TEXAS RE
Ensuring electric reliability for Texans

Texas Reliability Entity, Inc.
Texas RE Member Representatives Committee
Meeting Agenda

September 17, 2025, at 9:30 a.m. Central Time**
Virtual Meeting

WebEx Link:
https://texasre.webex.com/texasre/j.php?MTID=mf93a7b3833495af731eee23a298938ff

Call-In: 1-855-797-9485

Item	Member Representatives Committee Meeting
1.	**Call to Order** *Daniela Hammons, MRC Vice-Chair*
2.	**Antitrust Admonition*** *Thad Crow, Communications and Training Coordinator*
3.	**Approval of May 14, 2025, Meeting Minutes* (Vote)** *Daniela Hammons, MRC Vice-Chair*
4.	**NERC BOT Meeting Update** *Daniela Hammons, MRC Vice Chair*
5.	**Election of MRC Sector Representatives*** *Matthew Barbour, Manager, Communications & Training*
6.	**SAR-013 Revision to BAL-001-TRE-2 Update* (Vote)** *Rachel Coyne, Executive Chief of Staff*
7.	**Special Topics:** a. IBRWG Activities* *Julia Matevosyan, IBRWG Chair* b. Iberian Blackout* *Dan Woodfin, ERCOT*
8.	**NSRF Update*** *Chris Seaman*
9.	**CIPWG Update*** *Trevor Tidwell*
10.	**NERC Standing Committee Updates:** a. NERC Reliability and Security Technical Committee* *Venona Greaff* b. NERC Compliance and Certification Committee* *Daniela Hammons*
11.	**NERC Program Area Reports:** *(Staff may not present on these reports, but will be available to answer questions)* a. NERC Program Area Overview *Joseph Younger, Vice President and Chief Operating Officer*

	b. Compliance Assessments Report and Risk Assessment Report* *Kenath Carver, Director, Compliance Assessments* c. Enforcement Report and Registration Report* *Katie Van Zee, Director, Enforcement and Registration* d. Reliability Services Report* *David Penney, Director, Reliability Services* e. Standards Report* *Rachel Coyne, Executive Chief of Staff*
12.	**Other Business & Future Agenda Items** *Daniela Hammons, MRC Vice-Chair*
	Adjourn Meeting

* Background material may be distributed electronically prior to or at meeting.
** Start and end times may be adjusted should meetings conclude early or extend past their scheduled end time.

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Antitrust Compliance Reminder

Because this event brings together market participants who may be viewed as actual or potential competitors, we must be mindful to conduct it in a manner that is consistent with the antitrust and competition laws. Participants should not disclose non-public, proprietary, or competitively sensitive information.

Attendees should exercise independent judgment and avoid even the appearance of discussions of agreements or concerted actions that may be viewed as restraining competition. For example, avoid discussions regarding current or potential vendors or suppliers that involve sensitive information like pricing or terms, or discussions involving employee wages or hiring decisions. Any company decisions that are informed by your discussions today must be made independently.

This guidance is not intended as legal advice, and each attendee is responsible for seeking their own legal advice with respect to compliance with applicable antitrust and competition laws. However, any questions on Texas RE's Antitrust Compliance Corporate Policy may be directed to Texas RE's General Counsel.

Member Representatives Committee Meeting
May 14, 2025

Attendance

1. **The attendees were as follows:**

Name	Company	Sector	In Person	Virtual
Curt Brockmann, Chair	CPS Energy	Municipal	X	
Daniela Hammons, Vice Chair	CenterPoint Energy Houston Electric, LLC	Transmission/Distribution	X	
Chad Thompson	ERCOT	System Coord & Planning	X	
Brandon Gleason (Alternate)	ERCOT	System Coord & Planning		
Lance Spross	Oncor Electric Delivery Company, LLC	Transmission/Distribution	X	
Frank Owens	Rayburn Electric Co-op	Cooperative	X	
Shari Heino	Brazos Electric Power Cooperative	Cooperative		
Brock Carter	Austin Energy	Municipal	X	
Cameron Zahn (Alternate)	Denton Municipal Electric	Municipal		X
Rob Robertson	Leeward Renewable Energy	Generation	X	
Kristina Marriott	Miller Bros. Solar	Generation		X
Jeremy Carpenter	Tenaska Power Services, Inc.	Load Serving & Marketing	X	
Venona Greaff	Occidental Power Services, Inc.	Load Serving & Marketing	X	
Jeffrey A. Corbett	Texas RE Board Chair		X	
Suzanne Spaulding	Texas RE Board Vice Chair		X	
Crystal E. Ashby	Texas RE Independent Director		X	
Milton B. Lee	Texas RE Independent Director		X	
Thomas Gleeson	Public Utility Commission of Texas			
Benjamin Barkley	OPUC			
Jim Albright	Texas RE		X	
Joseph Younger	Texas RE		X	
Derrick Davis	Texas RE		X	
Donna Bjornson	Texas RE		X	
Bill Carroll	Texas RE		X	

Kenath Carver	Texas RE		X	
Mark Henry	Texas RE		X	
Kara Murray	Texas RE		X	
David Penney	Texas RE		X	
Kaitlin Van Zee	Texas RE		X	
Paul Curtis	Texas RE		X	
Matthew Barbour	Texas RE		X	
Rachel Coyne	Texas RE		X	
Chris Seaman	Rayburn Electric		X	
Trevor Tidwell	TNMP		X	
Other Texas RE staff members and stakeholders attended in person and via conference call				

At least two-thirds of the voting representatives on the MRC, either in person or by proxy, are required to constitute a quorum. A quorum was established.

Discussions and Activities

2. **Call to Order, Announce Proxies and Telephone Attendees; Antitrust Admonition**

Curt Brockmann called the MRC meeting to order at 9:00 a.m. Central Time. There were no proxies. Thad Crow reviewed the antitrust admonition.

3. **Approval of February 19, 2025, and April 17, 2025, MRC Meeting Minutes**

Venona Greaff made a motion to approve the February 19, 2025, and April 17, 2025, meeting minutes. Chad Thompson seconded the motion. The Motion passed by unanimous voice vote.

4. **NERC BOT Meeting Update**

Curt Brockmann gave the NERC Board of Trustees (BOT) update. He said the Board approved updated Regional Delegation Agreements with the Regional Entities and adopted revisions to the EOP-012-2 Reliability Standard.

5. **SAR-013 Revision to BAL-001-TRE-2 Standard Drafting Team Approval**

Rachel Coyne, Executive Chief of Staff, provided a progress update on the SAR-013 Revision to BAL-001-TRE-2. She said the Standard Drafting Team had scheduled three meetings and was working diligently on the project.

6. Special Topics

Devin Ferris, Manager, CIP Compliance Monitoring, presented on the 2025 Cloudstrike Global Threat Report.

Kyle Thomas, Vice President – Engineering & Compliance Services, Elevate Energy Consulting, presented on Large Loads.

7. NSRF Update

Chris Seaman, NSRF Chair, reported on the February, March, and April NSRF meetings. Meeting topics included transmission planning and modeling, integration of large loads, and PRC-027 coordination of protection systems during faults.

8. CIPWG Update

Trevor Tidwell, CIPWG Chair, provided an update on CIPWG activities. He said that the working group received a closed briefing from E-ISAC in May.

9. NERC Standing Committee Updates

Venona Greaff provided updates on the NERC Reliability and Security Technical Committee's recent meetings, including approval of a reliability guideline.

Vice Chair Hammons provided an update on the Compliance and Certification Committee's meeting. She said the CCC discussed CMEP and ORCP reports, discussed CMEP enhancements, and received a NERC Internal Audit update.

10. Program Area Quarterly Reports

Joseph Younger, Vice President and Chief Operating Officer, discussed issues concerning inverter based resources, transmission planning and modeling, and remote connectivity.

Texas RE staff provided written program area quarterly reports and were available to answer questions.

11. Other Business & Future Agenda Items

None.

The meeting adjourned at approximately 10:58 a.m. Central Time.

Membership Update

Member Representatives Committee Meeting

September 17, 2025

Public

2025 Membership Registration and Renewal

Texas RE Membership Perks:

- Vote to approve Texas RE Bylaws, Independent Directors for the Board of Directors, and MRC Sector representatives

Renewal for Current Members:

- Complete the Membership Form

Application for New Members:

- Complete the Membership Form
- Sign the Membership Agreement

Public

Recent and Upcoming Membership Votes

September 2025:
- Crystal Ashby and Jeffrey Corbett: Independent Directors

November 2025:
- Each primary and alternate representative for the 2026-27 MRC

January 2026:
- Chair and vice chair for the 2026-27 MRC

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MEMORANDUM

To:	Texas RE Member Representatives Committee
From:	Rachel Coyne, Executive Chief of Staff
Date:	September 17, 2025
Re:	Item 06 - Request Approval for Posting Project SAR-013: Revisions to Regional Standard BAL-001-TRE-2

I am requesting the MRC approve the Work Product for Project SAR-013 for a 45-day public comment and 15-day ballot period for proposed Regional Standard BAL-001-TRE-3. The following are included for the MRC's consideration:

- Updated Work plan
- Draft Regional Standard BAL-001-TRE-3, including Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs)
- Draft implementation plan
- Description of Revisions

Background

On June 28, 2024, ERCOT submitted a Regional Standard Authorization Request (SAR) to revise Texas RE's Regional Standard BAL-001-TRE-2. The MRC accepted the SAR as a project during its September 18, 2024, meeting.

The SAR consisted of three objectives:

- Include a provision that allows any generation resource that is not qualified to provide Operating Reserves to widen the resource's Governor deadband to +/- 0.036 Hz upon confirmation from the Balancing Authority (BA).
- Clarify the roles of the Generator Owner (GO), Compliance Enforcement Authority (CEA), and the BA as they pertain to the Compliance Monitoring Period and Reset Time Frame (Section C: 1.2) in regards to resetting the 12-month rolling average Primary Frequency Response (PFR) performance score.
- Define PFR performance requirements for Battery Energy Storage Systems (BESS).

SDT Activities after May MRC Meeting

The SDT held an all-day hybrid work session on June 6, 2025, to discuss PFR performance requirements for Battery Energy Storage Systems (BESS). Subsequently, the SDT performed the quality review and prepared the documents for the MRC and public posting.

I am happy to answer any questions regarding the status of the SAR-013 project.

SAR-013: Revisions to Regional Standard BAL-001-TRE-2 Project Update

Member Representatives Committee Meeting
September 17, 2025

Request for Approval

Request for the MRC to approve for a 45-day public comment and ballot period:

- **Draft Regional Standard BAL-001-TRE-3, including Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs)**
- **Draft implementation plan**

Public

Additional Documents for Reference

Updated Work Plan

Description of Revisions

Standard Authorization Request

Include a provision that allows any generation resource that is not qualified to provide Operating Reserves to widen the resource's Governor deadband to +/- 0.036 Hz upon confirmation from the Balancing Authority (BA).

Clarify the roles of the Generator Owner (GO), Compliance Enforcement Authority (CEA), and the Balancing Authority (BA) as they pertain to the Compliance Monitoring Period and Reset Time Frame (Section C: 1.2) regarding resetting the 12-month rolling average Primary Frequency Response (PFR) performance score.

Define PFR performance requirements for Battery Energy Storage Systems (BESSs).

Standard Drafting Team Activity (May-September)

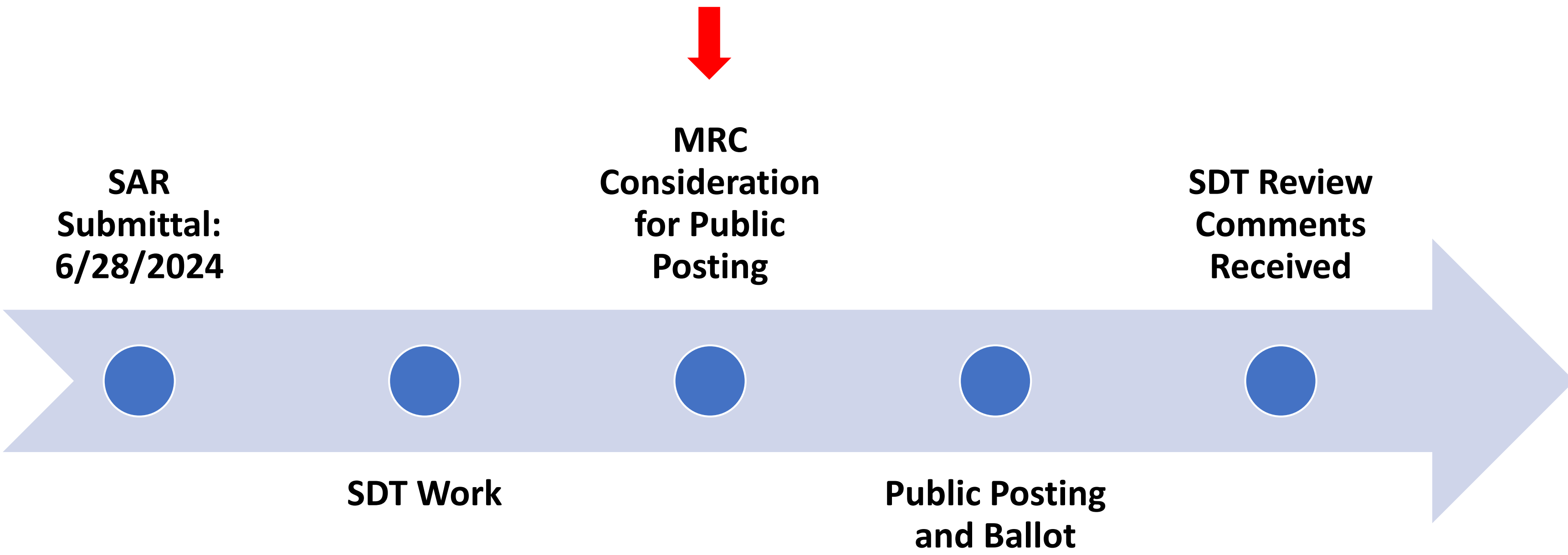
June 6, 2025, hybrid meeting to draft the work product

- Revisions to Section C1.2 Compliance Monitoring Period and Reset Time Frame
- Revisions to Requirement R6 (widen Governor deadband)
- BESS Language
- Revisions to Primary Frequency Response Reference Document

SDT approved the language by July 2, 2025

July - August 2025: quality review performed

SAR-013 Timeline



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Work Plan
Project SAR-013 Revisions to Regional Standard BAL-001-TRE-2

The Standard Drafting Team (SDT) and the Manager, Reliability Standards Program (RSM) developed the following work plan for Project SAR-013 Revisions to Regional Standard BAL-001-TRE-2. This work plan lays out the steps for revising Regional Standard BAL-001-TRE-2 in accordance with Texas RE's Regional Standards Development Process (RSDP) document.

Milestone	Anticipated Date	Location	Comments
Standard Drafting Team Kick-off Meeting • The SDT shall elect the permanent chair and vice chair.	12/19/2024	Conference Call	
RSM and SDT develop a work plan.	1/21/2025	Conference Call	
SDT has first working meeting • SDT drafts the work product	2/7/2025	Conference Call	
Work plan delivered to the MRC.	2/19/2025	Hybrid MRC Meeting at Texas RE	
Subsequent SDT meeting(s) to draft the work product	Q2 2025	Conference Call/Possible Hybrid Meeting	
MRC approves the work product to be posted for a public comment and ballot period.	9/17/2025	Conference Call or Hybrid MRC Meeting at Texas RE	
The RSM shall post the work product for a 45-day public comment period with the ballot period occurring in the last 15 days.	9/22/2025 – 11/6/2025	N/A	
The RSM shall send a notice for registered entities to join the Registered Ballot Pool (RBP).	9/22/2025	N/A	
The SDT shall meet to discuss comments received within 30 days of the conclusion of the posting period. During the meeting, the SDT shall: • prepare responses to comments received; and • prepare a "modification report".	November - December 2025	Conference Call/Possible Hybrid Meeting	

Placeholder for second comment period if necessary.	Q1 2026	N/A	
When the ballot passes in accordance with section 4.12 and 4.13, the RSM shall conduct a final ballot.	Q1 2026*	N/A	
Once the final ballot final ballot, the MRC shall approve the final Work Product to be provided to the Texas RE Board for action.	Q1 2026	Conference Call or Hybrid MRC Meeting at Texas RE	
The Work Product shall be posted at least seven days prior to action by the Texas RE Board.	Q1 2026	N/A	
If deemed appropriate, the Texas RE Board will adopt the work product.	Q1 2026	Conference Call or Hybrid Board Meeting at Texas RE	
The RSM will submit the work product to NERC.	Q1 2026	N/A	
Once the Work Product is approved by FERC, the RSM shall send notification of the effective date to Texas RE stakeholders.	TBD	N/A	

*This and all subsequent dates will be later in 2026 if there is an additional comment and ballot period.

A. Introduction

1. **Title:** Primary Frequency Response in the ERCOT Region
2. **Number:** BAL-001-TRE-3
3. **Purpose:** To maintain Interconnection steady-state frequency within defined limits.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Generator Owners

   4.1.3 Generator Operators

   4.2. Exemptions

   4.2.1 Existing generating facilities regulated by the U.S. Nuclear Regulatory Commission prior to the Effective Date are exempt from Standard BAL-001-TRE-3.

   4.2.2 Generating units/generating facilities while operating in synchronous condenser mode are exempt from Standard BAL-001-TRE-3.

   4.2.3 Any generators that are not required by the Balancing Authority to provide primary frequency response are exempt from this standard.

5. **Effective Date:** See Implementation Plan for Regional Standard BAL-001-TRE-3.
6. **Background:** The ERCOT Interconnection was initially given a waiver of BAL-001 R2 (Control Performance Standard CPS2). In FERC Order 693, NERC was directed to develop a Regional Standard as an alternate means of assuring frequency performance in the ERCOT Interconnection. NERC was explicitly directed to incorporate key elements of the existing Protocols, Section 8.5. This required governors to be in service and performing with an un-muted response to assure an Interconnection minimum Frequency Response to a Frequency Measurable Event (FME) (that starts at t(0)).

   This Regional Standard provides requirements related to identifying Frequency Measurable Events, calculating the Primary Frequency Response of each resource in the Region, calculating the Interconnection minimum Frequency Response and monitoring the actual Frequency Response of the Interconnection, setting Governor deadband and droop parameters, and providing Primary Frequency Response performance requirements.

   Under this standard, two Primary Frequency Response (PFR) performance measures are calculated: “initial” and “sustained”. The initial PFR performance (R9) measures the actual response compared to the expected response in the period from 20 to 52 seconds after an FME starts. The sustained PFR performance (R10) measures the best actual response between 46 and 60 seconds after t(0) compared to the expected response based on the system frequency at a point 46 seconds after t(0).

In this Regional Standard the term “resource” is synonymous with “generating unit/generating facility/battery energy storage system (BESS)”.

B. Requirements and Measures

R1. The Balancing Authority shall identify Frequency Measurable Events (FMEs), and within 14 calendar days after each FME the Balancing Authority shall notify the Compliance Enforcement Authority and make FME information (time of FME (t(0)), pre-perturbation average frequency, post-perturbation average frequency) publicly available. *[Violation Risk Factor – Lower] [Time Horizon – Operations Assessment]*

M1. The Balancing Authority shall have evidence that it reported each FME to the Compliance Enforcement Authority and that it made FME information publicly available within 14 calendar days after the FME as required in Requirement R1.

R2. The Balancing Authority shall calculate the Primary Frequency Response of each generating unit/generating facility/BESS in accordance with this standard and the Primary Frequency Response Reference Document.[1] This calculation shall provide a 12-month rolling average of initial and sustained Primary Frequency Response performance. This calculation shall be completed each month for the preceding 12 calendar months. *[Violation Risk Factor = Lower] [Time Horizon = Operations Assessment]*

2.1. The performance of a combined cycle facility will be determined using an expected performance droop of 5.78%.

2.2. The calculation results shall be submitted to the Compliance Enforcement Authority and made available to the Generator Owner by the end of the month in which they were completed.

2.3. If a generating unit/generating facility/BESS has not participated in a minimum of (8) eight FMEs in a 12-month period, its performance shall be based on a rolling eight FME average response.

[1] Attachment 1: Primary Frequency Response Reference Document contains the calculations that the Balancing Authority will use to determine Primary Frequency Response performance of generating units/generating facilities/BESS. This reference document is a Texas RE-controlled document that is subject to revision by the Texas RE Board of Directors.

M2. The Balancing Authority shall have evidence it calculated and reported the rolling average initial and sustained Primary Frequency Response performance of each generating unit/generating facility/BESS monthly as required in Requirement R2.

R3. The Balancing Authority shall determine the Interconnection minimum Frequency Response (IMFR) in December of each year for the following year, and make the IMFR, the methodology for calculation and the criteria for determination of the IMFR publicly available. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

M3. The Balancing Authority shall demonstrate that the IMFR was determined in December of each year per Requirement R3. The Balancing Authority shall demonstrate that the IMFR, the methodology for calculation and the criteria for determination of the IMFR are publicly available.

R4. After each calendar month in which one or more FMEs occur, the Balancing Authority shall determine and make publicly available the Interconnection's combined Frequency Response performance for a rolling average of the last six (6) FMEs by the end of the following calendar month. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M4. The Balancing Authority shall provide evidence that the rolling average of the Interconnection's combined Frequency Response performance for the last six (6) FMEs was calculated and made public per Requirement R4.

R5. Following any FME that causes the Interconnection's six-FME rolling average combined Frequency Response performance to be less than the IMFR, the Balancing Authority shall direct any necessary actions to improve Frequency Response, which may include, but are not limited to, directing adjustment of Governor deadband and/or droop settings. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M5. The Balancing Authority shall provide evidence that actions were taken to improve the Interconnection's Frequency Response if the Interconnection's six-FME rolling average combined Frequency Response performance was less than the IMFR, per Requirement R5.

R6. Each Generator Owner shall set its Governor parameters as follows:

6.1. Limit Governor deadbands within those listed in Table 6.1, unless directed otherwise by the Balancing Authority.

Table 6.1 Governor Deadband Settings

Generator Type	Max. Deadband
Steam and Hydro Turbines with Mechanical Governors	+/- 0.034 Hz
Generating Units that are not qualified [2] to provide Operating Reserves and have obtained prior approval from the Balancing Authority to widen their deadband settings	+/- 0.036 Hz
All Other Generating Units/Generating Facilities/BESS[3]	+/- 0.017 Hz

6.2. Limit Governor droop settings such that they do not exceed those listed in Table 6.2, unless directed otherwise by the Balancing Authority.

Table 6.2 Governor Droop Settings

Generator Type	Max. Droop % Setting
Hydro	5%
Combustion Turbine (Simple Cycle and Single-Shaft Combined Cycle)	5%
Combustion Turbine (Combined Cycle)	4%
Steam Turbine[4]	5%
Diesel	5%
BESS	5%
DC Tie Providing Ancillary Services	5%
Variable Renewable (Non-Hydro)	5%

[2] Refers to ancillary service qualification criteria as required by the Balancing Authority.

