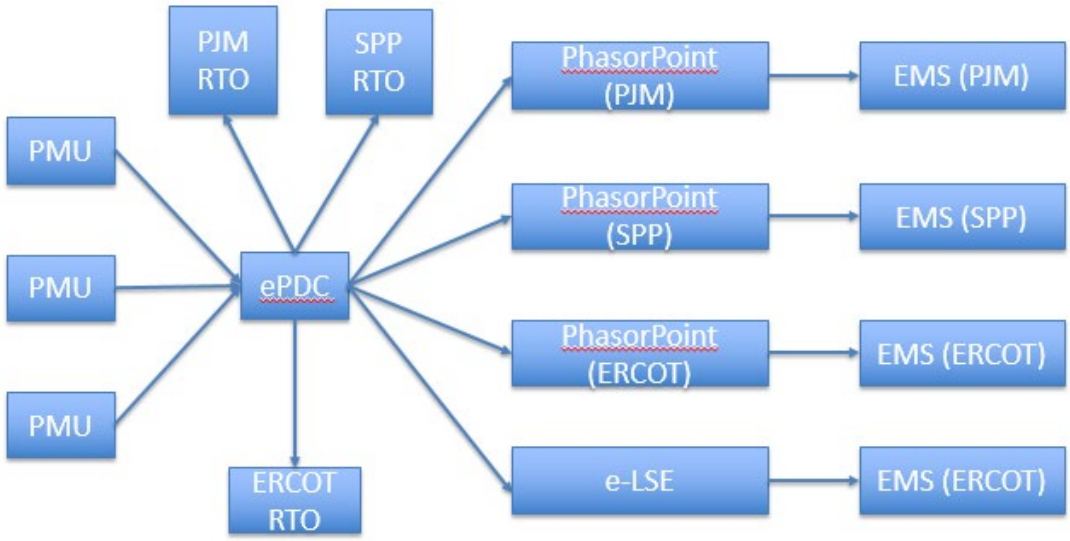


Figure 5.17: AEP's PMU Configuration

AEP has deployed close to 400 PMUs across its three footprints governed by PJM, SPP, and ERCOT. With the large amount of data accumulated, real-time oscillation event detection on frequency and active power was developed and deployed in control room to enhance situational awareness.

5.6.1 AEP Real-Time Oscillation Monitoring and Event Detection

Taking advantage of the high sampling rate of phasor measurement units, system dynamics are visualized and documented in PhasorPoint. The purpose of developing this event detection mechanism is to help control room personnel quickly identify harmful oscillations from common system variations. With online modal decomposition in PhasorPoint, system dynamics were decomposed in real time with oscillation magnitude and decay time as two critical metrics to measure the severity of the oscillation. The bigger the magnitude and longer the decay time, the more sever the oscillation will be. While it is preferred to avoid alarms on the small and quickly damped oscillations, the lingering ones with big swings are supposed to be caught by operators as quickly as possible.

With this purpose in mind, a kernel density estimation (KDE)-based methodology[45] was developed to detect oscillation events. In this methodology, a cross-validated KDE was adopted to regress historical oscillation data. As a result, a bi-variable probability density function was derived to summarize the distribution of documented oscillation data. Knowing that severe oscillatory disturbances are statistically rare, a cut-off probability initialized at three standard deviations above the mean was used to identify historical observations of oscillation events. With heuristic[46] training based on a historical event list, this cut-off probability would be finalized, and observations of past oscillation events were picked and located on Locus plot like shown in **Figure 5.18.**

[45] AEP's experience in Detecting and Analyzing Oscillation Events using PMU based applications - https://www.wecc.org/Administrative/09f_Lu_JSIS_AEP's experience in Detecting and Analyzing Oscillation Events using PMU based applications_May 2021.pdf

[46] In mathematical optimization and computer science, **heuristic** (from Greek εὑρίσκω "I find, discover") is a technique designed for solving a problem more quickly when classic methods are too slow, or for finding an approximate solution when classic methods fail to find any exact solution. This is achieved by trading optimality, completeness, accuracy, or precision for speed. In a way, it can be considered a shortcut.

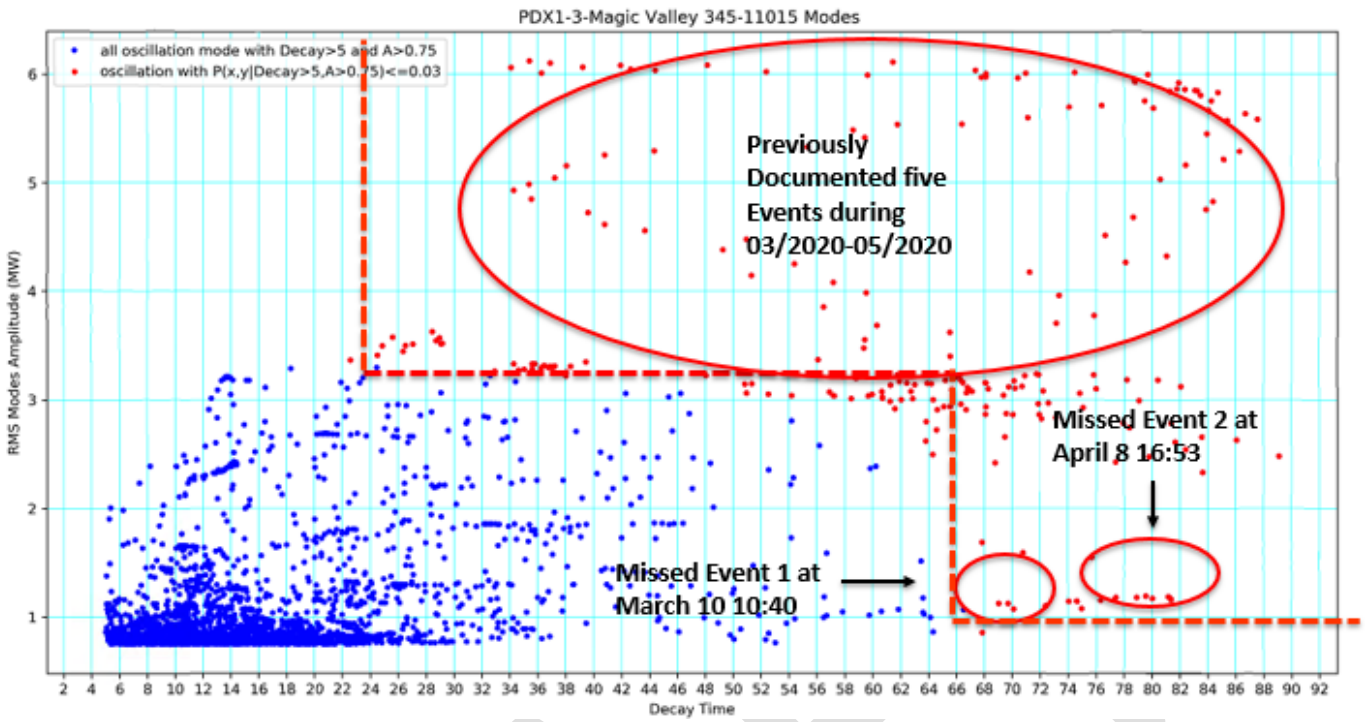


Figure 5.18: Locus Demonstration of Observations Representing an Oscillation Event

With all event observation labeled in red in Figure 5.18, the alarm settings concerning amplitude and decay time were configured. For the particular PMU signal demonstrated in Figure 5.18. Its finalized alarm configuration is listed in Table 5.1.

Table 5.1: Alarm Setting for PMU @Magic Valley

	Decay Time Exclusion	Decay Time Threshold	Amplitude Exclusion	Amplitude Threshold
Alarm Setting	24 seconds	66 seconds	1MW	3.25MW

The alarm configurations obtained from KDE-based methodology were more reliable than the previous intuitive configurations. Historical event studies proved the method's enhanced sensitivity as the method could detect previously missed oscillation events. In addition, over one-year of control room deployment has verified long lasting reliability of the methodology as the rate of false alarms is significantly reduced. Table 5.2 is a performance overview on the KDE-based online event detection.

Table 5.2: Performance Overview of KDE-based event detection

Footprint	Production Deployment	False Alarm Count	False Alarm Rate (after)	False Alarm Rate (before)	Footprint
ERCOT	07/2020	<30	Around 6%	50+%	ERCOT
SPP	09/2020	<10	Less than 5%	45%–50%	SPP
PJM	10/2020	<20	Less than 5%	50+%	PJM

With the KDE-based event detection in place, all the oscillation events captured in PhasorPoint will be streamed in real-time to control room and documented in daily PMU reports for offline studies.

5.6.2 AEP Auto Daily PMU Report Implementation

In order to enhance the situational awareness of AEP's system for control rooms, the Daily PMU report is automatically generated as a pdf file and is archived in an internal shared folder. So far, this report includes information of the system average frequency and PMU data quality statistics and also lists the poor-quality PMUs that are in need of maintenance. In addition, the reports summarize the oscillation events and have the charts attached of event details, such as related PMU measurement waveform charts and oscillation mode information charts. More information and charts are planned to be included in future daily reports.

As shown in **Figure 5.19**, the daily reports are created by retrieving data through Phasorpoint SQL database via the Open Database Connectivity (ODBC) connector. Then python scripts have been written to access the SQL data to make necessary plots and tables, and a pdf file report containing all the information needed will be automatically generated by the script. The purpose of daily reports is to help operators and engineers have a better situational awareness of AEP's system operation. Therefore, three daily reports for each AEP's footprint (ERCOT, SPP, and PJM) are generated on a daily basis. So far, there are seven modules in the daily report that each cover the system frequency chart, the daily/monthly PMU data quality statistics pie chart, and the daily/monthly poor PMU quality list as well as the oscillation event summary list and detailed charts. Some examples of the charts in the AEP Daily PMU report are provided in **Figure 5.20–Figure 5.23**.

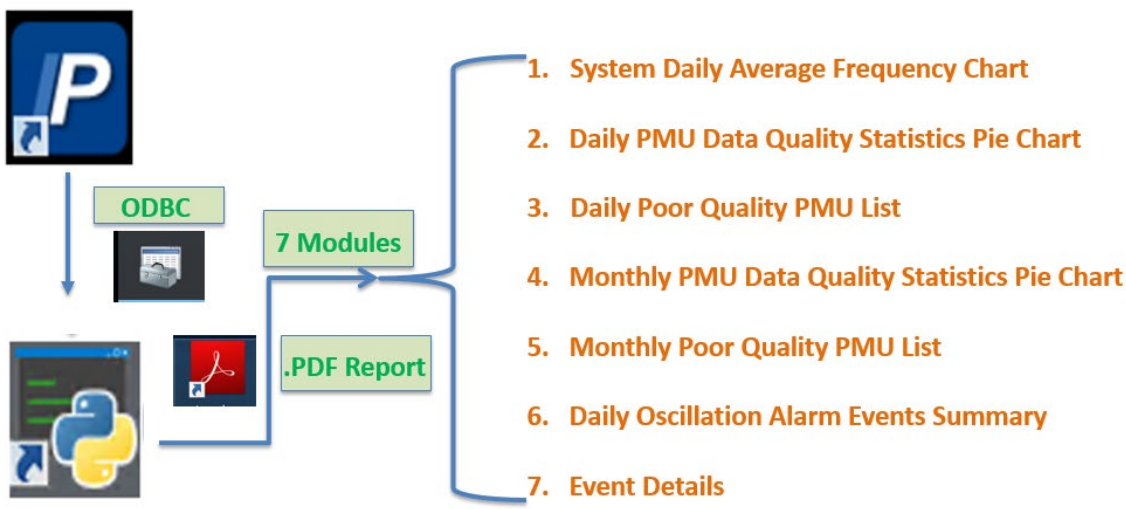


Figure 5.19: AEP Auto Daily PMU Report Deployment

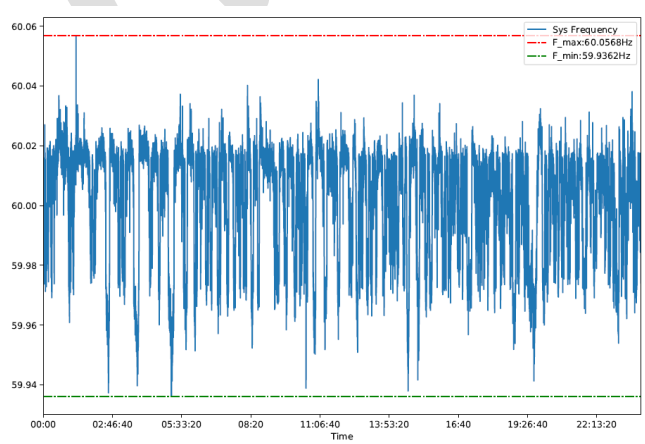


Figure 5.20: System Daily Average Frequency Chart

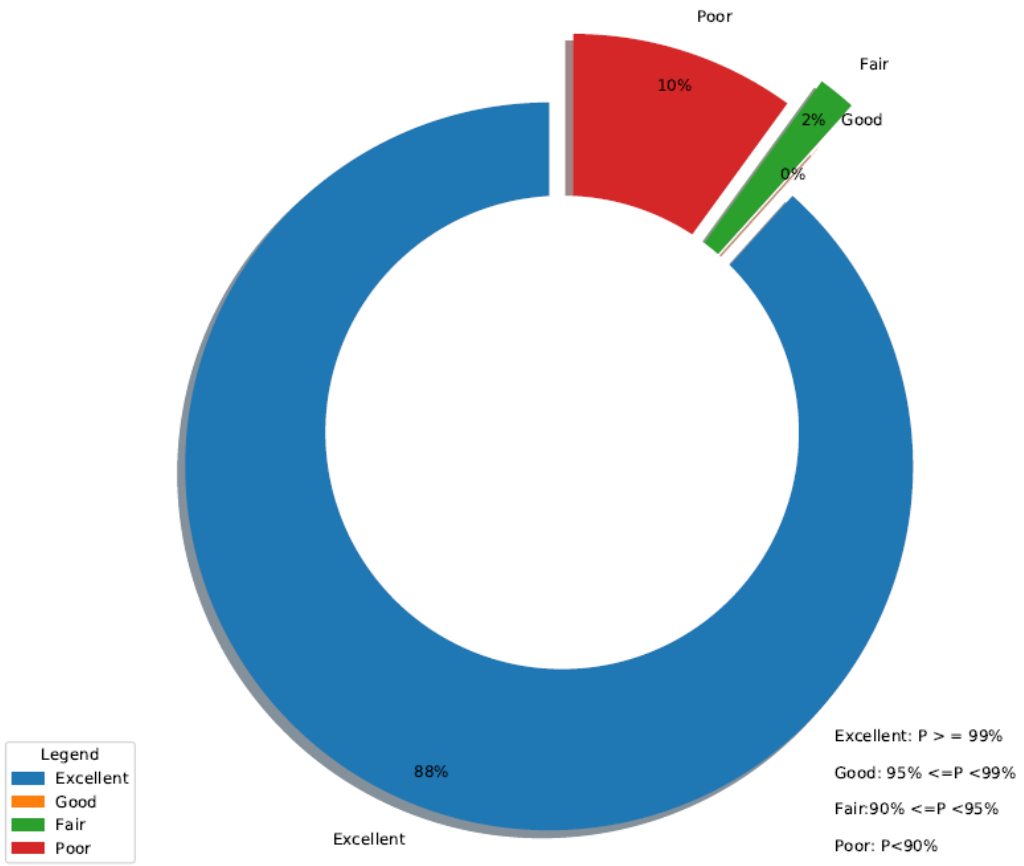


Figure 5.21: Daily PMU Data Quality Statistics

Index	Date	Time	measurement_group	measurement	parameter	message
1	2021-04-29	10:56:01	RH	12345 (ABC@RH)	P	PDX1-3 event status alarm

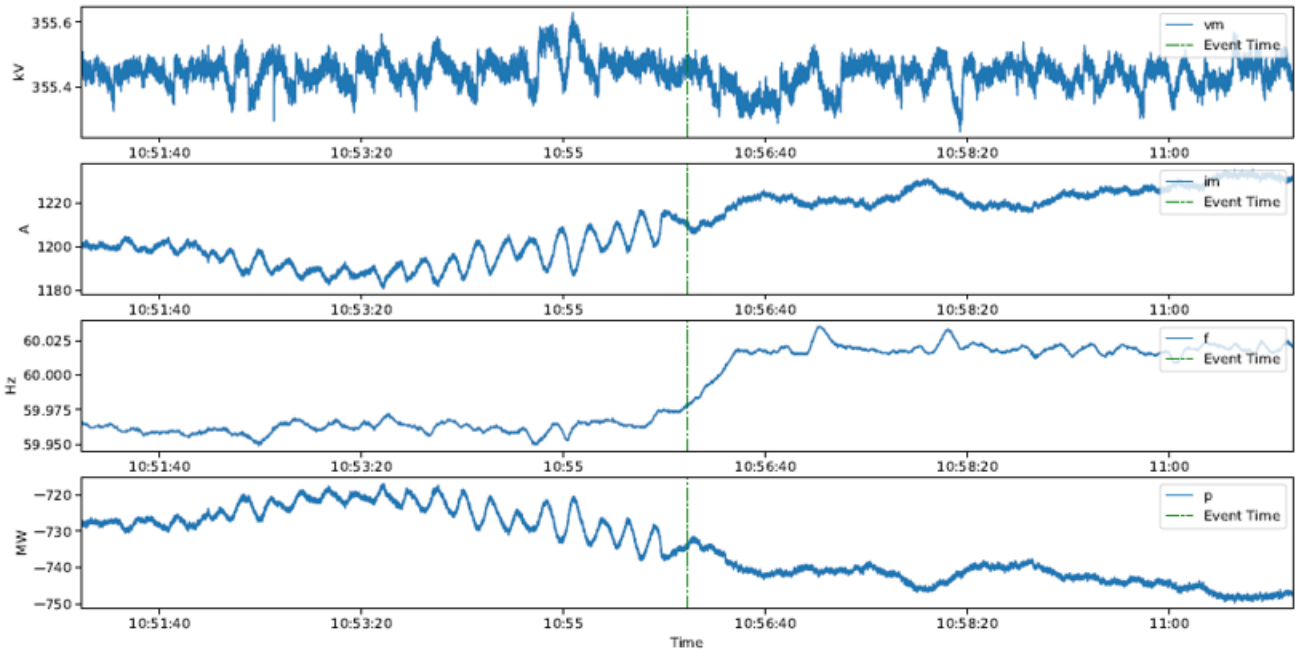


Figure 5.22: Event 1 PMU measurements

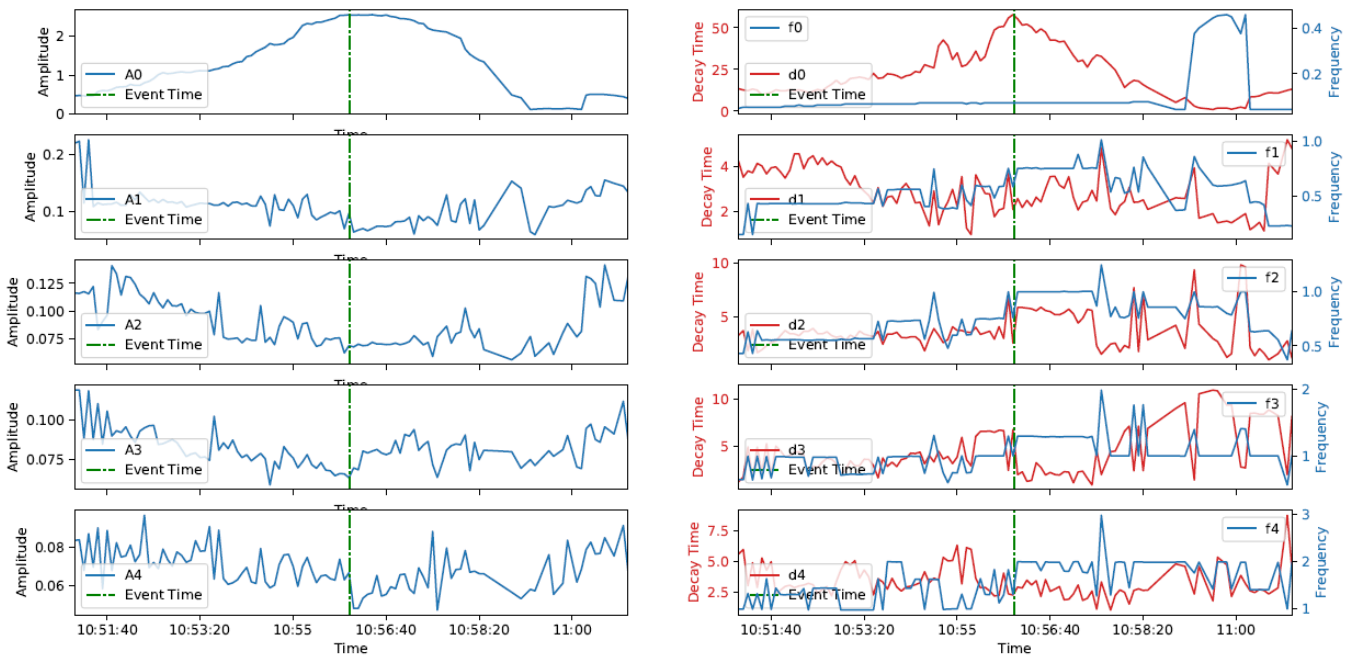


Figure 5.23: Event 1 Oscillation Mode

Appendix A: Determining the Impact of Forced Oscillations

This appendix describes through an example of how one can determine the impact of forced oscillations at frequencies closer to the inter-area modes that need to be monitored.

During the January 11, 2019, forced oscillation event, several EI GOs and System Operators set their plant AVRs to manual control and ramped down online pumped storage plants upon identifying the undamped oscillation. Following the event, there were questions on whether those were the appropriate actions and whether there were any other actions the operators could have taken to mitigate the event. This example describes how a wide-area resonant forced oscillation can be recreated in dynamic simulation and how possible mitigations can be tested. For simplicity, example simulations shown below were performed on a subset of the EI model that does not include a large enough area to capture the modes involved in the January 11, 2019, event.

Modeling of Forced Oscillations

The source of the oscillation was a steam turbine in Florida that experienced 200 MW peak-to-peak oscillations due to controller failure causing the intercept valves to open and close every four seconds. As the intercept valves cyclically open and close, they increase and decrease the flow of steam through the turbine, effectively causing the mechanical power input to the generator to oscillate between full output and zero. To represent this controller failure in dynamic simulation, a user model is needed to oscillate a generator's mechanical power at a defined amplitude and frequency. The FORTRAN code for a Power System Simulation for Engineering (PSSE) user model, named "GOV_OSCILLATE," accomplishes this as shown in **Figure A.1**.

Without delving into the details of user model writing in PSSE, the inputs to this model are as follows:

- The machine number — I
- The amplitude and frequency of the mechanical power oscillation — CON(J) and CON(J+1)
- The initial mechanical power — STATE(K)
- No used variables (VARS) or integer constants (ICONS)

Each PSSE dynamic model performs various computations at different stages of the dynamic simulation:

- In Mode 1, dynamic models are initialized. The initial mechanical power is saved in the state variable, STATE(K).
- In Mode 3, governor type models must compute the current value of mechanical power and populate the mechanical power (PMECH) arrays. As shown in line 42 of **Figure A.1**, PMECH(I) is only modified if the simulation time is greater than 1 second. After 1 second, PMECH(I) is by the equation below:

$$P_{Mech} = P_{Mech\_Initial} + \frac{Amplitude}{MVA_{base}} * \sin[2\pi f(t-1)]$$

GOV_OSCILLATE_rev2.flx

```
      SUBROUTINE GOV_OSCILLATE(I,ISLOT)
C     Logic to add a 10 MW oscillation on Pmech at time >1s
C
      INCLUDE 'COMON4.INS'
C
      INTEGER I, ISLOT
C     I     = MACHINE ARRAY INDEX
C     ISLOT = ARRAY ALLOCTION TABLE INDEX
C             J = STRTIN(1, ISLOT) [ USES CON(J) AND CON(J+1) ]
C             K = STRTIN(2, ISLOT) [ USES STATE(K) ]
C
      INTRINSIC SIN
      INTEGER J, K
      REAL PMECH_INITIAL
C
      IF (MODE.EQ.8)
      .  CON_DSCRPT(1) = 'Amplitude'
      .  CON_DSCRPT(2) = 'Frequency'
      .  RETURN
      ...FIN
C
C  GET STARTING 'CON' INDICES
C
      J=STRTIN(1,ISLOT)
      K=STRTIN(2,ISLOT)
C
      IF (MODE .GT. 4) GO TO 1000
C
      GO TO (100,200,300,400), MODE
C
C MODE = 1: INITIALIZE
C
 100  STATE(K) = PMECH(I)
      RETURN
C
C MODE = 2: CALCULATE DERIVATIVES
C
 200  RETURN
C
C MODE = 3: SET PMECH
C
 300  IF (TIME .GT. 1) THEN
          PMECH(I) = STATE(K) + CON(J)*SIN(6.2832*CON(J+1)*(TIME-1))/MBASE(I)
      END IF
      RETURN
C
C MODE = 4: SET NINTEG
C
 400  NINTEG=MAX(NINTEG,K+1)
      RETURN
C
 1000 RETURN
      END
```

Figure A.1: PSSE USER Model to Create Forced Oscillation

After compiling the FORTRAN code in **Figure 2.4** and creating a *.dll file the user model can be utilized using the statement in **Figure A.2**. The highlighed variables indicate that the model should be applied to machine 1 at bus 4, the amplitude of oscillation is 100MW (200 MW peak-to-peak), and the frequency of oscillation is 0.67hz. The other parameters are required for PSSE to classify it as a Turbine-Governor model and reserve the necessary space in the ICONS, CONS, STATES, and VARS arrays.

TP4_gov_oscillate_rev.dyr | GOV_OSCILLATE_rev2.flx

```
4 'USRMDL' 1 'GOV_OSCILLATE' 5 0 0 2 1 0 100 0.67 /
```

Figure A.2: User Model Calling Statement

Figure A.3 shows the mechanical power of a unit that this model is applied to.

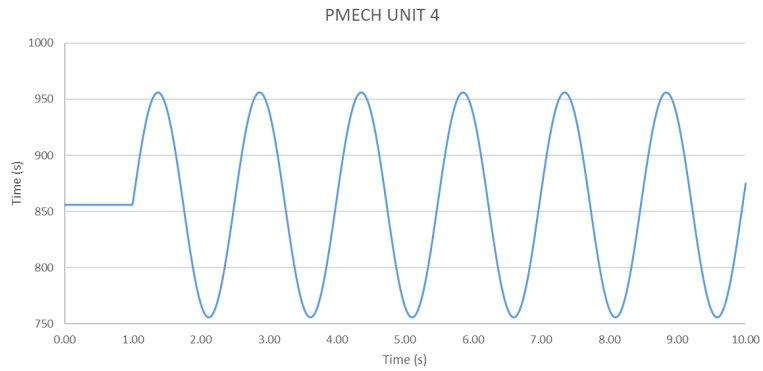


Figure A.3: Mechanical Power for Source of Forced Oscillation

Modeling Wide-area Resonant Forced Oscillations

The previous section described how a forced oscillation in mechanical power with a defined amplitude and frequency can be applied to any machine in a PSSE dynamic case. However, there are three conditions required for wide-area resonant forced oscillations:

- A source oscillating at a frequency close to a system mode
- The system mode is poorly damped
- The source is near a strong participation location of that system mode

An essential step to simulating wide-area resonant forced oscillations is to identify natural system modes that are poorly damped and determine which units strongly participate in those modes. Software packages, such as PSSE's SINCAL or Power Tech's SSAT, can be used to perform eigenvalue analysis. The software packages take the load flow and dynamic models as inputs and then provide a list of natural modes within a specified frequency range (e.g., 0.1–2 Hz). The poorly damped modes should be further analyzed to determine their mode shape and participation factors. This will illustrate which source location will most excite the poorly damped modes and which areas of the grid will experience higher oscillations.

Figure A.4 and **Figure A.5** demonstrate how wide-area resonant forced oscillations can be simulated. Eigenvalue analysis was used to identify a lightly damped natural system mode with a frequency of 0.67 Hz, that unit 4 strongly participates. **Figure 2.7** shows system variables throughout a wide area when Unit 4 experiences a cyclical failure at 0.25 Hz. The first condition for resonant forced oscillations is not well satisfied and the wide-area impact is minimal. **Figure 4.1** shows the same variables when Unit 4 experiences a cyclical failure at 0.67 Hz, such that all three conditions for resonant forced oscillations are well satisfied. The electrical power oscillations on Unit 4 are higher than the mechanical power oscillations indicating amplification or resonance. The difference between a local forced oscillation and a wide-area resonant forced oscillation is clearly demonstrated by observing oscillations in frequency and power throughout the system. Even the mode shape can be verified by observing which units oscillate against each other.