[3] Requirements R6.1, R6.2, and R6.3 are not applicable to steam turbine(s) of a combined cycle resource.

[4] Requirements R6.1, R6.2, and R6.3 are not applicable to steam turbine(s) of a combined cycle resource.

6.3. For digital and electronic Governors, once frequency deviation has exceeded the Governor deadband from 60.000 Hz, the Governor setting shall follow the slope derived from the formula below.

Where

For 5% Droop: $$\text{Slope} = \frac{MW_{GCS}}{(3.0\ Hz - Governor\ Deadband\ Hz)}$$

For 4% Droop: $$\text{Slope} = \frac{MW_{GCS}}{(2.4\ Hz - Governor\ Deadband\ Hz)}$$

MW_{GCS} is the maximum megawatt control range of the Governor control system. For mechanical Governors, droop will be proportional from the deadband by design. See Attachment 1: Primary Frequency Response Reference Document for specific calculations. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M6. Each Generator Owner shall have evidence that it set its Governor parameters in accordance with Requirement R6. Examples of evidence include but are not limited to:

- Governor test reports
- Governor setting sheets
- Performance monitoring reports

R7. Each Generator Owner shall operate each generating unit/generating facility/BESS that is connected to the interconnected transmission system with the Governor in service and responsive to frequency when the generating unit/generating facility/BESS is online and released for dispatch, unless the Generator Owner has a valid reason for operating with the Governor not in service and the Generator Operator has been notified that the Governor is not in service. *[Violation Risk Factor = Medium] [Time Horizon = Real-time Operations]*

M7. Each Generator Owner shall have evidence that it notified the Generator Operator as soon as practical each time it discovered a Governor not in service when the generating unit/generating facility/BESS was online and released for dispatch. Evidence may include but not be limited to: operator logs, voice logs, or electronic communications.

R8. Each Generator Operator shall notify the Balancing Authority as soon as practical but within 30 minutes of the discovery of a status change (in service, out of service) of a Governor. *[Violation Risk Factor = Medium][Time Horizon = Real-time Operations]*

M8. Each Generator Operator shall have evidence that it notified the Balancing Authority within 30 minutes of each discovery of a status change (in service, out of service) of a Governor.

R9. Each Generator Owner shall meet a minimum 12-month rolling average initial Primary Frequency Response performance of 0.75 on each generating unit/generating facility/BESS, based on participation in at least eight FMEs. See Attachment 1: Primary Frequency Response Reference Document for specific calculations.

9.1. The initial Primary Frequency Response performance shall be the ratio of the Actual Primary Frequency Response to the Expected Primary Frequency Response during the initial measurement period following the FME.

9.2. If a generating unit/generating facility/BESS has not participated in a minimum of eight FMEs in a 12-month period, performance shall be based on a rolling eight-FME average.

9.3. A generating unit/generating facility's/BESS initial Primary Frequency Response performance during an FME may be excluded from the rolling average calculation by the Balancing Authority due to a legitimate operating condition that prevented normal Primary Frequency Response performance. Examples of legitimate operating conditions that may support exclusion of FMEs include, but are not limited to:

- Operation at or near auxiliary equipment operating limits (such as boiler feed pumps, condensate pumps, pulverizers, and forced draft fans);
- Data telemetry failure. The Balancing Authority may request raw data from the Generator Owner as a substitute.

[Violation Risk Factor = Medium] [Time Horizon = Operations Assessment]

M9. Each Generator Owner shall have evidence that each of its generating units/generating facilities/BESS achieved a minimum rolling average of initial Primary Frequency Response performance level of at least 0.75 as described in Requirement R9. Each Generator Owner shall have documented evidence of any FMEs where the generating unit performance was excluded from the rolling average calculation.

R10. Each Generator Owner shall meet a minimum 12-month rolling average sustained Primary Frequency Response performance of 0.75 on each generating unit/generating facility/BESS, based on participation in at least eight FMEs. See Attachment 1: Primary Frequency Response Reference Document for specific calculations. *[Violation Risk Factor = Medium] [Time Horizon = Operations Assessment]*

10.1. The sustained Primary Frequency Response performance shall be the ratio of the Actual Primary Frequency Response to the Expected Primary Frequency Response during the sustained measurement period following the FME.

10.2. If a generating unit/generating facility/BESS has not participated in a minimum of eight FMEs in a 12-month period, performance shall be based on a rolling eight- FME average.

10.3. A generating unit/generating facility's/BESS sustained Primary Frequency Response performance during an FME may be excluded from the rolling average calculation by the Balancing Authority due to a legitimate operating condition that prevented normal Primary Frequency Response performance. Examples of legitimate operating conditions that may support exclusion of FMEs include, but are not limited to:

- Operation at or near auxiliary equipment operating limits (such as boiler feed pumps, condensate pumps, pulverizers, and forced draft fans);
- Data telemetry failure. The Balancing Authority may request raw data from the Generator Owner as a substitute.

M10. Each Generator Owner shall have evidence that each of its generating units/generating facilities/BESS achieved a minimum rolling average of sustained Primary Frequency Response performance of at least 0.75 as described in Requirement R10. Each Generator Owner shall have documented evidence of any Frequency Measurable Events where generating unit performance was excluded from the rolling average calculation.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Compliance Monitoring Period and Reset Time Frame: If a generating unit's/generating facility's/BESS's rolling average for R9 or R10 falls below the required minimum rolling average(s) performance level, and the CEA has approved the GO's mitigation activities, the GO may initiate a request to the CEA to reset the rolling average(s). If the CEA approves the request to reset the rolling average(s), the CEA shall notify the BA that the GO may begin a new rolling average(s). In the CEA's notice to the BA, the CEA shall provide the BA with an effective date of the reset time for the rolling average(s). Upon receipt of the notice from the CEA, the BA shall, as soon as practicable, implement the change to the GO's rolling average(s). The first performance during an FME following the CEA's effective date to the BA shall count as the first event in the rolling average(s), and the entity will have an average frequency performance score after 12 successive months or eight events under Requirements R9 and R10 of the Regional Standard.

1.3. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Balancing Authority, Generator Owner, and Generator Operator shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Balancing Authority shall retain a list of identified FMEs and shall retain FME information since its last compliance audit for Requirement R1, Measure M1.
- The Balancing Authority shall retain all monthly PFR performance reports since its last compliance audit for Requirement R2, Measure M2.
- The Balancing Authority shall retain all annual IMFR calculations, and related methodology and criteria documents, relating to time periods since its last compliance audit for Requirement R3, Measure M3.
- The Balancing Authority shall retain all data and calculations relating to the Interconnection's combined Frequency Response performance, and all evidence of actions taken to increase the Interconnection's combined Frequency Response performance, since its last compliance audit for Requirements R4 and R5, Measures M4 and M5.
- Each Generator Operator shall retain evidence since its last compliance audit for Requirement R8, Measure M8.
- Each Generator Owner shall retain evidence since its last compliance audit for Requirements R6, R7, R9 and R10, Measures M6, M7, M9 and M10.

If an entity is found non-compliant, it shall retain information related to the non-compliance until found compliant, or for the duration specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent records.

1.4. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Balancing Authority reported an FME more than 14 days but less than 31 days after identification of the event.	The Balancing Authority reported an FME more than 30 days but less than 51 days after identification of the event.	The Balancing Authority reported an FME more than 50 days but less than 71 days after identification of the event.	The Balancing Authority reported an FME more than 70 days after identification of the event.
R2.	The Balancing Authority submitted a monthly report more than one month but less than 51 days after the end of the reporting month.	The Balancing Authority submitted a monthly report more than 50 days but less than 71 days after the end of the reporting month.	The Balancing Authority submitted a monthly report more than 70 days but less than 91 days after the end of the reporting month.	The Balancing Authority failed to submit a monthly report within 90 days after the end of the reporting month.
R3.	The Balancing Authority did not make the calculation and criteria for determination of the IMFR publicly available.	The Balancing Authority did not make the IMFR publicly available.	The Balancing Authority did not calculate the IMFR for the following year in December.	The Balancing Authority did not calculate the IMFR for a calendar year.
R4.	N/A	N/A	The Balancing Authority did not make public the six-FME rolling average Interconnection combined Frequency Response by the end of the following month.	The Balancing Authority did not calculate the six- FME rolling average Interconnection combined Frequency Response for any month in which an FME occurred.

R5.	N/A	N/A	N/A	The Balancing Authority did not take action to improve Frequency Response when the Interconnection's rolling-average combined Frequency Response performance was less than the IMFR.
R6.	Any Governor parameter setting was > 10% and ≤ 20% outside setting range specified in R6.	Any Governor parameter setting was > 20% and ≤ 30% outside setting range specified in R6.	Any Governor parameter setting was > 30% and ≤ 40% outside setting range specified in R6.	Any Governor parameter setting was > 40% outside setting range specified in R6, – OR – an electronic or digital Governor was set to step into the droop curve.
R7.	N/A	N/A	N/A	The Generator Owner operated with its Governor out of service and did not notify the Generator Operator upon discovery of its Governor out of service.
R8	The Generator Operator notified the Balancing Authority of a change in Governor status between 31 minutes and one hour after the General Operator was	The General Operator notified the Balancing Authority of a change in Governor status more than 1 hour but within 4 hours after the Generator Operator was	The Generator Operator notified the Balancing Authority of a change in Governor status more than 4 hours but within 24 hours after the Generator	The Generator Operator failed to notify the Balancing Authority of a change in Governor status within 24 hours after the Generator Operator was notified of the discovery of the change.

	notified of the discovery of the change.	notified of the discovery of the change.	Operator was notified of the discovery of the change.	
R9	A Generator Owner’s rolling average initial Primary Frequency Response performance per R9 was < 0.75 and ≥ 0.65.	A Generator Owner’s rolling average initial Primary Frequency Response performance per R9 was < 0.65 and ≥ 0.55.	A Generator Owner’s rolling average initial Primary Frequency Response performance per R9 was < 0.55 and ≥ 0.45.	A Generator Owner’s rolling average initial Primary Frequency Response performance per R9 was < 0.45.
R10	A Generator Owner’s rolling average sustained Primary Frequency Response performance per R10 was < 0.75 and ≥ 0.65.	A Generator Owner’s rolling average sustained Primary Frequency Response performance per R10 was < 0.65 and ≥ 0.55.	A Generator Owner’s rolling average sustained Primary Frequency Response performance per R10 was < 0.55 and ≥ 0.45.	A Generator Owner’s rolling average sustained Primary Frequency Response performance per R10 was < 0.45.

D. Regional Variances

None

E. Associated Documents

Regional Standard BAL-001-TRE-3 Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	8/15/2013	Adopted by NERC Board of Trustees	
1	1/16/2014	FERC Order issued approving BAL-001-TRE-1. (Order becomes effective April 1, 2014.)	
2	12/11/2019	Approved by Texas RE Board of Directors	Removed the requirement Governor droop and deadband settings for Steam Turbine(s) of combined cycle resources. Edited Requirements R9.3 and R10.3 to reflect the current process and legitimate operating conditions for submitting an FME exclusion request. Removed Attachment 1, which is the implementation plan for Regional Standard BAL-001-TRE-1.
3			Include a provision that allows any generation resource that is not qualified to provide Operating Reserves to widen the resource's Governor deadband to +/- 0.036 Hz upon confirmation from the Balancing Authority (BA). Clarify the roles of the Generator Owner (GO), Compliance Enforcement Authority (CEA), and the BA as they pertain to the Compliance Monitoring Period and Reset Time Frame (Section C: 1.2) in regard to resetting the 12-month rolling average

			Primary Frequency Response (PFR) performance score. Define PFR performance requirements for Battery Energy Storage Systems (BESS).

Standard Attachments

1. Attachment 1 – Primary Frequency Response Reference Document, including Flow Charts A and B.

    a. This document provides implementation details for calculating Primary Frequency Response performance as required by Requirements R2, R9, and R10. This reference document is a Texas RE-controlled document that is subject to revision by the Texas RE Board of Directors. It is not part of the FERC-approved regional standard.

    b. The following process will be used to revise the Primary Frequency Response Reference Document. A Primary Frequency Response Reference Document revision request may be submitted to the Texas RE Reliability Standards Manager, who will present the revision request to the Texas RE Member Representatives Committee (MRC) for consideration. The revision request will be posted in accordance with MRC procedures. The MRC shall discuss the revision request in a public meeting and will accept and consider verbal and written comments pertaining to the request. The MRC will make a recommendation to the Texas RE Board of Directors, which may adopt the revision request, reject it, or adopt it with modifications. Any approved revision to the Primary Frequency Response Reference Document shall be filed with NERC and FERC for informational purposes.

Attachment 1

Primary Frequency Response Reference Document

Texas Reliability Entity, Inc.
BAL-001-TRE-2
Requirements R2, R9, and R10
Performance Metric Calculations

I. Introduction

This Primary Frequency Response Reference Document provides a methodology for determining the Primary Frequency Response (PFR) performance of individual generating units/generating facilities following Frequency Measurable Events (FMEs) in accordance with Requirements R2, R9 and R10. Flowcharts in Attachment A (Initial PFR) and Attachment B (Sustained PFR) show the logic and calculations in graphical form, and they are considered part of this Primary Frequency Response Reference Document. Several Excel spreadsheets implementing the calculations described herein for various types of generating units are available[1] for reference and use in understanding and performing these calculations.

This Primary Frequency Response Reference Document is not considered to be a part of the regional standard. This document is maintained by Texas RE and subject to modifications as approved by the Texas RE Board of Directors, without being required to go through the formal Standard Development Process.

Revision Process: The following process will be used to revise the Primary Frequency Response Reference Document. A Primary Frequency Response Reference Document revision request may be submitted to the Texas RE Reliability Standards Manager, who will present the revision request to the Texas RE Member Representatives Committee (MRC) for consideration. The MRC shall discuss the revision request in a public meeting and will accept and consider verbal and written comments pertaining to the request. The MRC will make a recommendation to the Texas RE Board of Directors, which may adopt the revision request, reject it, or adopt it with modifications. Any approved revision to the Primary Frequency Response Reference Document shall be filed with NERC and FERC for informational purposes.

As used in this document the following terms are defined as shown:

> **High Sustained Limit (HSL)** for a generating unit/generating facility/BESS: The limit established by the GO/GOP, continuously updatable in Real-Time, that describes the maximum sustained energy production capability of a generating unit/generating facility/BESS.
>
> **Low Sustained Limit (LSL)** for a generating unit/generating facility/BESS: The limit

[1] These spreadsheets are available on Texas RE's public website.

established by the GO/GOP, continuously updatable in Real-Time, that describes the minimum sustained energy capability of a generating unit/generating facility/BESS. This value could be negative for BESS to represent the charging capability.

Maximum Megawatt Governor Control System (MW_{GCS}) for the purposes of this standard, maximum megawatt control range of the Governor control system. For all generator types, except BESS, MW_{GCS}, is calculated from HSL to 0 while BESS is calculated from HSL to LSL.
In this regional standard, the term "resource" is synonymous with "generating unit/generating facility/BESS".

Design Settings versus real-time Evaluation: Settings and verifications (R6) are constructed around unit design parameters, while frequency response expectations and evaluation scores, for every frequency event, are based upon real-time telemetered values.

II. Initial Primary Frequency Response Calculations

Requirement 9

R9. Each Generator Owner shall meet a minimum 12-month rolling average initial Primary Frequency Response performance of 0.75 on each generating unit/generating facility/BESS, based on participation in at least eight FMEs. See Attachment 1: Primary Frequency Response Reference Document for specific calculations.

9. 1 The initial Primary Frequency Response performance shall be the ratio of the Actual Primary Frequency Response to the Expected Primary Frequency Response during the initial measurement period following the FME.

9.2 If a generating unit/generating facility/BESS has not participated in a minimum of eight FMEs in a 12-month period, performance shall be based on a rolling eight-FME average.

9.3 A generating unit/generating facility's/BESS initial Primary Frequency Response performance during an FME may be excluded from the rolling average calculation by the Balancing Authority due to a legitimate operating condition that prevented normal Primary Frequency Response performance. Examples of legitimate operating conditions that may support exclusion of FMEs include, but are not limited to:

- Operation at or near auxiliary equipment operating limits (such as boiler feed pumps, condensate pumps, pulverizers, and forced draft fans);
- Data telemetry failure. The Balancing Authority may request raw data from the Generator Owner as a substitute.

Initial Primary Frequency Response Performance Calculation Methodology

This portion of this PFR Reference Document establishes the process used to calculate initial PFR performance for each Frequency Measurable Event (FME) and then average the events over a 12-month period (or 8-event minimum) to establish whether a resource is compliant with Requirement R9.

This process calculates the initial per unit Primary Frequency Response of a resource [$P.U.PFR_{Resource}$] as a ratio between the adjusted actual PFR ($APFR_{Adj}$),adjusted for the pre-event ramping of the unit, and the final expected Primary Frequency Response ($EPFR_{final}$) as calculated using the pre-perturbation and post-perturbation time periods of the initial measure.

This comparison of actual performance to a calculated target value establishes, for each type of resource, the initial per unit PFR [$P.U.PFR_{Resource}$] for any FME.

Initial Primary Frequency Response performance requirement

$$Avg_{Period}[P.U.PFR_{Resource}] \geq 0.75,$$

Where $P.U.PFR_{Resource}$ is the per unit measure of the initial PFR of a resource during identified FMEs.

$$P.U.PFR_{\text{Resource}} = \frac{Actual\ \Pr imary\ Frequency\ \text{Re}\,sponse_{Adj}}{Expected\ \Pr imary\ Frequency\ \text{Re}\,sponse_{final}}$$

Where $P.U.PFR_{Resource}$ for each FME is limited to values between 0.0 and 2.0.

The adjusted actual PFR (APFRAdj) and the final expected PFR (EPFRfinal) are calculated as described below.

EPFR calculations use droop and deadband values as stated in Requirement R6 with the exception of combined-cycle facilities while being evaluated as a single resource (MW production of both the combustion turbine generator and the steam turbine generator are included in the evaluation) where the evaluation droop will be 5.78%.[2]

Actual Primary Frequency Response (APFRadj)

The adjusted actual Primary Frequency Response (APFRadj) is the difference between Post-perturbation Average MW and Pre-perturbation Average MW, including the ramp magnitude adjustment.

[2] The effective droop of a typical combined-cycle facility with governor settings per Requirement R6 is 5.78%, assuming a 2-to-1 ratio between combustion turbine capacity and steam turbine capacity. Use 5.78% effective droop in all combined-cycle performance calculations.

$$APFR_{adj} = MW_{post-perturbation} - MW_{pre-perturbation} - Ramp\ Magnitude$$

Where:

Pre-perturbation Average MW: Actual MW averaged from T-16 to T-2

$$MW_{pre\ -\ perturbation} = \frac{\sum_{T-16}^{T-2} MW}{\#\,Scans}$$

Post-perturbation Average MW: Actual MW averaged from T+20 to T+52

$$MW_{post\ -\ perturbation} = \frac{\sum_{T+20}^{T+52} MW}{\#\,Scans}$$

Ramp Adjustment: The actual PFR number that is used to calculate P.U.PFR is adjusted for the ramp magnitude of the generating unit/generating facility/BESS during the pre-perturbation minute. The ramp magnitude is subtracted from the APFR.

Ramp Magnitude = (MWT-4 – MWT-60)*0.59

(MWT-4 – MWT-60) represents the MW ramp of the generator resource/generator facility for a full minute prior to the event. The factor 0.59 adjusts this full minute ramp to represent the ramp that should have been achieved during the post-perturbation measurement period.

Expected Primary Frequency Response (EPFR)

For all generator types, the *ideal* expected Primary Frequency Response ($EPFR_{ideal}$) is calculated as the difference between the $EPFR_{post\text{-}perturbation}$ and the $EPFR_{pre\text{-}perturbation}$.

$$EPFR_{ideal} = EPFR_{post-perturbation} - EPFR_{pre-perturbation}$$

When the frequency is outside the Governor deadband and above 60Hz:

$$EPFR_{pre-perturbation} = \left[\frac{(HZ_{pre-perturbation} - 60.0 - deadband_{max})}{(60\ x\ droop_{max} - deadband_{max})}\ x\ (-1)\ x\ (MW_{GCS} - PA\ Capacity)\right]$$

$$EPFR_{post-perturbation} = \left[\frac{(HZ_{post-perturbation} - 60.0 - deadband_{max})}{(60\ x\ droop_{max} - deadband_{max})}\ x\ (-1)\ x\ (MW_{GCS} - PA\ Capacity)\right]$$

When the frequency is outside the Governor deadband and below 60Hz:

$$EPFR_{pre-perturbation} = \left[\frac{(HZ_{pre-perturbation} - 60.0 + deadband_{max})}{(60\ x\ droop_{max} - deadband_{max})}\ x\ (-1)\ x\ (MW_{GCS} - PA\ Capacity)\right]$$

$$EPFR_{post-perturbation} = \left[\frac{(HZ_{post-perturbation} - 60.0 + deadband_{max})}{(60\ x\ droop_{max} - deadband_{max})}\ x\ (-1)\ x\ (MW_{GCS} - PA\ Capacity)\right]$$

For each formula, when frequency is within the Governor deadband the appropriate EPFR value is zero. The deadbandmax and droopmax quantities come from Requirement R6.

Where:

Pre-perturbation Average Hz: Actual Hz averaged from T-16 to T-2

$$Hz_{pre-perturbation} = \frac{\sum_{T-16}^{T-2} Hz}{\#\,Scans}$$

Post-perturbation Average Hz: Actual Hz averaged from T+20 to T+52

$$Hz_{post-perturbation} = \frac{\sum_{T+20}^{T+52} Hz}{\#\,Scans}$$

Capacity and net dependable capacity (NDC) are used interchangeably and the term capacity will be used in this document. Capacity is the official reported seasonal capacity of the generating unit/generating facility.

Power Augmentation: For Combined Cycle facilities, capacity is adjusted by subtracting power augmentation (PA) capacity, if any, from the HSL. Other generator types may also have power augmentation that is not frequency responsive. This could be "over-pressure" operation of a steam turbine at valves wide open or operating with a secondary fuel in service. The GO should provide the BA with documentation and conditions when power augmentation is to be considered in PFR calculations.

$EPFR_{final}$ for Combustion Turbines and Combined Cycle Facilities

$$EPFR_{final} = EPFR_{ideal} + \left(HZ_{post-perturbation} - 60.0\right) x\ 10\ x\ 0.00276\ x\ (MW_{GCS} - PA\ Capacity)$$

Note: The 0.00276 constant is the MW/0.1 Hz change per MW of capacity and represents the MW change in generator output due to the change in mass flow through the combustion turbine due to the speed change of the turbine during the post-perturbation measurement period. This factor is based on empirical data from a major 2003 event as measured on multiple combustion turbines in ERCOT.