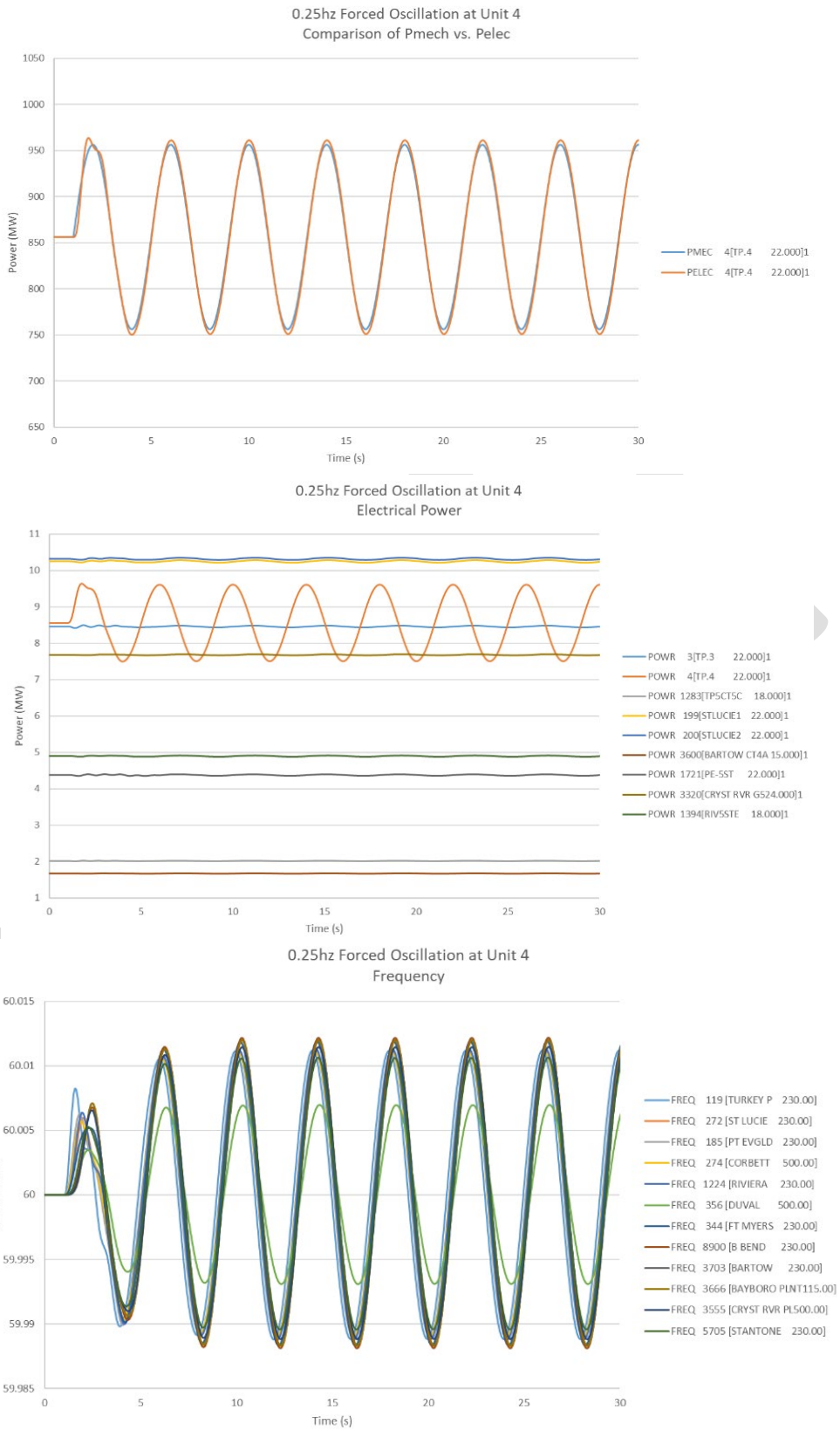


Figure A.4: Local Forced Oscillation

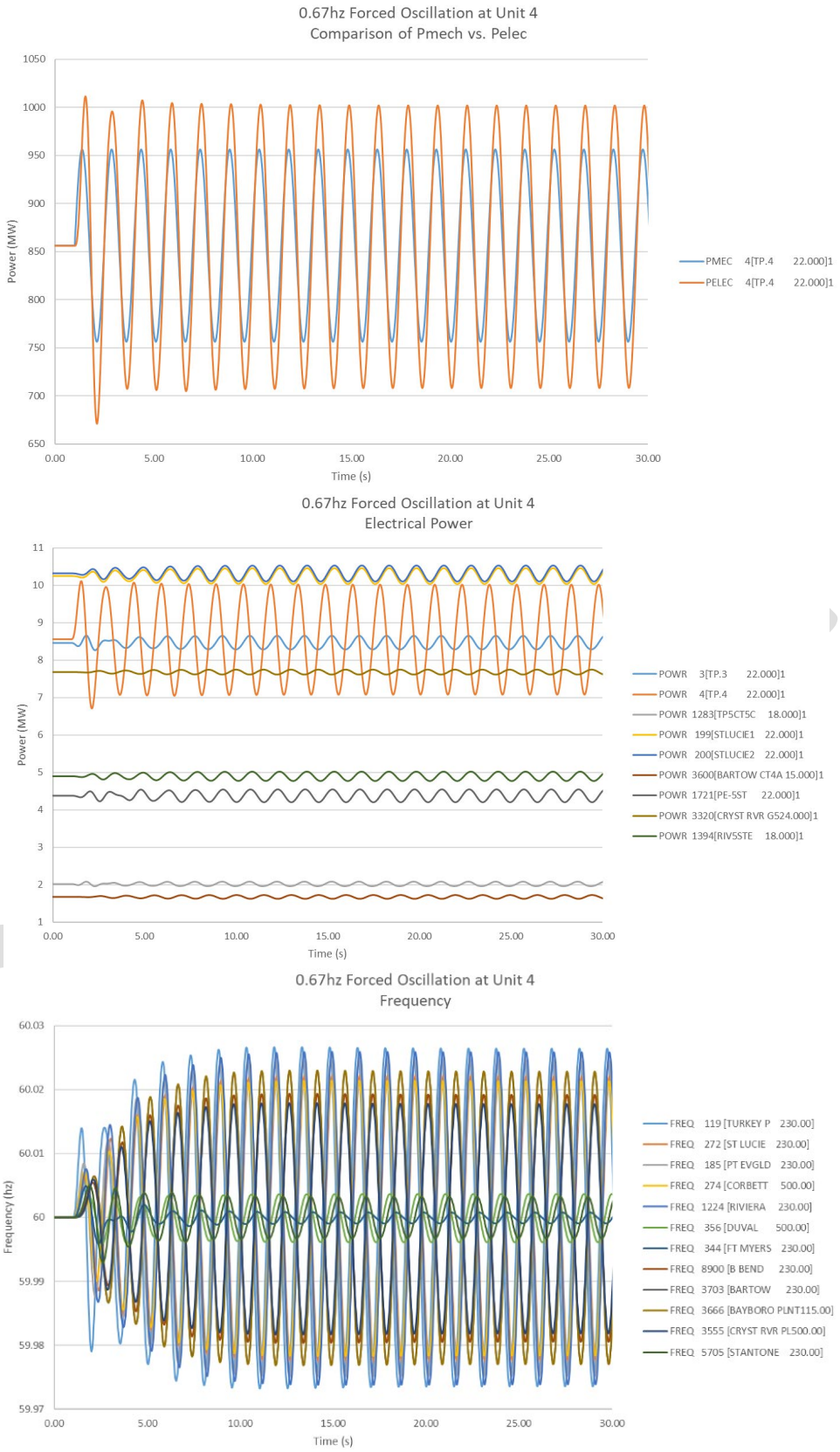


Figure A.5: Wide-Area Resonant Forced Oscillation

Appendix B: Contributors

NERC would like to thank all members of the NERC SMWG for their participation and guidance in developing this report. The following list of contributors were involved in the development of this report.

Table B.1: Contributors	
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Ken Martin	Electric Power Group
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Ryan Lott	Southwest Power Pool
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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Recommended Oscillation Analysis for Monitoring and Mitigation

Synchronized Measurement Working Group

~~September~~ November 2021

RELIABILITY | RESILIENCE | SECURITY




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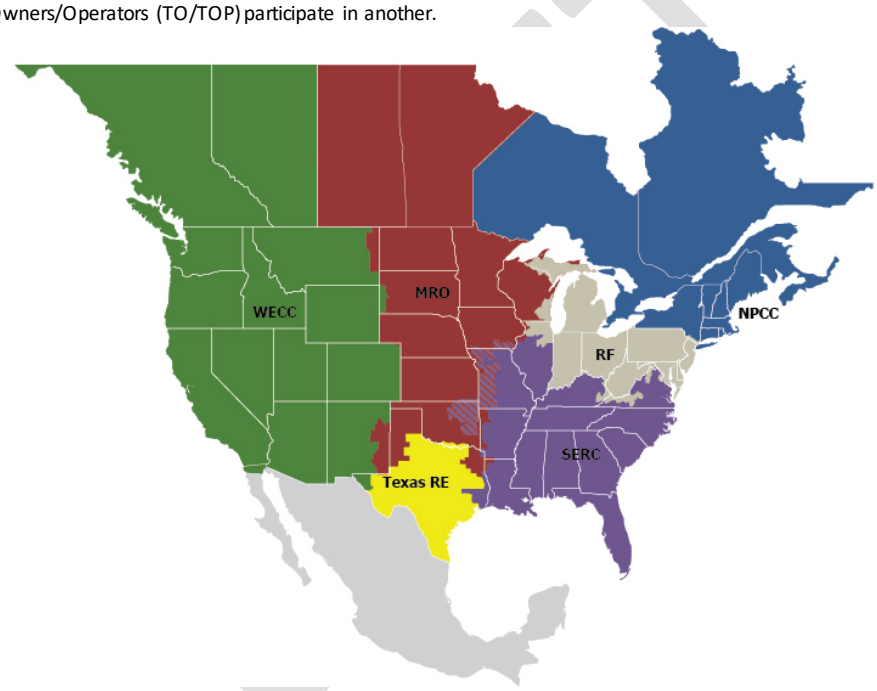
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one RE while associated Transmission Owners/Operators (TO/TOP) participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

Executive Summary

Recent oscillation events, such as the January 11, 2019, forced oscillation event in Florida that interacted with a natural system mode of the Eastern Interconnection and le~~a~~d to propagation of the oscillation across the Interconnection, have highlighted the need for increased monitoring and consistency in the monitoring of oscillation disturbances. Some of the key recommendations from the report[1] on the event included the need for Reliability Coordinators (RCs) and Transmission Operators (TOPs) to utilize real-time oscillation detection tools. RCs and TOPs should have real-time oscillation detection tools in place to identify when oscillations are occurring and determine if the oscillations~~e~~ are limited locally within their ~~applicable~~ footprint or are more widespread. Equally important is to be able to distinguish between forced oscillations, poorly damped natural system modes, or scenarios where forced oscillations may be propagating across a wider area due to resonance conditions. In addition, there was a recognition that RCs should improve their communication with ~~neighboring~~ RCs in the event of widespread oscillation disturbances i~~o~~n ~~the~~ BPS and when operating procedures could be an effective means of ensuring this coordination upon the identification of an oscillation.

The NERC Synchronized Measurement Working Group (SMWG) was also ~~recommended~~ requested to develop guidance on oscillation analysis methods to encourage consistency in the system quantities that are monitored for oscillation events and the respective thresholds for alarms. The detection and alarming of oscillations and their classification in a consistent manner is critical in ensuring coordinated mitigation of both local and widespread oscillation disturbances ~~on the~~in BPS.

In addition, it is also important to identify what kind of operator actions are necessary for ~~the~~ different kind of oscillations. These actions can range from locating the source of ~~the oscillations for~~ forced oscillations to reducing power transfers across major transmission paths. Actions can also include ~~and making~~making topological changes ~~for improving~~to improve damping of ~~system modes for~~ wide-spread natural system oscillations or combinations of those actions if there is ~~due to~~ interaction of the forced oscillations with ~~a~~ natural system modes that results in ~~causing~~ propagation ~~of oscillations~~ across the~~an~~ Interconnection.

The f~~F~~ollowing are ~~the~~ key findings and recommendations of this white paper:

- For monitoring of inter-area or natural oscillations, various methods exist that can utilize ambient or post-disturbance data to determine the system modes that are significant. These assessments are recommended to be done annually or based on significant changes in the system. After identifying the significant modes, additional analyses can be performed to determine the locations where the modes are observable and the respective thresholds for alarming or operator action based on damping and the energy of the modes. ~~These locations can be utilized for monitoring the respective modes.~~ In addition, analyses using power-flow cases and the associated dynamic models can be utilized to validate the modeling of the observed significant modes and to determine what~~the~~ mitigation actions ~~that are~~ might be effective in improving the damping of ~~system~~ those modes.
- Forced oscillations can be detected using~~by~~ various ~~detection~~ methods that utilize thresholds established by prior analyses to differentiate between sustained forced oscillations ~~from~~ and normal ambient changes in system conditions. Once the forced oscillations are detected, various methods exist to determine the locations from where the forced oscillations originate.
- Under certain conditions, forced oscillations can propagate across an Interconnection due to resonance with a natural system mode. Mitigation of such wide spread oscillations can require a combination of mitigation actions ranging from locating and eliminating the source of the oscillation to taking actions to reduce the impacts across the system by improving the damping of the impacted system mode.

[1] Lesson Learned: Interconnection Oscillation Disturbances: https://www.nerc.com/pa/rrm/ea/Lessons_Learned_Document_Library/LL20210501_Interconnection_Oscillation_Disturbances.pdf

- Mitigation of local and widespread oscillation disturbances and their impact requires effective tools and coordination between RCs and TOPs to determine the type of oscillation and the appropriate mitigation actions.

Introduction

The SMWG, formerly the Synchronized Measurement Subcommittee, has provided well-accepted guidance on what oscillations are, why they occur, and what are the various tools to monitor them. Various previously published reports on Interconnection oscillation analyses[2] and forced oscillation events[3] provide recommendations on what Reliability Coordinators (RC) and TOPs should do to monitor oscillations, emphasizing the need to coordinate and develop tools. Monitoring of oscillations requires the setup and configuration of real-time tools that require a certain level of analyses and preparation to determine the quantities for monitoring, what should be their respective thresholds for alarms, and the respective operator actions.

The analysis that is required can vary depending on whether a tool is being set up to monitor a natural inter-area oscillation or a forced oscillation. The levels at which operator actions are necessary to intervene and mitigate for any potential reliability impacts of oscillations can also vary based on the type and location of oscillation. RCs and TOPs are in the process of developing operating procedures to supplement the monitoring of oscillations. These operating procedures contain specific actions for operators to follow during critical oscillatory conditions. Model-based simulations provide an opportunity to determine required mitigation actions for consistency in developed operating procedures and mitigation plans.

This white paper addresses two distinct types of power system oscillations,~~:~~ natural and forced and ~~. This report~~ is divided into five distinct chapters:

- **Chapter 1** addresses inter-area electromechanical oscillations. These oscillations are often referred to as natural oscillations because they arise from the dynamics inherent to any power system. A system's inter-area modes of oscillation govern the periodic exchange of energy between generators in different parts of the system. Natural oscillations can take on different forms depending on how the system's dynamics are excited: ambient oscillations resulting from continuous perturbation by random load changes and ringdown oscillations caused by an impulsive disturbance, such as a generator tripping off-line.
- **Chapter 2** addresses forced oscillations, which are the response of a system to a particular periodic input, such as a generator with a steam valve cycling on and off continuously.
- **Chapter 3** discusses the case where a forced oscillation becomes observable across a wide area.
- **Chapter 4** provides recommended guidelines for operators to address wide-area oscillations.
- **Chapter 5** discusses examples of existing practices by RCs and operators.

In summary, the chapters of this white paper aim at providing a framework of methods to do the following:

- Conduct natural-mode-related and forced oscillation analysis by using examples to illustrate what is normal and what is not
- Determine quantities to be monitored and quantify their boundaries and how to implement these boundaries as monitoring thresholds in tools
- Determine and validate mitigation actions and establish distinction between local and system issues

[2] Interconnection Oscillation Analysis: https://www.nerc.com/comm/PC/SMSResourcesDocuments/Interconnection_Oscillation_Analysis.pdf
[3] Eastern Interconnection Oscillation Disturbance: https://www.nerc.com/pa/rrm/ea/Documents/January_11_Oscillation_Event_Report.pdf

Chapter 1: Inter-Area Electromechanical Oscillations

As demonstrated by the *2019 Interconnection Oscillation Analysis* *Reliability Assessment* [4] different Interconnections have different known modes. In fact, there are a large number of modes, but they can be reduced to only a handful that are dominant, important, and observable and actually have a noticeable effect on electrical signal dynamics of the system. This reduction usually leads to roughly a half dozen or so modes in each Interconnection (depending on grid size and complexity) that are worth understanding and tracking. Some of the commonly known modes are shown in **Table 1.1**, which demonstrates the differences between the Interconnections and the expected Hz range for these oscillations.

Table 1.1: Major Modes in Various Interconnections

Interconnection	Mode Name	Mode Frequency Range (Hz)
Eastern	N–S	0.16–0.22
	NW–S	0.29–0.32
	NE–NW–S	0.23–0.24
Texas	N–SE	0.62–0.73
Western	North-South ~~Mode~~ A (NSA)	0.20~~37~~–0.30~~42~~
	North-South ~~Mode~~ B (NSB)	0.35~~24~~–0.45~~27~~
	~~Montana Mode~~East-West A (EWA)	0.35-0.45~~8~~
	British Columbia ~~Mode~~(BC)	0.50-0.72~~6~~
	~~East-West Mode~~Montana	0.70-0.90~~45~~

The next section provides a summary of known methods that help determine the following:

- The modes of significance in an Interconnection that are recommended to be monitored, for a given system topology and operating condition, typically appear as consistent peaks in the signal spectrum (see **Figure 1.1**). When mode monitoring algorithms (both ringdown and ambient measurement-based) are used, the estimated modes tend to form clusters (as shown in **Figure 1.2**) over time or across multiple signals on a complex plane. In addition, significant modes tend to have much higher pseudo modal energy [5] compared to all other estimated modes from the same measurement window. This can be verified by looking at curve fitting errors from a small subset of the estimated modes.
- M~~The m~~ethods ~~of~~for determining the effective mitigation actions should be used ~~needed~~ to increase damping of the determined modes.
- M~~The m~~ethods ~~of~~for determining the measurements ~~that~~ should be ~~utilized~~ used to monitor the significant modes.

[4] Interconnection Oscillation Analysis: https://www.nerc.com/comm/PC/SMSResourcesDocuments/Interconnection_Oscillation_Analysis.pdf
[5] Trudnowski, Daniel J., John W. Pierre, Ning Zhou, John F. Hauer, and Manu Parashar. "Performance of three mode-meter block-processing algorithms for automated dynamic stability assessment." IEEE Transactions on Power Systems 23, no. 2 (2008): 680–690.

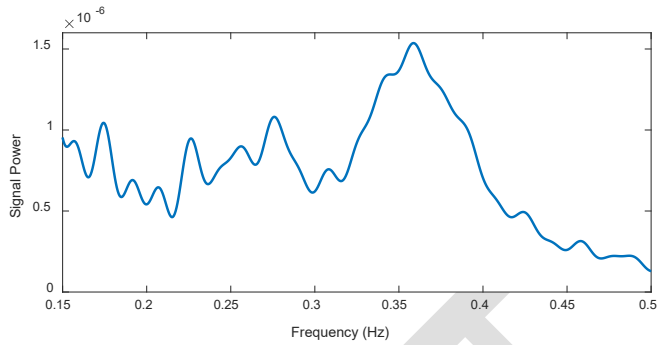


Figure 1.1: Estimate of the Spectral Content of the Frequency Signal

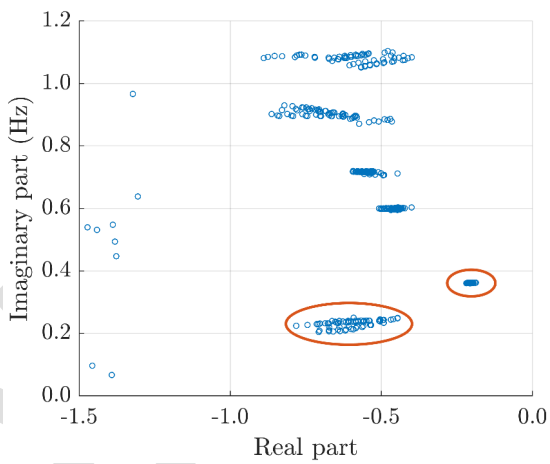


Figure 1.2: Example of clusters formed by eigenvalue estimates

1.1 Interconnection-Wide Analysis to Determine Significant Modes

This section provides a framework of known small-signal stability analysis methods to determine the inter-area modes of significance, input data, and any other information required to do these analyses. Guidance is also provided on the recommended frequencies of these studies. The *2019 Interconnection Oscillation Analysis*[6] report presented various types of oscillation analysis techniques for modal identification. In addition, more comprehensive details on these methods are available in the IEEE Power and Energy Society (PES) developed technical report: *Identification of Electromechanical Modes in Power Systems.*[7] Several of the methods described in this section have been deployed in commercial tools and deployed by system operators. Examples are provided in **Chapter 5**.

These methods fall into three main categories:

[6] Interconnection Oscillation Analysis: https://www.nerc.com/comm/PC/SMSResourcesDocuments/Interconnection_Oscillation_Analysis.pdf

[7] IEEE Task Force on Identification of Electromechanical Modes, *Identification of Electromechanical Modes in Power Systems, IEEE Technical Report PES-TR15*, June 2012 (http://resourcecenter.ieee-pes.org/pes/product/technical-publications/PESTR15).

Ringdown Methods: These are used to analyze natural oscillations that result from large disturbances on the BPS. These methods can be utilized with phasor measurement data or simulated data from offline power-flow dynamic simulations. The post-disturbance trajectories of relevant power system states, or sometimes combinations of statements, are commonly referred to as "ringdowns." Analysis of ringdowns provides valuable insight into the frequency, damping ratio, and shape of the system's inter-area modes of oscillation. It can also serve as a useful tool in model validation (i.e., ensuring that the modal characteristics of real-time or planning base cases match those of the actual system). There are various algorithms and methods employed for modal analysis of disturbance data that are distinct from the techniques used to analyze ambient data.

Ambient Methods: These are used to analyze signals during normal, steady-state conditions where the primary excitation to the system is random load changes. These methods are typically in real-time tools or offline tools for analysis of phasor measurement data. They can be used to track the frequency, damping ratio, shape of specific modes of oscillation, or to identify periods of low damping in any mode. They can also be used to analyze ambient periods surrounding disturbance data to provide validation for ringdown methods.

Eigenvalue Analysis Method: This method can be implemented by using power-flow cases along with the associated dynamic data to determine the modes that exist in a system. The mode frequency, damping and associated mode shape, controllability, and participation factor of participating generators can be determined. The method can be utilized on offline powerflow base-cases used for transmission planning and operational planning studies or with real-time state estimator snapshots.

Table 1.2 shows a summary of the methods along with the type of data or model where the methods are applicable.

Table 1.2: Methods for Modal Analysis

Data Type	Ringdown Methods	Ambient Methods	Eigenvalue Analysis
Synchrophasor Data (Ambient Data)		X	
Synchrophasor Data (Post-Disturbance Data)	X		
Powerflow Base-Cases (Offline Planning Models or Real-Time State Estimator Snapshots) with associated dynamic data	X		X

The results of the analyses will help to determine the modes that are important from a monitoring perspective. The modes are typically defined by a frequency and a mode shape that lists the participating generators and the respective areas in the mode. The analysis also provides the damping[8] of the respective modes that can vary significantly based on system operating conditions and generator controller configurations. These methods are summarized in **Table 1.3** for a quick comparison of the approaches and data requirements.

[8] Modes are often represented as complex numbers in rectangular form: $\lambda = \sigma + j\omega$. A mode's frequency is given by $f = \frac{\omega}{2\pi}\ Hz$ and its damping ratio is often expressed in percent as $\zeta = \frac{-\sigma}{\sqrt{\sigma^2+\omega^2}} \times 100\%$. A system maintains small-signal stability as long as all of its modes have a positive damping ratio.

Table 1.3: Ringdown and Ambient Methods		
Name of Method	**Algorithm**	**Data required**
Prony Methods[9]	• Estimates damped sinusoidal components in a linear system response • Expressing the system outputs as linear combinations of fundamental sinusoidal modal components • Singular Value Decompositions (SVDs) for handling the measurement noise and for reducing the computational burden	Post-Disturbance Data
Eigensystem Realization Algorithm[10]	• Singular value decomposition of a matrix whose entries are samples of the system impulse response (Hankel matrix) • Using the decomposition, a reduced linear system realization is computed (i.e., the system state matrices)	Post-Disturbance Data
Matrix Pencil[11]	• Compute a pseudo-inverse of a matrix using an SVD technique (This also includes a built-in filter for leaving out noise related phenomena in the SVD formulation.)	Post-Disturbance Data
Variable Projection (VARPRO)[12]	• General nonlinear least-squares optimization technique	Post-Disturbance Data
Hankel Total Least Squares (HTLS)[13]	• Formulate a Hankel matrix from the observed Phasor Measurement Unit (PMU) measurements of the event • Use a Total Least Squares approach for evaluating the eigenvalues again using a SVD computation	Post-Disturbance Data

[9] D. J. Trudnowski, J. M. Johnson and J. F. Hauer, "Making Prony analysis more accurate using multiple signals," in IEEE Transactions on Power Systems, vol. 14, no. 1, pp. 226-231, Feb. 1999.

[10] J. J. Sanchez-Gasca, "Identification of power system low order linear models using the ERA/OBS method," in IEEE PES Power and Systems Conference and Exposition, 2004.

[11] Guoping Liu, J. Quintero and V. M. Venkatasubramanian, "Oscillation monitoring system based on wide-area synchrophasors in power systems," 2007 iREP Symposium - Bulk Power System Dynamics and Control - VII. Revitalizing Operational Reliability, Charleston, SC, 2007, pp. 1–13.

[12] A. R. Borden and B. C. Lesieutre, "Variable Projection Method for Power System Modal Identification," in IEEE Transactions on Power Systems, vol. 29, no. 6, pp. 2613–2620, Nov. 2014.

[13] J. J. Sanchez-Gasca and J. H. Chow, "Computation of power system low-order models from time domain simulations using a Hankel matrix," in IEEE Transactions on Power Systems, vol. 12, no. 4, pp. 1461–1467, Nov. 1997.

Table 1.3: Ringdown and Ambient Methods		
Name of Method	**Algorithm**	**Data required**
Yule Walker[14]	• Method operates by first estimating the autocovariance sequence of the measured data • It then fits a model that describes the relationship between the autocovariance sequence at different lag values • The parameters of this model are associated with a rational polynomial whose poles correspond to the power system's electromechanical modes • An extension allows the parameters of electromechanical modes and forced oscillations to be identified simultaneously[15]	Ambient synchrophasor measurements
Least Squares[16]	• Fits a model that describes the current measurement in terms of past measurements and the current random input • This model parameterized as a rational polynomial whose poles correspond to the power system's electromechanical modes • An extension allows the parameters of electromechanical modes and forced oscillations to be identified simultaneously[17]	Ambient synchrophasor measurements
Frequency Domain Decomposition[18]	• Power spectral density (PSD) functions of the ambient measurements are first estimated in the frequency domain • Singular value decomposition (SVD) then used to combine and extract the principal singular values of the multiple PSD estimates	Ambient synchrophasor measurements

[14] R. W. Wies, J. W. Pierre and D. J. Trudnowski, "Use of ARMA block processing for estimating stationary low-frequency electromechanical modes of power systems," in IEEE Transactions on Power Systems, vol. 18, no. 1, pp. 167–173, Feb. 2003, doi: 10.1109/TPWRS.2002.807116.
[15] U. Agrawal, J. Follum, J. W. Pierre and D. Duan, "Electromechanical Mode Estimation in the Presence of Periodic Forced Oscillations," in IEEE Transactions on Power Systems, vol. 34, no. 2, pp. 1579–1588, March 2019.
[16] N. Zhou, J. W. Pierre, D. J. Trudnowski and R. T. Guttromson, "Robust RLS Methods for Online Estimation of Power System Electromechanical Modes," in IEEE Transactions on Power Systems, vol. 22, no. 3, pp. 1240–1249, Aug. 2007.
[17] J. Follum, J. W. Pierre and R. Martin, "Simultaneous Estimation of Electromechanical Modes and Forced Oscillations," in IEEE Transactions on Power Systems, vol. 32, no. 5, pp. 3958–3967, Sept. 2017.
[18] Guoping Liu and V. Venkatasubramanian, "Oscillation monitoring from ambient PMU measurements by Frequency Domain Decomposition," 2008 IEEE International Symposium on Circuits and Systems, Seattle, WA, 2008, pp. 2821–2824.