$EPFR_{final}$ for Steam Turbine

$$EPFR_{final} = \left(EPFR_{ideal} + MW_{adj}\right) \times \frac{Throttle\ Pressure}{Rated\ Throttle\ Pressure}$$

Where:

$$MW_{adj} = EPFR_{ideal}\ x\ \frac{K}{Rated\ Trottle\ Pressure}\ x\ (MW_{GCS} - PA\ Capacity)\ x\ Steam\ Flow\ Change\ Factor\ x - 1$$

Where:

$$\%\ Steam\ Flow = \frac{MW_{post-perturbation}}{(MW_{GCS} - PA\ Capacity)}$$

$$Steam\ Flow\ Change\ Factor = \frac{\%\ Steam\ Flow}{0.5}$$

Throttle Pressure = Interpolation of Pressure curve at $MW_{pre\text{-}perturbation}$

The rated throttle pressure and the pressure curve, based on generator MW output, are provided by the GO to the BA. This pressure curve is defined by up to six pair of pressure and MW breakpoints where the rated throttle pressure and MW output, where rated throttle pressure is achieved, is the first pair and the minimum throttle pressure and MW output, where the minimum throttle pressure is achieved, as the last pair of breakpoints. If fewer breakpoints are needed, the pair values will be repeated to complete the six pair table.

The K factor is used to model the stored energy available to the resource. The value ranges between 0.0 and 0.6 psig per MW change when responding during an FME. The GO can measure the drop in throttle pressure when the resource is operating near 50% output of the steam turbine during a FME and provide this ratio of pressure change to the BA. K is then adjusted based on rated throttle pressure and resource capacity. An additional sensitivity factor, the steam flow change factor, is based on resource loading (% steam flow) and further modifies the MW adjustment. This sensitivity factor will decrease the adjustment at resource outputs below 50% and increase the adjustment at outputs above 50%. The GO should determine the fixed K factor for each resource that generally results in the best match between EPFR and APFR (resulting in the highest $P.U.PFR_{Resource}$). For any generating unit, K will not change unless the steam generator is significantly reconfigured.

$EPFR_{final}$ for Other Generating Units/Generating Facilities

$$EPFR_{final} = EPFR_{ideal} + X$$

Where X is an adjustment factor that may be applied to properly model the delivery of PFR. The X factor will be based on known and accepted technical or physical limitations of the resource. X may be adjusted by the BA and may be variable across the operating range of a resource. X shall be zero unless the BA accepts an alternative value.

III. Sustained Primary Frequency Response Calculations

Requirement 10

R10. Each Generator Owner shall meet a minimum 12-month rolling average sustained Primary Frequency Response performance of 0.75 on each generating unit/generating facility/BESS, based on participation in at least eight FMEs. See Attachment 1: Primary Frequency Response Reference Document for specific calculations. *[Violation Risk Factor = Medium] [Time Horizon = Operations Assessment]*

10.1 The sustained Primary Frequency Response performance shall be the ratio of the Actual Primary Frequency Response to the Expected Primary Frequency Response during the sustained measurement period following the FME.

10.2 If a generating unit/generating facility/BESS has not participated in a minimum of eight FMEs in a 12-month period, performance shall be based on a rolling eight-FME average.

10.3 A generating unit/generating facility's/BESS sustained Primary Frequency Response performance during an FME may be excluded from the rolling average calculation by the Balancing Authority due to a legitimate operating condition that prevented normal Primary Frequency Response performance. Examples of legitimate operating conditions that may support exclusion of FMEs include, but are not limited to:

- Operation at or near auxiliary equipment operating limits (such as boiler feed pumps, condensate pumps, pulverizers, and forced draft fans);
- Data telemetry failure. The Balancing Authority may request raw data from the Generator Owner as a substitute.

Sustained Primary Frequency Response Performance Calculation Methodology

This portion of this PFR Reference Document establishes the process used to calculate sustained Primary Frequency Response performance for each Frequency Measurable Event

(FME) and then average the events over a 12-month period (or 8-event minimum) to establish whether a resource is compliant with Requirement R10.

This process calculates the per unit sustained PFR of a resource [$P.U.SPFR_{Resource}$] as a ratio between the maximum actual unit response at any time during the period from T+46 to T+60, adjusted for the pre-event ramping of the unit, and the final expected PFR (EPFR) value at time T+46.[3]

This comparison of actual performance to a calculated target value establishes, for each type of resource, the per unit sustained PFR [$P.U.SPFR_{Resource}$] for any FME.

<u>Sustained Primary Frequency Response performance requirement:</u>

The standard requires an average performance over a period of 12 months (including at least 8 measured events) that is ≥ 0.75.

$$Avg_{Period}\,[P.U.SPFR_{Resource}] \geq 0.75$$

$Avg_{Period}\,[P.U.SPFR_{Resource}]$ is either:

- the average of each resource's sustained PFR performances [$P.U.SPFR_{Resource}$] during all of the assessable Frequency Measurable Events (FMEs), for the most recent rolling 12 month period; or
- if the unit has not experienced at least 8 assessable FMEs in the most recent 12 month period, the average of the unit's last 8 sustained PFR performances when the unit provided frequency response during an FME.

Sustained Primary Frequency Response Calculation (P.U.SPFR)

$$P.U.PFR_{\text{Resource}} = \frac{\text{Actual Sustained Primary Frequency Response}_{Adj}}{\text{Expected Sustained Primary Frequency Response}_{final}}$$

$P.U.SPFR_{Resource}$ is the per unit (P.U.) measure of the sustained PFR of a resource during identified FMEs. For any given event $P.U.SPFR_{Resource}$ for each FME will be limited to values between 0.0 and 2.0.

<u>Actual Sustained Primary Frequency Response (*ASPFR*) Calculations</u>

$$ASPFR = MW_{MaximumResponse} - MW_{pre-perturbation}$$

[3] The time designations used in this section refer to relative time after an FME occurs. For example, "T+46" refers to 46 seconds after the frequency deviation occurred.

Where:

Pre-perturbation Average MW: Actual MW averaged from T-16 to T-2.

$$MW_{pre\,-\,perturbation} = \frac{\sum_{T-16}^{T-2} MW}{\#\,Scans}$$

And:

$MW_{MaximumResponse}$ **=** *maximum MW value telemetered by a unit from T+46 through T+60 during low frequency events and the minimum MW value telemetered by a unit from T+46 through T+60 during a high frequency event.*

Actual Sustained Primary Frequency Response, Adjusted (*ASPFRAdj*)

$$ASPFR_{Adj} = ASPFR - RampMW\ Sustained$$

RampMW Sustained (MW) – The Standard requires a unit/facility to sustain its response to a Frequency Measureable Event. An adjustment available in determining a unit's sustained PFR performance (*P.U.*$SPFR_{Resource}$) is to account for the direction in which a resource was moving (increasing or decreasing output) when the event occurred T=t(0). This is the *RampMW* Sustained adjustment:

RampMW Sustaine*d* = (MW_{T-4} – MW_{T-60}) x 0.821

Note: The terminology "MW_{T-4}" *refers to MW output at 4 seconds before the Frequency Measurable Event (FME) occurs at T=t(0).*

By subtracting a reading at 4 seconds before, from a reading at 60 seconds before, the formula calculates the MWs a generator moved in the minute (56 seconds) prior to T=t(0). The formula is then modified by a factor to indicate where the generator would have been at T+46, had the event not occurred: the "*RampMW Sustained*." It does this by multiplying the MW change over 56 seconds before the event (MWT-4 – MWT-60) by a modifier. This extrapolates to an equivalent number of MWs the generator would have changed if it had been allowed to continue on its ramp to T+46 unencumbered by the FME. The modifier is $\frac{46\ \text{seconds}}{56\ \text{seconds}}$ or 0.821.

<u>Expected Sustained Primary Frequency Response (*ESPFR*) Calculations</u>

The expected sustained PFR ($ESPFR_{final}$) is calculated using the actual frequency at T+46, HZ_{T+46}.

This $ESPFR_{final}$ is the MW value a unit should have responded with if it is properly sustaining the output of its generating unit/generating facility in response to an FME. Determination of this value begins with establishing where it would be in an ideal situation; considers proper droop and dead-band values established in Requirement R6, HSLLSL and actual frequency. It then allows for adjusting the value to compensate for the various types of Limiting Factors each generating units / generating facilities may have and any power augmentation capacity (PA capacity) that may be included in the HSL/LSL.

Establishing the Ideal Expected Sustained Primary Frequency Response

For all generator types, the ideal expected sustained PFR ($ESPFR_{ideal}$) is calculated as the difference between the $ESPFR_{T+46}$ and the $EPFR_{pre\text{-}perturbation}$. The $EPFR_{pre\text{-}perturbation}$ is the same $EPFR_{pre\text{-}perturbation}$ value used in the Initial measure of R9.

$$ESPFR_{ideal} = ESPFR_{T+46} - EPFR_{pre-perturbation}$$

When the frequency is outside the Governor deadband and above 60Hz:

$$ESPFR_{T+46} = \left[\frac{(HZ_{T+46} - 60 - \ deadband_{max})}{(droop_{max}\ x\ 60 - \ deadband_{max})}\ x\ (MW_{GCS} - PA\ Capacity)\ x\ (-1)\right]$$

When the frequency is outside the Governor deadband and below 60Hz:

$$ESPFR_{T+46} = \left[\frac{(HZ_{T+46} - 60 + \ deadband_{max})}{(droop_{max}\ x\ 60 - \ deadband_{max})}\ x\ (MW_{GCS} - PA\ Capacity)\ x\ (-1)\right]$$

Capacity andNDC are used interchangeably and the term capacity will be used in this document. Capacity is the official reported seasonal capacity of the generating unit/generating facility. The $deadband_{max}$ and $droop_{max}$ quantities come from Requirement R6.

For combined cycle facilities, determination of capacity includes subtracting power augmentation (PA) capacity, if any, from the original MW_{GCS}. Other generator types may also have power as that is not frequency responsive. This could be “over-pressure” operation of a steam turbine at valves wide open or operating with a secondary fuel in service. The GO is required to provide the BA with documentation and identify conditions when this augmentation is in service.

$ESPFR_{final}$ for Combustion Turbines and Combined Cycle Facilities

$$ESPFR_{final} = ESPFR_{ideal} + \ (HZ_{T+46} - 60.0)\ x\ 10\ x\ 0.00276\ x\ (MW_{GCS} - PA\ Capacity)$$

Note: The 0.00276 constant is the MW/0.1 Hz change per MW of capacity and represents the MW change in generator output due to the change in mass flow through the combustion turbine due to the speed change of the turbine at HZ_{T+46}. (This is based on empirical data from a major 2003 event as measured on multiple combustion turbines in ERCOT.)

$ESPFR_{final}$ for Steam Turbine

$$ESPFR_{final} = \left(ESPFR_{ideal} + MW_{Adj}\right) \times \frac{Throttle\ Pressure}{Rated\ Throttle\ Pressure}$$

Where:

$$MW_{adj} = ESPFR_{ideal}\ x\ \frac{K}{Rated\ Trottle\ Pressure}\ x\ (MW_{GCS} - PA\ Capacity)\ x\ Steam\ Flow\ Change\ Factor\ x(-1)$$

Where:

$$\%\ Steam\ Flow = \frac{MW_{post-perturbation}}{(MW_{GCS} - PA\ Capacity)}$$

$$Steam\ Flow\ Change\ Factor = \frac{\%\ Steam\ Flow}{0.5}$$

Throttle Pressure = Interpolation of Pressure curve at $MW_{pre\text{-}perturbation}$

The rated throttle pressure and the pressure curve, based on generator MW output, are provided by the GO to the BA. This pressure curve is defined by up to six pair of pressure and MW breakpoints where the rated throttle pressure and MW output where rated throttle pressure is achieved is the first pair and the minimum throttle pressure and MW output where the minimum throttle pressure is achieved as the last pair of breakpoints. If fewer breakpoints are needed, the pair values will be repeated to complete the six pair table.

The K factor is used to model the stored energy available to the resource and ranges between 0.0 and 0.6 psig per MW change when responding during an FME. The GO can measure the drop in throttle pressure, when the resource is operating near 50% output of the steam turbine during a FME and provide this ratio of pressure change to the BA. K is then adjusted based on rated throttle pressure and resource capacity. An additional sensitivity factor, the steam flow change factor, is based on resource loading (% steam flow) and further modifies the MW adjustment. This sensitivity factor will decrease the adjustment at resource outputs below 50% and increase the adjustment at outputs above 50%. The GO should determine the fixed K factor for each resource that generally results in the best match between ESPFR and ASPFR (resulting in the highest $P.U.SPFR_{Resource}$). For any generating unit, K will not change unless the steam generator is significantly reconfigured.

ESPFR$_{final}$ for Other Generating Units/Generating Facilities/BESS

$$ESPFR_{final} = ESPFR_{Ideal} + X$$

Where X is an adjustment factor that may be applied to properly model the delivery of PFR. The X factor will be based on known and accepted technical or physical limitations of the resource. X may be adjusted by the BA and may be variable across the operating range of a resource. X shall be zero unless the BA accepts an alternative value.

IV. Limits on Calculation of Primary Frequency Response Performance (Initial and Sustained):

If a generating unit/generating facility is operating within 2% of its (MW_{GCS} – PA capacity)or within 5 MW (whichever is greater), or a BESS is operating within 2% or 3 MW of its MW_{GCS} from its applicable operating limit (high or low) at the time an FME occurs (pre-perturbation), then that resource's Primary Frequency Response performance is not evaluated for that FME.

For frequency deviations below 60 Hz (Hz$_{Post\text{-}perturbation}$ < 60 if:

$$MW_{pre-perturbation} \geq \min[([MW_{GCS} - PA\ Capacity]\ x\ .98), ([MW_{GCS} - PA\ Capacity] - X\ MW)]$$

then PFR is not evaluated for this FME, where X is 5 MW for generating units/generating facility and 3 MW for BESS

For frequency deviations above 60 Hz (Hz$_{Post\text{-}perturbation}$ > 60, if:

$$MW_{pre-perturbation} \leq \max[(LSL + ([MW_{GCS} - PA\ Capacity]\ x\ 0.02)), (LSL +\ X\ MW)]$$

then PFR is not evaluated for this FME where X is 5 MW for generating units/generating facility and 3 MW for BESS

Final Expected Primary Frequency Response (EPFR$_{final}$) is greater than Operating Margin: Caps and limits exist for resources operating with adequate reserve margin to be evaluated at least 2% of (MW_{GCS} less PA capacity) or 5 MW for generating units/generating facilities or 3 MW for BESS, but with Expected Primary Frequency Response$_{final}$ greater than the actual margin available.

1. The P.U.PFR$_{Resource}$ will be set to the greater of 0.75 or the calculated P.U.PFR$_{Resource}$ if all of the following conditions are met:
    a. The generating unit/generating facility's pre-perturbation operating margin (appropriate for the frequency deviation direction) is greater than 2% of its (HSL less PA capacity) and greater than 5 MW; and

b. The BESS's pre-perturbation operating margin (appropriate for the frequency deviation direction) is greater than 2% of its (MW_{GCS} less PA capacity) and greater than 3 MW; and
c. The Expected Primary Frequency Response$_{final}$ is greater than the generating unit/generating facility's/BESS available frequency responsive capacity[4]; and
d. The generating unit/generating facility's/BESS $APFR_{adj}$ response is in the correct direction.

2. When calculation of the $P.U.PFR_{Resource}$ uses the resource's (MW_{GCS} less PA capacity) as the maximum expected output, the calculated $P.U.PFR_{Resource}$ will not be greater than 1.0.

3. When calculation of the $P.U.PFR_{Resource}$ uses the resource's LSL as the minimum expected output, the calculated $P.U.PFR_{Resource}$ will not be greater than 1.0.

4. If the $APFR_{Adj}$ is in the wrong direction, then $P.U.PFR_{Resource}$ is 0.0.

5. These caps and limits apply to both the initial and sustained PFR measures.

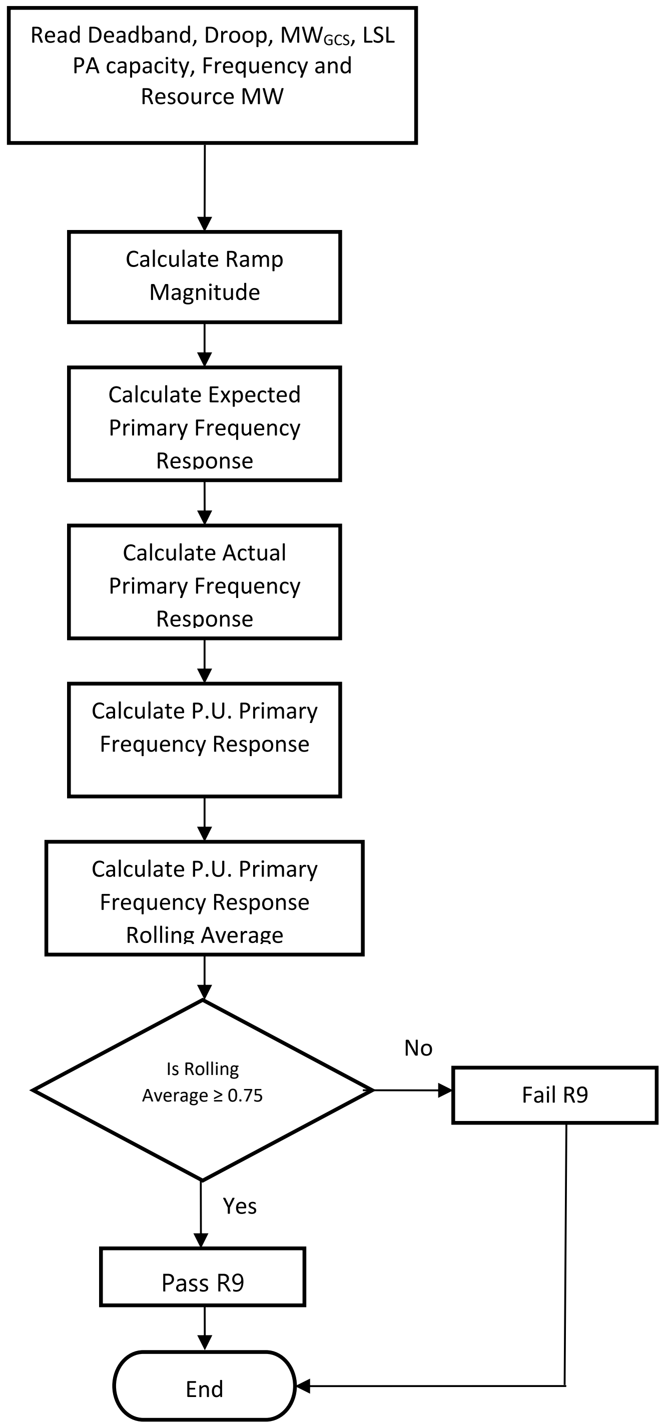
[4] In this circumstance, when frequency is below 60 Hz, the $EPFR_{final}$ is set to operating margin based on MW_{GCS} (adjusted for any augmentation capacity) AND when frequency is above 60 Hz, the $EPFR_{final}$ is set to operating margin based on LSL for the purpose of calculating $PUPFR_{resource}$.

Attachment A to
Primary Frequency Response Reference Document

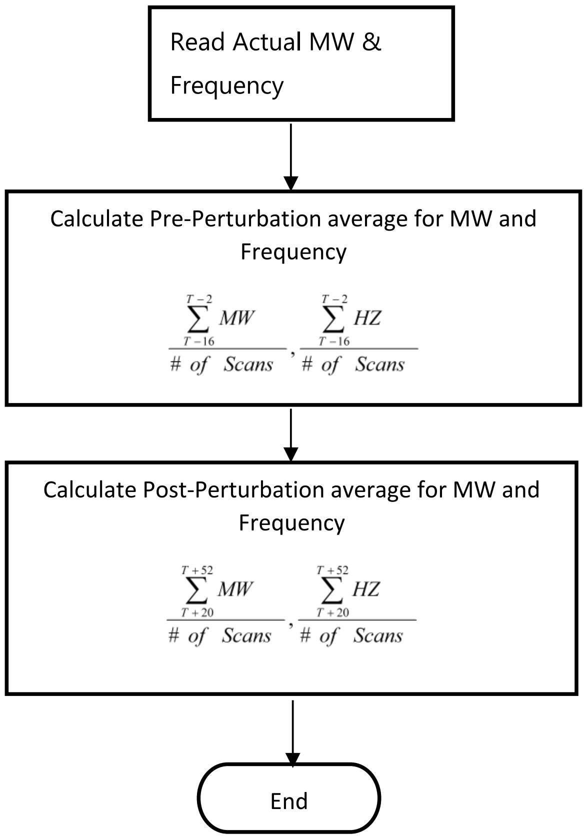
Initial Primary Frequency Response Methodology for
BAL-001-TRE-2

Primary Frequency Response Measurement and Rolling Average Calculation – Initial Response

PA=Power Augmentation
HSL=High Sustained Limit
LSL = Low Sustained Limit
MW_{GCS} = maximum megawatt control range of the Governor control system


Read Deadband, Droop, MW_{GCS}, LSL PA capacity, Frequency and Resource MW
Calculate Ramp Magnitude
Calculate Expected Primary Frequency Response
Calculate Actual Primary Frequency Response
Calculate P.U. Primary Frequency Response
Calculate P.U. Primary Frequency Response Rolling Average
Is Rolling Average ≥ 0.75
No
Fail R9
Yes
Pass R9
End

Pre/Post-Perturbation Average MW and Average Frequency Calculations



Ramp Magnitude Calculation

$$\text{Ramp Magnitude} = (MW_{T-4} - MW_{T-60})*0.59$$

End

$(MW_{T-4} - MW_{T-60})$ represents the MW ramp of the generator resource/generator facility for a full minute prior to the event. The factor 0.59 adjusts this full minute ramp to represent the ramp that should have been achieved during the post-perturbation measurement period.

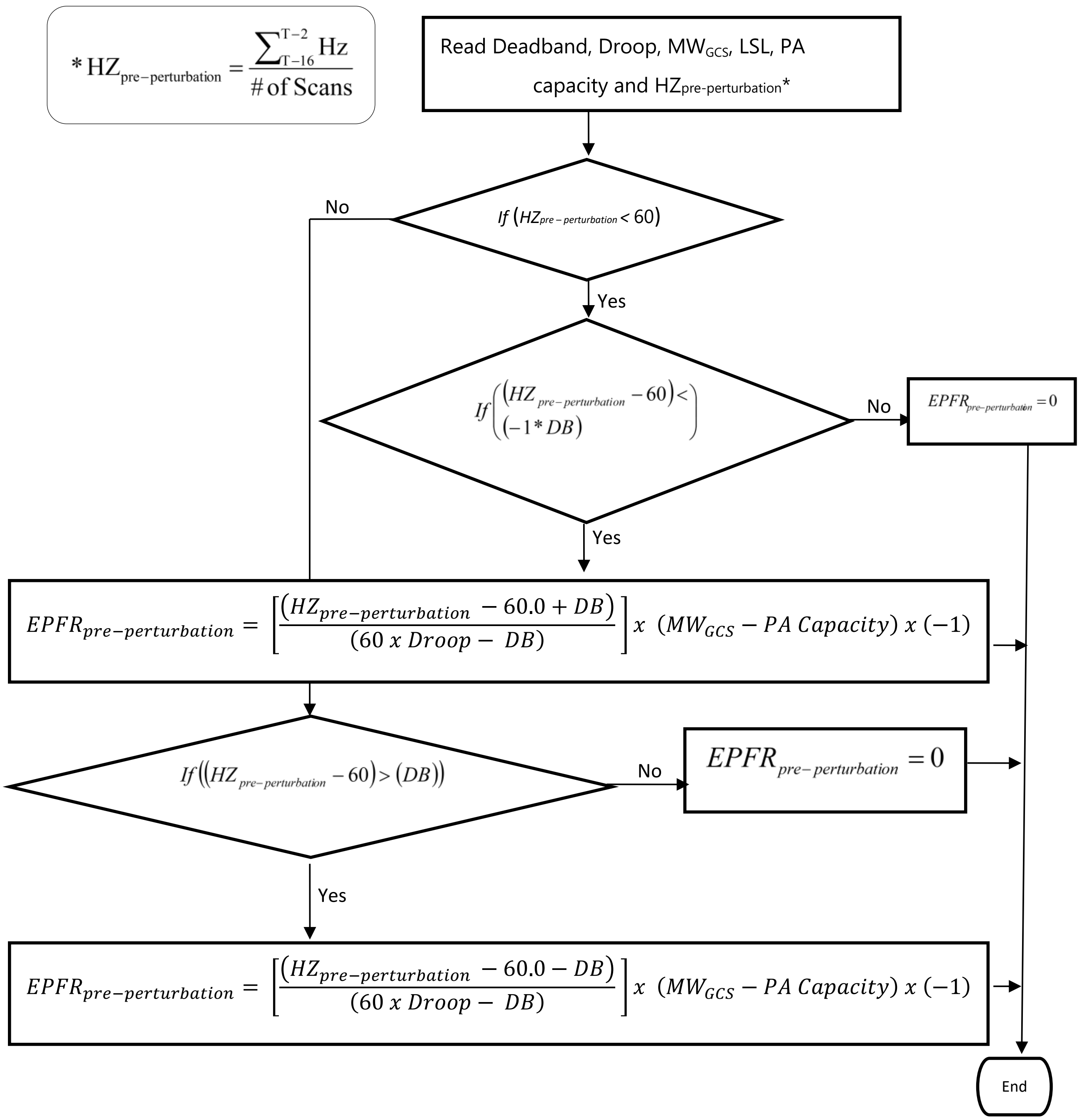
Actual Primary Frequency Response ($APFR_{Adj}$)

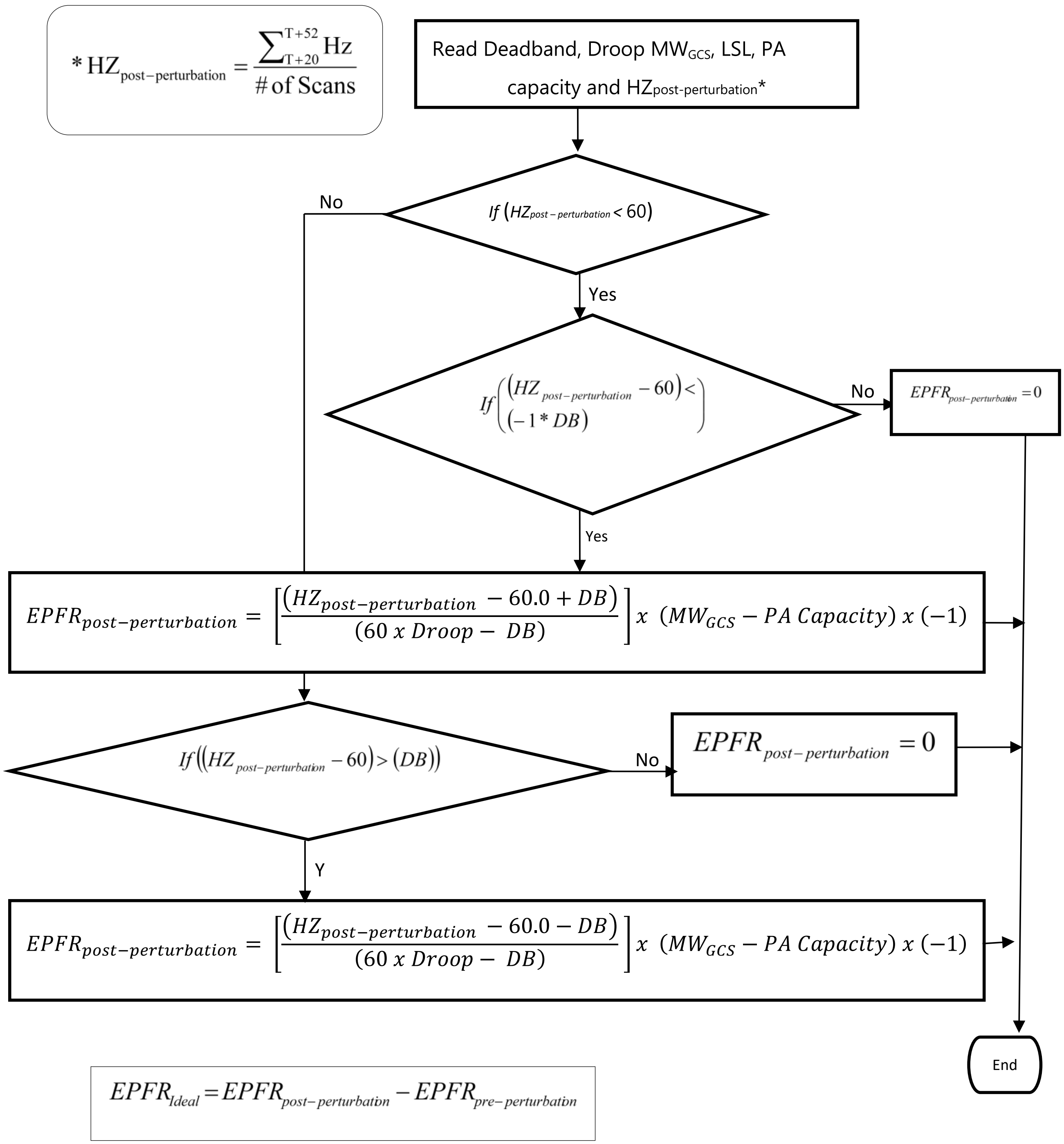
$$APFR_{Adj} = MW_{post\text{-}perturbation} - MW_{pre\text{-}perturbation} - \text{Ramp Magnitude}$$

End

Expected Primary Frequency Response Calculation

Use the maximum droop and maximum deadband as required by R6. For Combined Cycle Facility evaluation as a single resource (includes MW production of the steam turbine generator), the EPFR will use 5.78% droop in all calculations.




$* HZ_{post-perturbation} = \frac{\sum_{T+20}^{T+52} Hz}{\# of Scans}$
Read Deadband, Droop MW_{GCS}, LSL, PA capacity and $HZ_{post-perturbation}$*
$If\ (HZ_{post-perturbation} < 60)$
No
Yes
$If\left(\begin{matrix}(HZ_{post-perturbation} - 60) < \\ (-1 * DB)\end{matrix}\right)$
No
$EPFR_{post-perturbation} = 0$
Yes
$EPFR_{post-perturbation} = \left[\frac{(HZ_{post-perturbation} - 60.0 + DB)}{(60\ x\ Droop - DB)}\right] x\ (MW_{GCS} - PA\ Capacity)\ x\ (-1)$
$If\left((HZ_{post-perturbation} - 60) > (DB)\right)$
No
$EPFR_{post-perturbation} = 0$
Y
$EPFR_{post-perturbation} = \left[\frac{(HZ_{post-perturbation} - 60.0 - DB)}{(60\ x\ Droop - DB)}\right] x\ (MW_{GCS} - PA\ Capacity)\ x\ (-1)$
End
$EPFR_{Ideal} = EPFR_{post-perturbation} - EPFR_{pre-perturbation}$

Adjustment for Steam Turbine

Read K(Limiting Factor), Throttle Pressure curve breakpoints, $MW_{pre\text{-}perturbation}$ and $MW_{post\text{-}perturbation}$

↓

$$\%\ Steam\ Flow = \frac{MW_{post-perturbation}}{(MW_{GCS} - PA\ Capacity)}$$

↓

$$Steam\ Flow\ Change\ Factor = \frac{\%\ Steam\ Flow}{0.5}$$

↓

$$MW_{adj} = EPFR_{ideal}\ x\ \frac{K}{Rated\ Trottle\ Pressure}\ x (MW_{GCS} - PA\ Capacity)\ x\ Steam\ Flow\ Change\ Factor\ x(-1)$$

↓

Throttle Pressure = Interpolation of Pressure curve at $MW_{pre\text{-}perturbation}$

↓

$$EPFR_{final} = \left(EPFR_{Ideal} + MW_{Adjustment}\right) * \frac{\text{Throttle Pressure}}{\text{Rated Throttle Pressure}}$$

↓

End

Adjustment for Combustion Turbines and Combined Cycle Facilities

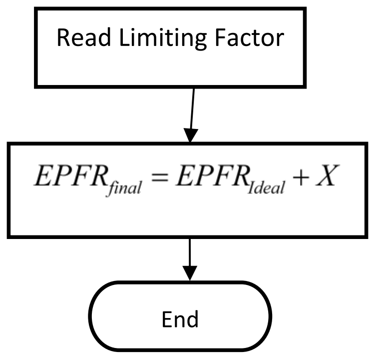
Read MW_{GCS}, PA capacity, $HZ_{post\text{-}perturbation}$*

$$EPFR_{final} = EPFR_{ideal} + (HZ_{post-perturbation} - 60.0)\ x\ 10\ x\ 0.00276\ x\ (MW_{GCS} - PA\ Capacity)$$

End

0.00276 is the MW/0.1 Hz change per MW of capacity and represents the MW change in generator output due to the change in mass flow through the combustion turbine due to the speed change of the turbine during the post-perturbation measurement period. (This factor is based on empirical data from a major 2003 event as measured on multiple combustion turbines in ERCOT.)

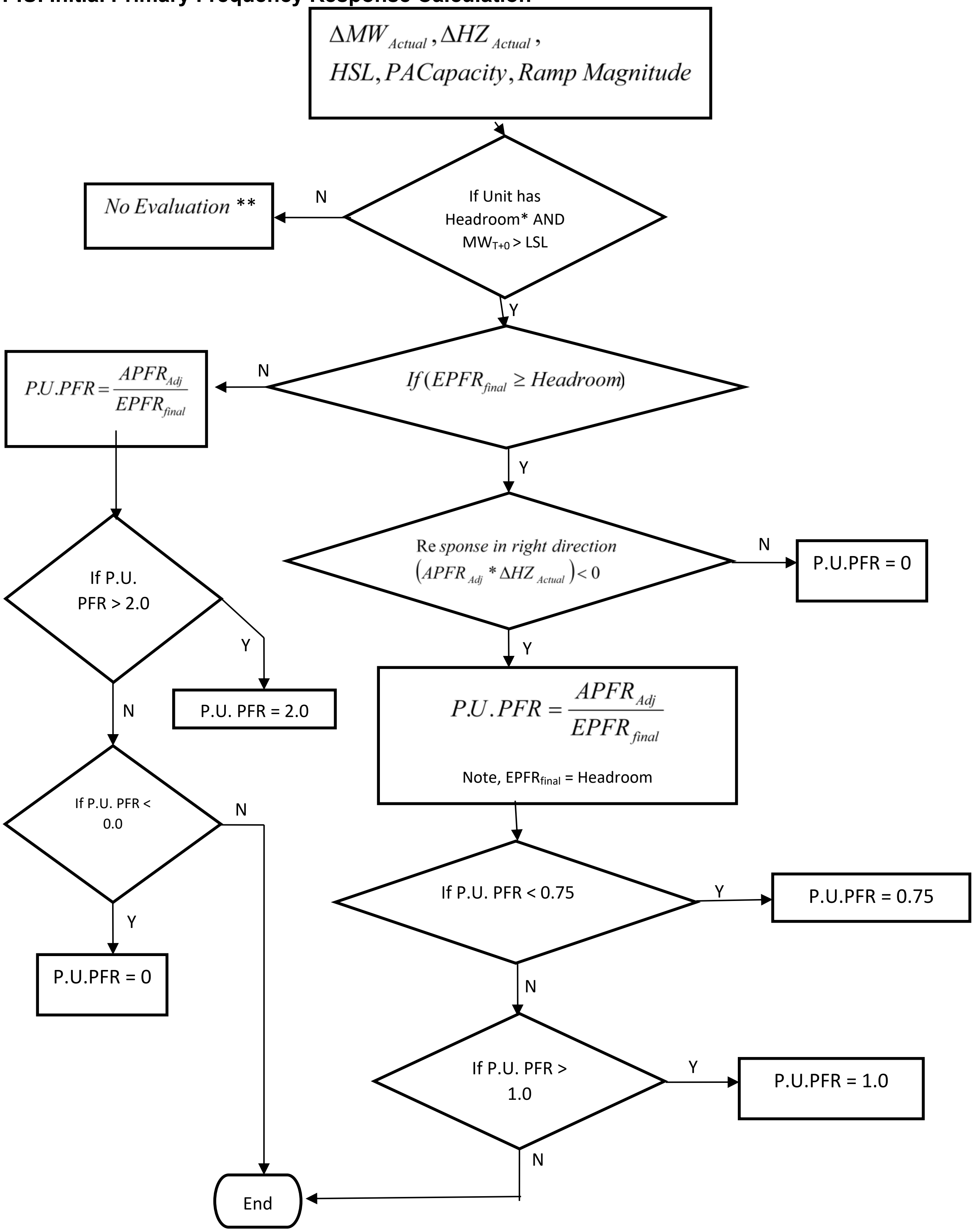
Adjustment for Other Units



$$* \mathrm{HZ}_{\mathrm{post-perturbation}} = \frac{\sum_{\mathrm{T+20}}^{\mathrm{T+52}} \mathrm{HZ}_{\mathrm{Actual}}}{\#\,\mathrm{of\ Scans}}$$

This adjustment Factor X will be developed to properly model the delivery of PFR due to known and approved technical limitations of the resource. X may be adjusted by the BA and may be variable across the operating range of a resource.

P.U. Initial Primary Frequency Response Calculation



*Check for adequate up headroom, low frequency events. Headroom must be greater than either XMW or 2% of(MW_{GCS} less PA capacity) , whichever is larger. If a unit does not have adequate up headroom, the unit is considered operating at full capacity and will not be evaluated for low frequency events, where X is 5 MW for generating unit/generating facility and 3 MW for BESS

Check for adequate down headroom, high frequency events. Headroom must be greater than either XMW or 2% of (MW_{GCS} less PA capacity), whichever is larger. If a unit does not have adequate down headroom, the unit is considered operating at low capacity and will not be evaluated for high frequency events, where X is 5 MW for generating unit/generating facility and 3 MW for BESS

For low frequency events:

$$\boxed{Headroom = MW_{GCS} - PA\ Capacity - MW_{T-2}}$$

For high frequency events:

$$\boxed{Headroom = MW_{T-2} - LSL}$$

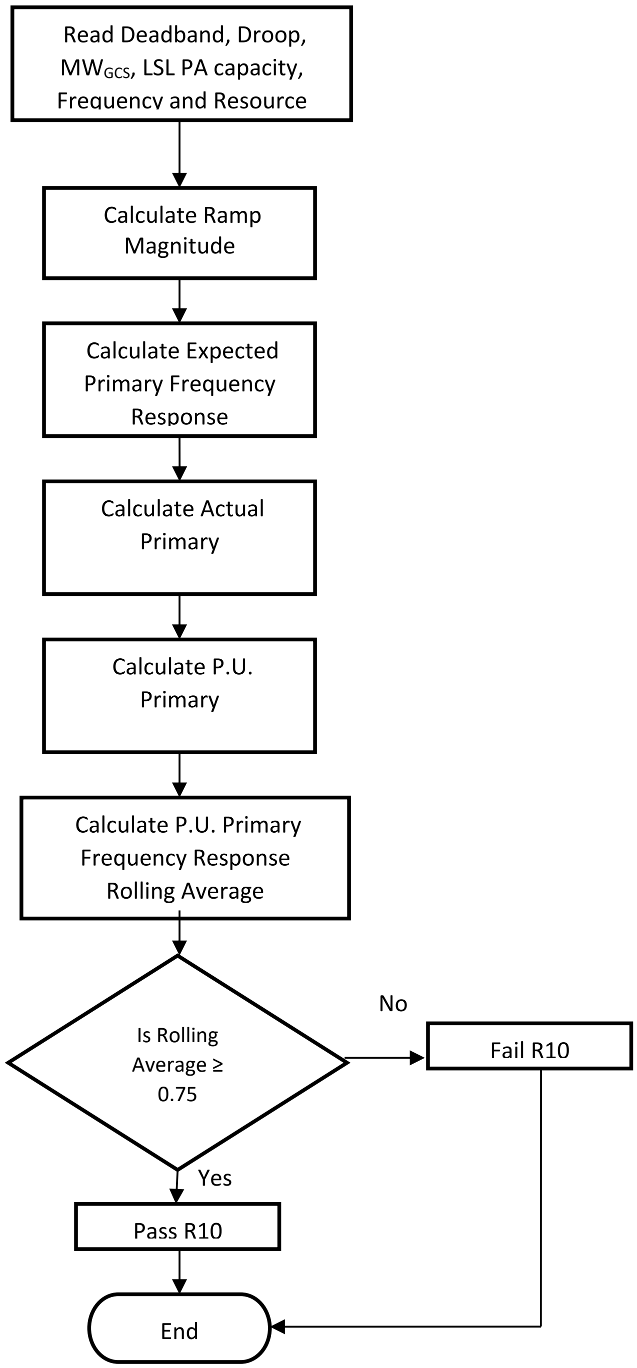
**No further evaluation is required for Sustained Primary Frequency Response. This event will not be included in the Rolling Average calculation of either Initial or Sustained Primary Frequency Response.

T = Time in Seconds

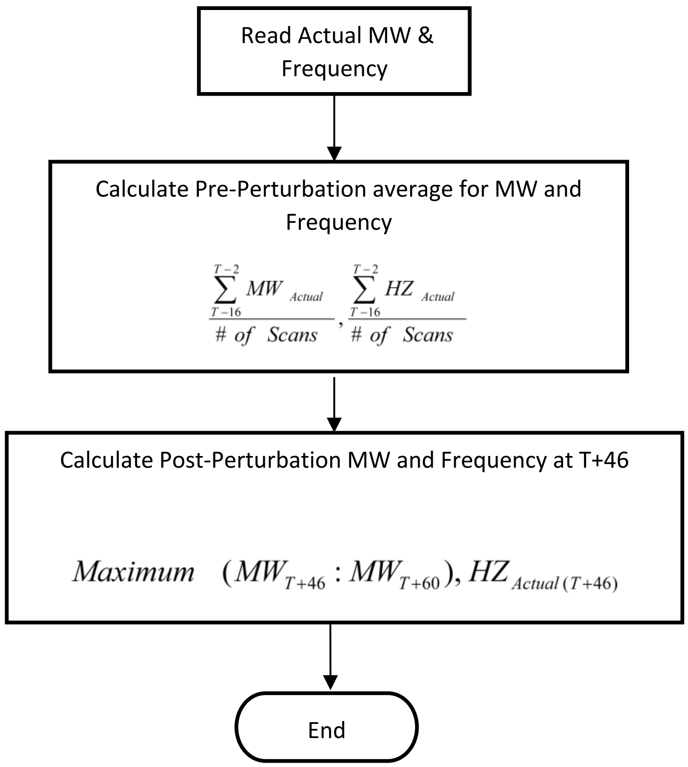
Attachment B to
Primary Frequency Response Reference Document

Sustained Primary Frequency Response Methodology for
BAL-001-TRE-2

Primary Frequency Response Measurement and Rolling Average Calculation–Sustained Response



Pre/Post-Perturbation Average MW and Average Frequency Calculations



Ramp Magnitude Calculation - Sustained

$$Ramp\ Magnitude_{Sustained} = (MW_{T-4} - MW_{T-60}) * 0.821$$

End

(MW_{T-4} – MW_{T-60}) represents the MW ramp of the generator resource/generator facility for a full minute prior to the event. The factor 0.821 adjusts this full minute ramp to represent the ramp the generator would have changed the system had it been allowed to continue on its ramp to T+46 unencumbered.