Table 1.3: Ringdown and Ambient Methods		
Name of Method	**Algorithm**	**Data required**
	• Local peaks among the singular values to correspond to frequencies of system modes and oscillations observed in the data • Modal properties estimated by analyzing these principal singular values near the peak frequencies	
Stochastic subspace identification (SSI)[19]	• Formulate the PMU measurements as outputs of a linear system being excited by unknown random load fluctuations, modeled as independent white noise inputs. • Essential features of the linear system model describing the power system can then be estimated	Ambient synchrophasor measurements
Eigenvalue Analysis	• QR-based methods for complete eigenvalue decomposition • Arnoldi-based methods for partial eigenvalue decomposition • Provides information on observability, controllability, and participation factor of generators along with frequency and damping ratio of respective modes	Powerflow Case and Dynamic Data

The recommendation is to perform these analyses on a regular basis after events by using the post-mortem analysis methods and by using the powerflow base cases and associated dynamic data on a seasonal or yearly basis. Significant system changes can also be used as triggers for performing these analyses, such as the following:

- Changes in system
- Retirement of generation facilities
- Changes in power system injection points due to an increase in renewable resources penetration or generation dispatch patterns and inverter-based resource
- Other significant changes in generation dispatch patterns

In addition, the modes can also be validated by using post-mortem analysis through planned signal tests in the Interconnection. The annual Chief Joseph Brake insertion test in the Western Interconnection (WI) is an example of a signal test allowing the validation and update of some of the known modes.

[19] S. A. Nezam Sarmadi and V. Venkatasubramanian, "Electromechanical Mode Estimation Using Recursive Adaptive Stochastic Subspace Identification," in IEEE Transactions on Power Systems, vol. 29, no. 1, pp. 349–358, Jan. 2014

1.1.1 Commonalities on Interconnection Oscillation Analysis using Modal Analysis of Ringdowns

This section presents an example of modal analysis performed using power system data collected during a disturbance, either observed or simulated. The ringdown method is used as an example. The intent of this section is to discuss concepts that are generally applicable to all ringdown methods. The notion of curve fitting is central to modal analysis of ringdowns. In broad terms, curve fitting is the process of specifying a model whose output provides the best fit to measured data under some mathematical criteria. The model identified by a curve-fitting routine can then be used to extract information about the resonant properties of the system. Specifically, the identified model permits estimation of the eigenvalues and eigenvectors of a linearized representation of the system dynamics that correspond to a particular operating point. For studying electro-mechanical oscillations, measurements of rotor speed, bus frequency, and intertie active power flows provide useful input data.

A crucial step in any curve fitting procedure is to specify the structure of the model being fit to the data. For power system applications, common choices include autoregressive models and discrete-time state-space models. Often, choosing a specific model structure helps to determine which algorithm is best suited to the problem. For instance, Prony's method identifies an autoregressive model to determine the coefficients of the characteristic polynomial. In contrast, the Eigensystem Realization Algorithm identifies a discrete-time state-space model. Often (but not always), autoregressive models are used for single-channel analysis whereas state-space models are inherently multi-channel. In this context, "single-channel" refers to the analysis of one ringdown while "multi-channel" refers to the simultaneous analysis of multiple ringdowns.

Data Collection and Pre-Processing

In general, it may not be possible to analyze all of the modes of interest by using data collected for a single disturbance. The reason for this limitation is that a given disturbance may not excite all of the modes, or it may not excite them enough to permit estimation with the desired accuracy. For example, following a Chief Joseph Brake insertion in the WI, it may be possible to estimate the frequency and damping of the North-South B mode but not the East-West A mode. When characterizing dynamic models, this limitation can be mitigated by simulating multiple disturbances that originate from various points in the system. The data for each simulated disturbance can then be used to estimate a subset of the system modes.

Modal analysis may be performed by using data collected during a wide variety of disturbances; however, special considerations arise in the case of transient disturbances during which the operating point of the system may move from one equilibrium to another. For example, following the loss of a transmission line, the active power transfer on the remaining ac lines may change. If these power transfer measurements are used as inputs to a modal analysis framework, the dc offset corresponding to the post-disturbance power flow must be subtracted from the original signal. In the case of generator trips, the trajectories of rotor speeds and bus frequency measurements contain considerable low-frequency content that lies below the range of the electromechanical modes. It is generally desirable to remove this very low frequency component of the system response to better highlight oscillatory phenomena. This may be done by forming pairs of relative signals that represent the difference in bus frequency (or rotor speed) measured at two different points in the system. If an estimate of a particular mode is sought, these pairs may be selected based on knowledge of its shape. Alternatively, the center-of-inertia frequency (or speed) may be subtracted from each individual frequency (or speed) signal. This is a useful technique when the mode shapes are not known in advance. If the subsequent deviations after detrending the data are small, scaling (or normalizing) the data may improve numerical performance, if it is done in a consistent manner.

In order to get the best possible results from any modal analysis technique, care must be taken in collecting and preparing the input data. When analyzing data collected from actual disturbances, it is often beneficial to use a lowpass filter to mitigate the impact of high-frequency measurement noise and/or process noise. When circumstances allow, as in a posteriori analysis, high-order finite impulse response filters are preferred because they can be designed with a linear phase response, preserving a constant group delay across the entire frequency band.

The corner of this lowpass filter should be placed such that the oscillatory phenomena of interest falls firmly within the passband. This step may be omitted when analyzing simulated data arising from real-time or planning base cases when noise is not present.

To maximize the accuracy of mode frequency estimates, the input data may be resampled via a combination of anti-aliasing and decimation. A useful rule-of-thumb is to set the sampling rate of the input data to approximately 10 times the highest frequency of interest. For example, if the highest mode frequency of interest is 1 Hz, this would imply a sampling rate in the range of 10–12 sps (samples per second). During this process, the sampling rate of the original data should also be taken into account. Resampling generally yields the best results when the final sampling rate is an integer factor of the original rate. For instance, if the original data is sampled at 60 sps, it would be advisable to resample the data at 10 or 12 sps, as opposed to 11 sps. Choosing the final sampling rate in this way obviates the need to upsample (i.e., interpolate, the original data, which is not advisable in modal analysis applications). Before downsampling the original data, it must be passed through an anti-aliasing (lowpass) filter that limits its bandwidth to satisfy the Nyquist-Shannon sampling theorem. For example, if 60 sps data is going to be resampled at 12 sps, the stopband of the anti-aliasing filter should begin at 6 Hz. As with noise reduction filters, high-order linear phase finite impulse response filters are preferred for this application where possible.

Curve Fitting Sensitivities

Most curve fitting algorithms for modal analysis are designed to operate on the so-called "free response" of the system (i.e., the period in which the input or forcing function has gone to zero). Thus, the position of the curve-fitting window must be aligned with the free response for best accuracy. For example, if the system stimulus is a dynamic brake insertion, the left endpoint of the curve-fitting window should be placed no sooner than the instant when the brake is removed. In general, it is a good practice to allow some additional time to elapse, perhaps 0.5–1s, to ensure that the dynamics within the curve-fitting window correspond to the free response. In special circumstances where the forcing function is known (such as probe testing), this rule for positioning the curve-fitting window may be relaxed; however, the analysis algorithm may require modification. The positioning of the right endpoint of the curve-fitting window is equally important. A useful rule-of-thumb is that the duration of the window should be approximately 3–4 cycles of the lowest oscillation of interest if possible. For example, if the lowest mode frequency of interest is 0.25 Hz, this would imply a curve fitting window length of approximately 12–16 s. A caveat is that the window should not include flat or nearly flat signal content. This is an indication that the system has reached a new steady state that is not helpful in characterizing its dynamics and that the right endpoint must be placed no later than the final data sample.

There are multiple ways to quantify a curve-fitting error, some of which depend on whether the analytical formulation is single-channel or multi-channel in nature. Two commonly employed approaches are the ℓ_2-norm and the closely related mean squared error (MSE). Both methods correspond to so-called least-squares error minimization. In the single-channel case, the ℓ_2-norm is given by

$$f(z,\tilde{z}) = \sqrt{\sum\nolimits_{k\in\mathcal{K}} (z_k - \tilde{z}_k)^2},$$

Where z_k the input data, and $\tilde{z}_k$ the output of the model. Here k denotes the sample index and $\mathcal{K}$ the set of points in the analysis window. Similarly, the mean squared error is defined as

$$f_{\text{mse}}(z,\tilde{z}) = \frac{1}{|\mathcal{K}|}\sum\nolimits_{k\in\mathcal{K}} (z_k - \tilde{z}_k)^2,$$

Where $|\mathcal{K}|$ is the total number of samples in the window. These methods may be extended to the multi-channel case by summing over not only time but also the various signal channels. This type of least-squares minimization is implicit in many algorithms, such as Prony's method and dynamic mode decomposition (DMD).

When curve-fitting routines are used for modal analysis, attention must be paid not only to the fitting error but also to the estimates of the eigenvalues and eigenvectors derived from the results. These estimates are sensitive to various factors, including (but not limited to) the model order, the position of the curve-fitting window, and the value of any additional parameters. Many algorithms, such as Prony's method, require the user to specify the model order, or the number of poles, as an input. As discussed above, the user must also specify the position and duration of the curve-fitting window. Furthermore, optimization-based curve fitting routines may utilize additional parameters, such as constants allowing the user to trade-off between various terms in a multi-objective optimization formulation. All of these user-specified inputs have an impact on both the curve fitting error and the mode estimates returned by the algorithm.

When performing modal analysis of ringdowns, it is generally advisable to sample the space of possible input parameter combinations. For example, an input parameter combination may comprise a given model order, analysis window, and trade-off parameter value. At the start of the procedure, a set of possible combinations is defined that spans some portion of the space of interest. Then, the results of analysis are recorded for each combination that creates a collection of mode estimates. Eigenvalue estimates may be categorized first according to their position in the complex plane and then according to the corresponding eigenvectors. This process produces clusters of eigenvalue estimates in the complex plane, each that roughly takes the form of an ellipse. Categorizing estimates based on the eigenvectors helps to distinguish modes that are close to one another in the complex plane but have different shapes. Likewise, categorizing mode estimates purely in terms of their frequency and damping is insufficient because their mode shapes may be different. For example, the North-South B mode and the East-West A mode reside at very similar frequencies in the WI; however, they have different mode shapes. Final mode estimates may be derived by averaging individual estimates that have been confirmed to have the same shape.

Examples

This subsection presents practical examples stemming from modal analysis of a simulated Chief Joseph Brake insertion in the WI. To generate this simulated data, the dynamic brake was inserted at the 5s mark for a duration of 0.5s. In these examples, the inputs to the curve fitting routine were bus frequency measurements recorded at 26 points distributed geographically throughout the system. Each bus frequency was calculated by using a backward difference derivative approximation applied to the voltage angle. To model the effect of a bandlimited sensor, the output of the derivative approximation was then passed through a first-order lowpass filter. Modal analysis was performed by using an optimization-based, multi-channel curve-fitting algorithm. As with ERA, this method identifies a reduced-order state-space model that can then be fed into eigen analysis routines.

Figure 1.3 shows the frequency deviation (from nominal) measured at Nicola, British Columbia, and Genesee, Alberta. The dashed traces show the measured state trajectories, and the colored traces show the output of the model constructed by the algorithm. In this case, the curve-fitting window begins at the 6.5s mark and is 12s in length.

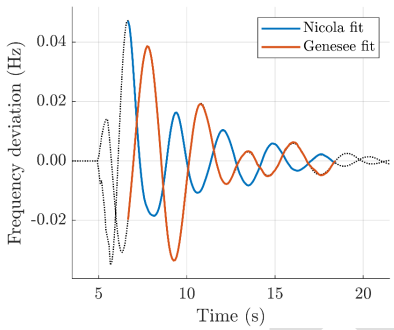


Figure 1.3: Example Curve Fit

Figure 1.4 shows the frequency difference measured between Nicola and Genesee. As explained above, computing the frequency difference between two points can make modal analysis easier by cancelling out common mode behavior. The dashed trace shows the relative frequency itself, and the colored traces show the two dominant modal components of the ringdown, the North-South A and B (NSA and NSB) modes. This decomposition can be performed by solving for the minimum-norm solution to an overdetermined system of linear equations as in Prony's method.

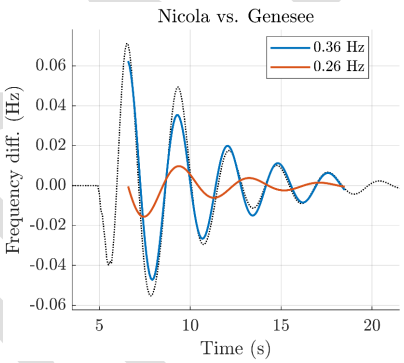


Figure 1.4: Decomposition of the Relative Frequency

The curve fitting procedure was repeated for 64 unique combinations of input parameters that spanned eight different analysis windows and eight values of a trade-off parameter used in the optimization. **Figure 1.2** shows the eigenvalue estimates generated using this approach. The orange ellipses highlight the estimates of the North-South A and B Modes generated from this disturbance. As discussed above, after the estimates were clustered according to their position in the complex plane, the eigenvectors were checked to ensure that all of the estimates within a given ellipse had matching mode shapes. In general, the variance associated with mode frequency estimates is lower than the variance associated with damping estimates. Furthermore, it is generally true that the variance associated with damping estimates increases as the true damping of the underlying mode increases. For this disturbance, the North-South B mode may be estimated with a higher degree of confidence than the North-South A mode because the variance is lower in both dimensions.

Figure 1.5 shows the shape of the North–South A mode overlaid on a map of the WI. Likewise, **Figure 1.6** shows the shape of the North–South B mode. Recall that mode shapes correspond to the right eigenvectors of the linearized state matrix. The shape of a mode provides information about how observable it is in a particular state or at a particular location. The shape also provides information about the phase of the oscillation, which can be used to determine which complexes of generators (or other components) are oscillating against one another. In the maps, the area of each marker is proportional to the magnitude of the entry of the right eigenvector corresponding to state measured at that location. Likewise, the arrow emanating from the center of each marker shows the precise phase of the oscillation. The color gradient indicates which states are oscillating against one another, as delineated in the key. This analysis is useful in verifying that the modal properties of dynamic models used in operations and planning match those of the actual system.

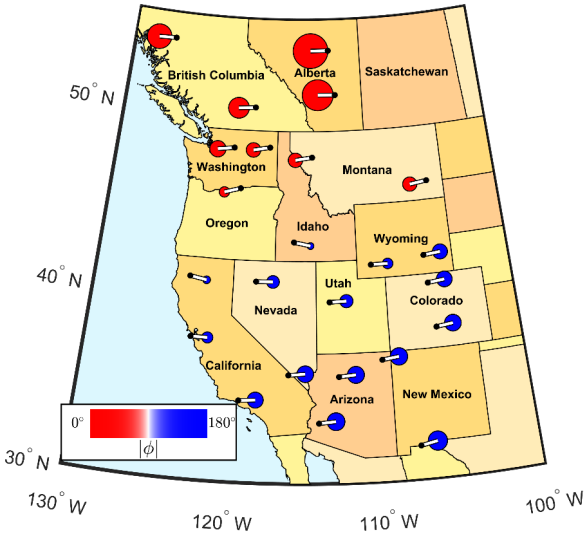


Figure 1.5: Map of the Shape for the 0.26 Hz North-South A mode

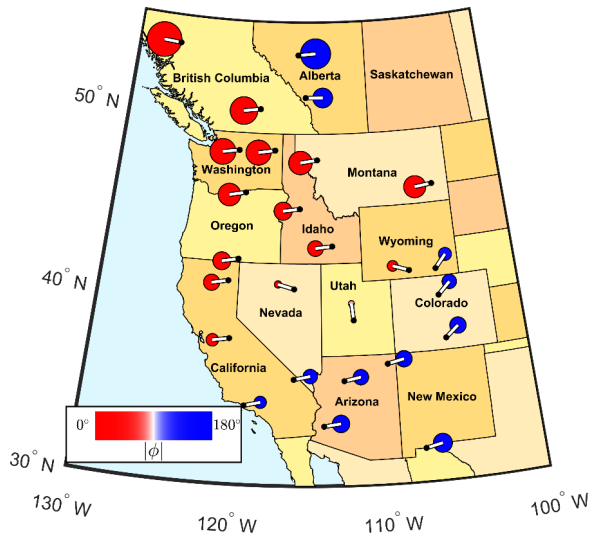


Figure 1.6: Map of the Shape for the 0.36 Hz North–South B mode

1.1.2 Commonalities on Interconnection Oscillation Analysis using Modal Analysis

This section describes ambient analysis techniques and the commonalities between them. The fundamental assertion behind modal analysis of ambient data is that the power system's dynamics are continuously excited by random load changes. Through proper analysis, the results of this excitation can be observed in synchrophasor data even during ambient conditions.

A measurement of frequency from a PMU during ambient conditions is plotted in **Figure 1.7**. Modal oscillations are not apparent from visual inspection, but the impact of the system's modes is present in the signal's random variation. To better see this, consider the estimate of the signal's frequency-domain spectrum in **Figure 1.8**. This estimate was generated by analyzing 30 minutes of data, including the 60 seconds in **Figure 1.7**, by applying a method based on the Discrete Fourier Transform (DFT). Note the spectrum's peak near 0.35 Hz. This peak corresponds to the well-known North-South B mode in the WI.

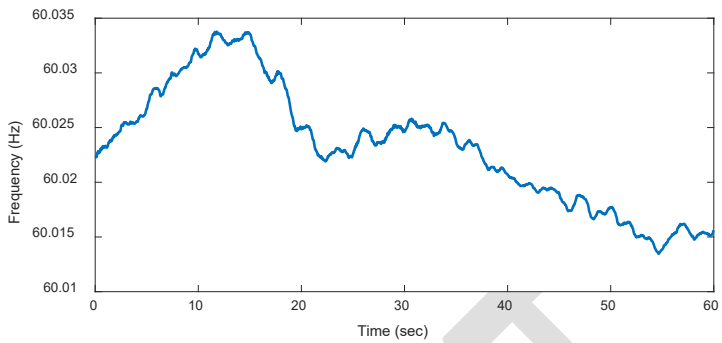


Figure 1.7: Plot of Frequency Measurements from a PMU during Ambient Conditions

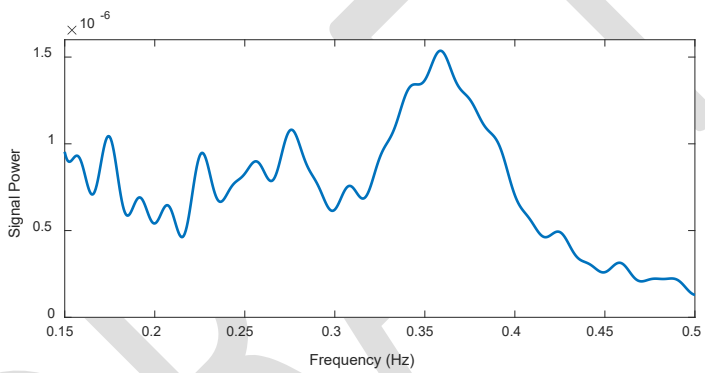


Figure 1.8: Estimate of the Spectral Content of the Frequency Signal

The observability of modes in the frequency-domain spectra of PMU measurements forms the basis for several ambient modal analysis algorithms. The Least Squares and Yule-Walker algorithms used in mode meters are actually spectral estimation methods. The methods determine model parameters to estimate the spectrum. These models can then be evaluated to extract estimates of the system's modes. Similarly, the fast frequency domain decomposition (FFDD) algorithm used in oscillation monitoring tools is based on estimation of power spectrum densities from all available PMU measurements. Further details are provided in **Section 2.1.2**.

Ambient algorithms were primarily developed to provide improved situational awareness to system operators in real-time environments. They can also be useful tools for identifying modes that need to be monitored. Ambient algorithms can be applied to historic data to obtain mode estimates that are updated regularly, even at one-minute intervals. This approach provides a much more granular view of each mode's behavior than can be obtained with transient analysis. Ambient analysis can also be used to understand how modes change during different loading conditions, system topologies, and seasons. This information can be critical in understanding of which modes need to be monitored and what conditions may lead to poor system damping.

1.2 Determination of Mitigation Actions

In addition to monitoring, operators would need guidance on how to mitigate inter-area oscillations. It is important to determine and validate mitigation actions in a consistent manner. These actions are developed ahead of time in

operational planning studies and summarized in operating guides. There are two main model-based methods to determine and validate mitigation actions that can be included in the operating guidelines provided to operators:

- Eigenvalue analysis with powerflow cases and associated dynamic data
- Ringdown analysis with simulated disturbances on powerflow base cases and associated dynamic data

1.2.1 Eigenvalue Analysis with Powerflow Base Cases to Determine Mitigation Actions

Powerflow cases along with the associated dynamic data provide an opportunity to determine the significant modes along with their damping. The global positioning system (GPS) coordinates of the generating resources in the powerflow cases can help to establish the geographical mode shapes in addition to determining the participating generators in the various modes. Additionally, eigenvalue analysis also provides information on the controllability of participating generators for each mode. Using this information can help identify generators that have more control over a specific mode and therefore help with identifying strategies to improve damping ratio of that mode, such as tuning of Power System Stabilizers (PSS) of generators having high controllability for a mode to improve the damping ratio of that specific mode. This approach can be applied to both offline powerflow cases used for transmission and operational planning purposes and with real-time powerflow cases that utilize the state estimation solution and real-time conditions. The model-based approach to determine the mitigation actions provides some advantages:

- It allows for real-time validation of the provided mitigation approaches in operating guidelines provided to operators when used with real-time powerflow cases and the associated dynamic data.
- It allows testing different strategies such as varying transfers along major transmission corridors, varying topology conditions, such as status of transmission lines or series capacitors or generation redispatch.
- It allows testing the impact of contingencies on the damping of the significant modes. This can provide situational awareness to operators of the impact of contingencies when the damping of the monitored modes is below the critical levels for a sustained period.

The basic approach in this method is to calculate the eigenvalues within a certain frequency and damping range. It is recommended to pick a frequency range of 0.1 to 0.95 Hz to capture all possible inter-area modes and make the damping range large enough to capture the known significant modes. It is also recommended to filter out all modes that have a damping of more than 25% to focus on the modes of interest that show lower damping. Once a known significant mode is identified, mode tracing can be utilized to trace the impact of transfer across a path and variation of other topological conditions or equipment status, such as PSS on the damping of the known significant mode. This allows the development of guidelines for operators when developing mitigation actions for reducing damping of the monitored modes.

Figure 1.9 and **Figure 1.10** are examples of eigenvalue analysis performed by using the above approach in with the Small Signal Analysis Tool (SSAT) on the real-time state estimator snapshots along with the associated dynamic models at RC West. Mapping the GPS coordinates to each of the resources allows the development of the mode shape plots. This allows the validation of the mode shapes with state estimator cases when the damping and energy of the monitored modes reaches critical levels.

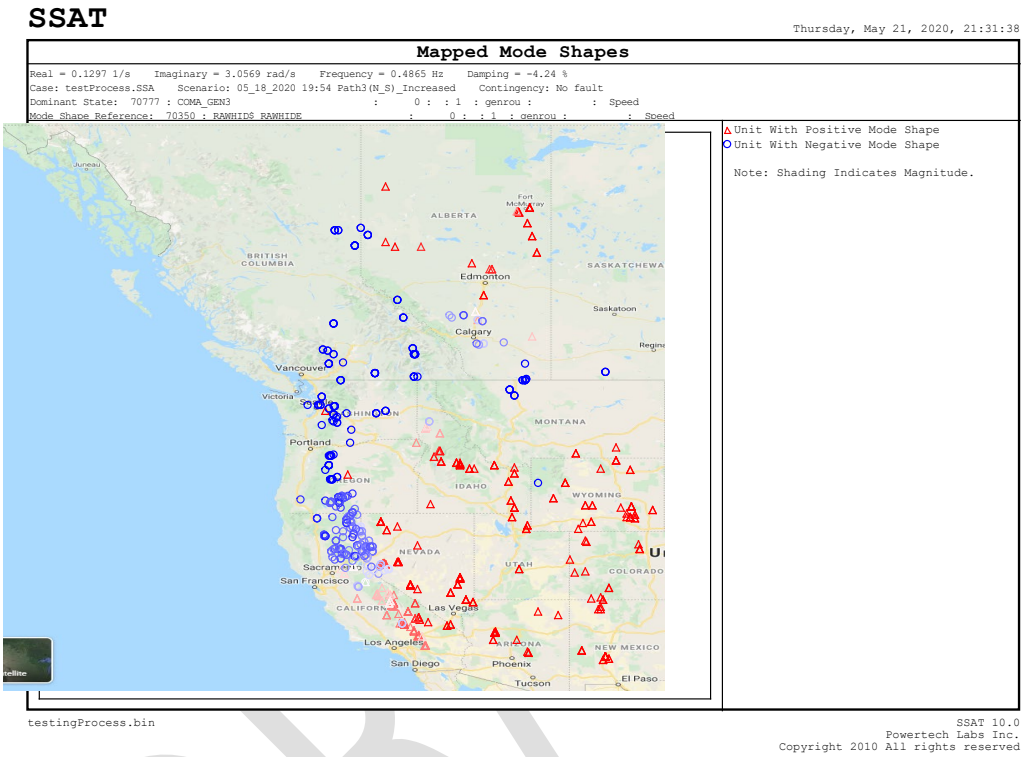


Figure 1.9: Mode Frequency Damping and Shape Estimated Using Eigenvalue Analysis

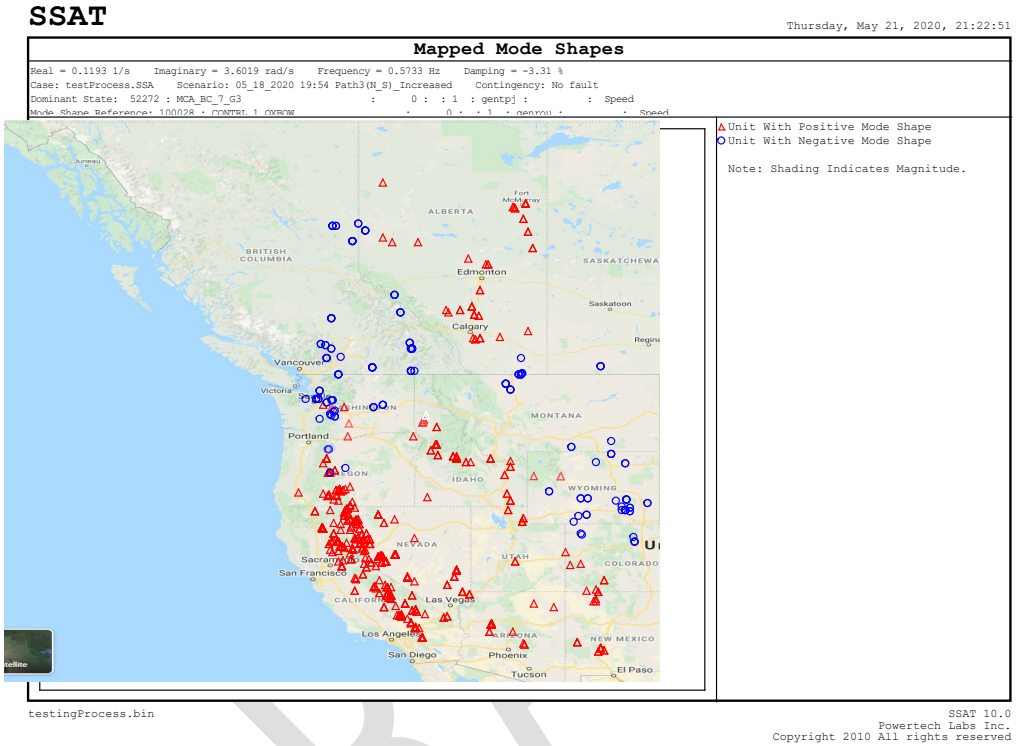


Figure 1.10: Mode Frequency Damping and Shape Estimated Using Eigenvalue Analysis

1.2.2 Ringdown Analysis with Powerflow Base Cases to Determine Mitigation Actions

Utilizing ringdown analysis with powerflow base cases using simulated disturbances is very similar to the earlier described process to determine the various modes and their associated frequencies and shapes. The proposed mitigation actions, such as change in interface MW transfer levels or change in topological conditions, would be simulated in the powerflow base cases and the ringdown analysis would be repeated to determine if there is change in the damping of the mode being tracked while also ensuring that the mode shape is more or less constant. This iterative process helps to determine and validate mitigation actions.

1.3 Monitored Quantities Informed by Analysis

Monitoring the modes of significance requires determining which synchrophasor data that should be utilized in tools to monitor the modes. Various quantities can be used, such as voltage angle pairs, voltages, or flows. It is important for system operators to monitor modes in a consistent manner. This section provides guidance on which quantities can be selected.

While the number of PMU measurements are limited, all the system variables' dynamics, to some extent, are affected by each mode. This means that measurements of electrical quantities, to some extent, will contain information on

the modes that can be extracted/estimated for analysis and tracking purposes. This does not mean that all measurements are the same when it comes to tracking modes; some measurement points are affected by certain modes more than others are and have more unique properties that are useful for the process of tracking the stability of each mode. For example, the answer is to use signals that make the mode(s) of interest highly and easily observable and therefore easy to track when trying to track a particular mode and decide whether to use voltage, power, or frequency signals. For inter-area mode estimation/tracking, angle-pair derivative signals are a great choice because they consist of two individual PMU voltage angle measurements from different grid locations that, with proper signal choice and setup, produce a single signal that amplifies a single mode's presence and ideally attenuates all other modes. As mentioned before, this makes the tracking of individual dominant modes much easier. There are many methods for modal analysis and signal selection. Below is just one example of the process of choosing signals for a mode meter setup.

Consider the following frequency trend lines at different substations spread out through the WI over a one-hour duration in **Figure 1.11**.