Actual Sustained Primary Frequency Response ($ASPFR_{adj}$)

For low frequency events:

$$ASPFR_{Adj} = Maximum(MW_{T+46} : MW_{T+60}) - MW_{pre\text{-perturbation}} - Ramp\ Magnitude_{Sustained}$$

End

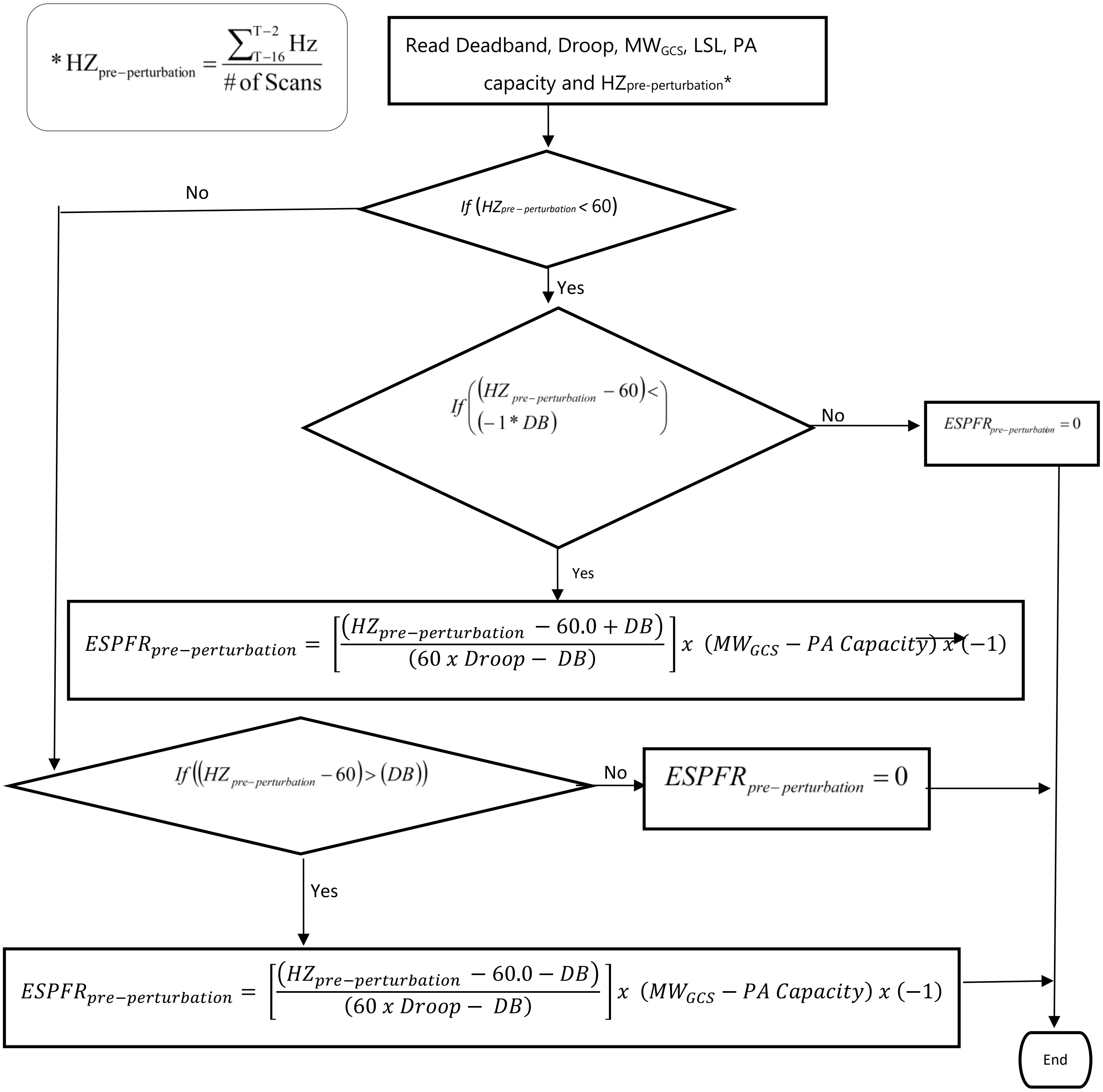
For high frequency events:

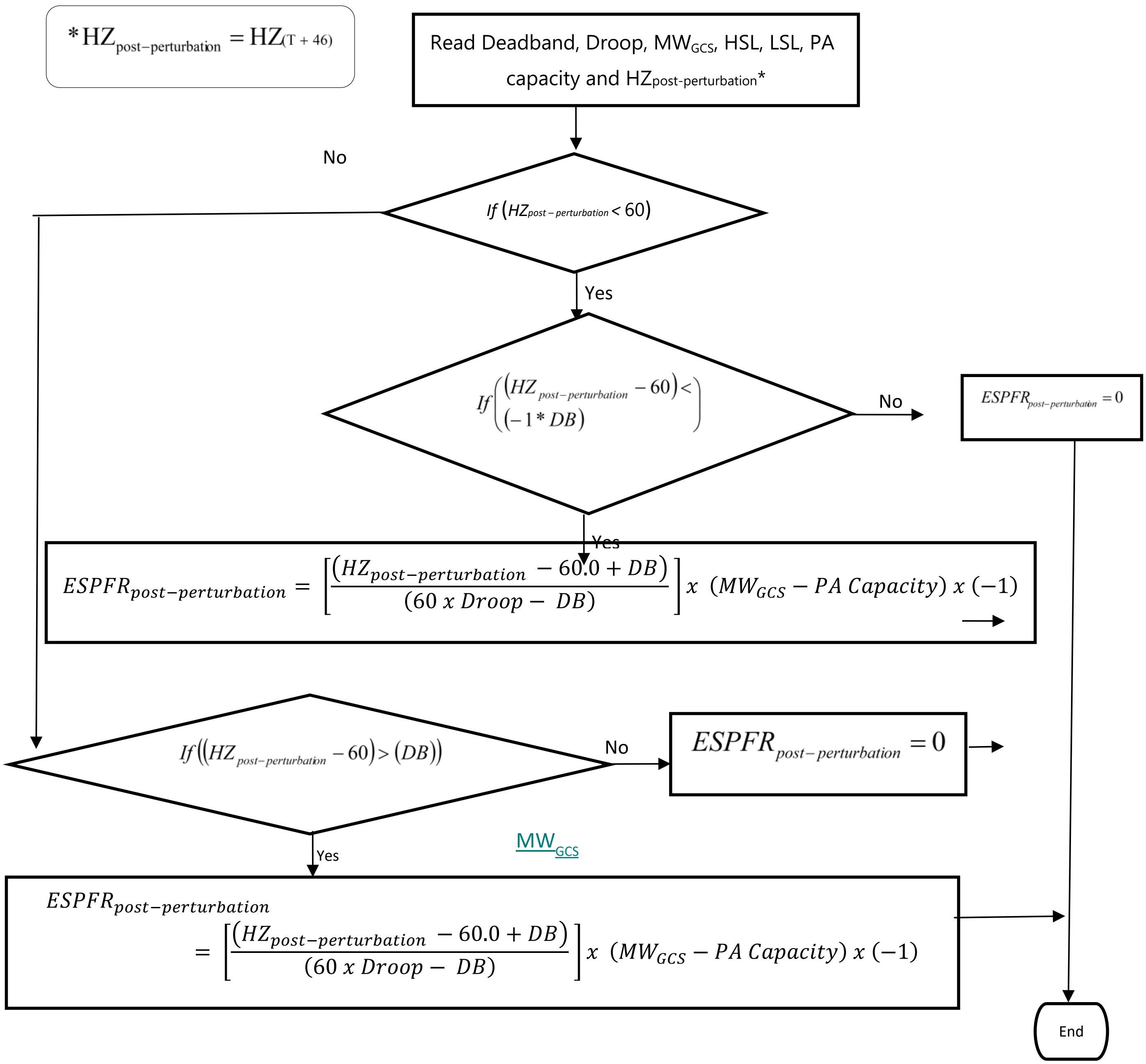
$$ASPFR_{Adj} = Minimum(MW_{T+46} : MW_{T+60}) - MW_{pre\text{-perturbation}} - Ramp\ Magnitude_{Sustained}$$

End

Expected Sustained Primary Frequency Response Calculation

Use the droop and deadband as required by R6. For Combined Cycle Facility evaluation as a single resource (includes MW production of the steam turbine generator), the EPFR will use 5.78% droop in all calculations.





$$ESPFR_{Ideal} = ESPFR_{post-perturbation} - ESPFR_{pre-perturbation}$$

Adjustment for Steam Turbine

Read K(Limiting Factor), Throttle Pressure curve breakpoints, MW_{GCS}, $MW_{pre\text{-}perturbation}$ and $MW_{post\text{-}perturbation}$

$$\% \, Steam \, Flow = \frac{MW_{post-perturbation}}{(MW_{GCS} - PA \, Capacity)}$$

$$Steam \, Flow \, Change \, Factor = \frac{\% \, Steam \, Flow}{0.5}$$

$$MW_{adj} = ESPFR_{ideal} \, x \, \frac{K}{Rated \, Trottle \, Pressure} \, x(MW_{GCS} - PA \, Capacity)xSteam \, Flow \, Change \, Factorx(-1)$$

Throttle Pressure = Interpolation of Pressure curve at $MW_{pre\text{-}perturbation}$

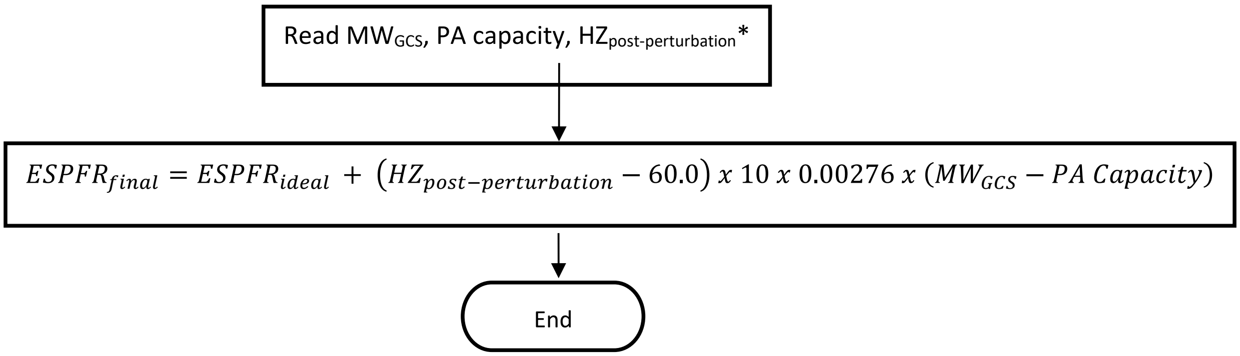
$$ESPFR_{final} = \left(ESPFR_{Ideal} + MW_{Adjustment}\right) * \frac{\text{Throttle Pressure}}{\text{Rated Throttle Pressure}}$$

End

$MW_{post-perturbation}$ = Maximum (MW_{T+46} : MW_{T+60}) for low frequency events.

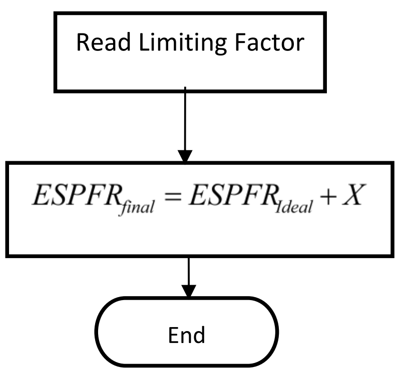
$MW_{post-perturbation}$ = Minimum (MW_{T+46} : MW_{T+60}) for high frequency events.

Adjustment for Combustion Turbines and Combined Cycle Facilities



0.00276 is the MW/0.1 Hz change per MW of capacity and represents the MW change in generator output due to the change in mass flow through the combustion turbine due to the speed change of the turbine during the post-perturbation measurement period. (This factor is based on empirical data from a major 2003 event as measured on multiple combustion turbines in ERCOT.)

Adjustment for Other Units

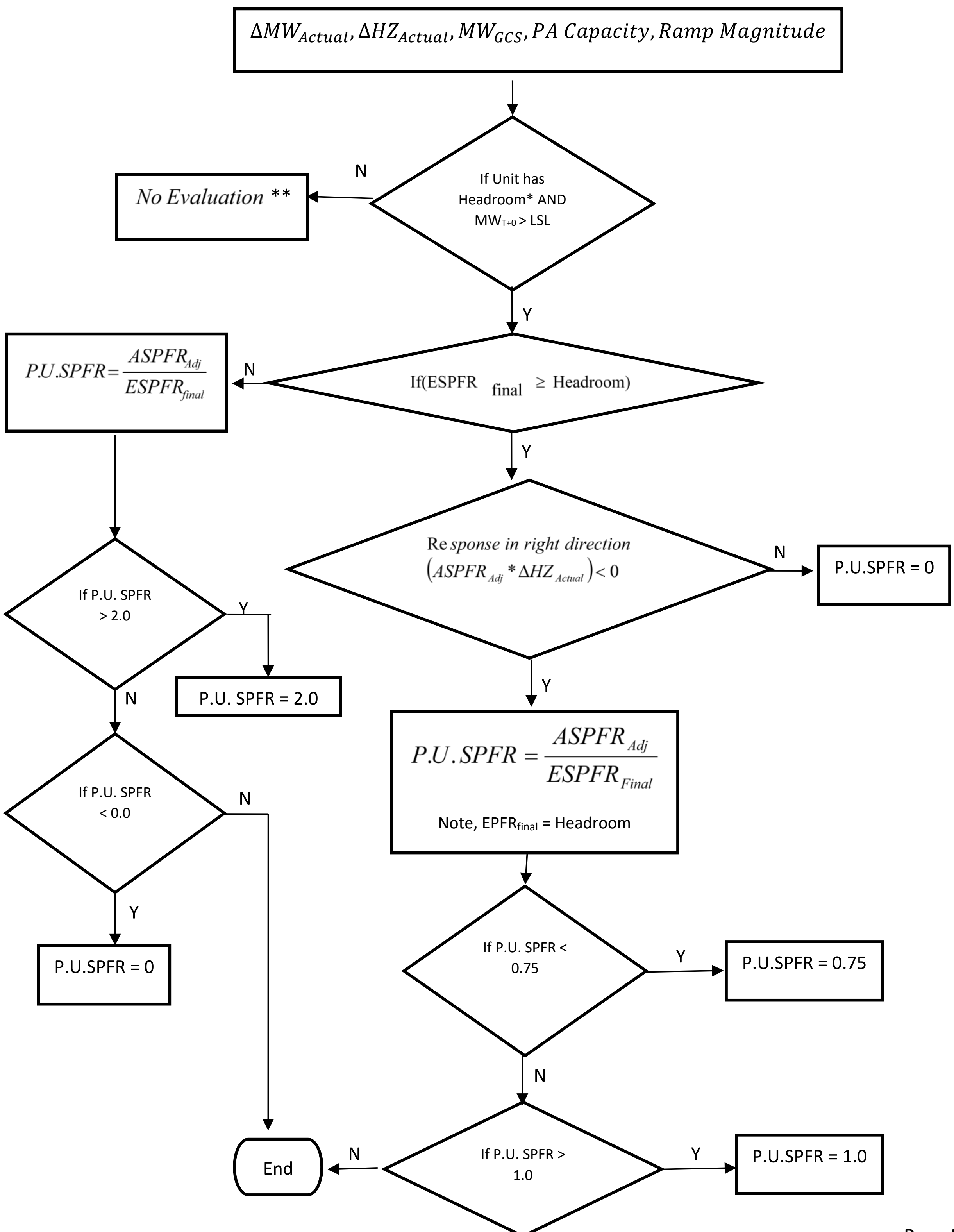


$* HZ_{Actual} = HZ_{(T + 46)}$

This adjustment Factor X will be developed to properly model the delivery of PFR due to known and approved technical limitations of the resource. X may be adjusted by the BA and may be variable across the operating range of a resource.

P.U. Sustained Primary Frequency Response Calculation

$$*\mathrm{HZ}_{\mathrm{Actual}} = \mathrm{HZ}_{(\mathrm{T}\,+\,46)}$$


$\Delta MW_{Actual}, \Delta HZ_{Actual}, MW_{GCS}, PA\ Capacity, Ramp\ Magnitude$
If Unit has Headroom* AND MW_{T+0} > LSL
N
No Evaluation **
Y
If(ESPFR final ≥ Headroom)
N
$P.U.SPFR = \frac{ASPFR_{Adj}}{ESPFR_{final}}$
Y
Response in right direction $(ASPFR_{Adj} * \Delta HZ_{Actual}) < 0$
N
P.U.SPFR = 0
If P.U. SPFR > 2.0
Y
P.U. SPFR = 2.0
N
Y
$P.U.SPFR = \frac{ASPFR_{Adj}}{ESPFR_{Final}}$
Note, $EPFR_{final}$ = Headroom
If P.U. SPFR < 0.0
N
Y
P.U.SPFR = 0
If P.U. SPFR < 0.75
Y
P.U.SPFR = 0.75
N
If P.U. SPFR > 1.0
N
End
Y
P.U.SPFR = 1.0

*Check for adequate up headroom, low frequency events. Headroom must be greater than either XMW or 2% of (MW_{GCS} less PA capacity), whichever is larger. If a unit does not have adequate up headroom, the unit is considered operating at full capacity and will not be evaluated for low frequency events, where X is 5 MW for generating unit/generating facility and 3 MW for BESS.

Check for adequate down headroom, high frequency events. Headroom must be greater than either XMW or 2% of (MW_{GCS} less PA capacity), whichever is larger. If a unit does not have adequate down headroom, the unit is considered operating at low capacity and will not be evaluated for high frequency events, where X is 5 MW for generating unit/generating facility and 3 MW for BESS.

For low frequency events:

$$\boxed{Headroom = MW_{GCS} - PA\ Capacity - MW_{T-2}}$$

For high frequency events:

$$\boxed{Headroom = MW_{T-2} - LSL}$$

**No further evaluation is required for Sustained Primary Frequency Response. This event will not be included in the Rolling Average calculation of either Initial or Sustained Primary Frequency Response.

T = Time in Seconds

Revision History

Version	Date	Action	Change Tracking
1	7/25/2011	Approved by SDT and submitted to Texas RE RSC for approval to post for regional ballot	
1.1	12/7/2012	Approved by SDT for submission to Texas RE RSC for approval to post for second regional ballot.	Changed sustained measure from average over event recovery period to point at 46 seconds after FME, and other changes to respond to field trial results, comments, and corrections.
1.1	3/6/2013	Texas RE RSC approves submittal to Texas RE Board	
1.1	4/23/2013	Texas RE Board approves submittal to NERC and FERC	
1.1	9/18/2013	NERC and Texas RE file Petition for approval to FERC	
1.1	1/16/2014	Approved by FERC	
1.2	5/21/2015	Texas RE Board approves revisions to Attachment 2 Primary Frequency Response Reference Document	For clarification and consistency of the equations used in the Attachment, changes performed to: - "T" in the equations refers to the start of the Frequency Measurable Event. - "T-2" nomenclature utilized for clarity rather than "t(-2)" (applicable to numerous equations) - Removed floating x in $EPFR_{final}$ for Steam Turbine equation - Corrected sign convention for Expected Sustained Primary Frequency Response to match the calculation for expected primary frequency response. Corrected Adjusted MW for $ESPFR_{final}$ for Steam Turbine by multiplying -1 to calculate proper value. - On Steam Flow Change Factor removed floating x and reinserted PA capacity. - Clarified Footnote 5 for scenario of high frequency event for setting LSL as operating margin (similar to HSL for low frequency events). - Clarified in flowcharts for both P.U. Initial Primary & Sustained

			Frequency Response Calculations: ○ Unit needs to have Headroom and be above LSL to be scored. ○ Cap $EPFR_{final}$ at value of Headroom on unit - Per RSC 5/11/2015, all references to "Final" were changed to "final". - Per RSC 5/11/2015, P.U.PFR and P.U.S.PFR removed italics in flowcharts.
1.3	11/14/2016	RSC approves minor changes to Attachment 2 Primary Frequency Response Reference Document	Replaced Reliability Standards Committee with Members Representative Committee to conform with changes to the Texas RE bylaws and regional standards development process.
1.3	12/07/2016	Texas RE Board approves minor changes to Attachment 2 Primary Frequency Response Reference Document.	Replaced Reliability Standards Committee with Members Representative Committee to conform with changes to the Texas RE bylaws and regional standards development process.
2.0	12/11/2019	Texas RE Board approves changes to the Attachment.	Removed the requirement for Governor droop and deadband settings for Steam turbines of combined cycle resources. Edited Requirements R9.3 and R10.3 to reflect the current process for submitting an exclusion request. Removed Attachment 1, which is the implementation plan for Regional Standard BAL-001-TRE-1. Changed numbering on Attachment 2 to Attachment 1
3.0	TBD		[Description of Changes to reference document]

A. Introduction

1. **Title:** Primary Frequency Response in the ERCOT Region
2. **Number:** BAL-001-TRE-3~~2~~
3. **Purpose:** To maintain Interconnection steady-state frequency within defined limits.
4. **Applicability:**

   4.1. Functional Entities:

   - **4.1.1** Balancing Authority
   - **4.1.2** Generator Owners
   - **4.1.3** Generator Operators

   4.2. Exemptions

   - **4.2.1** Existing generating facilities regulated by the U.S. Nuclear Regulatory Commission prior to the Effective Date are exempt from Standard BAL-001-TRE-3~~2~~.
   - **4.2.2** Generating units/generating facilities while operating in synchronous condenser mode are exempt from Standard BAL-001-TRE-3~~2~~.
   - **4.2.3** Any generators that are not required by the Balancing Authority to provide primary frequency response are exempt from this standard.

5. **Effective Date:** See Implementation Plan for Regional Standard BAL-001-TRE-3~~2~~.
6. **Background:** The ERCOT Interconnection was initially given a waiver of BAL-001 R2 (Control Performance Standard CPS2). In FERC Order 693, NERC was directed to develop a Regional Standard as an alternate means of assuring frequency performance in the ERCOT Interconnection. NERC was explicitly directed to incorporate key elements of the existing Protocols, Section 8.5. This required governors to be in service and performing with an un-muted response to assure an Interconnection minimum Frequency Response to a Frequency Measurable Event (FME) (that starts at t(0)).

   This Regional Standard provides requirements related to identifying Frequency Measur~~e~~able Events, calculating the Primary Frequency Response of each resource in the Region, calculating the Interconnection minimum Frequency Response and monitoring the actual Frequency Response of the Interconnection, setting Governor deadband and droop parameters, and providing Primary Frequency Response performance requirements.

   Under this standard, two Primary Frequency Response (PFR) performance measures are calculated: ~~-~~"initial" and "sustained". The initial PFR performance (R9) measures the actual response compared to the expected response in the period from 20 to 52 seconds after an FME starts. The sustained PFR performance (R10) measures the best actual response between 46 and 60 seconds after t(0) compared to the expected response based on the system frequency at a point 46 seconds after t(0).

In this Regional Standard the term “resource” is synonymous with “generating unit/generating facility/battery energy storage system (BESS)”.

B. Requirements and Measures

R1. The Balancing Authority shall identify Frequency Measurable Events (FMEs), and within 14 calendar days after each FME the Balancing Authority shall notify the Compliance Enforcement Authority and make FME information (time of FME (t(0)), pre-perturbation average frequency, post-perturbation average frequency) publicly available. *[Violation Risk Factor – Lower] [Time Horizon – Operations Assessment]*

M1. The Balancing Authority shall have evidence that it reported each FME to the Compliance Enforcement Authority and that it made FME information publicly available within 14 calendar days after the FME as required in Requirement R1.

R2. The Balancing Authority shall calculate the Primary Frequency Response of each generating unit/generating facility/BESS in accordance with this standard and the Primary Frequency Response Reference Document.[1] This calculation shall provide a 12-month rolling average of initial and sustained Primary Frequency Response performance. This calculation shall be completed each month for the preceding 12 calendar months. *[Violation Risk Factor = Lower] [Time Horizon = Operations Assessment]*

2.1. The performance of a combined cycle facility will be determined using an expected performance droop of 5.78%.

2.2. The calculation results shall be submitted to the Compliance Enforcement Authority and made available to the Generator Owner by the end of the month in which they were completed.

2.3. If a generating unit/generating facility/BESS has not participated in a minimum of (8) eight FMEs in a 12-month period, its performance shall be based on a rolling eight FME average response.

[1] Attachment 1: Primary Frequency Response Reference Document contains the calculations that the Balancing Authority will use to determine Primary Frequency Response performance of generating units/generating facilities/BESS. This reference document is a Texas RE-controlled document that is subject to revision by the Texas RE Board of Directors.

M2. The Balancing Authority shall have evidence it calculated and reported the rolling average initial and sustained Primary Frequency Response performance of each generating unit/generating facility/BESS monthly as required in Requirement R2.

R3. The Balancing Authority shall determine the Interconnection minimum Frequency Response (IMFR) in December of each year for the following year, and make the IMFR, the methodology for calculation and the criteria for determination of the IMFR publicly available. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

M3. The Balancing Authority shall demonstrate that the IMFR was determined in December of each year per ~~per~~ Requirement R3. The Balancing Authority shall demonstrate that the IMFR, the methodology for calculation and the criteria for determination of the IMFR are publicly available.

R4. After each calendar month in which one or more FMEs occur, the Balancing Authority shall determine and make publicly available the Interconnection's combined Frequency Response performance for a rolling average of the last six (6) FMEs by the end of the following calendar month. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M4. The Balancing Authority shall provide evidence that the rolling average of the Interconnection's combined Frequency Response performance for the last six (6) FMEs was calculated and made public per Requirement R4.

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R5. Following any FME that causes the Interconnection's six-FME rolling average combined Frequency Response performance to be less than the IMFR, the Balancing Authority shall direct any necessary actions to improve Frequency Response, which may include, but are not limited to, directing adjustment of Governor deadband and/or droop settings. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M5. The Balancing Authority shall provide evidence that actions were taken to improve the Interconnection's Frequency Response if the Interconnection's six-FME rolling average combined Frequency Response performance was less than the IMFR, per Requirement R5.

R6. Each Generator Owner shall set its Governor parameters as follows:

6.1. Limit Governor deadbands within those listed in Table 6.1, unless directed otherwise by the Balancing Authority.

Table 6.1 Governor Deadband Settings

Generator Type	Max. Deadband
Steam and Hydro Turbines with Mechanical Governors	+/- 0.034 Hz
Generating Units that are not qualified [2] to provide Operating Reserves and have obtained prior approval from the Balancing Authority to widen their deadband settings	+/- 0.036 Hz
All Other Generating Units/Generating Facilities/BESS[3]*	+/- 0.017 Hz

~~Table 6.1 Governor Deadband Settings~~

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

6.2. Limit Governor droop settings such that they do not exceed those listed in Table 6.2, unless directed otherwise by the Balancing Authority.

Table 6.2 Governor Droop Settings

Generator Type	Max. Droop % Setting
Hydro	5%
Combustion Turbine (Simple Cycle and Single-Shaft Combined Cycle)	5%
Combustion Turbine (Combined Cycle)	4%

[2] Refers to ancillary service qualification criteria as required by the Balancing Authority.

[3] Requirements R6.1, R6.2, and R6.3 are not applicable to steam turbine(s) of a combined cycle resource.

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Steam Turbine[4]~~*~~	5%
Diesel	5%
BESS	5%
DC Tie Providing Ancillary Services	5%
Variable Renewable (Non-Hydro)	5%

~~*Requirements R6.1, R6.2, and R6.3 are not applicable to steam turbine(s) of a combined cycle resource.~~

6.3. For digital and electronic Governors, once frequency deviation has exceeded the Governor deadband from 60.000 Hz, the Governor setting shall follow the slope derived from the formula below.

Where

$$\text{For 5\% Droop:} \quad \text{Slope} = \frac{MW_{GCS}}{(3.0\ Hz - Governor\ Deadband\ Hz)}$$

$$\text{For 4\% Droop:} \quad \text{Slope} = \frac{MW_{GCS}}{(2.4\ Hz - Governor\ Deadband\ Hz)}$$

MW_{GCS} is the maximum megawatt control range of the Governor control system. For mechanical Governors, droop will be proportional from the deadband by design. See Attachment 1: Primary Frequency Response Reference Document for specific calculations. ~~–~~*[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M6. Each Generator Owner shall have evidence that it set its Governor parameters in accordance with Requirement R6. Examples of evidence include but are not limited to:

- Governor test reports
- Governor setting sheets
- Performance monitoring reports

R7. Each Generator Owner shall operate each generating unit/generating facility/BESS that is connected to the interconnected transmission system with the Governor in service and responsive to frequency when the generating unit/generating facility/BESS is online and released for dispatch, unless the Generator Owner has a valid reason for operating with the Governor not in service and the Generator Operator has been

[4] Requirements R6.1, R6.2, and R6.3 are not applicable to steam turbine(s) of a combined cycle resource.

notified that the Governor is not in service. *[Violation Risk Factor = Medium] [Time Horizon = Real-time Operations]*

M7. Each Generator Owner shall have evidence that it notified the Generator Operator as soon as practical each time it discovered a Governor not in service when the generating unit/generating facility/BESS was online and released for dispatch. Evidence may include but not be limited to: operator logs, voice logs, or electronic communications.

R8. Each Generator Operator shall notify the Balancing Authority as soon as practical but within 30 minutes of the discovery of a status change (in service, out of service) of a Governor. *[Violation Risk Factor = Medium][Time Horizon = Real-time Operations]*

M8. Each Generator Operator shall have evidence that it notified the Balancing Authority within 30 minutes of each discovery of a status change (in service, out of service) of a Governor.

R9. Each Generator Owner shall meet a minimum 12-month rolling average initial Primary Frequency Response performance of 0.75 on each generating unit/generating facility/BESS, based on participation in at least eight FMEs. See Attachment 1: Primary Frequency Response Reference Document for specific calculations.

9.1. The initial Primary Frequency Response performance shall be the ratio of the Actual Primary Frequency Response to the Expected Primary Frequency Response during the initial measurement period following the FME.

9.2. If a generating unit/generating facility/BESS has not participated in a minimum of eight FMEs in a 12-month period, performance shall be based on a rolling eight-FME average.

9.3. A generating unit/generating facility's/BESS initial Primary Frequency Response performance during an FME may be excluded from the rolling average calculation by the Balancing Authority due to a legitimate operating condition that prevented normal Primary Frequency Response performance. Examples of legitimate operating conditions that may support exclusion of FMEs include, but are not limited to:

- Operation at or near auxiliary equipment operating limits (such as boiler feed pumps, condensate pumps, pulverizers, and forced draft fans);
- Data telemetry failure. The Balancing Authority may request raw data from the Generator Owner as a substitute.

[Violation Risk Factor = Medium] [Time Horizon = Operations Assessment]

M9. Each Generator Owner shall have evidence that each of its generating units/generating facilities/BESS achieved a minimum rolling average of initial Primary Frequency Response performance level of at least 0.75 as described in Requirement R9. Each Generator Owner shall have documented evidence of any FMEs where the generating unit performance was excluded from the rolling average calculation.

R10. Each Generator Owner shall meet a minimum 12-month rolling average sustained Primary Frequency Response performance of 0.75 on each generating unit/generating facility/BESS, based on participation in at least eight FMEs. See Attachment 1: Primary Frequency Response Reference Document for specific calculations. *[Violation Risk Factor = Medium] [Time Horizon = Operations Assessment]*

10.1. The sustained Primary Frequency Response performance shall be the ratio of the Actual Primary Frequency Response to the Expected Primary Frequency Response during the sustained measurement period following the FME.

10.2. If a generating unit/generating facility/BESS has not participated in a minimum of eight FMEs in a 12-month period, performance shall be based on a rolling eight- FME average.

10.3. A generating unit/generating facility's/BESS sustained Primary Frequency Response performance during an FME may be excluded from the rolling average calculation by the Balancing Authority due to a legitimate operating condition that prevented normal Primary Frequency Response performance. Examples of legitimate operating conditions that may support exclusion of FMEs include, ~~,~~but are not limited to:

- Operation at or near auxiliary equipment operating limits (such as boiler feed pumps, condensate pumps, pulverizers, and forced draft fans);
- Data telemetry failure. The Balancing Authority may request raw data from the Generator Owner as a substitute.

M10. Each Generator Owner shall have evidence that each of its generating units/generating facilities/BESS achieved a minimum rolling average of sustained Primary Frequency Response performance of at least 0.75 as described in Requirement R10. Each Generator Owner shall have documented evidence of any Frequency Measurable Events where generating unit performance was excluded from the rolling average calculation.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Compliance Monitoring Period and Reset Time Frame: If a generating unit's/generating facility's/BESS's rolling average for R9 or R10 falls below the required minimum rolling average(s) performance level, and the CEA has approved the GO's mitigation activities, the GO may initiate a request to the CEA to reset the rolling average(s). If the CEA approves the request to reset the rolling average(s), the CEA shall notify the BA that the GO may begin a new rolling average(s). In the CEA's notice to the BA, the CEA shall provide the BA with an effective date of the reset time for the rolling average(s). Upon receipt of the notice from the CEA, the BA shall, as soon as practicable, implement the change to the GO's rolling average(s). The first performance during an FME following the CEA's effective date to the BA shall count as the first event in the rolling average(s), and the entity will have an average frequency performance score after 12 successive months or eight events under Requirements R9 and R10 of the Regional Standard.~~If a generating unit/generating facility completes a mitigation plan and implements corrective action(s) to meet requirements R9 and R10 of the standard, and if approved by the BA and Compliance Enforcement Authority, then the generating unit/generating facility may begin a new rolling event average performance on the next performance during an FME. This will count as the first event in the performance calculation and the entity will have an average frequency performance score after 12 successive months or eight events per R9 and R10.~~

1.3. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Balancing Authority, Generator Owner, and Generator Operator shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

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- The Balancing Authority shall retain a list of identified FMEs and shall retain FME information since its last compliance audit for Requirement R1, Measure M1.
- The Balancing Authority shall retain all monthly PFR performance reports since its last compliance audit for Requirement R2, Measure M2.
- The Balancing Authority shall retain all annual IMFR calculations, and related methodology and criteria documents, relating to time periods since its last compliance audit for Requirement R3, Measure M3.
- The Balancing Authority shall retain all data and calculations relating to the Interconnection's combined Frequency Response performance, and all evidence of actions taken to increase the Interconnection's combined Frequency Response performance, since its last compliance audit for Requirements R4 and R5, Measures M4 and M5.
- Each Generator Operator shall retain evidence since its last compliance audit for Requirement R8, Measure M8.
- Each Generator Owner shall retain evidence since its last compliance audit for Requirements R6, R7, R9 and R10, Measures M6, M7, M9 and M10.

If an entity is found non-compliant, it shall retain information related to the non-compliance until found compliant, or for the duration specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent records.

1.4. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Balancing Authority reported an FME more than 14 days but less than 31 days after identification of the event.	The Balancing Authority reported an FME more than 30 days but less than 51 days after identification of the event.	The Balancing Authority reported an FME more than 50 days but less than 71 days after identification of the event.	The Balancing Authority reported an FME more than 70 days after identification of the event.
R2.	The Balancing Authority submitted a monthly report more than one month but less than 51 days after the end of the reporting month.	The Balancing Authority submitted a monthly report more than 50 days but less than 71 days after the end of the reporting month.	The Balancing Authority submitted a monthly report more than 70 days but less than 91 days after the end of the reporting month.	The Balancing Authority failed to submit a monthly report within 90 days after the end of the reporting month.
R3.	The Balancing Authority did not make the calculation and criteria for determination of the IMFR publicly available.	The Balancing Authority did not make the IMFR publicly available.	The Balancing Authority did not calculate the IMFR for the following year in December.	The Balancing Authority did not calculate the IMFR for a calendar year.
R4.	N/A	N/A	The Balancing Authority did not make public the six-FME rolling average Interconnection combined Frequency Response by the end of the following month.	The Balancing Authority did not calculate the six- FME rolling average Interconnection combined Frequency Response for any month in which an FME occurred. ~~FME rolling average Interconnection combined~~

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				~~Frequency Response for any month in which an FME occurred.~~
R5.	N/A	N/A	N/A	The Balancing Authority did not take action to improve Frequency Response when the Interconnection's rolling-average combined Frequency Response performance was less than the IMFR.
R6.	Any Governor parameter setting was > 10% and ≤ 20% outside setting range specified in R6.	Any Governor parameter setting was > 20% and ≤ 30% outside setting range specified in R6.	Any Governor parameter setting was > 30% and ≤ 40% outside setting range specified in R6.	Any Governor parameter setting was > 40% outside setting range specified in R6, – OR – an electronic or digital Governor was set to step into the droop curve.
R7.	N/A	N/A	N/A	The Generator Owner operated with its Governor out of service and did not notify the Generator Operator upon discovery of its Governor out of service.
R8	The Generator Operator notified the Balancing Authority of a change in Governor status between 31	The General Operator notified the Balancing Authority of a change in Governor status more than 1	The Generator Operator notified the Balancing Authority of a change in Governor status more than 4	The Generator Operator failed to notify the Balancing Authority of a change in Governor status within 24

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	minutes and one hour after the General Operator was notified of the discovery of the change.	hour but within 4 hours after the Generator Operator was notified of the discovery of the change.	hours but within 24 hours after the Generator Operator was notified of the discovery of the change.	hours after the Generator Operator was notified of the discovery of the change.
R9	A Generator Owner's rolling average initial Primary Frequency Response performance per R9 was < 0.75 and ≥ 0.65.	A Generator Owner's rolling average initial Primary Frequency Response performance per R9 was < 0.65 and ≥ 0.55.	A Generator Owner's rolling average initial Primary Frequency Response performance per R9 was < 0.55 and ≥ 0.45.	A Generator Owner's rolling average initial Primary Frequency Response performance per R9 was < 0.45.
R10	A Generator Owner's rolling average sustained Primary Frequency Response performance per R10 was < 0.75 and ≥ 0.65.	A Generator Owner's rolling average sustained Primary Frequency Response performance per R10 was < 0.65 and ≥ 0.55.	A Generator Owner's rolling average sustained Primary Frequency Response performance per R10 was < 0.55 and ≥ 0.45.	A Generator Owner's rolling average sustained Primary Frequency Response performance per R10 was < 0.45.

D. Regional Variances

None

E. Associated Documents

Regional Standard BAL-001-TRE-~~2~~ 3 Implementation Plan

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Version History

Version	Date	Action	Change Tracking
1	8/15/2013	Adopted by NERC Board of Trustees	
1	1/16/2014	FERC Order issued approving BAL-001-TRE-1. (Order becomes effective April 1, 2014.)	
2	12/11/2019	Approved by Texas RE Board of Directors	Removed the requirement Governor droop and deadband settings for Steam Turbine(s) of combined cycle resources. Edited Requirements R9.3 and R10.3 to reflect the current process and legitimate operating conditions for submitting an FME exclusion request. Removed Attachment 1, which is the implementation plan for Regional Standard BAL-001-TRE-1.
3			Include a provision that allows any generation resource that is not qualified to provide Operating Reserves to widen the resource's Governor deadband to +/- 0.036 Hz upon confirmation from the Balancing Authority (BA). Clarify the roles of the Generator Owner (GO), Compliance Enforcement Authority (CEA), and the BA as they pertain to the Compliance Monitoring Period and Reset Time Frame (Section C: 1.2) in regard to resetting the 12-month rolling average

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			Primary Frequency Response (PFR) performance score. Define PFR performance requirements for Battery Energy Storage Systems (BESS).

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Standard Attachments

1. Attachment 1 – Primary Frequency Response Reference Document, including Flow Charts A and B.

    a. This document provides implementation details for calculating Primary Frequency Response performance as required by Requirements R2, R9, and R10. This reference document is a Texas RE-controlled document that is subject to revision by the Texas RE Board of Directors. It is not part of the FERC-approved regional standard.

    b. The following process will be used to revise the Primary Frequency Response Reference Document. A Primary Frequency Response Reference Document revision request may be submitted to the Texas RE Reliability Standards Manager, who will present the revision request to the Texas RE Member Representatives Committee (MRC) for consideration. The revision request will be posted in accordance with MRC procedures. The MRC shall discuss the revision request in a public meeting and will accept and consider verbal and written comments pertaining to the request. The MRC will make a recommendation to the Texas RE Board of Directors, which may adopt the revision request, reject it, or adopt it with modifications. Any approved revision to the Primary Frequency Response Reference Document shall be filed with NERC and FERC for informational purposes.

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Attachment 1

Primary Frequency Response Reference Document

Texas Reliability Entity, Inc.
BAL-001-TRE-2
Requirements R2, R9, and R10
Performance Metric Calculations

I. Introduction

This Primary Frequency Response Reference Document provides a methodology for determining the Primary Frequency Response (PFR) performance of individual generating units/generating facilities following Frequency Measurable Events (FMEs) in accordance with Requirements R2, R9 and R10. Flowcharts in Attachment A (Initial PFR) and Attachment B (Sustained PFR) show the logic and calculations in graphical form, and they are considered part of this Primary Frequency Response Reference Document. Several Excel spreadsheets implementing the calculations described herein for various types of generating units are available[1] for reference and use in understanding and performing these calculations.

This Primary Frequency Response Reference Document is not considered to be a part of the regional standard. This document is maintained by Texas RE and subject to modifications as approved by the Texas RE Board of Directors, without being required to go through the formal Standard Development Process.

Revision Process: The following process will be used to revise the Primary Frequency Response Reference Document. A Primary Frequency Response Reference Document revision request may be submitted to the Texas RE Reliability Standards Manager, who will present the revision request to the Texas RE Member Representatives Committee (MRC) for consideration. The MRC shall discuss the revision request in a public meeting, and will accept and consider verbal and written comments pertaining to the request. The MRC will make a recommendation to the Texas RE Board of Directors, which may adopt the revision request, reject it, or adopt it with modifications. Any approved revision to the Primary Frequency Response Reference Document shall be filed with NERC and FERC for informational purposes.

As used in this document the following terms are defined as shown:

> **High Sustained Limit (HSL)** for a generating unit/generating facility/BESS: The limit established by the GO/GOP, continuously updatable in Real-Time, that describes the maximum sustained energy production capability of a generating unit/generating facility/BESS.

> **Low Sustained Limit (LSL)** for a generating unit/generating facility/BESS: The limit

[1] These spreadsheets are available ~~at www.TexasRE.org~~on Texas RE's public website.

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established by the GO/GOP, continuously updatable in Real-Time, that describes the minimum sustained energy ~~production~~ capability of a generating unit/generating facility/BESS. This value could be negative for BESS to represent the charging capability.

Maximum Megawatt Governor Control System (MW_{GCS}) for the purposes of this standard, maximum megawatt control range of the Governor control system. For all generator types, except BESS, MW_{GCS}, is calculated from HSL to 0 while BESS is calculated from HSL to LSL.

In this regional standard, the term "resource" is synonymous with "generating unit/generating facility/BESS".

Design Settings versus real-time Evaluation: Settings and verifications (R6) are constructed around unit design parameters, while frequency response expectations and evaluation scores, for every frequency event, are based upon real-time telemetered values.

II. Initial Primary Frequency Response Calculations

Requirement 9

R9. Each Generator Owner shall meet a minimum 12-month rolling average initial Primary Frequency Response performance of 0.75 on each generating unit/generating facility/BESS, based on participation in at least eight FMEs. See Attachment 1: Primary Frequency Response Reference Document for specific calculations.

9. 1 The initial Primary Frequency Response performance shall be the ratio of the Actual Primary Frequency Response to the Expected Primary Frequency Response during the initial measurement period following the FME.

9.2 If a generating unit/generating facility/BESS has not participated in a minimum of eight FMEs in a 12-month period, performance shall be based on a rolling eight-FME average.

9.3 A generating unit/generating facility's/BESS initial Primary Frequency Response performance during an FME may be excluded from the rolling average calculation by the Balancing Authority due to a legitimate operating condition that prevented normal Primary Frequency Response performance. Examples of legitimate operating conditions that may support exclusion of FMEs include, but are not limited to:

- Operation at or near auxiliary equipment operating limits (such as boiler feed pumps, condensate pumps, pulverizers, and forced draft fans);
- Data telemetry failure. The Balancing Authority may request raw data from the Generator Owner as a substitute.

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Initial Primary Frequency Response Performance Calculation Methodology

This portion of this PFR Reference Document establishes the process used to calculate initial ~~Primary Frequency Response~~PFR performance for each Frequency Measurable Event (FME) and then average the events over a 12-month period (or 8-event minimum) to establish whether a resource is compliant with Requirement R9.

This process calculates the initial p~~P~~er u~~U~~nit Primary Frequency Response of a resource [$P.U.PFR_{Resource}$] as a ratio between the adjusted a~~A~~ctual ~~Primary Frequency Response~~PFR ($APFR_{Adj}$),adjusted for the pre-event ramping of the unit, and the f~~F~~inal e~~E~~xpected Primary Frequency Response ($EPFR_{final}$) as calculated using the p~~P~~re-perturbation and p~~P~~ost-perturbation time periods of the initial measure.

This comparison of actual performance to a calculated target value establishes, for each type of resource, the initial p~~P~~er u~~U~~nit ~~Primary Frequency Response~~PFR [$P.U.PFR_{Resource}$] for any ~~Frequency Measurable Event (~~FME~~)~~.

<u>Initial Primary Frequency Response performance requirement</u>

$$Avg_{Period}[P.U.PFR_{Resource}] \geq 0.75,$$

Where P.U.PFR$_{Resource}$ is the per unit measure of the initial ~~Primary Frequency Response~~PFR of a resource during identified FMEs.

$$P.U.PFR_{Resource} = \frac{Actual\ Primary\ Frequency\ Response_{Adj}}{Expected\ Primary\ Frequency\ Response_{final}}$$

Where P.U.PFR$_{Resource}$ for each FME is limited to values between 0.0 and 2.0.

The a~~A~~djusted a~~A~~ctual ~~Primary Frequency Response~~PFR (APFRAdj) and the f~~F~~inal e~~E~~xpected ~~Primary Frequency Response~~PFR (EPFRfinal) are calculated as described below.

EPFR c~~C~~alculations use droop and deadband values as stated in Requirement R6 with the exception of combined-cycle facilities while being evaluated as a single resource (MW production of both the combustion turbine generator and the steam turbine generator are included in the evaluation) where the evaluation droop will be 5.78%.[2]

[2] The effective droop of a typical combined-cycle facility with governor settings per Requirement R6 is 5.78%, assuming a 2-to-1 ratio between combustion turbine capacity and steam turbine capacity. Use 5.78% effective droop in all combined-cycle performance calculations.

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Actual Primary Frequency Response (APFRadj)

The adjusted ~~A~~actual Primary Frequency Response (APFRadj) is the difference between Post-perturbation Average MW and Pre-perturbation Average MW, including the ramp magnitude adjustment.

$$APFR_{adj} = MW_{post-perturbation} - MW_{pre-perturbation} - Ramp\ Magnitude$$

Where:

Pre-perturbation Average MW: Actual MW averaged from T-16 to T-2

$$MW_{pre\ -\ perturbation} = \frac{\sum_{T-16}^{T-2} MW}{\#\, Scans}$$

Post-perturbation Average MW: Actual MW averaged from T+20 to T+52

$$MW_{post\ -\ perturbation} = \frac{\sum_{T+20}^{T+52} MW}{\#\, Scans}$$

Ramp Adjustment: The a~~A~~ctual ~~Primary Frequency Response~~PFR number that is used to calculate P.U.PFR is adjusted for the ramp magnitude of the generating unit/generating facility/BESS during the pre-perturbation minute. The ramp magnitude is subtracted from the APFR.

Ramp Magnitude = (MWT-4 – MWT-60)*0.59

(MWT-4 – MWT-60) represents the MW ramp of the generator resource/generator facility for a full minute prior to the event. The factor 0.59 adjusts this full minute ramp to represent the ramp that should have been achieved during the post-perturbation measurement period.