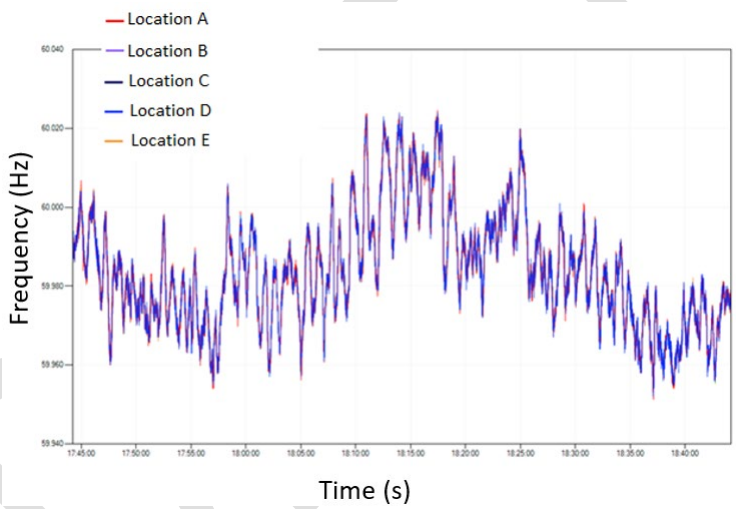


Figure 1.11: Sample Frequency Trend in the WI

At first glance, this looks like a 60 Hz frequency signal with some random ambient noise. In truth, this represents that the modes are manifesting themselves onto the frequency signal measurements at each location, but they are not apparent in the waveforms. If the signal's spectra are plotted, their energy as a function of frequency can help identify dominant modes. **Figure 1.12** conveys that dominant modes truly exist with their frequencies characterized by broad peaks.

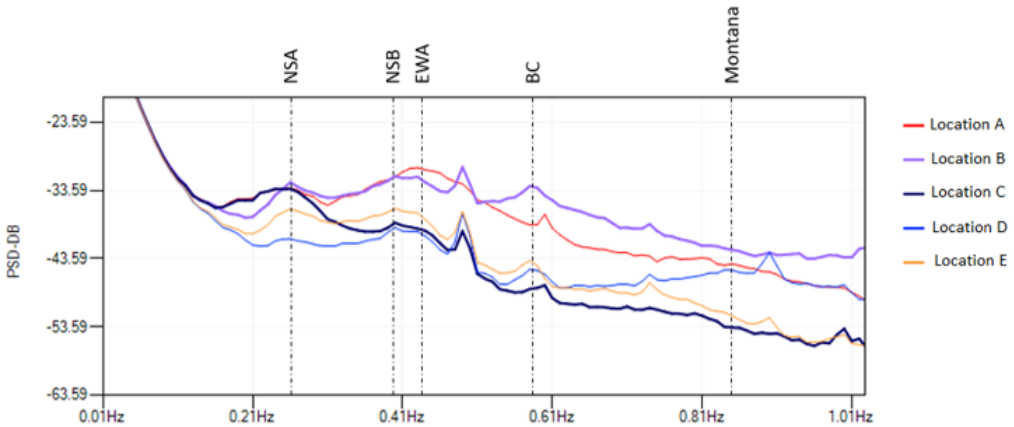


Figure 1.12: Mode Observability at different PMU locations

Upon close inspection, it becomes clear that certain modes only manifest themselves (or show themselves) in certain locations on this signal set. For example, the frequency signal spectrum at Location D shows that the M~~m~~ontana mode is observable in Location D's frequency signal spectrum but not in Location C's frequency signal spectrum. In addition, some locations' frequency signal spectrum (like Location A) show one mode overpowering all other modes by a considerable amount that dominates the modal contribution to the observable dynamics of the frequency signal at that location (e.g., East-West A Mode (EWA) for Location A).

From this sort of analysis, one can also extract one more piece of information, the "phase." Spectral analysis of the modes on a particular signal set at different PMU locations not only indicates what modes manifest themselves at each location for the given signal type of the signal set for each mode but also reveals the phase at one location relative to one another location when the mode ideally "shows itself" at both locations. Because the modes are linear ordinary differential equation (ODE) solutions, they are oscillatory and cause system variables to also oscillate to some extent in harmony or anti-harmony with one another. That means all of the interactions of system variables for each mode can be described by a set of sine and cosine waves that have magnitude and phase values describing their relationship to one another. The phase can be anywhere between 0 to +/-180 degrees. Essentially, the phase shows how a location's signal measurements interact with each other when under the influence of a single given mode. Locations with a phase near 0 degrees apart from one another are "in-phase." However, locations with a phase near 180 degrees apart from one another are "out-of-phase." Locations with a phase near 90 degrees apart from one another are "uncorrelated."

To put this concept into practice, consider the example scenario below. According to the power spectrum in the previous section, Location C and E are grid locations where the NSA mode clearly presents itself (~0.25Hz). According to the mode phase data shown in **Figure 1.13**, Location E is nearly -180 degrees "out-of-phase" with Location E, (approx. -157 degrees).

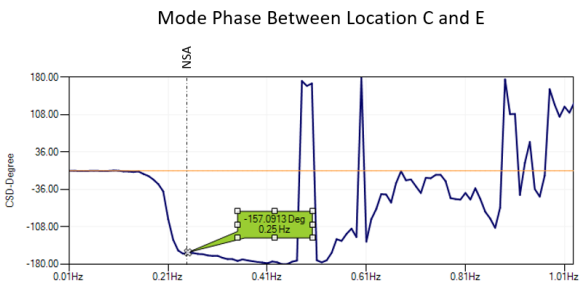


Figure 1.13: Example of Mode Phase between Two Locations

By taking the phase and mode energy data from the estimated power spectrums, a "mode shape" plot describes how all of the signals that are being influenced by the mode are related to one another. To visually show this, imagine a PMU at locations A and C that shows the ideal frequency signals of 60 Hz when suddenly the NSA mode becomes unstable and negatively damped. Consequently, a near-0.25 Hz oscillation starts to build and, due to the locations' relative mode phase as the signal at Location C swings up, the signal at Location E does exactly the opposite as shown in **Figure 1.14**. This is an example of an "inter-area oscillation" caused by an unstable and negatively damped mode.

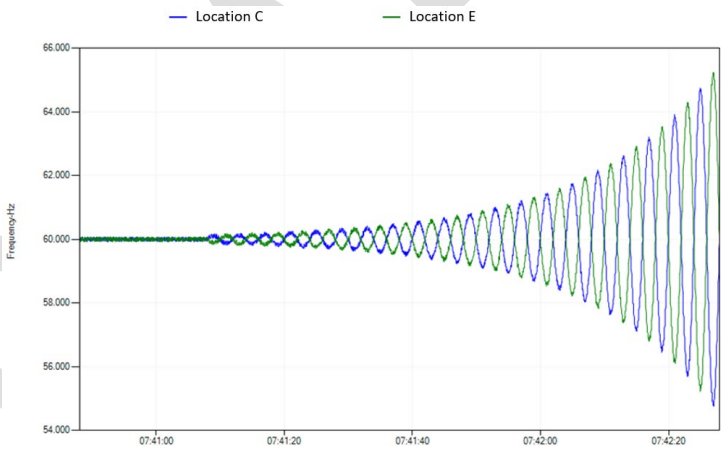


Figure 1.14: Example of Frequency at Different Locations during an Inter-area Oscillation

Since both signals exhibit the mode and have a relative mode phase near 180 degrees, these two signals can be used in a special way to gain an advantage for tracking a mode with a mode meter. Shown again in **Figure 1.15** are the sample estimated power spectrums of the frequency signals at Location C and E.

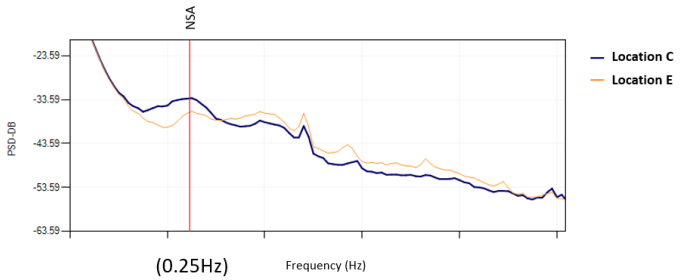


Figure 1.15: Sample Estimated Power Spectrums of Frequency Signals

By subtracting these two frequency (or numerical derivative of PMU voltage angle signal) signals at Locations E and E, creating a differential "angle pair" signal, we can see that the new signal makes the NSA mode "pop-out" as shown in **Figure 1.16** by attenuating common properties and amplifying differing properties in the Location C and E frequency signals.

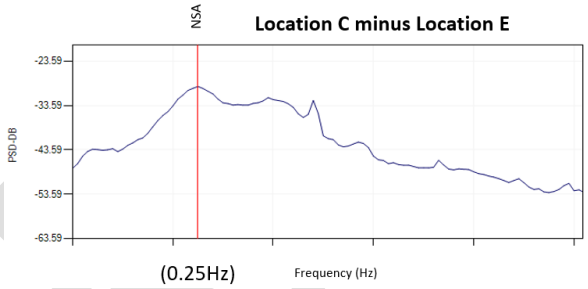


Figure 1.16: Sample Angle Pair Differential Pair Signal for North-South A Mode

As seem above, using the angle-pair differential signals can provide an effective to monitor a given mode in mode-meters. Therefore, it can more easily calculate and estimate frequency and damping ratio of a given mode if the system is in ambient conditions. If we do the same procedure over a large set of signals, we can better determine an acceptable input signal for a given mode meter. See example in **Figure 1.17**.

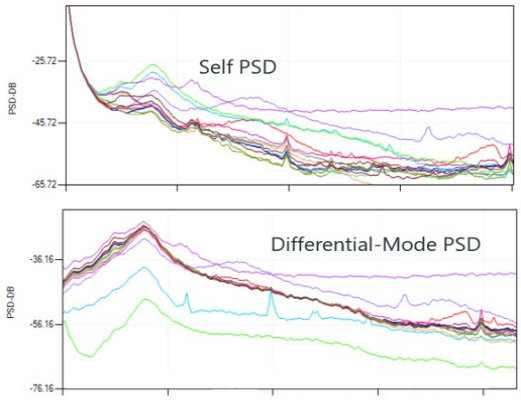


Figure 1.17: Sample Self and Differential Spectrums for Multiple Signals

So far, this paper has discussed a maximum of two signals. If two dominant modes are close in-terms of natural frequency, it might be necessary to either add more input signals to create a more unique output signal that distinguishes the two close modes or change the signal type since all signal types exhibit different network mode shapes. By utilizing the gain properties of differential and common signals, a unique signal for a given mode can be created that provides the best input to a given mode meter for a given set of available PMUs. For example, the sum of active power flows in two lines interconnecting Mexico to the rest of Central America is used to monitor and control unstable modal activities for opening the interconnection between Guatemala and El Salvador when unstable operating condition is detected.[20]

1.3.1 Thresholds for Damping and Energy

Simulation studies and review of historical mode estimates can help determine how much a contingency or credible set of contingencies can reduce a particular mode's damping ratio. This information can then be used to select alert and alarm thresholds to ensure that a sufficient stability margin is maintained in precontingency conditions to preserve stability in post-contingency. Offline studies are helpful to determine thresholds, but additional margins should be included to account for unforeseen contingencies and system conditions. Though alert and alarm thresholds should be based on studies, a damping ratio below 5% typically warrants investigation while corrective action is likely necessary if the damping ratio falls below 3%. The mode estimate should be validated before taking action to ensure that the low damping estimate is not the result of poor data quality, the presence of forced oscillations, or normal variation in the estimate. Offline modal baseline analysis can help determining the threshold for modal energy in different operating conditions.[21] Peak energy levels in the signal spectrum for a mode in a normal operating condition can be used to set the thresholds for energy.[22] As discussed next, mode shape and system conditions can also be evaluated to validate mode estimates.

[20] Espinoza, José Vicente, Armando Guzmán, Fernando Calero, Mangapathirao V. Mynam, and Eduardo Palma. "Wide-area protection and control scheme maintains Central America's power system stability." In 39th Annual Western Protective Relay Conference. 2012.
[21] Trudnowski, Daniel J., and Ferryman, Tom, Modal baseline Analysis of the WECC system for the 2008/9 Operating Season, Technical Report, September~~,~~ 2010
[22] Donnelly, Matt, Dan Trudnowski, James Colwell, John Pierre, and Luke Dosiek. "RMS-energy filter design for real-time oscillation detection." In 2015 IEEE Power & Energy Society General Meeting, pp. 1–5. IEEE, 2015.

1.3.2 Monitoring Mmode Sshape

In addition to monitoring the mode frequency and damping, it is also recommended that tools be set up to monitor the mode shapes of the various monitored modes. This will allow operators to validate that the mode where damping and energy are reaching critical levels is the same for which operators have been provided operating guidance.

1.3.3 Monitoring Ssystem Ceonditions

The system conditions identified for increasing damping and reducing the energy of the monitored modes should be monitored along with the damping, energy, and the mode shape. This is to ensure that system conditions are contributing to the damping and the energy of the monitored modes that reach critical levels where the next contingency can cause instability. Therefore, path flows, topology conditions (such as line status, series capacitor status, generator status) should be monitored along with damping and energy of the modes.

Chapter 2: Forced Oscillations

One among the many challenges faced by the electric power industry is the presence of forced oscillations in the power system grid and determining the source location of these forced oscillations in real-time. The existence of these oscillations is increasing as the grid characteristics change with the addition of wind, solar, and distributed technologies both on grid and behind the meter. Many oscillations have been observed in the power system over the past couple of years[23] across the North American system. Possible root-causes for forced oscillations include the following:

- Malfunctioning equipment
- Control systems with incorrect settings
- Control systems with faulty designs
- Incorrect power system stabilizer settings and governor control settings
- Incorrect dc converter station settings
- Cyclic load

The occurrence of these oscillations can be persistent or intermittent and with low energy or high energy. The presence of these oscillations may lead to undesired operation of the power system, including equipment tripping that causes further stress on the system. Therefore, the early detection and mitigation of oscillations in real-time is crucial to ensuring reliable operation of the grid.

Knowing that an oscillatory event exists in the system is the first step in the proposed methodology. In the past, many oscillation events went by unnoticed due to an inability to detect oscillations using supervisory control and data acquisition (SCADA) -measurements. Synchrophasors provide the resolution necessary to capture oscillations and provide real-time alarms for oscillations that are sustained on the system. This information is important for the operators to avoid further stress and outages in the system that may degrade system reliability.

The following are different methods for detecting forced oscillations and the respective quantities that should be monitored in these methods and how the alarm thresholds should be set up for these monitored quantities. Where applicable, baselining techniques are also provided to help determine the thresholds at which forced oscillations warrant immediate mitigation or further investigation.

2.1 Forced Oscillation Detection Methods

Examples of methods available to detect forced oscillations are described below.

2.1.1 Detection Method 1: Energy Bbands Monitoring Aapproach

Detection of oscillations in the power system requires not only identifying the existence of oscillatory signatures in the real-time measurements but also defining the thresholds to be used to differentiate oscillatory signatures from ambient changes in the measurements. Key metrics of power system oscillations can be monitored and analyzed to define the severity of oscillations and therefore establish the detection criteria. The main parameters for power system oscillations are as follows:

- **Oscillation Frequency:** Rate of change of fluctuations seen in the signal over time
- **Oscillation Energy:** indicator of severity of oscillation (high energy oscillations require operator attention)
- **Damping:** Indicator of the sustainability of oscillation over time

[23] Reliability Guideline: Forced Oscillation Monitoring & Mitigation - https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_Forced_Oscillations_-_2017-07-31_-_FINAL.pdf

Oscillation Frequency

It has been observed from oscillations forced on the system that similar devices lead to oscillations relatively close in frequency. Therefore, monitoring the oscillation frequency can be an indicator of type of oscillation (e.g., inter-area, local, control system problems, Flexible Alternating Current Transmission System (FACTS) device settings). In this approach, the frequency spectrum is divided in multiple bands where each band of frequency is used to indicate a common root-cause of the oscillation. Through observation of previous oscillation events and correlating the frequency to the identified root-cause, four bands of oscillations are defined corresponding to various types of oscillations. The oscillation frequency bands are useful to indicate the most likely cause of the oscillation. Frequency band details along with common causes are shown in the **Table 2.1**.

Table 2.1: Frequency Bands of Oscillations and Likely Causes

Frequency Band	Likely Cause of Oscillations
0.01–0.15 Hz	Governor, plant controller, automatic generation control
0.15–1 Hz	Electromechanical inter-area and local plant oscillations
1–5 Hz	Local plant modes, intra-plant modes, local generator control oscillations, excitation controls, dc circuit controls
>5 Hz	Torsional oscillations, sub-synchronous oscillations, fast acting controllers

Oscillation Energy

Amplitude is the most direct indicator of the severity of an oscillation at a particular frequency. When frequency bands are considered, the energy in each band can be monitored as a proxy for amplitude. Oscillations with high peak-to-peak amplitudes will result in high energy within their frequency band. Oscillations can be monitored by alerting or alarming when the energy in a band exceeds predefined thresholds. Monitoring energy in a band[24] can be more practical than estimating the amplitude of individual oscillations because oscillations may have time-varying frequencies and be accompanied by harmonics in the same frequency band.

Oscillation Damping

Oscillations are a part of every power system and can be observed every day while monitoring the dynamics of the system; however, sustained oscillations can cause reliability issues if not managed carefully. For this reason, it is important to distinguish oscillations that are normal from the ones that are of a potential concern. The damping of an oscillation is the indicator of the sustainability of oscillations over time. Highly damped oscillations dissipate quickly, meaning that the oscillation is observed over a short period before dissipating, while lower damped oscillations sustain for longer periods. Therefore, monitoring oscillations sustainability can be performed through monitoring damping or calculating oscillation continuity over time, as explained in the following sections.

This sets the stage for monitoring the oscillations in real-time. For effective real time oscillation monitoring, it is important to do the following:

- Establish frequency bands for oscillation monitoring:
  - What frequency bands to configure for monitoring?
- Establish thresholds for minimum energy:
  - At what level is an oscillation identified and detected?

[24] Real Time Dynamics Monitoring System – Electric Power Group: http://www.electricpowergroup.com/rtdms.html

In order to establish the parameters for real time oscillation monitoring, periodic analysis and baselining of key power system metrics is required to establish the proper oscillation thresholds for monitoring. The thresholds are usually system-specific and depend on the normal behavior of the power system. To identify the monitoring parameters, it is realistic to baseline the power system oscillations from a rich source of archived high-resolution phasor data. This requires mining historical phasor data to search for oscillations and gather the prerequisites required to monitor in real time. Phasor data mining studies would reveal both known and unknown oscillations. The unknown oscillations can be added to the bucket of known oscillations for additional monitoring until mitigation actions are executed to terminate the oscillations. The key steps in baselining study are as follows:

1. Access to archived phasor data
2. Data conditioning (filtering and conditioning, eliminating bad measurements)
3. Establishing mining criteria (Frequency bands, Energy, Oscillation period)
4. Scanning data and identifying events that meet mining criteria
5. Reviewing and interpreting mining results to identify types of oscillations
6. Preparing recommended parameters for real time oscillation monitoring—frequency bands, energy thresholds, damping, and key monitoring locations.

The basic requirement for data mining is high-resolution phasor data across the system from multiple locations for a minimum of three months to tabulate different oscillations based on the availability of events. The study can be extended to additional months to extend the research of new additional oscillations. The process could also be made iterative with a relatively short baseline study period to establish low thresholds and utilize prolonged periods of adjusting/increasing thresholds while learning of the system oscillatory properties.

The data mining process includes the following:

1. Scan through phasor data, detect low damped oscillations, and record the associated damping and energy value
2. Calculate statistics for each oscillation identified, including pattern of occurrence, highest energy value with timestamp, and PMU measurement
3. Record baseline oscillation characteristics: location, minimum energy level, and frequency band for additional monitoring in real-time

Data Analysis Procedure

The analysis procedure for establishing oscillations alarm thresholds steps are as follows:

1. Assess the quality of the phasor data using PMU quality flags. This step identifies the bad or unusable data (as indicated by the PMUs), which was then removed from the baselining analysis.
2. Identify additional bad data (not indicated by PMUs) using range check and stale check filters. The data dropouts in the communication links are eradicated in this step. Additionally, engineering judgment can be used to identify voltage signals that show significant deviations from the respective base voltages.
3. Perform oscillation analysis or the remaining good data. This step identifies oscillation in the data set and categorizes the events by location, severity, duration, and count to provide an event library for use in the study. Visual inspection of detected events and validation of oscillation energy detected through peak-peak oscillation variation is helpful in this step to eradicate false events.
4. Establish the oscillation alarm thresholds by calculating the oscillation energy in each frequency band for the dataset during ambient conditions. The average energy for each signal can be used to establish the suggested alarm thresholds for the bands.

Detection Procedure and Methodology

All available frequency, voltage magnitude, current magnitude, and voltage phase angle signals are to be initially used to mine for oscillation events. Bad data is to be removed prior to mining by using PMU quality flags, range check filters, and stale check filters. Oscillation events are detected based upon event filters listed in Table 2.2 below.

Table 2.2: Example Oscillations Mining Criteria

Event Filter Type	Filter Value	Description
Oscillation Frequency (Hz)	>= 0.1 Hz	An oscillation frequency filter is used to retain oscillation events above a certain oscillation frequency.
Duration (minutes)	>= 1 Minute	An oscillation event filter is used to retain sustained oscillations above certain duration.
Energy	> 3 times Standard Deviation	An oscillation energy filter is used to detect the significant energy in the oscillation.

Establishing Alarm Thresholds

The oscillation energy is calculated in each frequency band during ambient conditions for each of the four oscillation bands. When oscillations occur in a signal, the oscillation energy for that signal increases, indicating the existence of oscillatory signature in the signal. The mean energy and standard deviation for each signal in each of the oscillation bands is calculated to establish the suggested alarm thresholds. It is suggested that two levels of alarm threshold be established per the formulae below in Table 2.3. This method ensures that only significant oscillation events trigger alarms in real-time and provides multiple levels of alarms to differentiate oscillations requiring monitoring from the ones requiring mitigation. These thresholds should be evaluated using the data analysis approach described earlier on a regular basis to ensure that all significant oscillations are detected and alarms for insignificant oscillations are kept to a minimum.

Table 2.3: Example Criteria to Establish Alarm Threshold

Alarm Level (Each Band)	Alarm Threshold (Each Band)
Level-1 (Less Severe)	Mean Energy of Ambient Data Set+(3×Standard Deviation of Ambient Data Set)
Level-2 (More Severe)	Mean Energy of Ambient Data Set+(4×Standard Deviation of Ambient Data Set)

Detecting and Identifying Local-Area Oscillations

Forced Oscillations can be either localized to a small footprint in the Interconnection, or wide-area, resulting in multiple regions swinging against each other. Depending on the oscillation spread, the methods that are currently available to detect and identify the source may vary. Therefore, it is important to identify whether the oscillations detected are local oscillations or inter-area in nature.

Determining whether an oscillation is local or inter-area can be achieved by answering the following questions:

- What frequency band is generating the oscillation alarm? Is the oscillation frequency detected by the oscillation detector close to one of the system modal frequencies?
- Is my PMU coverage spread-out across the system? If so, is the pattern of alarms widespread across most PMUs or is it localized to a specific geographical area? Are the other entities in the Interconnection observing similar alarms?

The first indicator of local oscillations is the range of oscillation frequency. Based on the ranges defined in **Table 1.1**, if an oscillation is detected and is sustained for a period[25], an alarm will be generated from a specific band for each PMU that detects the high-energy oscillations. Referring to **Table 1.1**, local oscillations mostly reside in Band-2 or Band-3, with oscillation frequencies in the range of 0.15 -1 Hz and 1-5 Hz respectively. Oscillation alarms can be validated by observing the oscillation energy of the band at the PMU that generated the alarm. The energy trend should be increasing to exceed the alarming threshold, indicating the existence of an oscillation in that frequency band. Further validation can be done by observing the trend of the metric, which is used by the Oscillation Detection Module (ODM) to perform calculations at the PMU locations.

Secondly, local-area oscillations are contained to a specific geographical footprint and are detected by PMUs nearby the oscillation source. Therefore, only the PMUs relatively close to the source should detect and alarm for the event. That said, detection at the individual PMU level depends not only on the oscillation energy seen by the PMU but also on the alarm levels associated with the oscillation detection for the PMU. Hence, depending on the severity of the oscillation observed from different PMU locations, some PMUs relatively close to the oscillation might not alarm for the oscillation if the energy does not exceed the defined thresholds.

2.1.2 Detection Method 2: Detection of Sustained Oscillations of Any Type

Undamped oscillations can occur in power systems either from the presence of sustained oscillations related to natural power grid dynamics (stable limit cycles) or from the introduction of forced oscillations from external sources, such as from rough zone related vortex oscillations or from control failures. Thus, algorithms initially intended to detect poorly damped modal oscillations can also be used to detect sustained forced oscillations. Subsequent analysis would be needed to distinguish whether the underlying cause of the low damping is related to poor damping of natural modes or from the presence of external forced oscillations. This is important to ensure proper application of the appropriate mitigation measures, either improving a mode's damping (**Section 1.2**) or locating and disabling the forced oscillation's source (**Section 2.2**).

Multi-dimensional methods are effective for implementing this approach since they can point to oscillations present in any of the PMU signals included in the analysis. This includes algorithms, such as the FFDD and fast stochastic subspace identification (FSSI). Specifically, a FFDD that is based on estimation of power spectrum densities from all available PMU measurements is very effective in detecting sustained oscillations.

The FFDD first estimates a net energy estimate for the system in the frequency domain, called the Complex Mode Identification Function (CMIF),[26, 27] from all the available signals for each frequency value of interest. Then the local peaks in CMIF can be shown to be the dominant system modes and oscillations that are observable in the PMU data at that time in the system. Then using the shape of the CMIF near the local peaks, the FFDD associates a damping estimate for each of the peaks.

In this sense, sustained oscillations can be easily distinguished by the presence of sharp peaks in the CMIF estimate, and correspondingly, the damping estimates associated with sustained oscillation frequencies can be shown to be near zero. Therefore, the FFDD based approach can directly detect the presence of any sustained or forced oscillation in the frequency range of interest and only the oscillations that have significant energy compared to the other natural modes in the CMIF estimate are selected for detection. Therefore, the method is self-calibrating, in this sense, and does not require any baselining studies. Moreover, the FFDD directly provides the mode shape or oscillation shape

[25] Waiting period is configurable and can be set to dynamically change depending on event severity. Waiting period ensures filtering of transients and post-events ringdown behavior of the system.

[26] H. Khalilinia, L. Zhang and V. Venkatasubramanian, "Fast Frequency-Domain Decomposition for Ambient Oscillation Monitoring," in *IEEE Transactions on Power Delivery*, vol. 30, no. 3, pp. 1631–1633, June 2015

[27] G. Liu and V. Venkatasubramanian, "Oscillation monitoring from ambient PMU measurements by frequency domain decomposition", *Proc. IEEE ISCAS*, pp. 2821–2824, May 2008

directly from the power spectrum matrix as part of the FFDD estimation procedure, and the shape can be useful in understanding the nature and potential source of the sustained oscillation.

The FFDD was tested extensively at Peak Reliability as part of the Forced Oscillation Detection and Source Locator (FODSL) that used PMU based FFDD for oscillation detection and SCADA based engines for source location using generator MW and MVAR SCADA outputs. The FFDD was monitoring over a thousand current magnitude and MW power signals and was very effective at detecting hundreds of sustained oscillation events at Peak Reliability. The FFDD has been implemented as an action adapter into openPDC and has been tested at several other utilities in North America and in Europe. **Figure 2.1** shows an Illustration of FFDD estimates showing a forced oscillation event that occurred on September 5, 2015.

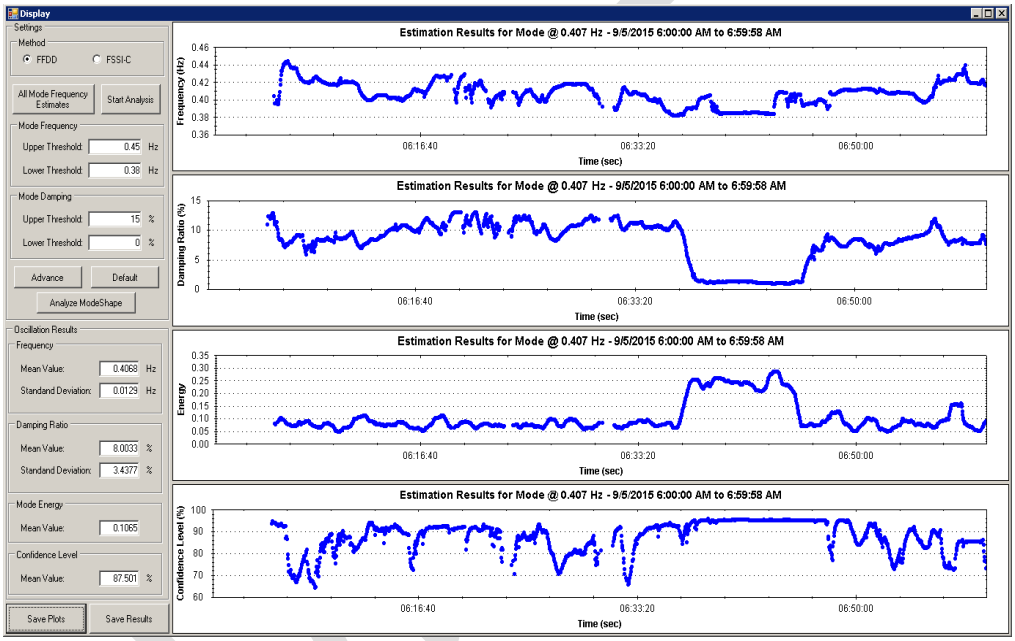


Figure 2.1: Illustration of FFDD Estimates Showing a Forced Oscillation Event that Occurred on September 5, 2015

2.1.3 Detection Method 3: Mode Frequency Band Monitoring Method

Interactions of different plants and controllers in power systems can result in small or large oscillations in the system. For a stable system, oscillations should decay by the passage of time. In an unstable system, oscillations can grow to dangerous levels where remedial actions are needed to mitigate the adverse effects of the oscillations.