Expected Primary Frequency Response (EPFR)

For all generator types, the *ideal* e~~E~~xpected Primary Frequency Response ($EPFR_{ideal}$) is calculated as the difference between the $EPFR_{post\text{-}perturbation}$ and the $EPFR_{pre\text{-}perturbation}$.

$$EPFR_{ideal} = EPFR_{post-perturbation} - EPFR_{pre-perturbation}$$

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When the frequency is outside the Governor deadband and above 60Hz:

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$$EPFR_{pre-perturbation} = \left[\frac{(HZ_{pre-perturbation} - 60.0 - deadband_{max})}{(60 \times droop_{max} - deadband_{max})} \times (-1) \times (\overset{MW\_GCS}{\cancel{HSL}} - PA\ Capacity)\right]$$

$$EPFR_{post-perturbation} = \left[\frac{(HZ_{post-perturbation} - 60.0 - deadband_{max})}{(60 \times droop_{max} - deadband_{max})} \times (-1) \times (\overset{MW\_GCS}{\cancel{HSL}} - PA\ Capacity)\right]$$

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When the frequency is outside the Governor deadband and below 60Hz:

$$EPFR_{pre-perturbation} = \left[\frac{(HZ_{pre-perturbation} - 60.0 + deadband_{max})}{(60 \times droop_{max} - deadband_{max})} \times (-1) \times (HSL - PA\ Capacity)\right]$$

$$EPFR_{post-perturbation} = \left[\frac{(HZ_{post-perturbation} - 60.0 + deadband_{max})}{(60 \times droop_{max} - deadband_{max})} \times (-1) \times (HSL - PA\ Capacity)\right]$$

$$EPFR_{pre-perturbation} = \left[\frac{(HZ_{pre-perturbation} - 60.0 + deadband_{max})}{(60 \times droop_{max} - deadband_{max})} \times (-1) \times (\overset{MW\_GCS}{\cancel{HSL}} - PA\ Capacity)\right]$$

$$EPFR_{post-perturbation} = \left[\frac{(HZ_{post-perturbation} - 60.0 + deadband_{max})}{(60 \times droop_{max} - deadband_{max})} \times (-1) \times (\overset{MW\_GCS}{\cancel{HSL}} - PA\ Capacity)\right]$$

For each formula, when frequency is within the Governor deadband the appropriate EPFR value is zero. The deadbandmax and droopmax quantities come from Requirement R6.

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Where:

Pre-perturbation Average Hz: Actual Hz averaged from T-16 to T-2

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$$Hz_{pre-perturbation} = \frac{\sum_{T-16}^{T-2} Hz}{\# Scans}$$

Post-perturbation Average Hz: Actual Hz averaged from T+20 to T+52

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$$Hz_{post-perturbation} = \frac{\sum_{T+20}^{T+52} Hz}{\# Scans}$$

Capacity and net dependable capacity (NDC) ~~(Net Dependable Capacity)~~ are used interchangeably and the term c~~C~~apacity will be used in this document. Capacity is the official reported seasonal capacity of the generating unit/generating facility. ~~The Capacity for wind-powered generators is the real time HSL of the wind plant at the time the FME occurred.~~

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Power Augmentation: For Combined Cycle facilities, c~~C~~apacity is adjusted by subtracting ~~power augmentation (PA) capacity, if any, from the HSL. Other generator~~ types may also have power augmentation that is not frequency responsive. This could be "over-pressure" operation of a steam turbine at valves wide open or operating with a secondary fuel in service. The GO should provide the BA with documentation and conditions when power augmentation is to be considered in PFR calculations.

EPFR$_{final}$ for Combustion Turbines and Combined Cycle Facilities

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$$EPFR_{final} = EPFR_{ideal} + (HZ_{post-perturbation} - 60.0) \times 10 \times 0.00276 \times (HSL - PA\ Capacity)$$

$$EPFR_{final} = EPFR_{ideal} + (HZ_{post-perturbation} - 60.0) \times 10 \times 0.00276 \times (\overset{MW\_GCS}{\cancel{HSL}} - PA\ Capacity)$$

Note: The 0.00276 constant is the MW/0.1 Hz change per MW of c~~C~~apacity and represents the MW change in generator output due to the change in mass flow through the combustion turbine due to the speed change of the turbine during the post-perturbation measurement period. This factor is based on empirical data from a major 2003 event as measured on multiple combustion turbines in ERCOT.

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EPFR$_{final}$~~EPFRfinal~~ for Steam Turbine

$$EPFR_{final} = (EPFR_{ideal} + MW_{adj}) \times \frac{Throttle\ Pressure}{Rated\ Throttle\ Pressure}$$

Where:

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$$MW_{adj} = EPFR_{ideal} \times \frac{K}{Rated\ Throttle\ Pressure} \times (\cancel{HSL}\ MW\_GCS - PA\ Capacity) \times Steam\ Flow\ Change\ Factor \times -1$$

Where:

$$\%\ Steam\ Flow = \frac{MW_{post-perturbation}}{(HSL - PA\ Capacity)}$$

$$Steam\ Flow\ Change\ Factor = \frac{\%\ Steam\ Flow}{0.5}$$

$$\%\ Steam\ Flow = \frac{MW_{post-perturbation}}{(\cancel{HSL}\ MW\_GCS - PA\ Capacity)}$$

$$Steam\ Flow\ Change\ Factor = \frac{\%\ Steam\ Flow}{0.5}$$

Throttle Pressure = Interpolation of Pressure curve at $MW_{pre\text{-}perturbation}$

The r~~R~~ated t~~T~~hrottle p~~P~~ressure and the p~~P~~ressure curve, based on generator MW output, are provided by the GO to the BA. This pressure curve is defined by up to six pair of p~~P~~ressure and MW breakpoints where the r~~R~~ated t~~T~~hrottle p~~P~~ressure and MW output, where r~~R~~ated t~~T~~hrottle p~~P~~ressure is achieved, is the first pair and the m~~M~~inimum t~~T~~hrottle p~~P~~ressure and MW output, where the m~~M~~inimum t~~T~~hrottle p~~P~~ressure is achieved, as the last pair of breakpoints. If fewer breakpoints are needed, the pair values will be repeated to complete the six pair table.

The K factor is used to model the stored energy available to the resource. The value ranges between 0.0 and 0.6 psig per MW change when responding during an FME. The GO can measure the drop in throttle pressure when the resource is operating near 50% output of the steam turbine during a FME and provide this ratio of pressure change to the BA. K is then adjusted based on rated throttle pressure and resource capacity. An additional sensitivity factor, the s~~S~~team f~~F~~low c~~C~~hange f~~F~~actor, is based on resource loading (% steam flow) and further modifies the MW adjustment. This sensitivity factor will decrease the adjustment at resource

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outputs below 50% and increase the adjustment at outputs above 50%. The GO should determine the fixed K factor for each resource that generally results in the best match between EPFR and APFR (resulting in the highest $P.U.PFR_{Resource}$). For any generating unit, K will not change unless the steam generator is significantly reconfigured.

$EPFR_{final}$ for Other Generating Units/Generating Facilities

$$EPFR_{final} = EPFR_{ideal} + X$$

Where X is an adjustment factor that may be applied to properly model the delivery of PFR. The X factor will be based on known and accepted technical or physical limitations of the resource. X may be adjusted by the BA and may be variable across the operating range of a resource. X shall be zero unless the BA accepts an alternative value.

III. Sustained Primary Frequency Response Calculations

Requirement 10

R10. Each Generator Owner shall meet a minimum 12-month rolling average sustained Primary Frequency Response performance of 0.75 on each generating unit/generating facility/BESS, based on participation in at least eight FMEs. See Attachment 1: Primary Frequency Response Reference Document for specific calculations. *[Violation Risk Factor = Medium] [Time Horizon = Operations Assessment]*

10.1 The sustained Primary Frequency Response performance shall be the ratio of the Actual Primary Frequency Response to the Expected Primary Frequency Response during the sustained measurement period following the FME.

10.2 If a generating unit/generating facility/BESS has not participated in a minimum of eight FMEs in a 12-month period, performance shall be based on a rolling eight-FME average.

10.3 A generating unit/generating facility's/BESS sustained Primary Frequency Response performance during an FME may be excluded from the rolling average calculation by the Balancing Authority due to a legitimate operating condition that prevented normal Primary Frequency Response performance. Examples of legitimate operating conditions that may support exclusion of FMEs include, ~~,~~but are not limited to:

- Operation at or near auxiliary equipment operating limits (such as boiler feed pumps, condensate pumps, pulverizers, and forced draft fans);
- Data telemetry failure. The Balancing Authority ~~-~~may request raw data from the Generator Owner as a substitute.

Sustained Primary Frequency Response Performance Calculation Methodology

This portion of this PFR Reference Document establishes the process used to calculate

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sustained Primary Frequency Response performance for each Frequency Measurable Event (FME) and then average the events over a 12-month period (or 8-event minimum) to establish whether a resource is compliant with Requirement R10.

This process calculates the p~~P~~er u~~U~~nit s~~S~~ustained ~~Primary Frequency Response~~PFR of a resource [P.U.SPFR$_{Resource}$] as a ratio between the maximum actual unit response at any time during the period from T+46 to T+60, adjusted for the pre-event ramping of the unit, and the f~~F~~inal e~~E~~xpected ~~Primary Frequency Response~~PFR (EPFR) value at time T+46.[3]

This comparison of actual performance to a calculated target value establishes, for each type of resource, the p~~P~~er u~~U~~nit s~~S~~ustained ~~Primary Frequency Response~~PFR [P.U.SPFR$_{Resource}$] for any ~~Frequency Measurable Event (~~FME~~)~~.

Sustained Primary Frequency Response performance requirement:

The standard requires an average performance over a period of 12 months (including at least 8 measured events) that is ≥ 0.75.

$$Avg_{Period}\,[P.U.SPFR_{Resource}] \geq 0.75$$

$Avg_{Period}\,[P.U.SPFR_{Resource}]$ is either:

- the average of each resource's sustained ~~Primary Frequency Response~~PFR performances [*P.U.SPFR$_{Resource}$*] during all of the assessable Frequency Measurable Events (FMEs), for the most recent rolling 12 month period; or
- if the unit has not experienced at least 8 assessable FMEs in the most recent 12 month period, the average of the unit's last 8 sustained ~~Primary Frequency Response~~PFR performances when the unit provided frequency response during an ~~Frequency Measurable Event~~FME.

Sustained Primary Frequency Response Calculation (P.U.SPFR)

$$P.U.PFR_{\text{Resource}} = \frac{\text{Actual Sustained Primary Frequency Response}_{Adj}}{\text{Expected Sustained Primary Frequency Response}_{final}}$$

P.U.SPFR$_{Resource}$ is the per unit (P.U.) measure of the sustained ~~Primary Frequency Response~~PFR of a resource during identified ~~Frequency Measurable Events~~FMEs. For any given event *P.U.SPFR$_{Resource}$* for each FME will be limited to values between 0.0 and 2.0.

Actual Sustained Primary Frequency Response (*ASPFR*) Calculations

[3] The time designations used in this section refer to relative time after an FME occurs. For example, "T+46" refers to 46 seconds after the frequency deviation occurred.

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$$ASPFR = MW_{MaximumResponse} - MW_{pre-perturbation}$$

Where:

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Pre-perturbation Average MW: Actual MW averaged from T-16 to T-2.

$$MW_{pre-perturbation} = \frac{\sum_{T-16}^{T-2} MW}{\#\,Scans}$$

And:

$MW_{MaximumResponse}$ = *maximum MW value telemetered by a unit from T+46 through T+60 during low frequency events and the minimum MW value telemetered by a unit from T+46 through T+60 during a high frequency event.*

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Actual Sustained Primary Frequency Response, Adjusted (*ASPFRAdj*)

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$$ASPFR_{Adj} = ASPFR - RampMW\ Sustained$$

RampMW Sustained (MW) – The Standard requires a unit/facility to sustain its response to a Frequency Measureable Event. An adjustment available in determining a unit's sustained ~~Primary Frequency Response~~PFR performance (*P.U.*SPFR$_{Resource}$) is to account for the direction in which a resource was moving (increasing or decreasing output) when the event occurred T=t(0). This is the *RampMW* Sustained adjustment:

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RampMW Sustained = (*MW_{T-4}* – *MW_{T-60}*) x 0.821

Note: The terminology "MW_{T-4}" *refers to MW output at 4 seconds before the Frequency Measurable Event (FME) occurs at T=t(0).*

By subtracting a reading at 4 seconds before, from a reading at 60 seconds before, the formula calculates the MWs a generator moved in the minute (56 seconds) prior to T=t(0). The formula is then modified by a factor to indicate where the generator would have been at T+46, had the event not occurred: the "*RampMW Sustained*." It does this by multiplying the MW change over 56 seconds before the event (MWT-4 – MWT-60) by a modifier. This extrapolates to an equivalent number of MWs the generator would have changed if it had been allowed to continue on its ramp to T+46 unencumbered by the FME. The modifier is $\frac{46\ \text{seconds}}{56\ \text{seconds}}$ or 0.821.

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Expected Sustained Primary Frequency Response (*ESPFR*) Calculations

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The e~~E~~xpected s~~S~~ustained ~~Primary Frequency Response~~PFR ($ESPFR_{final}$) is calculated using the actual frequency at T+46, HZ_{T+46}.

This $ESPFR_{final}$ is the MW value a unit should have responded with if it is properly sustaining the output of its generating unit/generating facility in response to an FME. Determination of this value begins with establishing where it would be in an ideal situation; considers proper droop and dead-band values established in Requirement R6, ~~High Sustainable Limit (~~HSL~~), Low Sustainable Limit (~~LSL~~)~~ and actual frequency. It then allows for adjusting the value to compensate for the various types of Limiting Factors each generating units / generating facilities may have and any p~~P~~ower a~~A~~ugmentation c~~C~~apacity (PA c~~C~~apacity) that may be included in the HSL/LSL.

Establishing the Ideal Expected Sustained Primary Frequency Response

For all generator types, the ideal e~~E~~xpected s~~S~~ustained ~~Primary Frequency Response~~PFR ($ESPFR_{ideal}$) is calculated as the difference between the $ESPFR_{T+46}$ and the $EPFR_{pre\text{-}perturbation}$. The $EPFR_{pre\text{-}perturbation}$ ~~EPFRpre-perturbation~~ is the same $EPFR_{pre\text{-}perturbation}$ ~~EPFRpre-perturbation~~ value used in the Initial measure of R9.

$$ESPFR_{ideal} = ESPFR_{T+46} - EPFR_{pre-perturbation}$$

When the frequency is outside the Governor deadband and above 60Hz:

~~$ESPFR_{T+46} = \left[\frac{(HZ_{T+46} - 60 - deadband_{max})}{(droop_{max} \times 60 - deadband_{max})} \times (HSL - \text{PA Capacity}) \times (-1)\right]$~~

$$ESPFR_{T+46} = \left[\frac{(HZ_{T+46} - 60 - deadband_{max})}{(droop_{max} \times 60 - deadband_{max})} \times (\overset{\text{MW\_GCS}}{\cancel{HSL}} - \text{PA Capacity}) \times (-1)\right]$$

When the frequency is outside the Governor deadband and below 60Hz:

~~$ESPFR_{T+46} = \left[\frac{(HZ_{T+46} - 60 + deadband\,max)}{(droop\,max \times 60 - deadband\,max)} \times (HSL - \text{PA Capacity}) \times (-1)\right]$~~

$$ESPFR_{T+46} = \left[\frac{(HZ_{T+46} - 60 + deadband\,max)}{(droop\,max \times 60 - deadband\,max)} \times (\overset{\text{MW\_GCS}}{\cancel{HSL}} - \text{PA Capacity}) \times (-1)\right]$$

Capacity and ~~Net Dependable Capability (NDC)~~NDC are used interchangeably and the term c~~C~~apacity will be used in this document. Capacity is the official reported seasonal capacity of the generating unit/generating facility. ~~The capacity for wind-powered generators is the real-time HSL of the wind plant at the time the FME occurred.~~ The $deadband_{max}$ and $droop_{max}$ quantities come

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from Requirement R6.

For combined cycle facilities, determination of c~~C~~apacity includes subtracting power augmentation (PA) capacity, if any, from the original ~~HSL~~MW_{GCS}. Other generator types may also have power as t~~t~~hat is not frequency responsive. This could be "over-pressure" operation of a steam turbine at valves wide open or operating with a secondary fuel in service. The GO is required to provide the BA with documentation and identify conditions when this augmentation is in service.

$ESPFR_{final}$ for Combustion Turbines and Combined Cycle Facilities

~~$ESPFR_{final} = ESPFR_{Ideal} + (HZ_{T+46} - 60)*10*0.00276*(HSL - PACapacity)$~~

$$ESPFR_{final} = ESPFR_{Ideal} + (HZ_{T+46} - 60)*10*0.00276*(\overset{MW\_GCS}{\cancel{HSL}} - PACapacity)$$

Note: The 0.00276 constant is the MW/0.1 Hz change per MW of c~~C~~apacity and represents the MW change in generator output due to the change in mass flow through the combustion turbine due to the speed change of the turbine at HZ_{T+46}. (This is based on empirical data from a major 2003 event as measured on multiple combustion turbines in ERCOT.)

$ESPFR_{final}$ for Steam Turbine

$$ESPFR_{final} = \left(ESPFR_{ideal} + MW_{Adj}\right) \times \frac{Throttle\ Pressure}{Rated\ Throttle\ Pressure}$$

Where:

~~$MW_{Adj} = ESPFR_{ideal} \times \frac{K}{Rated\ Throttle\ Pressure} \times (HSL - PACapacity) \times Steam\ Flow\ Change\ Factor \times (-1)$~~

$$MW_{Adj} = ESPFR_{ideal} \times \frac{K}{Rated\ Throttle\ Pressure} \times (\overset{MW\_GCS}{\cancel{HSL}} - PACapacity) \times Steam\ Flow\ Change\ Factor \times (-1)$$

Where:

$$\%\ Steam\ Flow = \frac{MW_{post-perturbation}}{(HSL - PA\ Capacity)}$$

$$Steam\ Flow\ Change\ Factor = \frac{\%\ Steam\ Flow}{0.5}$$

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$$\%\ Steam\ Flow = \frac{MW_{post-perturbation}}{(\cancel{HSL} - PA\ Capacity)}$$

MW_GCS

$$Steam\ Flow\ Change\ Factor = \frac{\%\ Steam\ Flow}{0.5}$$

Throttle Pressure = Interpolation of Pressure curve at $MW_{pre\text{-}perturbation}$

The r~~R~~ated t~~T~~hrottle p~~P~~ressure and the p~~P~~ressure curve, based on generator MW output, are provided by the GO to the BA. This pressure curve is defined by up to six pair of p~~P~~ressure and MW breakpoints where the rated t~~T~~hrottle p~~P~~ressure and MW output where r~~R~~ated t~~T~~hrottle p~~P~~ressure is achieved is the first pair and the m~~M~~inimum t~~T~~hrottle p~~P~~ressure and MW output where the m~~M~~inimum t~~T~~hrottle p~~P~~ressure is achieved as the last pair of breakpoints. If fewer breakpoints are needed, the pair values will be repeated to complete the six pair table.

The K factor is used to model the stored energy available to the resource and ranges between 0.0 and 0.6 psig per MW change when responding during an FME. The GO can measure the drop in throttle pressure, when the resource is operating near 50% output of the steam turbine during a FME and provide this ratio of pressure change to the BA. K is then adjusted based on rated throttle pressure and resource capacity. An additional sensitivity factor, the steam flow change factor, is based on resource loading (% steam flow) and further modifies the MW adjustment. This sensitivity factor will decrease the adjustment at resource outputs below 50% and increase the adjustment at outputs above 50%. The GO should determine the fixed K factor for each resource that generally results in the best match between ESPFR and ASPFR (resulting in the highest $P.U.SPFR_{Resource}$). For any generating unit, K will not change unless the steam generator is significantly reconfigured.

$ESPFR_{final}$ for Other Generating Units/Generating Facilities/BESS

$$ESPFR_{final} = ESPFR_{Ideal} + X$$

Where X is an adjustment factor that may be applied to properly model the delivery of PFR. The X factor will be based on known and accepted technical or physical limitations of the resource. X may be adjusted by the BA and may be variable across the operating range of a resource. X shall be zero unless the BA accepts an alternative value.

IV. Limits on Calculation of Primary Frequency Response Performance (Initial and Sustained):

If ~~the~~ a generating unit/generating facility is operating within 2% of its (MW_{GCS} – PA capacity)~~(HSL – PA Capacity)~~ or within 5 MW (whichever is greater), or a BESS is operating within 2% or 3 MW of its MW_{GCS} from its applicable operating limit (high or low) at the time an

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FME occurs (pre-perturbation), then that resource's Primary Frequency Response performance is not evaluated for that FME.

For frequency deviations below 60 Hz ($Hz_{Post-perturbation}$ < 60 if:

$$MW_{pre-perturbation} \geq min[([HSL - PA\ Capacity]\ x\ 0.98),\ ([HSL - PA\ Capacity] - 5\ MW)]$$

$$MW_{pre-perturbation} \geq min[([\overset{MW\_GCS}{\cancel{HSL}} - PA\ Capacity]\ x\ 0.98),\ ([\overset{MW\_GCS}{\cancel{HSL}} - PA\ Capacity] - \overset{X\ MW}{\cancel{5\ MW}})]$$

then ~~Primary Frequency Response~~PFR is not evaluated for this FME, where X is 5 MW for generating units/generating facility and 3 MW for BESS

For frequency deviations above 60 Hz ($Hz_{Post-perturbation}$ > 60, if:

$$MW_{pre-perturbation} \leq max[(LSL + ([HSL - PA\ Capacity]\ x\ 0.02)), (LSL + 5\ MW)]$$

$$MW_{pre-perturbation} \leq max[(LSL + ([\overset{MW\_GCS}{\cancel{HSL}} - PA\ Capacity]\ x\ 0.02)), (LSL + \overset{X\ MW}{\cancel{5\ MW}})]$$

then ~~Primary Frequency Response~~PFR is not evaluated for this FME ~~,~~ where X is 5 MW for generating units/generating facility and 3 MW for BESS

Final Expected Primary Frequency Response ($EPFR_{final}$) is greater than Operating Margin: Caps and limits exist for resources operating with adequate reserve margin to be evaluated at least 2% of (MW_{GCS} ~~HSL~~ less PA c~~C~~apacity) or 5 MW for generating units/generating facilities or 3 MW for BESS~~)~~, but with Expected Primary Frequency $Response_{final}$ greater than the actual margin available.

1. The $P.U.PFR_{Resource}$ will be set to the greater of 0.75 or the calculated $P.U.PFR_{Resource}$ if all of the following conditions are met:
   a. The generating unit/generating facility's pre-perturbation operating margin (appropriate for the frequency deviation direction) is greater than 2% of its (HSL less PA c~~C~~apacity) and greater than 5 MW; and
   ~~a.~~b. The BESS's pre-perturbation operating margin (appropriate for the frequency deviation direction) is greater than 2% of its (MW_{GCS} less PA capacity) and greater than 3 MW; and
   ~~b.~~c. The Expected Primary Frequency $Response_{final}$ is greater than the generating unit/generating facility's/BESS available frequency responsive c~~C~~apacity[4]; and

[4] In this circumstance, when frequency is below 60 Hz, the $EPFR_{final}$ is set to operating margin based on MW_{GCS}~~HSL~~ (adjusted for any augmentation capacity) AND when frequency is above 60 Hz, the $EPFR_{final}$ is set to operating margin based on LSL for the purpose of calculating $PUPFR_{resource}$.