Oscillations appear in power systems in different situations. One of the types of oscillations is forced oscillations (which are due to continuous cyclical excitation) as opposed to ambient oscillations (which are caused by white noise excitation). Forced oscillations can jeopardize the stability of the system when the amplitude of these oscillations is large or when these oscillations interact with system poorly-damped natural modes and the magnitude of the oscillations increases.

Power Dynamic Extraction (PDX)

Power Dynamics Extraction (PDX)[28] analysis method processes power system PMU signals to determine the presence of oscillatory components or system modes and their key parameters. For each oscillatory component, PDX determines these key parameters: frequency, damping ratio, mode shape, and amplitude of the mode. PDX down-samples the input signals with any sampling frequency to 10 Hz. The algorithm uses autoregressive model to obtain characteristics of the modes. PDX processing is applied to a window of the most recent data, and the dynamic characteristics of the system are derived for that time window. The analysis is updated at regular intervals. There are two variations of the algorithm:

- PDX-1 uses a short window (3 minutes) and updates every 5 seconds. This window is used for alarming as it can respond quickly to changes in amplitude and damping ratio.
- PDX-2 uses a longer window (more than 20 minutes) and updates every 20 seconds. This window gives more accurate and stable results. This could be used for model validation or for comparing different cases of well damped modes.

Mode Bands Management

In order to track modes in the frequency range of interest, mode bands should be defined. For example, a range may be constructed to contain a single persistently occurring low frequency mode. Defining effective mode boundaries is facilitated by collecting prior PDX1 and PDX2 processed data. Histograms containing large timespans of data (up to three days) can then be used to decide initial mode boundaries.

Alarms and Alerts

For each frequency band and each signal, some thresholds for estimated modes characteristics can be set for alarms and alerts. Damping ratio and amplitude thresholds are the most important limits. Alerts or alarms are issued when the damping ratio of a mode is below the threshold and the amplitude is larger than the threshold. There is another threshold by means of which the modes with small amplitudes are removed from alarming, regardless of their damping ratio. Similar threshold for damping ratio exists, very well-damped modes with high damping ratios are excluded from alarming regardless of the amplitude. Hysteresis limits can be set for alert and alarm events by requiring the threshold breach to persist for a defined period of time (in seconds) before an alert or alarm event is triggered.

Sustained Oscillation Detection

Any type of sustained oscillation, such as natural near zero damping mode or forced oscillation, can be detected by PDX method. These types of sustained oscillations are detected and presented by a near zero damping ratio mode by the PDX engine. However, for an appropriate mitigation plan, further analysis and investigation are required to understand whether the sustained oscillation is the result of a zero damping natural mode or a forced oscillation.

In the following simulation example, the understudy system is ESCA60 and a forced oscillation with the frequency of 0.5 Hz is injected to the system from a generator at Douglas substation. In **Figure 2.2**, it can be seen that a poorly-damped oscillation with the frequency of about 0.5 Hz is identified and an alarm is issued for this oscillation.

[28] PhaorPoint, GE Digital: https://www.ge.com/digital/applications/transmission/phasorpoint

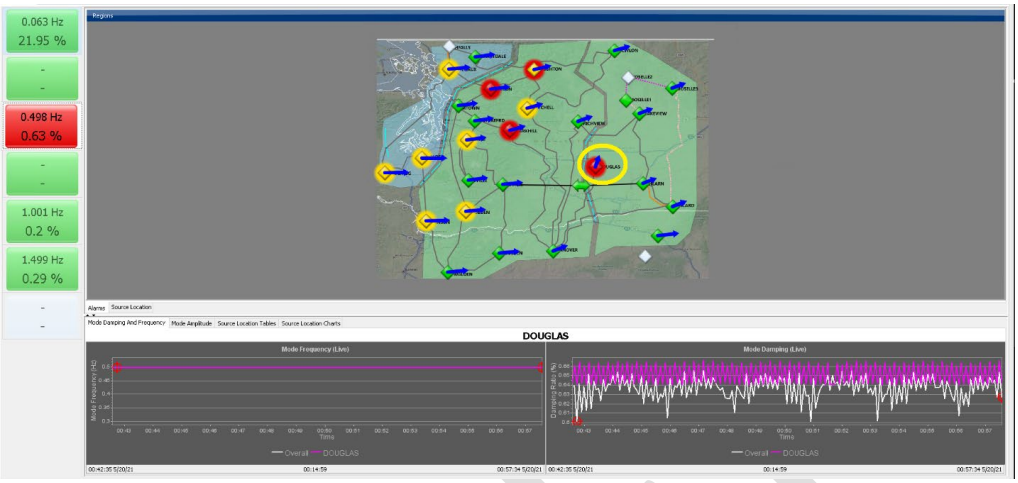


Figure 2.2: Identification of Forced Oscillation and Triggering an Alarm by PDX Method

From estimated modes, it can be seen that there are poorly-damped oscillations at 1 Hz and 1.5 Hz. These oscillations, which are harmonics of the forced oscillation at 0.5 Hz, are other indications of the presence of forced oscillation in the system. PDX could identify the forced oscillation and its harmonics that helps operators to validate the presence of forced oscillation and distinguish forced oscillation from system inter-area electromechanical oscillation.

As can be seen in **Figure 2.2**, the alarm is issued only for the estimated poorly-damped oscillation at 0.5 Hz (the estimate that corresponds to the main forced oscillation) and not for the 1 Hz and 1.5 Hz (harmonics). **Figure 2.3** illustrates the estimated damping ratio and amplitude (at the location of source) for 0.5 Hz oscillation along with the alarms and alerts thresholds. Both time plots and locus plot show that the estimated damping ratio and amplitude are in the alarm zone. In contrast, alarms or alerts are not triggered for harmonics at 1 Hz and 1.5 Hz despite their near zero damping ratio. **Figure 2.4** shows the time plots and the locus plot of estimated damping ratio and amplitude (at the location of source) for the oscillation at 1 Hz. As is evident in **Figure 2.4**, for the estimated oscillation at 1 Hz, the amplitude is below the alert and alarm thresholds.

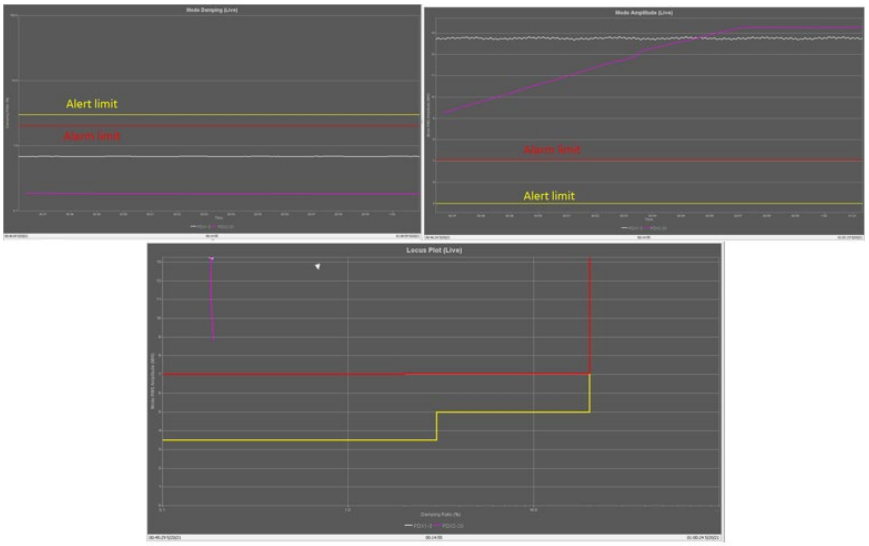


Figure 2.3: Example of Estimated Damping Ratio and Amplitude of Forced Oscillations

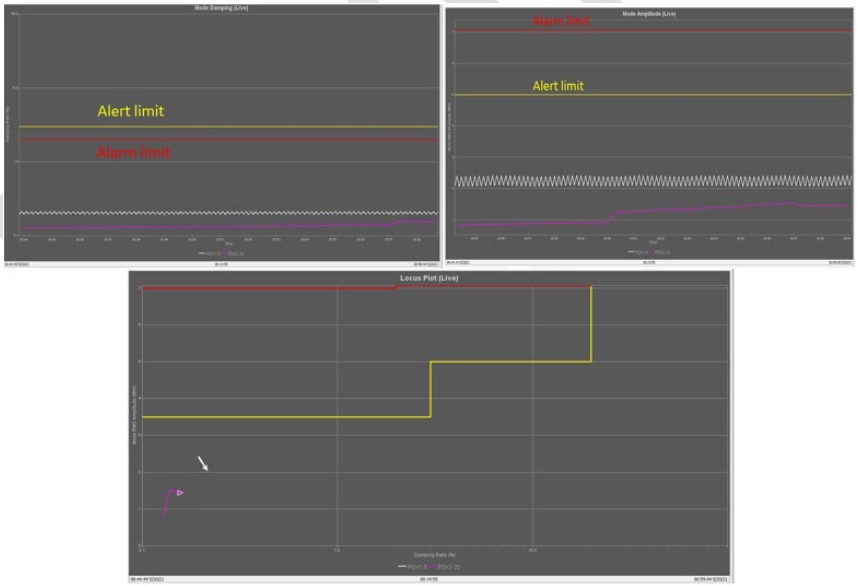


Figure 2.4: Time Plot and Locus Plot of Estimated Damping Ratio and Amplitude of the Harmonic of Forced Oscillation at 1 Hz Along with Alarm and Alert Limits

2.2 Determination of Oscillation Source

Determining the location of the source of forced oscillations can be challenging especially when the oscillation is widespread or there may not be sufficient PMU coverage to locate the exact source. For example, a RC may only be monitoring BPS level synchrophasor data, which would be utilized for alarming the operators. However, the RCs can always coordinate with the impacted TOPs to determine the source. The impacted TOPs would have a more granular view as they would be monitoring more synchrophasor data specific to the respective TOP area. In scenarios where the synchrophasor data itself is scarce, the available synchrophasor data can help to locate the local area from the oscillations originate; however, determining the exact source location would require further review of SCADA data and coordination and communication with the impacted TOPs, Balancing Authorities, and Generator Owners (GO).

When synchrophasor or telemetered data are available, the following methods help to determine the exact source location of forced oscillations or the local regions from where the oscillations originate.

2.2.1 Local Forced Oscillations

Figure 2.5 shows an example of a local forced oscillation where the source of the oscillation can be easily traced to a single location. The unit causing the oscillation may exist either at the location shown on the operator dashboard or may be in the underlying system connected to the location with the alarm if the operator dashboard does not have every location shown since synchrophasor data may not be available from every generator location. This gives the impacted RC and TOP a starting point to coordinate to determine the source.

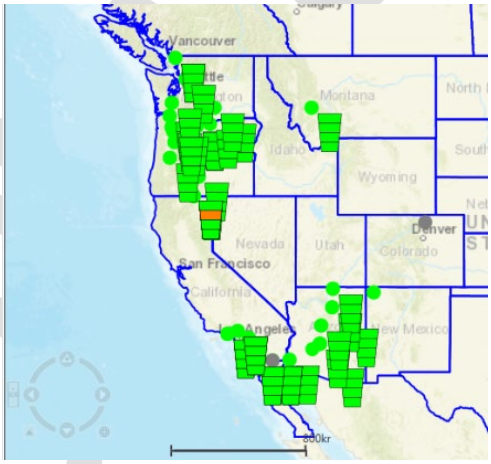


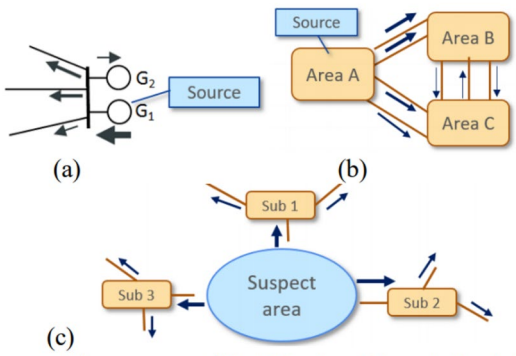
Figure 2.5: Example of Local Forced Oscillation

2.2.2 Forced Oscillations Impacting a Wide Area

When forced oscillations are observable over a wider area, location of the oscillation source can be more challenging. In certain cases, an oscillating unit can cause another unit to oscillate, which makes it difficult to pinpoint the suspect unit. The following methods help to locate oscillation sources when the forced oscillation is observable over a wider area.

Dissipating Energy Method

The method is based on tracing the flow of transient dissipating energy through the power system network (Maslennikov & Litvinov, 2020). By tracing the flow of energy back to its source, the equipment generating the oscillation is identified. When synchrophasor data is available at sufficient number of units, the method can point to the exact source of oscillation; the source will have the unique characteristic of dissipating energy flowing out of the generator. Similarly, when sufficient synchrophasor data does not exist at the terminals of generator, the suspect area can be localized by utilizing synchrophasor data from line flows. Examples of the interpretation of dissipating energy flow (DEF) results are presented in **Figure 2.6**. This method was developed and is in use at ISO New England.



The use cases of the DE pattern interpretation (a) PMU monitors POI of a power plant, (b) PMU monitor tie-lines between areas, (c) localization of suspect area non-observable by PMUs

Figure 2.6: Use Cases of the Dissipation Energy Method

Source Location Using the Phase of Oscillation

For the oscillation source location (OSL), voltage angle measurements are used to identify the PMU in the substation or region that is the closest to the sources of oscillations. This is achieved by analysing the phase of oscillations in the voltage angles from around the system. A leading phase indicates less damping contribution and the source is the location with the lowest damping contribution.[29]

Figure 2.7 shows an example of an oscillation source location map. As is evident, the source is identified and shown by the yellow circled area in the map.

[29] Al-Ashwal, N., D. Wilson, and M. Parashar. "Identifying sources of oscillations using wide-area measurements." *Proceedings of the CIGRE US National Committee 2014 grid of the future symposium, Houston.* Vol. 19. 2014.

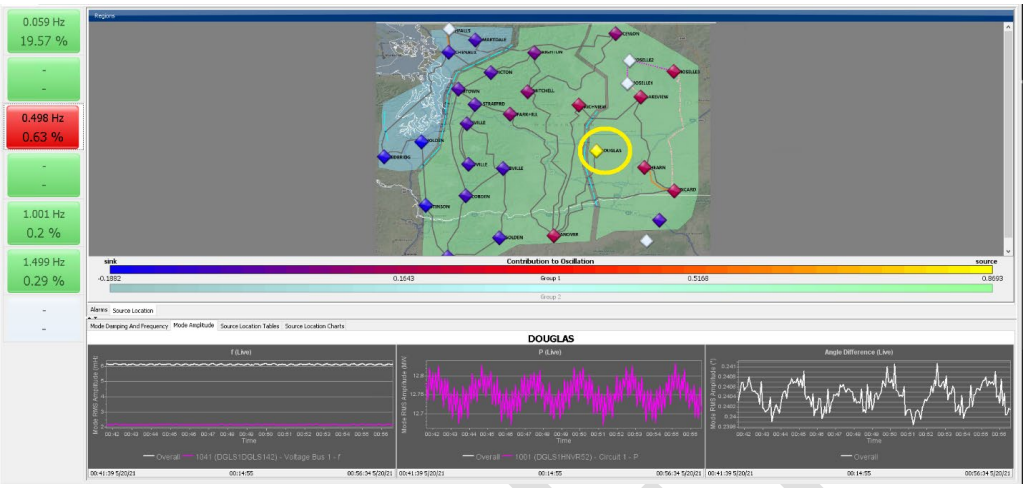


Figure 2.7: Identification of the Source of Forced Oscillation

SCADA Data Based Source Location

SCADA data can also be used to detect potential oscillation locations through the use of generator MW and MVAR telemetered data. SCADA data is easily available and, despite the lower resolution, SCADA data can help to point to the potential sources of oscillation based on the magnitude of the oscillation. This was one of the methods deployed at Peak Reliability for identifying sources of oscillation and validated with generator operators (GO) for real events.[30]

Other Oscillation Source Location Methods

Several other oscillation location methods have been developed to identify source locations under various imperfect signal conditions and practical event scenarios. These include ~~(1)~~ a method[31] that combines~~d~~ dissipated energy flow (DEF) ~~method~~ with a dynamic state estimator (DSE), ~~(2)~~ a machine-learning pattern recognition (ML-PR) method[32] that use~~sing~~ DEF results as inputs, and ~~(3)~~ a cross power spectral density (CPSD) based method.[33]

[30] Source Location of Forced Oscillations Using Synchrophasor and SCADA Data, https://pdfs.semanticscholar.org/97a8/48ae894edec07f462ccefe89db54a93ebf52.pdf

[31] Combined Dissipated Energy Flow Method, https://www.naspi.org/sites/default/files/2021-10/D3S8_02_estevez_fiuba.pdf

[32] Machine-Learning Pattern Recognition method, https://www.naspi.org/sites/default/files/2021-10/D3S8_03_zheng_ge_20211007_0.pdf

[33] Cross Power Spectral Density based Method, https://www.naspi.org/sites/default/files/2021-10/D3S8_04_osipov_rpi_20211007_0.pdf

Chapter 3: Forced Oscillations Causing Inter-Area Oscillations

This section addresses the phenomenon that lead to wide-spread impact of forced oscillations due to resonance conditions involving system modes. Also described is an example of how model-based simulations can be utilized to observe the impact of wide-spread oscillations during resonance conditions.

3.1 Conditions that Lead to this Phenomenon

A forced oscillation whose frequency is the same or very close to the frequency of an inter-area mode can lead to resonance that can potentially cause amplification of the oscillation across an Interconnection. Three major conditions are necessary for the resonance effect to be high:[34] [35]

- The forced oscillation frequency should be at or near a system mode frequency.
- The system mode should be poorly damped.
- The source is near a strong participation location of that system mode, such as the distant ends of the system mode. The distant end locations are the strongest participants in the system mode.

The forced oscillation event of January 11, 2019, had two of the above conditions leading to a high resonance effect. The frequency of the forced oscillation was exactly matching one of the inter-area modes at 0.25 Hz and the source was near a strong participation location. The natural system mode was well damped; however, the oscillation amplified in magnitude across the Interconnection. Oscillations higher in magnitude than the source (Florida) oscillation magnitude were observed in the Northeastern area and the rest of the Interconnection of tie-line flows leading to impact on automatic generation control operations.

3.2 Testing Possible Mitigations

Appendix A provides an example of how the impact of the January 11, 2019, forced oscillations can be determined by using model-based simulations and how possible mitigation plans can be determined for utilization in guidance provided to operators.

Since wide-area resonant forced oscillations can be simulated in dynamic analysis, the effect of various plant controls and operator actions can also be tested; see the following examples:

- Switching AVRs to manual mode
- Generation redispatch
- Curtailing power transfers
- Commissioning more PSS

The first step to the testing is to modify the load flow and dynamic cases accordingly and then perform eigenvalue analysis to determine whether the frequency of oscillation or damping of the mode being studied has been changed. Secondly, the forced oscillation should be simulated in dynamic analysis to validate changes in damping and to demonstrate any changes in the oscillation amplitude.

[34] S. Arash Nezam Sarmadi, Vaithianathan Venkatasubramanian, Armando Salazar, "Analysis of November 29, 2005 Western American Oscillation Event", *Power Systems IEEE Transactions on*, vol. 31, no. 6, pp. 5210–5211, 2016.

[35] S. A. N. Sarmadi and V. Venkatasubramanian, "Inter-area resonance in power systems from forced oscillations", *IEEE Trans. Power Syst.*, vol. 31, no. 1, pp. 378–386, Jan. 2016.

Chapter 4: Guidelines for Addressing Wide-Area Oscillations

This section addresses the analyses, tools, and procedures that RCs/TOPs need during a wide-area oscillation event. To begin, approaches for distinguishing between a natural and forced oscillation are described in **Section 4.1**. In the relatively rare case where the oscillation is due to a poorly damped inter-area electromechanical mode, the mitigation actions developed with methods described in **Section 1.2** should be implemented. If the oscillation is identified as forced, the second step is to determine if action should be taken; guidelines for making this determination are described (**Section 4.1**) then followed by a discussion of potential mitigation actions and their validation. The section concludes with a summary of the tools and procedures needed within and across RCs/TOPs footprints to enable the previously described analyses and actions.

4.1 Determining if an Oscillation is Natural or Forced

As described previously, forced oscillations become widespread when they excite one or more of a power system's inter-area electromechanical modes. For this to occur, the frequency of the forced oscillation must be similar to the frequency of the system mode. Thus, when a sustained oscillation occurs in the frequency range of electromechanical modes, it may not be immediately apparent whether the oscillation is forced or natural. The appropriate responses to natural and forced oscillations differ, so it is important to either classify the oscillation as forced or natural before taking action~~,~~ or ensure control and operator responses are appropriate for either type of oscillation. Currently, many of the entities operating grids are doing neither because methods for classifying sustained oscillations are not yet widely available in commercial tools. Additionally, sustained oscillations from inter-area electromechanical modes are uncommon because the operating conditions leading to these oscillations are typically identified and addressed in planning studies. Though relatively uncommon, sustained inter-area electromechanical modal oscillations do occur and pose a significant threat to reliable system operation.

One readily observable difference between natural and forced oscillations that is widely agreed upon is the presence of harmonics. Forced oscillations are often accompanied by harmonics due to the periodic nature of the driving input. For example, a 0.25 Hz oscillation may be accompanied by harmonics at 0.75 Hz, 1.25 Hz, etc. The appearance of harmonics is a clear indication of a forced oscillation because inter-area electromechanical modes do not possess harmonics. Some commercial tools may provide frequency estimates for each of an oscillation's harmonics. Others may enable spectral analysis so that the harmonics can be picked out by examining a plot. However, not all forced oscillations have harmonics and they may be too small to detect if they do. Thus, harmonics are an important characteristic to consider are not sufficient to make the distinction in all cases. **Figure 4.1** shows SSI estimates during a forced oscillation event that shows the presence of harmonics as zero damping oscillation estimates and as sharp peaks in the power spectrum plot. The forced oscillation at 0.28 Hz leads to harmonic peaks at 0.56 Hz, 0.84 Hz, and 1.12 Hz in the power spectrum plot (in the lower right side) and as 0.56 Hz, zero damping oscillation estimates in the mode estimation table (in the center).

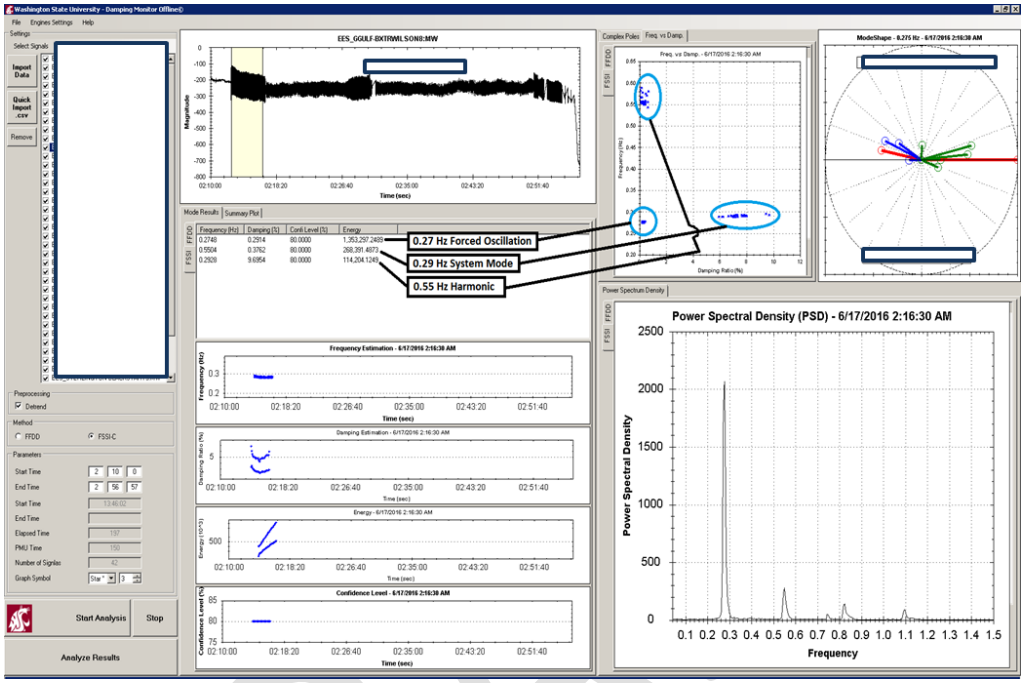


Figure 4.1: Example of Harmonics Present as Zero Damping Oscillation Estimates

The methods used to continuously monitor inter-area electromechanical modes described in **Section 1.1.2** can also help determine if an oscillation is natural or forced. These tools offer situational awareness that can help a well-trained engineer or operator understand what type of event is occurring. Forced oscillations are often (but not always) blue-sky events because they can be caused by a single piece of equipment. In contrast, poorly damped inter-area modal oscillations are often (but not always) associated with high stress conditions and/or multiple contingencies. Monitoring tools can provide an early warning of modes headed towards instability. If sustained oscillations occur following a progressive decline in a mode's damping, the oscillation is likely natural. If a sustained oscillation occurs under low-stress conditions apart from contingencies, there is a greater chance that it is forced. These are not hard and fast rules, but they can help operation staff interpret their tools appropriately.

In addition, some oscillation monitoring tools are capable of tracking forced oscillations and relatively well-damped electromechanical modes of oscillation simultaneously. If only the sustained oscillation is found at the frequency of the known electromechanical mode, there is increased likelihood that poor mode damping is leading to the oscillation. However, if the sustained oscillation and the known mode with sufficient damping are both identified, the sustained oscillation is most likely forced and has been observed before in RC operations.[36] Again, this approach requires training to help operations staff interpret results. Such approaches will be necessary while commercial tools that explicitly classify sustained oscillations as natural or forced are developed.

[36] H. Zhang, J. Ning, H. Yuan and V. Venkatasubramanian, "Implementing Online Oscillation Monitoring and Forced Oscillation Source Locating at Peak Reliability," 2019 North American Power Symposium (NAPS), 2019, pp. 1-6

4.2 Mitigating Actions

Once an oscillation is detected, a decision about whether to take mitigating actions must be made. Defining thresholds to determine if an oscillation is a reliability threat requiring action is a nontrivial task, but the key parameter is the oscillation's amplitude. Offline dynamic studies and reviews of relay settings can be used to set well-informed thresholds. In addition, regular investigation of oscillatory events can build an institution's understanding of how oscillations of various amplitudes, durations, and frequencies may impact reliability. As much as possible, oscillation scenarios should be studied in advance through the use of measurements and models to determine appropriate action.

When a wide-area oscillation occurs, effective communication among RCs/TOPs can help maintain system reliability by ensuring that only well-coordinated and effective mitigation actions are performed. Local oscillations can typically be addressed by an RC/TOP acting alone, but if the oscillation is observed throughout an RC/TOP footprint, coordination should begin quickly. Transmission operators should contact their RC, and RCs should reach out to neighboring RCs. In this way, the affected portion of the Interconnection can be quickly identified.

Any oscillation observed across an RC/TOP footprint warrants coordination. This coordination is important even when the source is readily apparent and the oscillation is not large enough to threaten reliability within the RC/TOP footprint from which it is originating. Due to the system's dynamics, a forced oscillation may be larger in far off areas of the system. RCs in those areas need to know that the source has been identified, and the RC/TOP from which it is originating needs to adjust their response if reliability of other portions of the grid are threatened. Even oscillations too low in energy to impact system reliability may be indicative of malfunctioning or misoperating equipment. When oscillations are found to originate from a power plant, RCs/TOPs can help the power plant operator maintain reliable and safe operation by communicating with them.

With coordination efforts in place, mitigation measures can be enacted effectively. Inter-area modal oscillations should be mitigated based on the results of studies as discussed in **Section 1.2**. If the mode of oscillation is unknown, reducing flows along tie-lines may reduce system stress and improve stability. In the case of wide-area forced oscillations, the most effective mitigation measure is to identify and disable the forcing input. Disabling the input does not necessarily mean that equipment needs to be taken offline. Certain areas of operation, such as the rough zone on hydro units, may lead to oscillations. In some cases, unintended control interactions leading to oscillations can also be mitigated by adjusting an operating point. Whether the mitigating action is simply adjusting an operating point or tripping a power plant offline, the source must first be identified. Methods for identifying the source of an oscillation were discussed in **Section 2.2**.

When a severe oscillatory event occurs and reliability is threatened, a potential action is to increase the damping of the excited electromechanical mode. This action can be performed while searching for the oscillation's source, which should be the primary action of all impacted RCs/TOPs. As listed previously, the three conditions leading to widespread forced oscillations are as follows:

- Proximity of the frequencies of the forced oscillation and an electromechanical mode of oscillation
- Low damping of an electromechanical mode with similar frequency
- Controllability of an electromechanical mode with similar frequency at the source of the forced oscillation

Of these three conditions, only the damping of the electromechanical mode can be effectively adjusted by RCs/TOPs through changes in the system's operating point. Increasing the damping ratio of a mode excited by a forced oscillation will not fully address the forced oscillation, which will continue until its source is disabled. However, increasing the damping ratio of the excited mode will reduce the forced oscillation's amplitude in other parts of the system that participate in the mode.

To implement this approach, studies must be conducted ahead of time to identify the operating conditions, such as flow along transmission corridors that can be adjusted to improve the damping of each mode. When a forced oscillation occurs near the frequency of a system mode, the measures designed for that mode can be implemented to improve damping. In many cases, these actions will be similar or identical to those designed to mitigate natural oscillations due to poor system damping, as described in **Section 1.2**.

Chapter 5: Examples of Oscillation Monitoring Implemented by RCs and TOPs

In this chapter, overviews of existing tools and procedures that RCs and TOPs have put into place are discussed. PMUs and the oscillation monitoring tools provided to system operators for situational awareness of concerns that could make a 15-minute impact on BPS equipment or operational decisions should be evaluated for NERC CIP applicability

5.1 Bonneville Power Administration

Implementation and Operating Experience with Oscillation Detection - Application at Bonneville Power Administration,[37] Synchrophasor Technology at BPA: From Wide-Area Monitoring to Wide-Area Control,[38] and Reliability Guideline: Forced Oscillation Monitoring & Mitigation[39] provide an overview of the ~~the~~ oscillation applications in use at Bonneville Power Administration (BPA). BPA's oscillation detection application has been deployed in the BPA control room since 2013, and it operates by monitoring PMU measurements for increased energy. This monitoring is performed for four frequency bands as described in **Section 2.1**. When a signal's energy exceeds the threshold, it is indicated on a geographical map in red as in **Figure 1.3**. An example where the oscillation is detected across a wide area is displayed in **Figure 5.1**. These displays provide operators with an initial indication of how widespread the oscillation is and what its type may be based on the frequency band. Once a detection is displayed, the operator can click on specific locations to obtain more detailed information as shown in **Figure 5.2** and **Figure 5.3**.

The BPA established operating procedures to accompany their oscillation detection application in 2016. If an alarm is issued for a single location, the system operator contacts the local operator or field staff to investigate further. If the alarm is issued for multiple locations, the oscillation is considered widespread. Depending on the situation, the RC may be contacted to identify the cause and develop a course of action. Potential operator actions, governed by BPA's operating procedures, include inserting series capacitors, inserting transmission lines that are out of service for voltage control, moving generation to increase system inertia, and curtailing schedules.

[37] Implementation and Operating Experience with Oscillation Detection - Application at Bonneville Power Administration: http://cigre-usnc.org/wp-content/uploads/2016/10/Kosterev.pdf

[38] Synchrophasor Technology at BPA: From Wide-Area Monitoring to Wide-Area Control: https://www.bpa.gov/Doing Business/TechnologyInnovation/Documents/2017/SYNCHROPHASORS_ATBPA_Nov_2017.pdf

[39] Reliability Guideline: Forced Oscillation Monitoring & Mitigation: https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_Forced_Oscillations_-_2017-07-31_-_FINAL.pdf

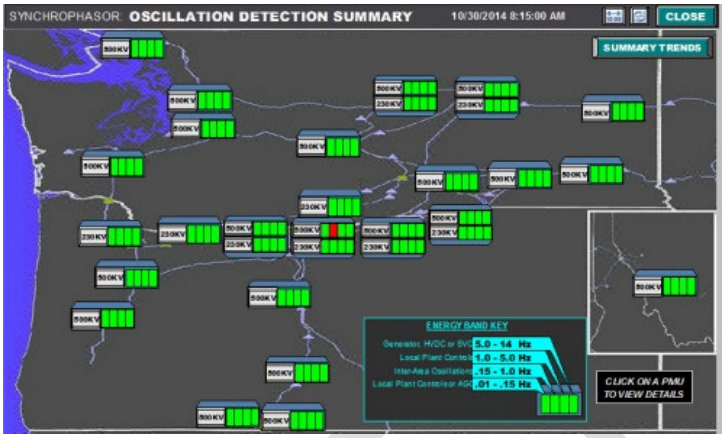


Figure 5.1: Control Room Display Indicating a Localized Oscillation in Band 2

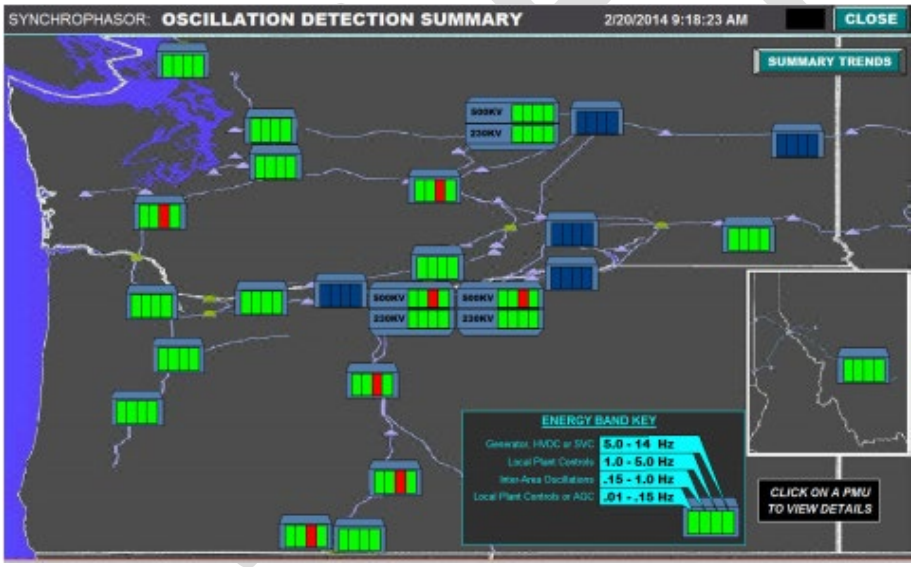


Figure 5.2: Control Room Display Indicating a Wide-Area Oscillation in Band 3

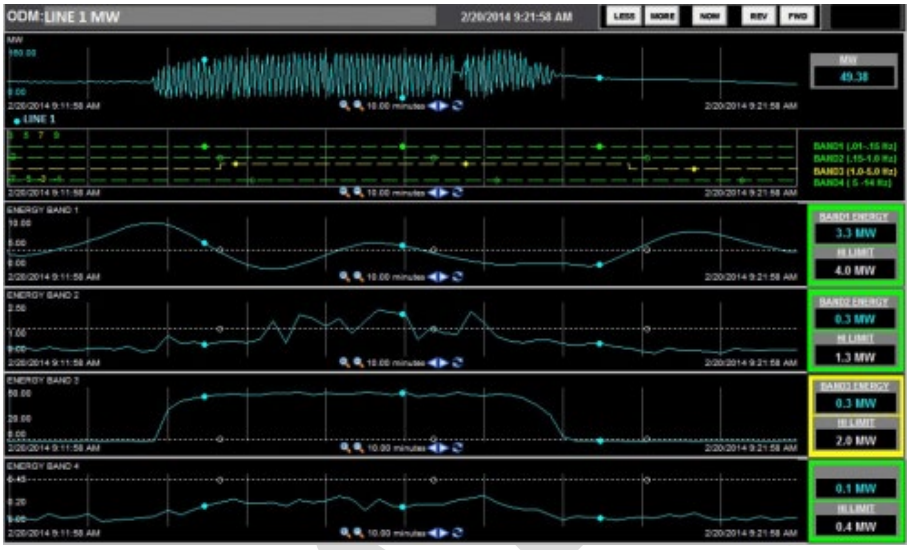


Figure 5.3: Control Room Display Providing Additional Information About a Band 3 Oscillation Alarm

BPA has also deployed a mode meter application to provide continuous tracking of known system modes. By regularly updating estimates of mode damping, the application could potentially be used to provide an early warning of inter-area oscillation problems due to high system stress; alarming and operating procedures are under development. The concept for a composite alarm that accounts for damping ratio estimates, power flows on major interfaces, and phase angle differences is displayed in **Figure 5.4**. Power flow and angle difference values have been removed from the figure.

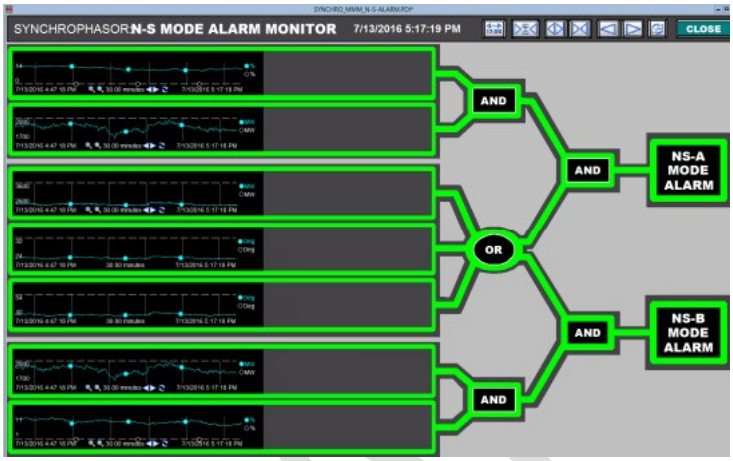


Figure 5.4: Example of a composite Alarm for Monitoring of Modes

5.2 ISO New England (ISO-NE)

Reliability Guideline: Forced Oscillation Monitoring & Mitigation[40] and ISO New England Experience in Locating the Source of Oscillations Online[41] provide an overview of oscillation applications in use at ISO-NE. ISO-NE uses the GE PhasorPoint application to detect and characterize oscillations between 0.05 Hz and 4 Hz. This frequency range is split into sub-bands that utilize their own threshold for alerts and alarms based on the magnitude and damping of the oscillations. When a sustained oscillation of significant magnitude is detected, ISO-NE follows a similar procedure regardless of whether the oscillation is natural or forced. The key objective of this procedure is to identify the oscillation's source.

ISO-NE utilizes the online OSL application to process events. The OSL application is based on the DEF method and has processed over 1,000 oscillatory events. As mentioned earlier, the equipment generating the oscillation is identified by tracing the flow of energy back to its source. Tie-lines between ISO-NE and neighboring system operators are also monitored so that ISO-NE can determine if an oscillation is coming from outside of their territory. The OSL's pattern recognition module converts the DEF in the network into a text message identifying a specific generator, power plant, or area as the containing the source of oscillation. The pattern recognition compares the energy flow with a set of pre-defined topology-based energy flow templates for all potential oscillation sources that could be uniquely identified based on system observability with PMU measurements.

[40] Reliability Guideline: Forced Oscillation Monitoring & Mitigation: https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_Forced_Oscillations_-_2017-07-31_-_FINAL.pdf

[41] S. Maslennikov and E. Litvinov, "ISO New England Experience in Locating the Source of Oscillations Online," in IEEE Transactions on Power Systems, vol. 36, no. 1, pp. 495-503, Jan. 2021

ISO-NE developed an alarm notification service to deliver the PhasorPoint and OSL results by e-mail and text messaging. An example e-mail is displayed in **Figure 5.5**.

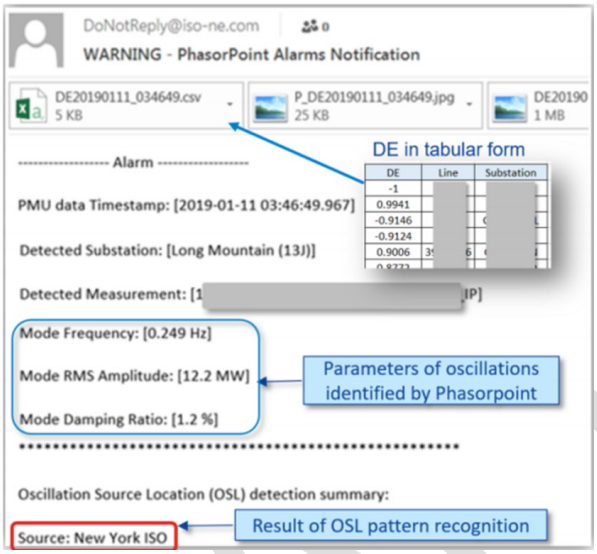


Figure 5.5: Example E-Mail from the Alarm Notification Service Detailing the Characteristics and Source of an Oscillation

E-mails from the alarm notification service are automatically generated and sent to ISO-NE control room staff and operation support engineers. If a specific power plant or generator is identified as the source, an e-mail is also sent to that generator's personnel and the local control center overseeing the generator. If the oscillation has a large magnitude, ISO-NE operational staff communicates with the operator of the source generator to apply remedial actions online. Potential mitigating measures include disconnecting the source generator from the network, adjusting the generator's MW output, or changing its control mode. If the oscillation is small, the mitigation process is shifted offline. Mitigation is again based on communication between ISO-NE personnel and the source generator's operator/owner. There is no formal distinction between a "large" and "small" oscillation at ISO-NE, but any persistent oscillation with a magnitude above the power system's ambient noise is investigated.

5.3 Oklahoma Gas & Electric (OG&E)

Reliability Guideline: Forced Oscillation Monitoring & Mitigation[42] provides an overview of the tool and procedures developed at OG&E to address oscillations in a concentrated portion of their transmission system associated with increasing wind generation resources. In recent years, the tool's use has extended to monitor low frequency oscillations related to inter-area modes. The application's oscillation detector is based on the magnitude of the Fast Fourier Transform (FFT), which is proportional to the amplitude and duration of the oscillation. The user interface shown in **Figure 5.6** allows the user to specify the detection threshold and the frequency range of interest.

[42] Reliability Guideline: Forced Oscillation Monitoring & Mitigation: https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_Forced_Oscillations_-_2017-07-31_-_FINAL.pdf

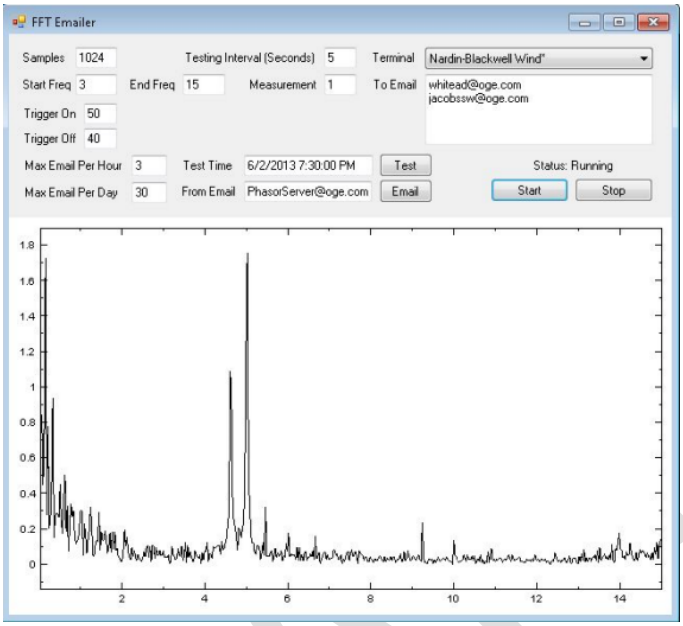


Figure 5.6: OG&E's Oscillation Detection Tool

When an oscillation is detected, the application automatically sends an e-mail like the one in **Figure 5.7** to operations support engineers. If further investigation reveals that mitigation action is necessary, the operations support engineers contact the transmission control center and recommend a mitigation strategy.

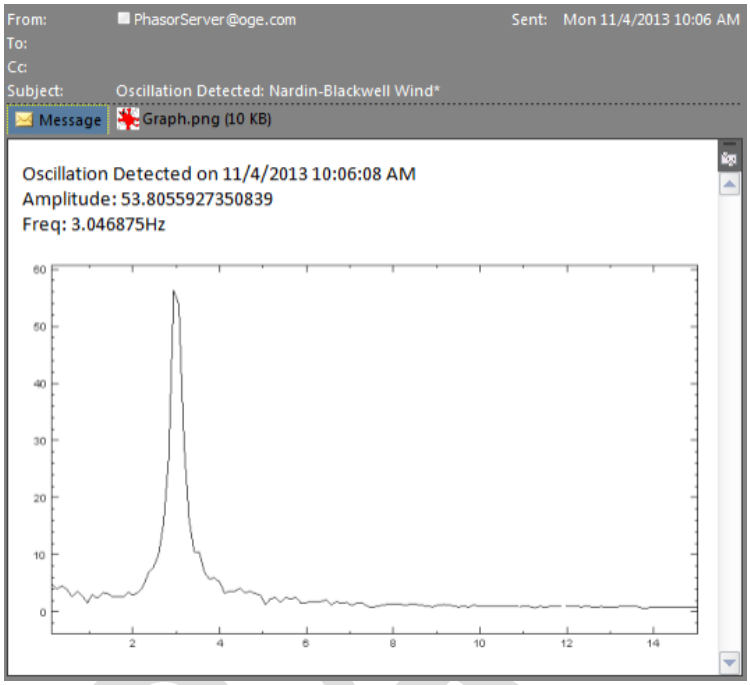


Figure 5.7: E-Mail Automatically Generated by OG&E's Oscillation Detection Tool

5.3 Peak Reliability Coordinator

Reliability Guideline: Forced Oscillation Monitoring & Mitigation[43] and Implementing Online Oscillation Monitoring and Forced Oscillation Source Locating at Peak Reliability[44] provide an overview of the oscillation applications used at Peak Reliability before its wind-down. These applications included both oscillation monitoring and source localization capabilities. Dominant inter-area modes of oscillation were monitored by analyzing PMU data in a mode meter application. This application provided updated frequency and damping ratio estimates every 10 seconds, much like the BPA tool described in a previous section. In addition, a PMU-based oscillation monitor was used to detect any high-energy oscillation, whether natural or forced. In addition, the frequencies, damping and energy levels, and mode shapes of inter-area modes and oscillations were estimated by analyzing hundreds of PMU signals using the FFDD, and the estimates were updated every 10 seconds.

Once an oscillation with a low damping ratio was detected with the FFDD, the source of the oscillation was identified using a SCADA-based application. SCADA measurements provided observability at many more power plants than was possible with PMU data. SCADA measurements also provide observability at generator level. SCADA measurements were collected asynchronously and updated at Peak every 10 seconds, restricting detailed oscillation analysis. Instead, the source localization application operated by identifying locations where measurements changed

[43] Reliability Guideline: Forced Oscillation Monitoring & Mitigation
https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_Forced_Oscillations_-_2017-07-31_-_FINAL.pdf
[44] H. Zhang, J. Ning, H. Yuan and V. Venkatasubramanian, "Implementing Online Oscillation Monitoring and Forced Oscillation Source Locating at Peak Reliability," *2019 North American Power Symposium (NAPS)*, 2019, pp. 1-6

significantly at the onset of the oscillation. In many cases, the generator exhibiting a significant change comparing to ambient condition (per ranking of normalized indices) was successfully identified as the source.

Results from the oscillation source localization application were automatically routed to network application engineers for review. After validating the results through further offline studies, engineers communicated with the corresponding entity system operator and generation plant operator to identify causes and implement mitigating actions.

5.4 RC West

RC West utilizes the Electric Power Group Real Time Dynamic Monitoring System (RTDMS) for monitoring of forced and natural oscillations. The monitoring of oscillations is supplemented with an RC operating guideline that provides guidelines to the operators for the following three scenarios:

- Forced oscillations
- Inter-area oscillations
- Forced oscillations causing Inter-area oscillations

The forced oscillation monitoring is accomplished using the ODM that monitors oscillations in the four energy bands at various locations across the RC West footprint. Figure 5.8 and Figure 5.9 show examples of forced oscillations observed over a wide area and a local area. Figure 5.10 and Figure 5.11 show examples of forced oscillations observed online flows and bus voltages.

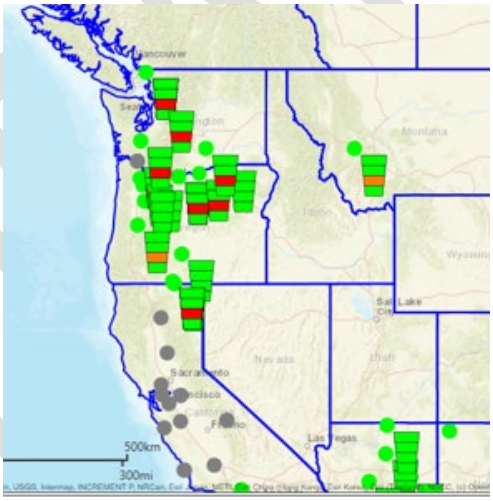


Figure 5.8: Wide-Area Forced Oscillations

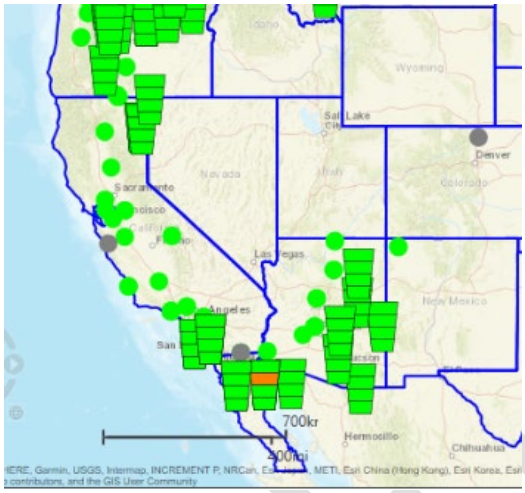


Figure 5.9: Local Forced Oscillations

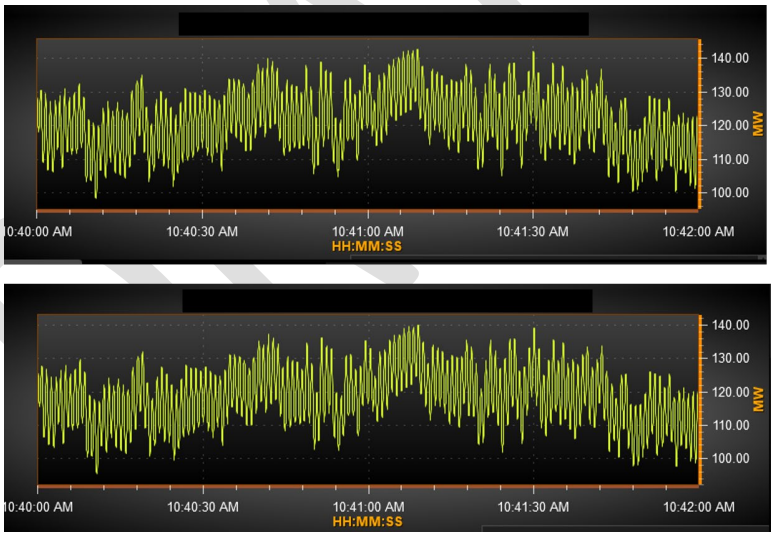


Figure 5.10: Forced Oscillations Observed on Line Flows

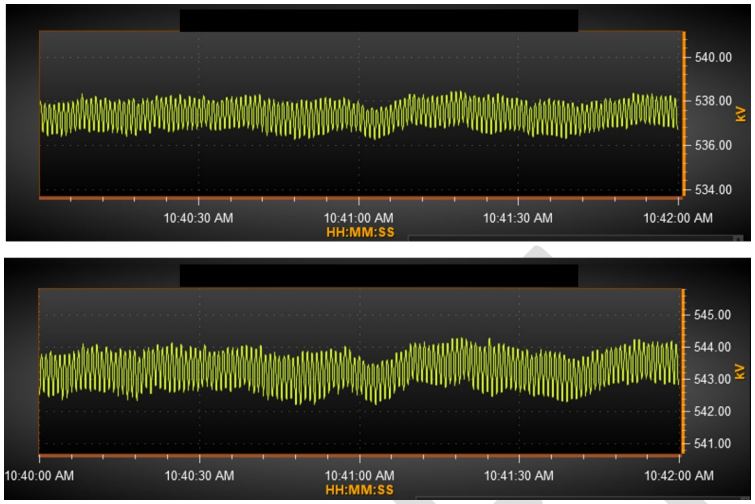


Figure 5.11: Forced Oscillations Observed on Voltages in RC West

In addition to monitoring forced oscillations, the RTDMS setup at RC West also monitors the five significant modes in the WI as shown in **Figure 5.12**: . Operators have been provided guidelines on path flows, or generators, relevant to each of these modes that can be utilized to increase damping in the event we have low sustained damping on any of these monitored modes.

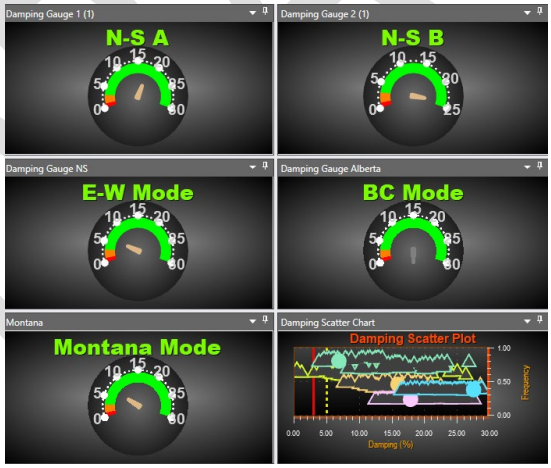


Figure 5.12: Mode Meter Monitoring

The mitigation actions for increasing damping of the modes are~~is~~ validated by performing SSAT analysis with real-time state estimation cases that are used along with the dynamic data applicable for the season. RC West has a running real-time transient stability analysis setup that provides the framework to perform small-signal stability analysis with the same input data from state estimation and dynamic data that is used for the transient stability

analysis. The SSAT analysis, as described in **Section 1.2.1**, allows operators to determine and validate relevant path flows or status of equipment and generators that can be adjusted to mitigate observed sustained low damping on any of the monitored modes.

5.5 Southwest Power Pool (SPP)

SPP uses PMU technology and Electric Power Group RTDMS for real-time non-decision-making oscillation monitoring to ensure wide-area situational awareness of Interconnection electrical signal dynamics. SPP utilizes the ODM and mode meter engines within RTDMS to extract grid dynamics information for the purposes.

ODM is used to agnostically monitor for manifested oscillations via the use of a sliding root mean square (RMS) window. An increase in signal dynamics directly translates to an increase in the RMS value. Therefore, if an oscillation occurs on a signal measurement, ODM detects this by comparing the real-time RMS value to a pre-set RMS threshold value. If the current RMS value stays above the pre-set threshold for a minimum amount of time (e.g., 60 or 120 seconds), operators are alerted of the possible oscillation event. The pre-set thresholds are set so that they represent an increase in signal dynamics above typical ambient conditions. This information can be extracted by performing statistical analysis on raw and post-processed signals and making a decision that suffices the needs of the end user. Several methods can be used (e.g., 3sigma above mean or more slightly advanced items like Dual-Dirac fitting). If there is an oscillation present and ODM detects it, internal SPP software will alert operators who then use RTDMS displays to assess the situation, such as oscillation location, signal type, oscillation frequency, and oscillation magnitude. From there, RCs will contact entities or other RCs to communicate the detection of the event. **Figure 5.13** and **Figure 5.14** shows an example of a real-time WI forced oscillation from 2019 that showed up in SPP's RTDMS system.

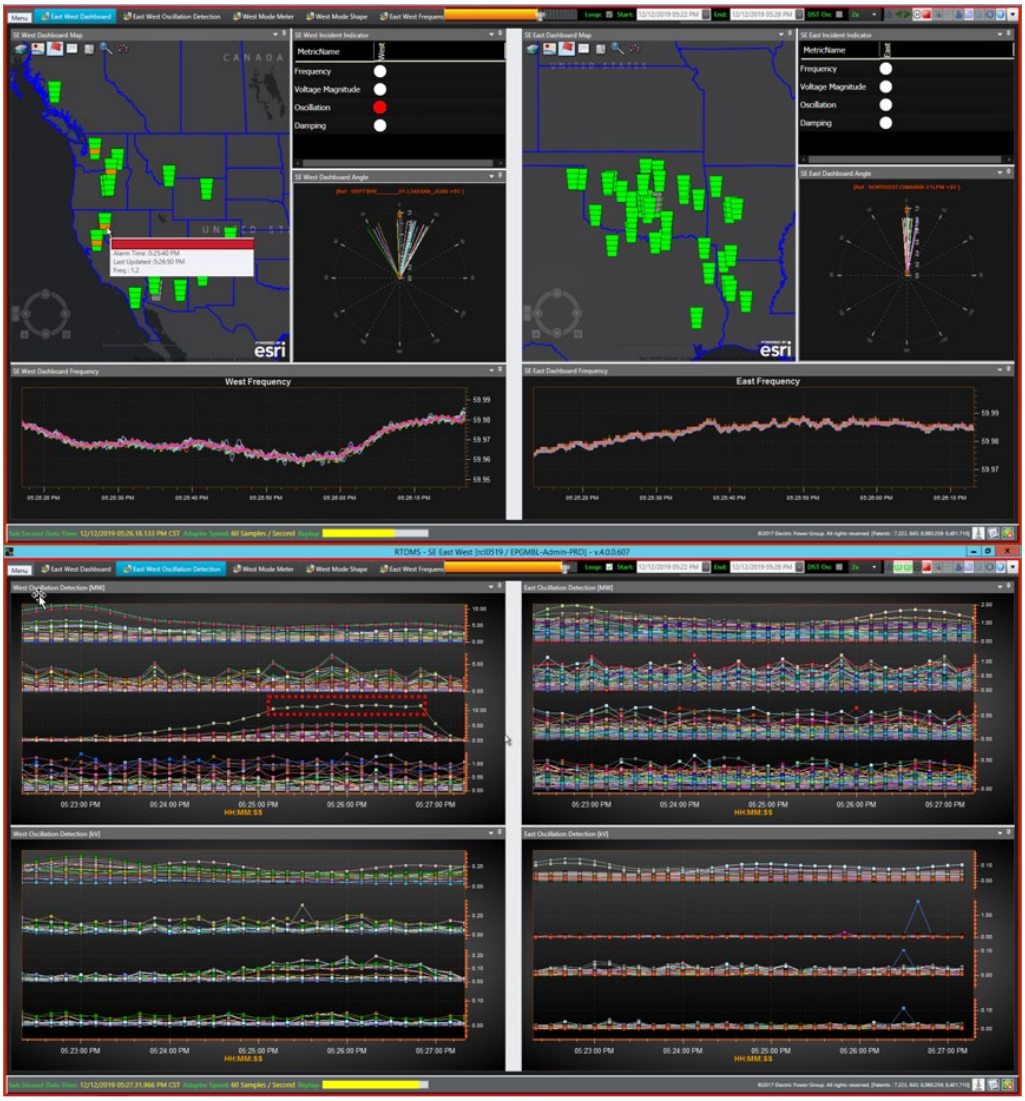


Figure 5.13: Forced Oscillation Observation in SPP

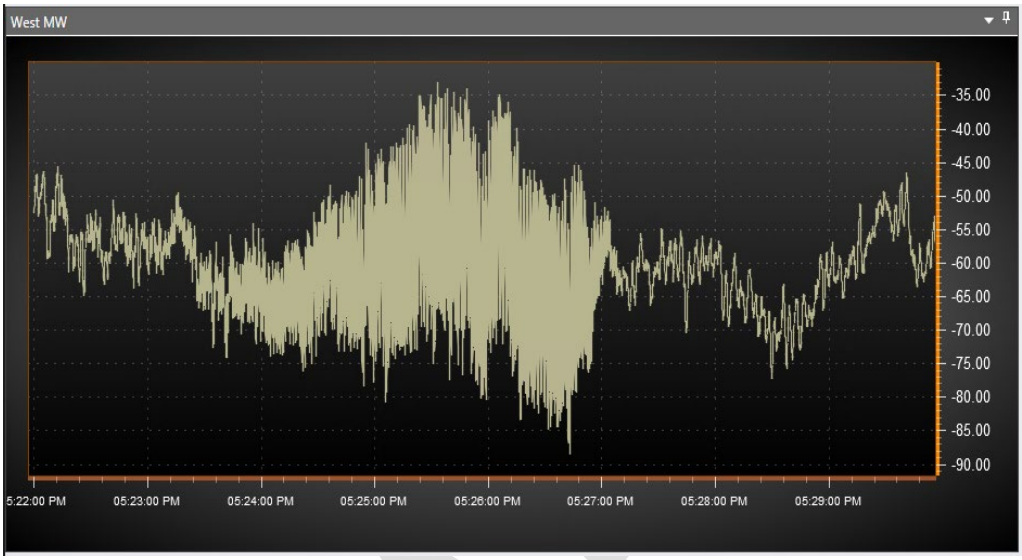


Figure 5.14: Forced Oscillation Observed on Line-Flows in SPP

On the other side of the spectrum, a mode meter is used to assess the current stability of known inter-area modes. The main outputs are the estimated damping ratio of the mode and the energy level of the composite signal used as an input to mode meter (SPP currently uses single angle pair composite signals). To assess the stability of the mode, only damping ratios are estimated and monitored in real-time. If the damping ratio of a mode drops below 3%, internal SPP software notifies the operator(s) of a potentially weakened mode. **Figure 5.15** shows an example of SPP's west mode meter display, showing the real-time states of the five main WI modes.

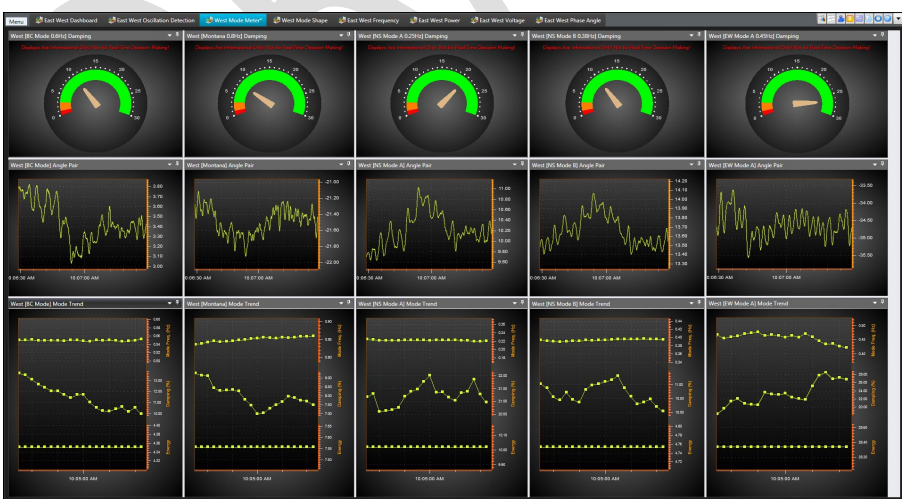


Figure 5.15: Mode Monitoring in SPP

SPP also uses the energy values in addition to damping ratio as a quasi-ODM for detecting system oscillations pertaining to a particular system mode. This can only be done with very careful signal choices for mode meter inputs. The basic premise is that current mode meters (not just in RTDMS) typically do not work well when a forced oscillation is happening and, in that event, will generally have damping ratio estimates drop dramatically and artificially to low levels (e.g., 0% to 3%). While there are currently fixes in place, this artifact can be exploited to our advantage. By coupling a low damping ratio percent with an energy threshold (like ODM, above typical ambient conditions), a mode meter can help operators and shift engineers assess whether there is an oscillation happening that pertains to a particular system mode whether that be an unstable mode causing growing oscillations or a case where a natural mode resonance happens. In both cases, estimated damping ratios drop and energy levels rise. **Figure 5.16** is an example conveying the concept as well as a real-use case. In addition, mode shapes are also plotted as another indicator to operators that a power system oscillation pertaining to a particular system mode is in effect.

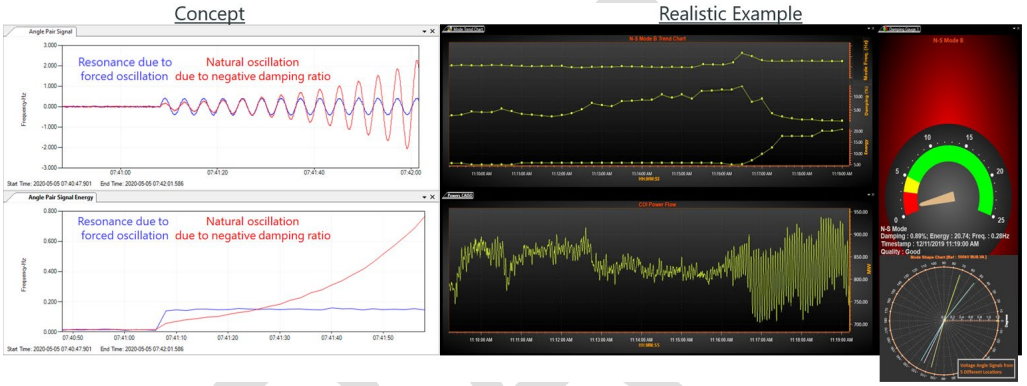


Figure 5.16: Mode Monitoring

5.6 American Electric Power (AEP)

Since early 2018, AEP has used PMU based applications for online oscillation analysis and offline event studies. Installed and maintained by AEP's protection and control team, field PMU units will stream high sampling data to an enhanced Phasor Data Concentrator (ePDC), which is a data repository. An ePDC will then dispatch PMU data streams to PhasorPoint in which real-time monitoring is enabled and alarms are generated and transmitted to energy management system (EMS) side. **Figure 5.17** illustrates the configuration of AEP's PMU system.

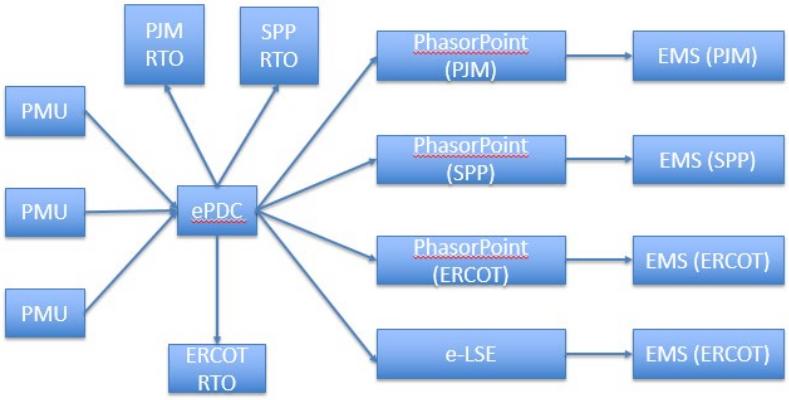


Figure 5.17: AEP's PMU Configuration

AEP has deployed close to 400 PMUs across its three footprints governed by PJM, SPP, and ERCOT. With the large amount of data accumulated, real-time oscillation event detection on frequency and active power was developed and deployed in control room to enhance situational awareness.

5.6.1 AEP Real-Time Oscillation Monitoring and Event Detection

Taking advantage of the high sampling rate of phasor measurement units, system dynamics are visualized and documented in PhasorPoint. The purpose of developing this event detection mechanism is to help control room personnel quickly identify harmful oscillations from common system variations. With online modal decomposition in PhasorPoint, system dynamics were decomposed in real time with oscillation magnitude and decay time as two critical metrics to measure the severity of the oscillation. The bigger the magnitude and longer the decay time, the more sever the oscillation will be. While it is preferred to avoid alarms on the small and quickly damped oscillations, the lingering ones with big swings are supposed to be caught by operators as quickly as possible.

With this purpose in mind, a kernel density estimation (KDE)-based methodology[45] was developed to detect oscillation events. In this methodology, a cross-validated KDE was adopted to regress historical oscillation data. As a result, a bi-variable probability density function was derived to summarize the distribution of documented oscillation data. Knowing that severe oscillatory disturbances are statistically rare, a cut-off probability initialized at three standard deviations above the mean was used to identify historical observations of oscillation events. With heuristic[46] training based on a historical event list, this cut-off probability would be finalized, and observations of past oscillation events were picked and located on Locus plot like shown in **Figure 5.18.**

[45] AEP's experience in Detecting and Analyzing Oscillation Events using PMU based applications - https://www.wecc.org/Administrative/09f_Lu_JSIS_AEP's_experience_in Detecting_and_Analyzing_Oscillation_Events_using_PMU based applications_May_2021.pdf

[46] In mathematical optimization and computer science, **heuristic** (from Greek εὑρίσκω "I find, discover") is a technique designed for solving a problem more quickly when classic methods are too slow, or for finding an approximate solution when classic methods fail to find any exact solution. This is achieved by trading optimality, completeness, accuracy, or precision for speed. In a way, it can be considered a shortcut.

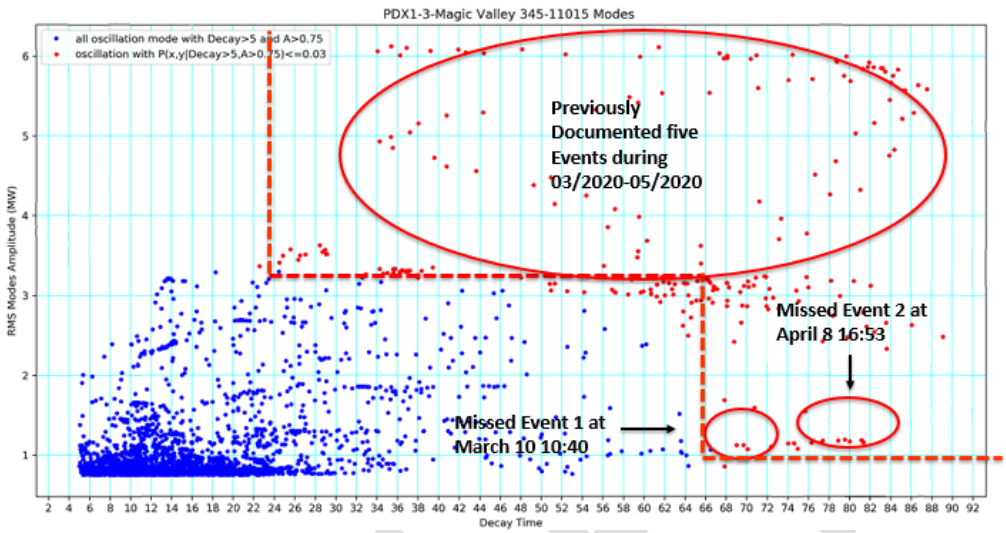


Figure 5.18: Locus Demonstration of Observations Representing an Oscillation Event

With all event observation labeled in red in Figure 5.18, the alarm settings concerning amplitude and decay time were configured. For the particular PMU signal demonstrated in Figure 5.18. Its finalized alarm configuration is listed in Table 5.1.

Table 5.1: Alarm Setting for PMU @ Magic Valley

	Decay Time Exclusion	Decay Time Threshold	Amplitude Exclusion	Amplitude Threshold
Alarm Setting	24 seconds	66 seconds	1MW	3.25MW

The alarm configurations obtained from KDE-based methodology were more reliable than the previous intuitive configurations. Historical event studies proved the method's enhanced sensitivity as the method could detect previously missed oscillation events. In addition, over one-year of control room deployment has verified long lasting reliability of the methodology as the rate of false alarms is significantly reduced. Table 5.2 is a performance overview on the KDE-based online event detection.

Table 5.2: Performance Overview of KDE-based event detection

Footprint	Production Deployment	False Alarm Count	False Alarm Rate (after)	False Alarm Rate (before)	Footprint
ERCOT	07/2020	<30	Around 6%	50+%	ERCOT
SPP	09/2020	<10	Less than 5%	45%–50%	SPP
PJM	10/2020	<20	Less than 5%	50+%	PJM

With the KDE-based event detection in place, all the oscillation events captured in PhasorPoint will be streamed in real-time to control room and documented in daily PMU reports for offline studies.

5.6.2 AEP Auto Daily PMU Report Implementation

In order to enhance the situational awareness of AEP's system for control rooms, the Daily PMU report is automatically generated as a pdf file and is archived in an internal shared folder. So far, this report includes information of the system average frequency and PMU data quality statistics and also lists the poor-quality PMUs that are in need of maintenance. In addition, the reports summarize the oscillation events and have the charts attached of event details, such as related PMU measurement waveform charts and oscillation mode information charts. More information and charts are planned to be included in future daily reports.

As shown in **Figure 5.19**, the daily reports are created by retrieving data through Phasorpoint SQL database via the Open Database Connectivity (ODBC) connector. Then python scripts have been written to access the SQL data to make necessary plots and tables, and a pdf file report containing all the information needed will be automatically generated by the script. The purpose of daily reports is~~are~~ to help operators and engineers have a better situational awareness of AEP's system operation. Therefore, three daily reports for each AEP's footprint (ERCOT, SPP, and PJM) are generated on a daily basis. So far, there are seven modules in the daily report that each cover the system frequency chart, the daily/monthly PMU data quality statistics pie chart, and the daily/monthly poor PMU quality list as well as the oscillation event summary list and detailed charts. Some examples of the charts in the AEP Daily PMU report are provided in **Figure 5.20–Figure 5.23**.

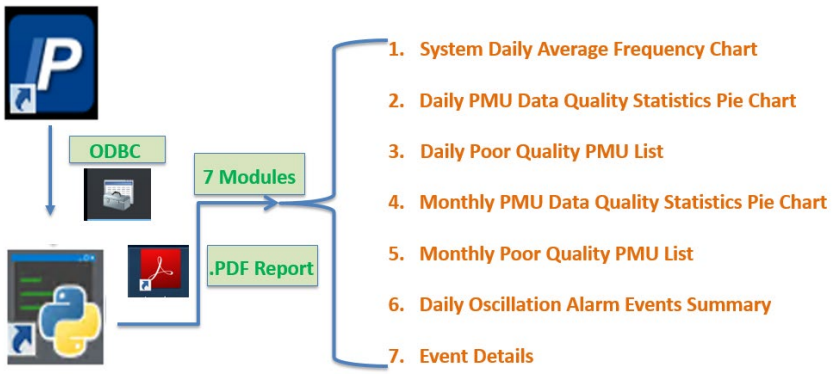


Figure 5.19: AEP Auto Daily PMU Report Deployment

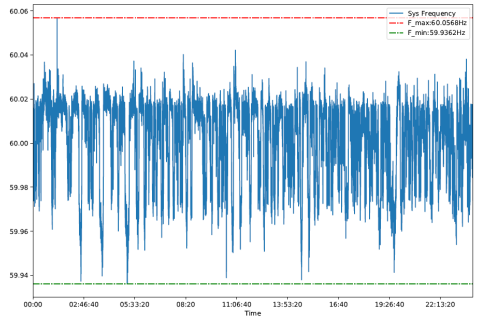


Figure 5.20: System Daily Average Frequency Chart

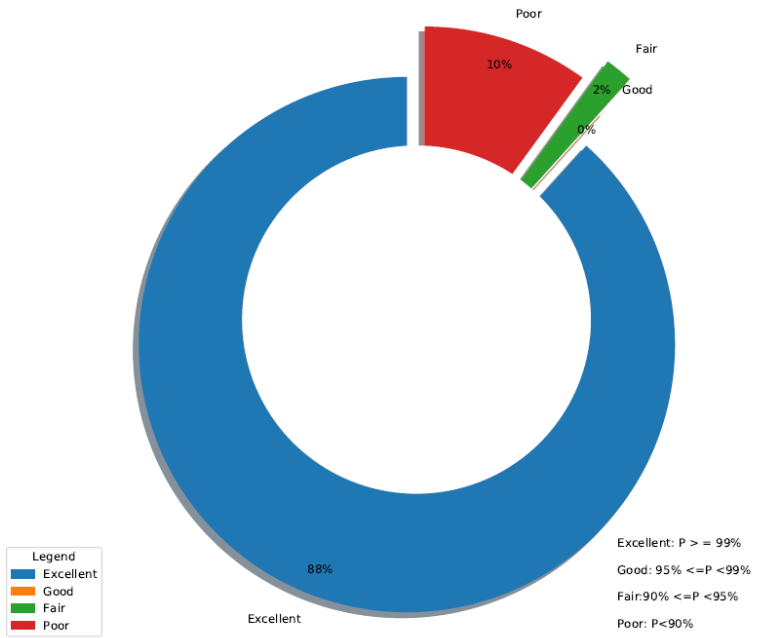


Figure 5.21: Daily PMU Data Quality Statistics

Index	Date	Time	measurement_group	measurement	parameter	message
1	2021-04-29	10:56:01	RH	12345 (ABC@RH)	P	PDX1-3 event status alarm

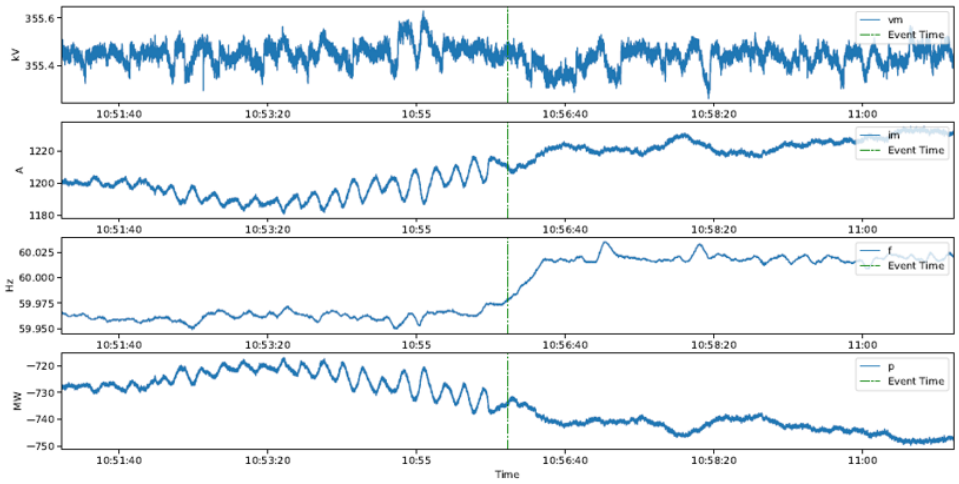


Figure 5.22: Event 1 PMU measurements

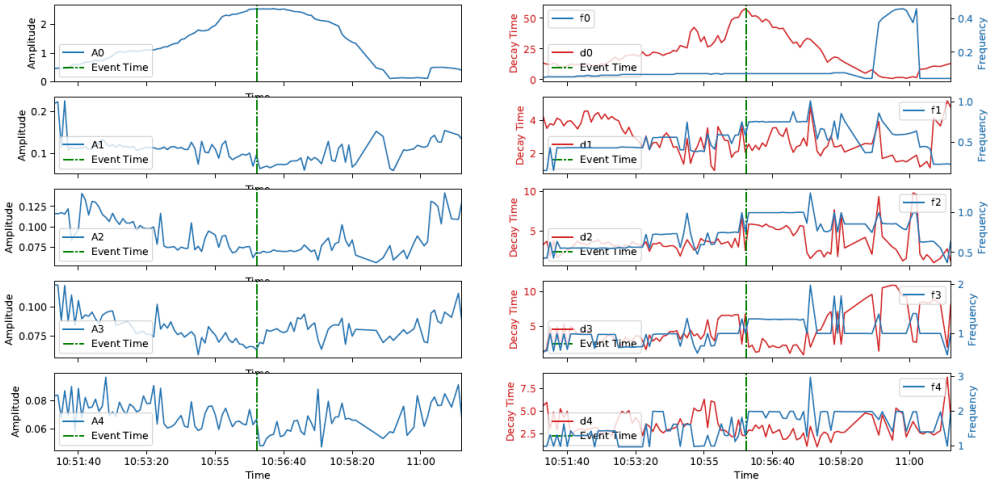


Figure 5.23: Event 1 Oscillation Mode

Appendix A: Determining the Impact of Forced Oscillations

This appendix describes through an example of how one can determine the impact of forced oscillations at frequencies closer to the inter-area modes that need to be monitored.

During the January 11, 2019, forced oscillation event, several EI GOs and System Operators set their plant AVRs to manual control and ramped down online pumped storage plants upon identifying the undamped oscillation. Following the event, there were questions on whether those were the appropriate actions and whether there were any other actions the operators could have taken to mitigate the event. This example describes how a wide-area resonant forced oscillation can be recreated in dynamic simulation and how possible mitigations can be tested. For simplicity, example simulations shown below were performed on a subset of the EI model that does not include a large enough area to capture the modes involved in the January 11, 2019, event.

Modeling of Forced Oscillations

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The source of the oscillation was a steam turbine in Florida that experienced 200 MW peak-to-peak oscillations due to controller failure causing the intercept valves to open and close every four seconds. As the intercept valves cyclically open and close, they increase and decrease the flow of steam through the turbine, effectively causing the mechanical power input to the generator to oscillate between full output and zero. To represent this controller failure in dynamic simulation, a user model is needed to oscillate a generator's mechanical power at a defined amplitude and frequency. The FORTRAN code for a Power System Simulation for Engineering (PSSE) user model, named "GOV_OSCILLATE," accomplishes this as shown in **Figure A.1**.

Without delving into the details of user model writing in PSSE, the inputs to this model are as follows:

- The machine number — I
- The amplitude and frequency of the mechanical power oscillation — CON(J) and CON(J+1)
- The initial mechanical power — STATE(K)
- No used variables (VARS) or integer constants (ICONS)

Each PSSE dynamic model performs various computations at different stages of the dynamic simulation:

- In Mode 1, dynamic models are initialized. The initial mechanical power is saved in the state variable, STATE(K).
- In Mode 3, governor type models must compute the current value of mechanical power and populate the mechanical power (PMECH) arrays. As shown in line 42 of **Figure A.1**, PMECH(I) is only modified if the simulation time is greater than 1 second. After 1 second, PMECH(I) is by the equation below:

$$P_{Mech} = P_{Mech\_Initial} + \frac{Amplitude}{MVA_{base}} * \sin[2\pi f(t-1)]$$

GOV_OSCILLATE_rev2.flx

```
      SUBROUTINE GOV_OSCILLATE(I,ISLOT)
C     Logic to add a 10 MW oscillation on Pmech at time >1s
C
      INCLUDE 'COMON4.INS'
C
      INTEGER I, ISLOT
C     I     = MACHINE ARRAY INDEX
C     ISLOT = ARRAY ALLOCTION TABLE INDEX
C             J = STRTIN(1, ISLOT) [ USES CON(J) AND CON(J+1) ]
C             K = STRTIN(2, ISLOT) [ USES STATE(K) ]
C
      INTRINSIC SIN
      INTEGER J, K
      REAL PMECH_INITIAL
C
      IF (MODE.EQ.8)
      .  CON_DSCRPT(1) = 'Amplitude'
      .  CON_DSCRPT(2) = 'Frequency'
      .  RETURN
      ...FIN
C
C  GET STARTING 'CON' INDICES
C
      J=STRTIN(1,ISLOT)
      K=STRTIN(2,ISLOT)
C
      IF (MODE .GT. 4) GO TO 1000
C
      GO TO (100,200,300,400), MODE
C
C MODE = 1: INITIALIZE
C
 100  STATE(K) = PMECH(I)
      RETURN
C
C MODE = 2: CALCULATE DERIVATIVES
C
 200  RETURN
C
C MODE = 3: SET PMECH
C
 300  IF (TIME .GT. 1) THEN
          PMECH(I) = STATE(K) + CON(J)*SIN(6.2832*CON(J+1)*(TIME-1))/MBASE(I)
      END IF
      RETURN
C
C MODE = 4: SET NINTEG
C
 400  NINTEG=MAX(NINTEG,K+1)
      RETURN
C
 1000 RETURN
      END
```

Figure A.1: PSSE USER Model to Create Forced Oscillation

After compiling the FORTRAN code in Figure 2.4 and creating a *.dll file the user model can be utilized using the statement in Figure A.2. The highlighted variables indicate that the model should be applied to machine 1 at bus 4, the amplitude of oscillation is 100MW (200 MW peak-to-peak), and the frequency of oscillation is 0.67hz. The other parameters are required for PSSE to classify it as a Turbine-Governor model and reserve the necessary space in the ICONS, CONS, STATES, and VARS arrays.

TP4_gov_oscillate_rev.dyr | GOV_OSCILLATE_rev2.flx

```
4 'USRMDL' 1 'GOV_OSCILLATE' 5 0 0 2 1 0 100 0.67 /
```

Figure A.2: User Model Calling Statement

Figure A.3 shows the mechanical power of a unit that this model is applied to.

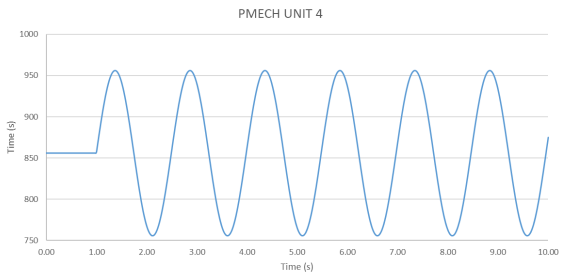

Figure A.3: Mechanical Power for Source of Forced Oscillation

Modeling Wide-area Resonant Forced Oscillations

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The previous section described how a forced oscillation in mechanical power with a defined amplitude and frequency can be applied to any machine in a PSSE dynamic case. However, there are three conditions required for wide-area resonant forced oscillations:

- A source oscillating at a frequency close to a system mode
- The system mode is poorly damped
- The source is near a strong participation location of that system mode

An essential step to simulating wide-area resonant forced oscillations is to identify natural system modes that are poorly damped and determine which units strongly participate in those modes. Software packages, such as PSSE's SINCAL or Power Tech's SSAT, can be used to perform eigenvalue analysis. The software packages take the load flow and dynamic models as inputs and then provide a list of natural modes within a specified frequency range (e.g., 0.1–2 Hz). The poorly damped modes should be further analyzed to determine their mode shape and participation factors. This will illustrate which source location will most excite the poorly damped modes and which areas of the grid will experience higher oscillations.

Figure A.4 and **Figure A.5** demonstrate how wide-area resonant forced oscillations can be simulated. Eigenvalue analysis was used to identify a lightly damped natural system mode with a frequency of 0.67 Hz, that unit 4 strongly participates. **Figure 2.7** shows system variables throughout a wide area when Unit 4 experiences a cyclical failure at 0.25 Hz. The first condition for resonant forced oscillations is not well satisfied and the wide-area impact is minimal. **Figure 4.1** shows the same variables when Unit 4 experiences a cyclical failure at 0.67 Hz, such that all three conditions for resonant forced oscillations are well satisfied. The electrical power oscillations on Unit 4 are higher than the mechanical power oscillations indicating amplification or resonance. The difference between a local forced oscillation and a wide-area resonant forced oscillation is clearly demonstrated by observing oscillations in frequency and power throughout the system. Even the mode shape can be verified by observing which units oscillate against each other.

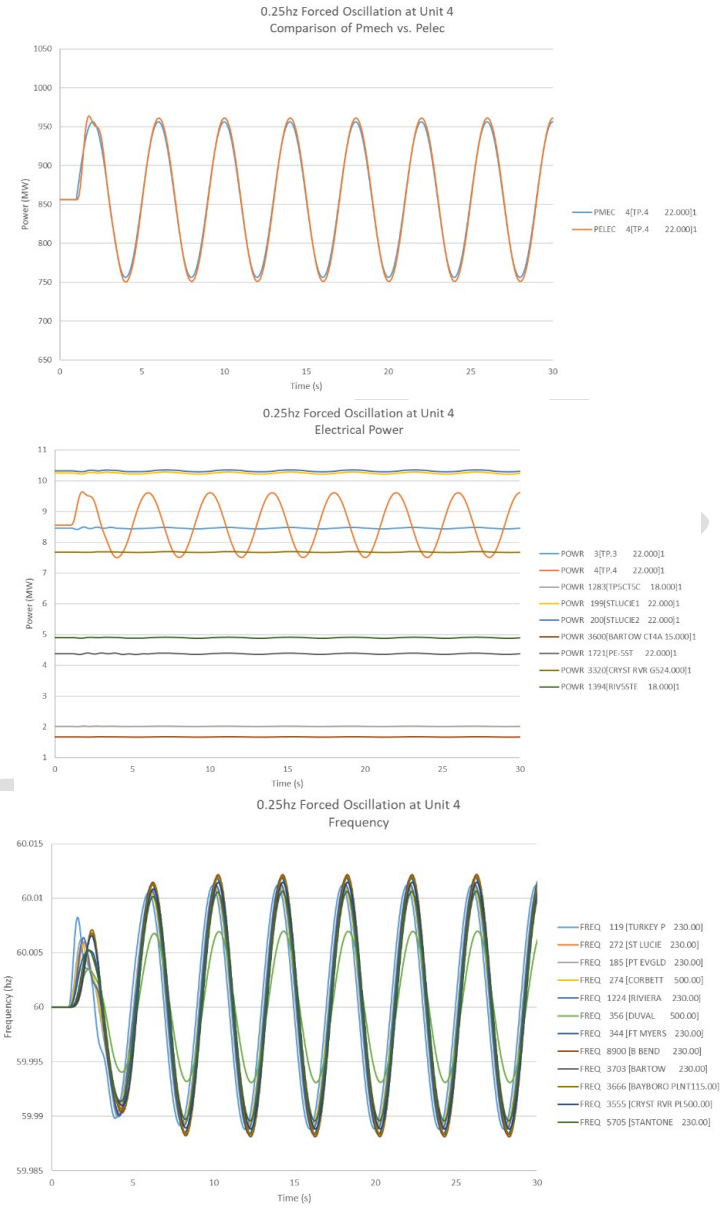

Figure A.4: Local Forced Oscillation

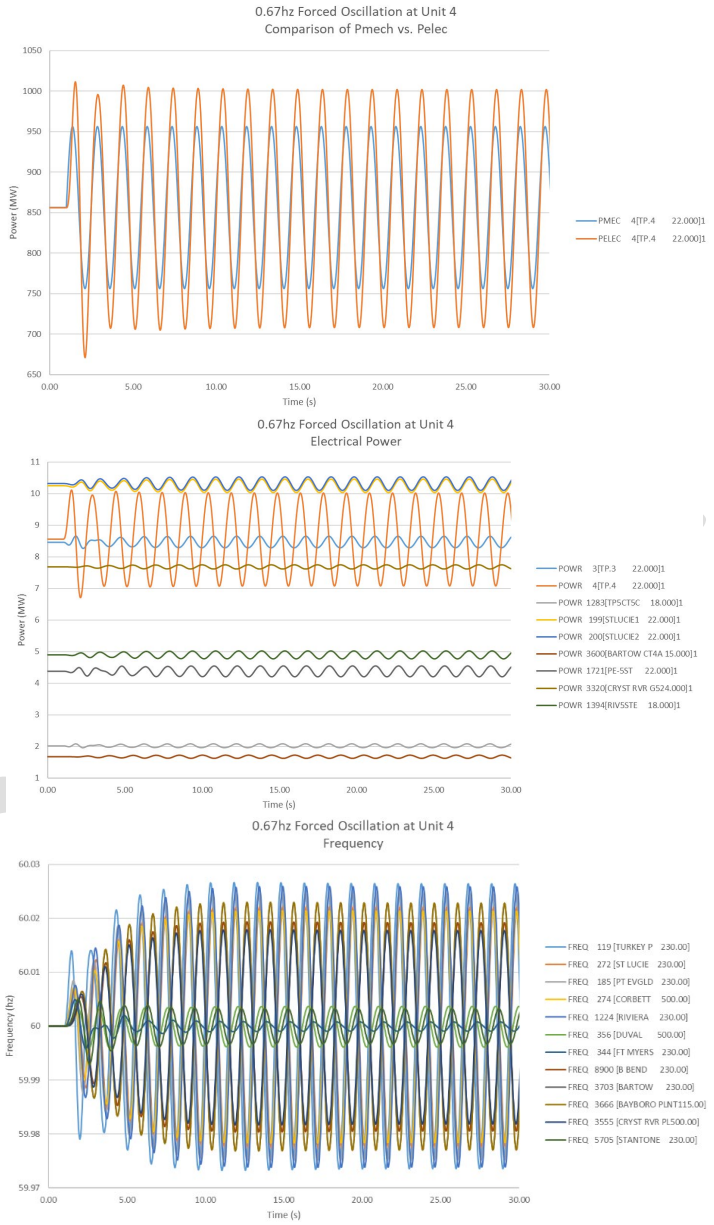

Figure A.5: Wide-Area Resonant Forced Oscillation

Appendix B: Contributors

NERC would like to thank all members of the NERC SMWG for their participation and guidance in developing this report. The following list of contributors were involved in the development of this report.

Table B.1: Contributors	
Name	**Entity**
Aftab Alam	California Independent System Operator
Jim Follum	Pacific Northwest National Laboratory
Jeff Dagle	Pacific Northwest National Laboratory
Urmila Agrawal	Pacific Northwest National Laboratory
Backer Abu-Jaradeh	Electric Power Group
Neeraj Nayak	Electric Power Group
Ken Martin	Electric Power Group
Slava Maslennikov	ISO New England
Arif Khan	Schweitzer Engineering Laboratories, Inc.
Ryan Lott	Southwest Power Pool
Ryan Elliot	Sandia National Labs
Andrew Arana	Florida Reliability Coordinating Council
Mani V. Venkatasubramanian	Washington State University
Hassan Ghoudjehbaklou	San Diego Gas and Electric
Sarma (NDR) Nuthalapati	Dominion Energy
Ron Markham	Pacific Gas and Electric
Michael (Ziwen) Yao	British Columbia Hydro
Frederic Howell	Powertech Labs Inc.
Bob Cummings	Red Yucca Power Consulting
Yidan Lu	American Electric Power
Feng Tu	American Electric Power
Yuan Kong	American Electric Power
Gang Zheng	GE Digital
Maddipour Mohammadreza	GE Digital
Austin White	Oklahoma Gas and Electric
Hongming Zhang	National Renewal Energy Laboratory
Alex Ning	Avangrid
Ashley Donahoo	Bonneville Power Administration
Yi Hu	Quanta Technology
Tim Fritch (SMWG Chair)	Tennessee Valley Authority
Frankie Zhang (SMWG Vice Chair)	ISO New England
Ryan Quint	North American Electric Reliability Corporation

Event Analysis Subcommittee Membership

Action
Approve

Summary
The EAS Scope document calls for RSTC approval of its membership. The EAS has a vacancy for the NPCC Regional Industry Representative. The EAS proposes Bill Temple (Avangrid) to fill the seat and is requesting RSTC approval.

RSTC Work Plan, RISC Report Recommendations and Joint FERC/NERC Cold Weather Report Recommendations

Action
Information

Summary
At the September RSTC meeting, the RISC Report recommendations were reviewed and a Tiger Team formed to review the RISC Report recommendations and the Joint FERC/NERC Cold Weather Report recommendations to create or modify RSTC work plan items to address the recommendations. The Tiger Team is providing a status update as well as a plan to coordinate with RSTC subgroups to review risks and develop mitigation activities and work plan items for future RSTC approval.

EMP Working Group Update

Action
Information

Summary
Chair Shaw will provide some of the current thinking on EMP Vulnerability Assessments as well as other EMPWG subteam's work plans. The intent of this presentation is to brief the RSTC members on the overall EMP project.

Nominating Subcommittee (NS) Update

Action
Information

Summary
The NS will report on upcoming activities and timelines for At-Large nominees to fill RSTC terms ending in 2022 as well as other At-Large vacancies.

Odessa Disturbance Report and Odessa Disturbance Follow-Up Document

Action
Approve

Summary
NERC Staff developed an in-depth review of the Odessa Disturbance with a report published by NERC in October 2021. Presenters will provide a detailed review of the event along with a summary of a brief white paper that was developed by the IRPWG as a follow-up to the disturbance report. That report contained a set of key findings and recommendations. The IRPWG discussed each of the key findings and recommendations in detail, and is providing a brief technical discussion and technical basis for each recommendation. Where appropriate, follow-up action items are identified. Table 1 shows the recommendations and actions needed from Chapter 3 of the NERC disturbance report on the left-hand column and the IRPWG follow-up and recommendations for each item in the right-hand column. The IRPWG has developed a follow up document with recommendations on this subject and is seeking RSTC approval.

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Odessa Disturbance Follow-Up

NERC Inverter-Based Resource Performance Working Group (IRPWG) White Paper – October 2021

This brief white paper was developed by the NERC Inverter-Based Resource Performance Working Group (IRPWG) as a follow-up to the ~~May and October 2021~~ Odessa Disturbance Report published by NERC in October 2021.[1] That report contained a set of key findings and recommendations. The IRPWG discussed each of the key findings and recommendations in detail~~,~~ and is providing a brief technical discussion and technical basis for each recommendation. Where appropriate, follow-up action items are identified. Table 1 shows the recommendations and actions needed from Chapter 3 of the NERC disturbance report on the left-hand column and the IRPWG follow-up and recommendations for each item in the right-hand column.

The following are the recommended actions from the IRPWG review:

1. FERC and NERC should collaboratively modernize the interconnection study process and applicable NERC Reliability Standards to ensure that 1) the recommendations outlined in the reliability guidelines are effectively and consistently converted to performance requirements for inverter-based resources. These requirements should not be overly burdensome nor discriminatory, yet should be clear, detailed, and effective in ensuring that developers, equipment manufacturers, and GOs understand the performance requirements needed to ensure reliable operation of the BPS moving forward.
2. IRPWG will develop standard authorization requests (SARs) related to a number of existing standards and possibly the addition of new standards to address the issues described below.
3. IRPWG will conduct a comprehensive assessment, taking into consideration the guidelines and reference documents developed thus far, to determine any performance gaps not addressed by the NERC Reliability Standards and will provide recommendation for additional SARs, where applicable. This assessment will also specifically evaluate the need for any inverter-specific performance requirements language.

[1] https://www.nerc.com/pa/rrm/ea/Documents/Odessa_Disturbance_Report.pdf

4. IRPWG will continue to develop guidelines, technical reference documents, and white papers to support industry advancements in the reliable integration of BPS-connected inverter-based resources. IRPWG will also support any other activities needed to advance industry efforts and help modernize and improve the process in which these resources are interconnected, modeled, studied, analyzed, and operated.

Table 1: Review of Disturbance Report Findings and Recommendations

#	Recommendation	IRPWG Follow-Up
Improved Requirements and Processes		
1	**Adoption of Reliability Guidelines:** While the IRPWG reliability guidelines are~~or~~ some of the most downloaded guidelines produced and most widely used across the industry, it is clear that industry is not adopting the recommendations contained within NERC reliability guidelines. GOs, GOPs, developers, and equipment manufacturers should adopt the performance recommendations provided in the NERC reliability guidelines. All TOs should establish (or improve) clear and consistent interconnection requirements for BPS-connected inverter-based resources to support the implementation of the NERC FAC-001-3 standard.	IRPWG has put a significant amount of time, effort, and expertise into developing clear recommended practices for industry in the areas of inverter-based resource performance, modeling, and studies. It is reassuring that industry is well-aware of the guidelines and that they are having a positive impact on industry efforts to-date. However, it is clear that the guidelines are not being adopted comprehensively due to numerous challenges related to the development of connection requirements, modifications to TOs' transmission tariffs, and other factors. Clear, consistent, and comprehensive performance requirements that are fair, just, and reasonable are strongly needed. Unclear requirements (lack of specificity and detail) has led to significant confusion by industry as they continue interconnecting new technologies, which have led to many different issues across the multiple NERC disturbance reports published. In most cases, the causes for solar PV reduction have been previously documented in reliability guidelines seeking improvements to correct the performance issues; however, the issues continue to occur (and new ones are being identified) because the guidelines are not being widely implemented. This needs to be addressed by a regulatory framework change. IRPWG supports a modernization and revamping of the performance requirements for inverter-based resources (and all generating resources) to ensure clarity, consistency, and minimal compliance burden. Either or both updates to the NERC reliability standards or improvements to the FERC generator interconnection process are needed to facilitate this modernization. **Recommended Action from IRPWG Follow-Up:** IRPWG has not identified a specific follow-up action item for this recommendation; however, IRPWG is willing to support ~~and~~ advancements in this area moving forward (see rows below).
2	**Improvements to Interconnection Process:** As stated, the NERC reliability guidelines are not being widely adopted in a comprehensive manner, leaving gaps in reliable interconnection of BPS-connected inverter-based resources. Significant improvements are needed to the FERC Generator Interconnection Process (GIP) and Generator Interconnection Agreement (GIA) that include comprehensive requirements that must be met during the interconnection process. These requirements should be clear, consistent, and ensure reliable operation of these resources prior to commercial operation of the facility. Presently, plants are being interconnected in an unreliable manner with inadequate studies to appropriately identify these issues ahead of commercial operation. These issues need to be addressed in the GIP and GIA, and they should not be left up to individual interconnecting TOs to address using only the NERC FAC-001-3 requirements.	

Table 1: Review of Disturbance Report Findings and Recommendations		
#	Recommendation	IRPWG Follow-Up
NERC Standards Updates Needed to Address Performance Gaps in Inverter-Based Resources		
	Significant NERC Standards Updates Needed Related to Performance: The systemic nature of these events across multiple interconnections and a wide range of facilities, many of which are recently energized, warrants significant enhancements to the NERC Reliability Standards to address gaps in BES inverter-based resources. As reported in this disturbance report (and building on past reports published by NERC), the following recommendations are provided. The NERC RSTC should facilitate and ensure the development of SARS to address each of the following issues:	See rows below.
3	• **Performance Validation Standard Needed:** TOPs, RCs, BAs (in coordination with the TP and PC) should have the capability to seek corrective actions to plants that are not performing adequately based on the requirements imposed on them at the time of interconnection. Any abnormal performance identified in real-time should be compared against the models provided during time of interconnection (or any material modification to the facility) as well as based on a comparison of any applicable interconnection requirements in place. Abnormalities in plant performance should be reported to NERC and the Regional Entity and should be corrected by the GO in a timely manner. Persistent deviations of performance from expectations are not acceptable.	IRPWG has repeatedly highlighted the criticality of TOs improving their interconnection requirements per FAC-001-3. IRPWG published NERC Reliability Guideline: Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources, which strongly recommends all TOs adopt the detailed recommendations laid out in their interconnection requirements. As industry continues to make improvements to their requirements, they need a clear and consistent means of ensuring that the requirements are adhered to and that corrective actions are taken if any abnormal performance is identified. In essence, a closed loop feedback is needed to ensure that those corrective actions are taken when abnormalities are identified. **Recommended Action from IRPWG Follow-Up:** IRPWG will develop a SAR regarding revisions to FAC-001-3 and FAC-002-2 to ensure that: 1) TOPs, RCs, and BAs that identify abnormal performance issues can work with the GO to seek corrective actions for resources not meeting their established interconnection requirements, 2) seek improvements to the requirements developed by the TO, TP, or PC (per FAC-001-3 or FAC-002-2) if gaps are identified, and 3) that those abnormal performance issues are reported to NERC for continued risk assessment.
4	• **Ride-Through Standard to Replace PRC-024-3:** The original intent of the PRC-024 standard was to ensure that plants remain connected to the BPS during frequency and voltage excursions. This was approved only as a protective relaying	IRPWG submitted a SAR seeking improvements to PRC-024-2 (resulting in PRC-024-3); however, it is clear from the Odessa disturbance and other disturbances that resources are tripping for issues outside the scope of PRC-024-3 and that further action is needed to address a reliability gap in resource performance. The Odessa Disturbance Report outlines the challenges and misinterpretation with the existing standard. IRPWG has observed similar

Table 1: Review of Disturbance Report Findings and Recommendations		
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	standard, but then caused significant confusion for inverter-based resource controls and protection within the individual inverters. Additionally, the events analyzed by NERC regarding fault-induced reductions in solar PV output and wind output have identified issues with controls and protections unrelated to voltage and frequency. For example, PLL loss of synchronism, sub-cycle ac overvoltage protection, dc reverse current, and wind converter crowbar failure are all examples of widespread tripping that are not addressed by PRC-024-3. Furthermore, industry continues to misinterpret PRC-024-3 and continues to set seemingly unnecessary voltage and frequency protection within facilities "for compliance reasons" even though the standard was updated to address this confusion. The growing evidence leads NERC to recommend that a ride-through standard focusing specifically on generator ride-through performance should be developed and implemented on an expedited timeline.	issues over the years and supports the enhancement of PRC-024-3 to a generator[2] protection and control ride-through standard. The standard should not specifically focus on generator auxiliary bus protection; rather, the protection and controls on the generator and collection system (GSU, collector system, etc.) should be in scope to ensure resources ride through normal grid events. The standard should be written in a performance-based manner, and not focus specifically on documentation. Resources failing to ride through normal grid disturbances should be identified and corrective actions should be implemented. IEEE P2800 activities can serve as a useful reference but should not be considered a replacement for this standard. **Recommended Action from IRPWG Follow-Up:** IRPWG will develop a SAR regarding revisions to PRC-024-3 to the effect described above, focusing specifically on all forms of ~~the~~ protection and controls of the generator and collection systems associated with the resource (not auxiliary systems). The SAR will ensure that PRC-024 revisions focus on a performance-based approach to resource ride-through for the plant rather than on only focusing on the protection system documentation alone.
5	• **Analysis and Reporting for Abnormal Inverter Operations:** Inverter-based resource power reductions of more than 75 MW in aggregate per facility should be analyzed and reported. While this may not be the present intent of the PRC-004 standard, the standard scope should be extended (or another standard introduced) to ensure that abnormal power reductions are analyzed, reported, and corrected in a timely manner. Ongoing, persistent tripping or reductions in inverter-based resources is the present situation and should not be considered acceptable.	As identified in multiple NERC disturbance reports, generator owners of solar PV facilities are often unaware of abnormal performance of the resource; however, when many resources are systemically performing abnormally, the BA, TOP, or RC will identify an event and report it to NERC if it meets the Category 1i criteria (or other applicable criteria). This approach does not ensure proactive mitigation of abnormal inverter-based resource performance issues before they elevate to a large disturbance. Therefore, IRPWG supports the extension of analysis and reporting of resource performance issues identified by the TOP, RC, or BA in an effort to seek better performance from inverter-based resources moving forward. **Recommended Action from IRPWG Follow-Up:** IRPWG will develop a SAR regarding either revisions to PRC-004 or a new standard that focuses specifically on analyzing, reporting, and correcting the abnormal performance of BES generating resources. These revisions may link

[2] This includes generator-specific protection and controls such as on machines and on inverters, and also includes plant-level protection and controls on the feeder/collector lines and at the plant-level controller.

Table 1: Review of Disturbance Report Findings and Recommendations		
#	Recommendation	IRPWG Follow-Up
		with those identified above regarding the performance validation standard. Both topics may be accomplished with a singular SAR.
6	• **Monitoring Data:** NERC should ensure that recording at all BES inverter-based resources includes plant-level high resolution oscillography data, plant SCADA data with a resolution of 1-second, sequence of events recording for all inverters that include all fault codes, and at least one inverter on each collector system configured to capture high resolution oscillography data within the inverter. These are standard features for modern inverters that should be enabled within all facilities to better understand their response to grid events and improve overall fleet performance. The Project 2021-04 Standard Drafting Team should consider whether these recommendations are within scope and adopt as possible. Otherwise, a future standards project should address this issue.	IRPWG has published reliability guidelines seeking these same monitoring capabilities from all newly connecting BPS-connected inverter-based resources. IRPWG submitted a SAR for PRC-002-2 seeking improvements to ensure sufficient monitoring capability is available. **Recommended Action from IRPWG Follow-Up:** IRPWG will engage the Project 2021-04 Standard Drafting Team leadership to determine if any of the recommendations are within scope of their project. IRPWG will develop a follow-on SAR if any recommendations outlined in the Odessa report are not being adopted by the SDT presently.
7	• **Inverter-Specific Performance Requirements:** The NERC IRPWG conducted an assessment of existing NERC Reliability Standards that should be updated to ensure clarity and consistency for inverter-based resources; however, the assessment did not comprehensively consider performance characteristics specific to inverter-based resources that should be addressed by a NERC Reliability Standard. This assessment should be conducted by the NERC IRPWG and any necessary SARs should be produced through the RSTC: ○ As one example, the absence of return to service timing requirements established consistently by BAs has introduced unexpected and anomalous behavior from inverter-based resources when returning from "minor faults" that trip the facility off-line. Furthermore, the lack of specifications around return-to-service could introduce challenges and complexity for RCs and TOPs in the	The IRPWG published an inverter-based resource performance guideline in 2018 which was one of the drivers for the IEEE P2800 efforts presently underway. IRPWG has supported the advancement in standardization of resource performance from inverter-based resources as they become a prominent component of the generation mix. Improving levels of standardization, and clear and consistent performance requirements for these resources (where needed) will help ensure reliable operation of the BPS moving forward. **Recommended Action from IRPWG Follow-Up:** IRPWG will conduct a comprehensive assessment, considering all guidelines and technical reference documents developed thus far, including IEEE P2800, to determine any performance gaps not addressed by the NERC Reliability Standards and will provide recommendation for additional SARs, where applicable.

Table 1: Review of Disturbance Report Findings and Recommendations		
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	event of a widespread outage conditions during blackstart recovery. Industry is not adhering to the recommendations in the NERC guideline and this should be addressed in a standard or within the FERC GIA. ○ Having inverter-specific requirements or standards has been considered by the SAR Drafting Teams focused on revisions to MOD-025, PRC-019, MOD-026, and MOD-027 given there are differences and unique characteristics of inverter-based resources that do not directly relate to synchronous generation.	
NERC Standards Updates Needed to Address Modeling and Studies Gaps for Inverter-Based Resources		
8	**Requirements for Accurate EMT Models at Time of Interconnection:** The existing NERC FAC-001 and NERC FAC-002 standards provide too much leverage and have led to inconsistency in how TPs and PCs are gathering modeling information and conducting interconnection studies. As the penetration of inverter-based resources is growing across North America, all TPs and PCs should have clear requirements to gather EMT models at the time of interconnection and execute EMT studies to ensure proper ride-through performance for BPS fault events. Presently, the approaches taken by industry are leading to modeling and study gaps and consequently unreliable performance of inverter-based resources once interconnected. The FAC-001 and FAC-002 standards more clearly align with the FERC GIP and GIA to clearly specify the models required and the studies to be conducted at the time of interconnection.	IRPWG has talked in depth about the need for improved EMT modeling capabilities and included detailed recommendations for improvements to interconnection requirements to gather accurate EMT models during the time of interconnection. IRPWG supports updates to interconnection requirements to ensure accurate EMT models are provided during the interconnection process. Further, EMT models are increasingly being required during the interconnection process; however, there is insufficient time with the pro forma GIP timelines to conduct adequate EMT studies. This has led to significant complications in the study process in areas of high penetrations of inverter-based resources. **Recommended Action from IRPWG Follow-Up:** IRPWG will develop a SAR to incorporate EMT modeling (and model validation) requirements and EMT study requirements for the interconnection study process. FAC-002-2 will be reviewed to determine the best strategy for incorporating these types of requirements. IRPWG will also develop a white paper specifically aimed at policy makers to clarify EMT modeling considerations and trade-offs as planning groups begin to adopt EMT into their planning processes.
9	**Update to NERC MOD-032 to Include EMT:** The NERC MOD-032 standard is used by TPs and PCs to ensure appropriate models for performing system studies are provided by equipment and data owners. Presently, it is unclear how EMT models are treated in this standard and this lack of clarity needs to be addressed with a	Industry has had significant challenges with the implementation of MOD-032, particularly around how to use models being validated under MOD-025, MOD-026, and MOD-027. IRPWG submitted SARs seeking improvements to those standards but did not address issues with MOD-032. Presently, MOD-032 is silent with respect to the collection of EMT models for any large-scale studies. Further, MOD-032 can be improved to ensure that the appropriate

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	standard revision. EMT models should be made available by GOs to ensure system studies are conducted in the planning horizon for growing levels of inverter-based resources, not just for newly interconnecting facilities. Larger-scale EMT studies will likely be needed in the future as penetration levels continue to rise.	models are provided during the annual case creation processes. While EMT modeling is still relatively new to many entities, it is becoming widely used and needed in many areas with high penetrations of inverter-based resources. To prepare for a future with significantly more inverter-based resources on the BPS, IRPWG support efforts towards ensuring that the modeling efforts and case creation processes provide clarity on how to handle EMT models. In situations where the TP or PC need the ability to develop a large-scale EMT model, they need to have the authority and capability to do so for reliability study purposes. The recommendation by NERC for ERCOT to conduct a system-wide model validation using EMT models (see ERCOT-specific recommendations in the Disturbance Report) is an excellent example of the need for collecting these models. **Recommended Action from IRPWG Follow-Up:** IRPWG will develop a SAR to ensure that EMT modeling is included in the MOD-032 efforts and that MOD-032 is clear on using accurate and validated models.
10	**Updates to Ensure Model Quality Checks and Model Improvements:** GOs need to provide accurate models to the TPs and PCs based on existing requirements. A feedback loop to ensure model accuracy (for any type of model) is only an optional specification in the existing MOD-032 standard. Model quality checks should be conducted by all TPs and PCs, and any modeling errors should be addressed by the equipment owner (i.e., the GO) in a timely manner. Model quality reviews should include more than just model usability—they should check for model parameterization issues or inconsistencies against plant performance to real events.	These issues also stem from complexities during the interconnection study process and the need for more transparent modeling practices and model quality checks conducted by the TP and PC. Without conducting model quality checks, TPs and PCs are running studies with models fraught with errors, which has led to resources operating in an unreliable manner (as observed in the Odessa disturbance). These issues need to be corrected, and TPs and PCs should be conducting detailed model quality and model performance checks during the interconnection study process and during annual planning assessments. Any models errors identified should be corrected. **Recommended Action from IRPWG Follow-Up:** IRPWG will develop a SAR to ensure that model quality and model performance checks are conducted during the interconnection study process (FAC-002-2) and annual case creation process (MOD-032), and that model improvements are made by the generator owner. Those checks should clearly include model parameter validation to ensure that the models actually reflect the as-built equipment in the field.
ERCOT Recommended Actions		
IRPWG did not review the ERCOT-specific recommendations.		

FERC - NERC - Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and the South Central United States

Action
Information

Summary
This report describes the severe cold weather event occurring between February 8 and 20, 2021 and how it impacted the reliability of the bulk electric system ("BES" or colloquially known as the grid) in Texas and the South Central United States (hereafter known as "the Event"). During the Event, extreme cold temperatures and freezing precipitation led 1,045 individual BES generating units, (with a combined 192,818 MW of nameplate capacity) in Texas and the South Central United States to experience 4,124 outages, derates or failures to start. Each individual generating unit could, and in many cases, did, have multiple outages from the same or different causes. To provide perspective on how significant the generating unit outages were, including generation already on planned or unplanned outages, the Electric Reliability Council of Texas (ERCOT) averaged 34,000 MW of generation unavailable (based on expected capacity) for over two consecutive days, from 7:00 a.m. February 15 to 1:00 p.m. February 17, equivalent to nearly half of its all-time winter peak electric load of 69,871 MW.