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~~c.~~d. The generating unit/generating facility's/BESS $APFR_{adj}$ response is in the correct direction.

2. When calculation of the $P.U.PFR_{Resource}$ uses the resource's (MW$_{GCS}$~~HSL~~ less PA c~~C~~apacity) as the maximum expected output, the calculated $P.U.PFR_{Resource}$ will not be greater than 1.0.

3. When calculation of the $P.U.PFR_{Resource}$ uses the resource's LSL as the minimum expected output, the calculated $P.U.PFR_{Resource}$ will not be greater than 1.0.

4. If the $APFR_{Adj}$ is in the wrong direction, then $P.U.PFR_{Resource}$ is 0.0.

5. These caps and limits apply to both the i~~I~~nitial and s~~S~~ustained ~~Primary Frequency Response~~PFR measures.

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Attachment A to
Primary Frequency Response Reference Document

Initial Primary Frequency Response Methodology for
BAL-001-TRE-2

Primary Frequency Response Measurement and Rolling Average Calculation – Initial Response

PA=Power Augmentation
HSL=High Sustained Limit
LSL = Low Sustained Limit
MW_{GCS} = maximum megawatt control range of the Governor control system

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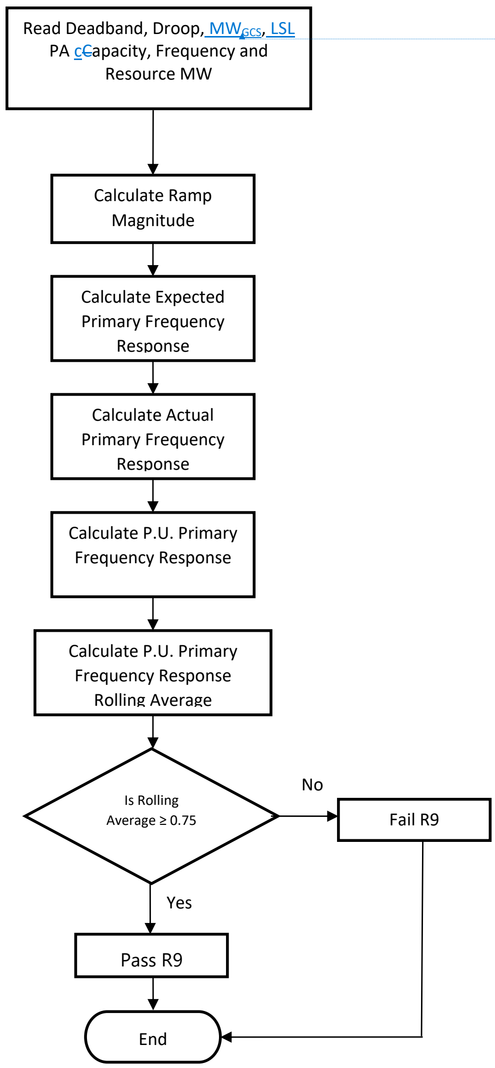

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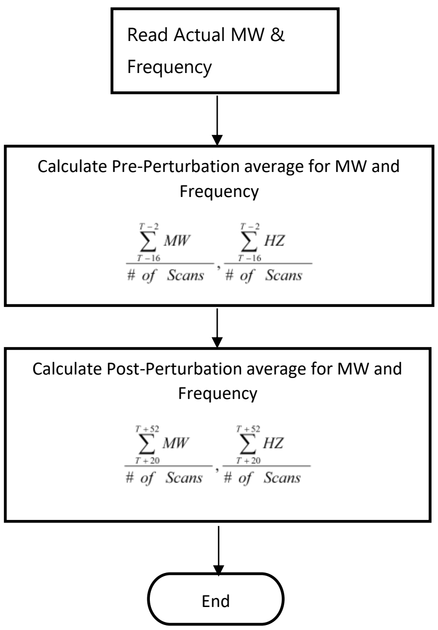
Pre/Post-Perturbation Average MW and Average Frequency Calculations



Ramp Magnitude Calculation

Ramp Magnitude = $(MW_{T-4} – MW_{T-60})*0.59$

End

$(MW_{T-4} – MW_{T-60})$ represents the MW ramp of the generator resource/generator facility for a full minute prior to the event. The factor 0.59 adjusts this full minute ramp to represent the ramp that should have been achieved during the post-perturbation measurement period.

Actual Primary Frequency Response ($APFR_{Adj}$)

$APFR_{Adj} = MW_{post\text{-}perturbation} – MW_{pre\text{-}perturbation}$ – Ramp Magnitude

End

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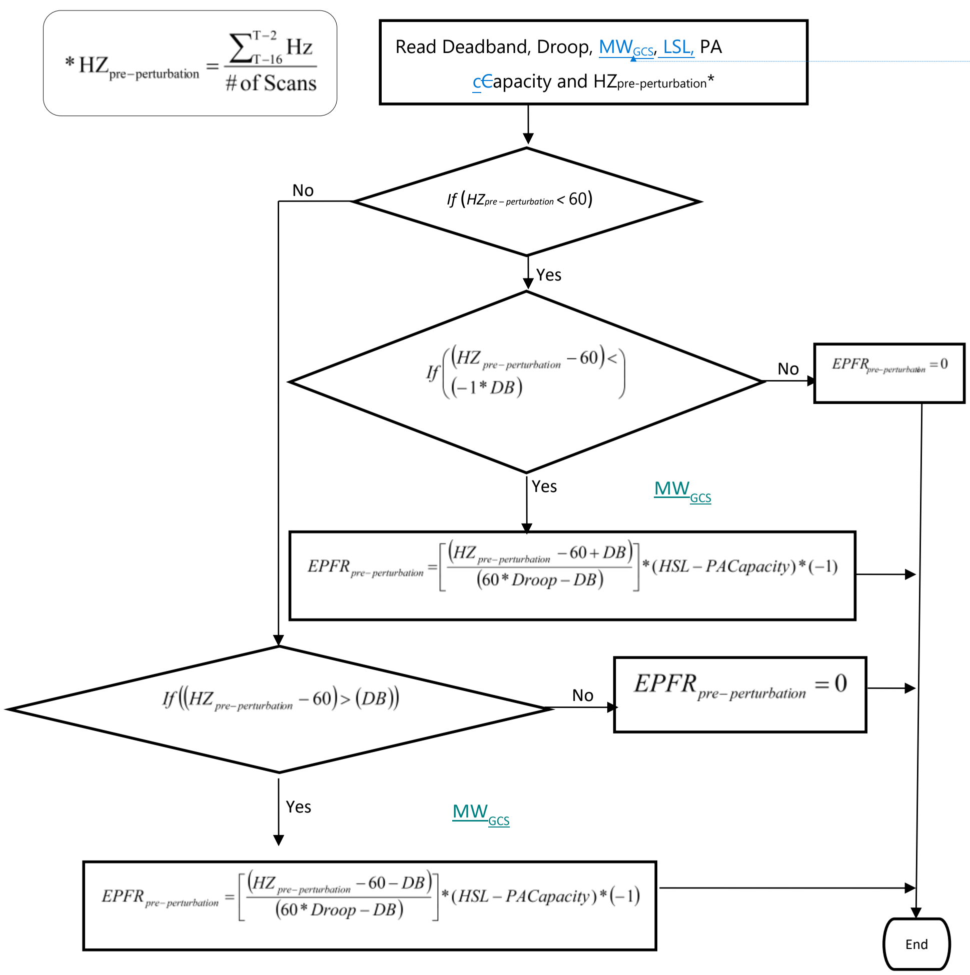
Expected Primary Frequency Response Calculation

Use the maximum droop and maximum deadband as required by R6. For Combined Cycle Facility evaluation as a single resource (includes MW production of the steam turbine generator), the EPFR will use 5.78% droop in all calculations.



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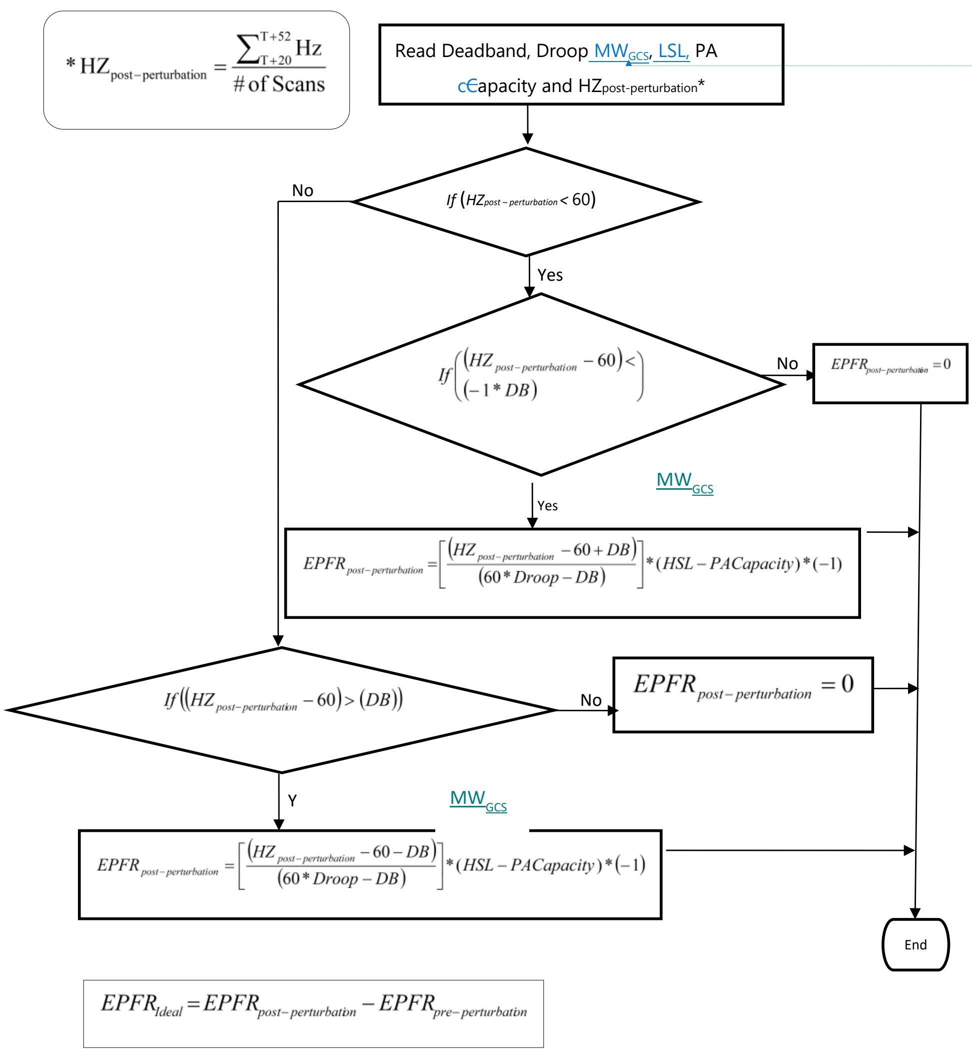

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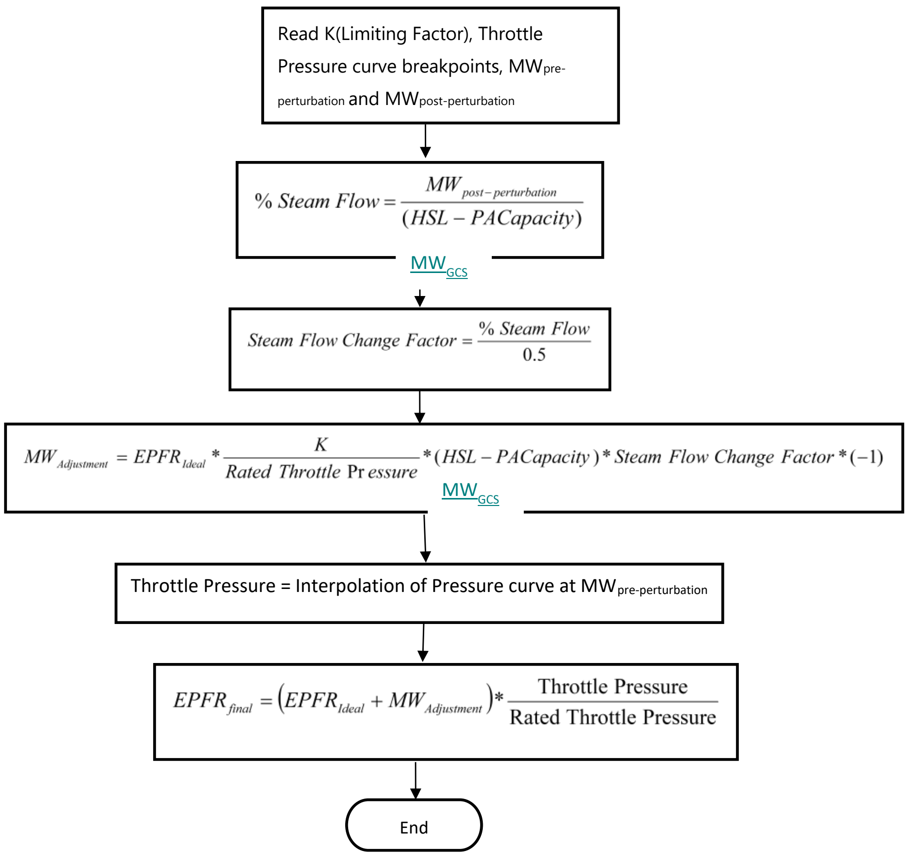
Adjustment for Steam Turbine



Adjustment for Combustion Turbines and Combined Cycle Facilities

Read MW_{GCS}, PA c~~C~~apacity, $HZ_{post-perturbation}$*

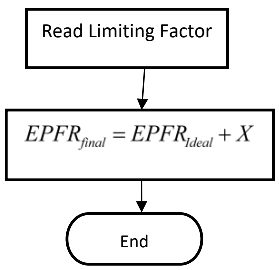
MW_{GCS}

$$EPFR_{final} = EPFR_{Ideal} + (HZ_{post-perturbation} - 60) * 10 * 0.00276 * (HSL - PACapacity)$$

End

0.00276 is the MW/0.1 Hz change per MW of c~~C~~apacity and represents the MW change in generator output due to the change in mass flow through the combustion turbine due to the speed change of the turbine during the post-perturbation measurement period. (This factor is based on empirical data from a major 2003 event as measured on multiple combustion turbines in ERCOT.)

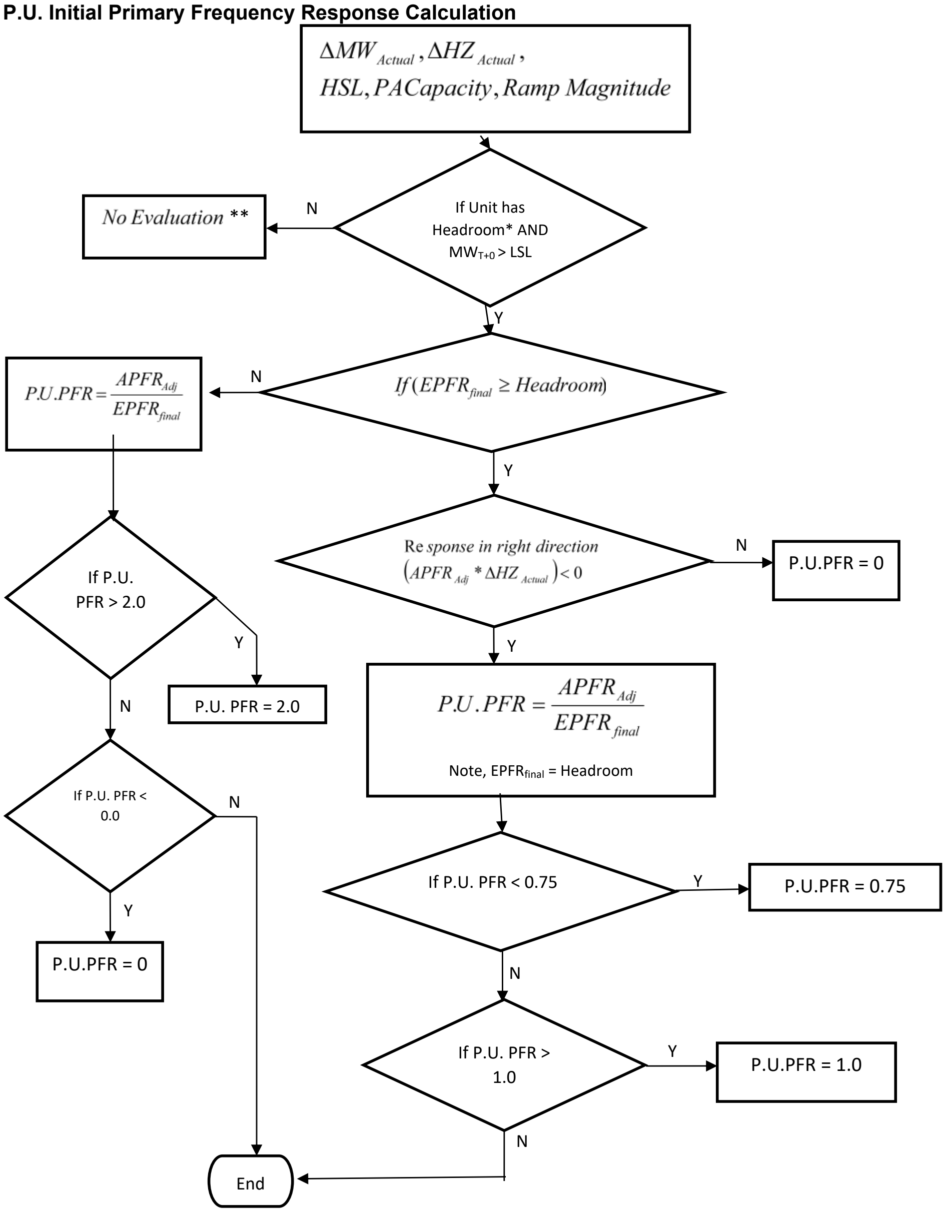
Adjustment for Other Units



$$* \mathrm{HZ}_{\text{post-perturbation}} = \frac{\sum_{T+20}^{T+52} \mathrm{HZ}_{\text{Actual}}}{\#\text{ of Scans}}$$

This adjustment Factor X will be developed to properly model the delivery of PFR due to known and approved technical limitations of the resource. X may be adjusted by the BA and may be variable across the operating range of a resource.

P.U. Initial Primary Frequency Response Calculation



*Check for adequate up headroom, low frequency events. Headroom must be greater than either X~~5~~MW or 2% of ~~(~~$(MW_{GCS}$ less PA capacity) ~~(HSL less PA Capacity)~~, whichever is larger. If a unit does not have adequate up headroom, the unit is considered operating at full capacity and will not be evaluated for low frequency events, where X is 5 MW for generating unit/generating facility and 3 MW for BESS~~.~~

Check for adequate down headroom, high frequency events. Headroom must be greater than either X~~5~~MW or 2% of $(MW_{GCS}$ less PA capacity)~~(HSL less PA Capacity)~~, whichever is larger. If a unit does not have adequate down headroom, the unit is considered operating at low capacity and will not be evaluated for high frequency events, ~~.~~ where X is 5 MW for generating unit/generating facility and 3 MW for BESS

For low frequency events:

$$\boxed{Headroom = \cancel{HSL}\ MW_{GCS} - PACapacity - MW_{T-2}}$$

For high frequency events:

$$\boxed{Headroom = MW_{T-2} - LSL}$$

**No further evaluation is required for Sustained Primary Frequency Response. This event will not be included in the Rolling Average calculation of either Initial or Sustained Primary Frequency Response.

T = Time in Seconds

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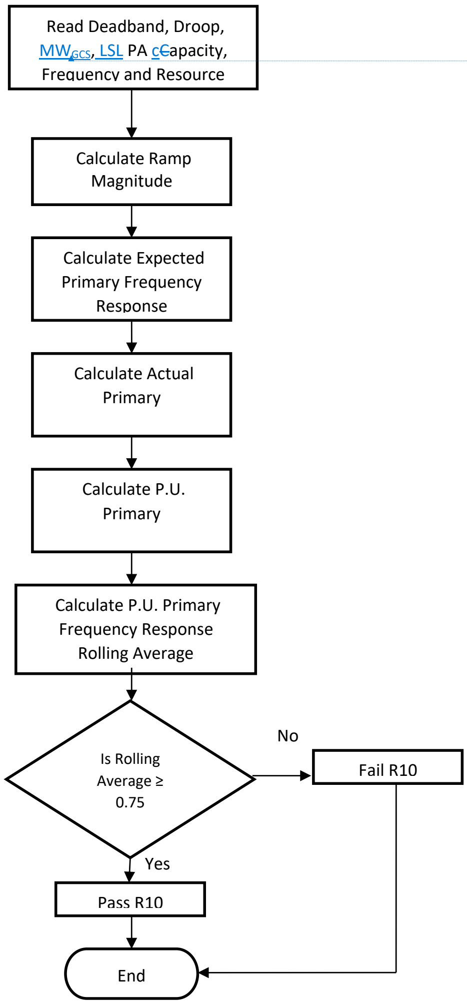
Attachment B to
Primary Frequency Response Reference Document

Sustained Primary Frequency Response Methodology for BAL-001-TRE-2

Primary Frequency Response Measurement and Rolling Average Calculation–Sustained Response



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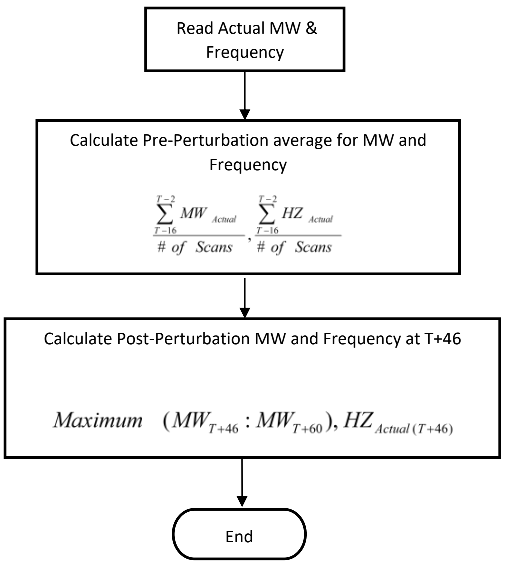
Pre/Post-Perturbation Average MW and Average Frequency Calculations



Ramp Magnitude Calculation - Sustained

$$Ramp\ Magnitude_{Sustained} = (MW_{T-4} - MW_{T-60}) * 0.821$$

End

(MW_{T-4} – MW_{T-60}) represents the MW ramp of the generator resource/generator facility for a full minute prior to the event. The factor 0.821 adjusts this full minute ramp to represent the ramp the generator would have changed the system had it been allowed to continue on its ramp to T+46 unencumbered.

Actual Sustained Primary Frequency Response ($ASPFR_{adj}$)

For low frequency events:

$$ASPFR_{Adj} = Maximum(MW_{T+46} : MW_{T+60}) - MW_{pre\text{-perturbation}} - Ramp\ Magnitude_{Sustained}$$

End

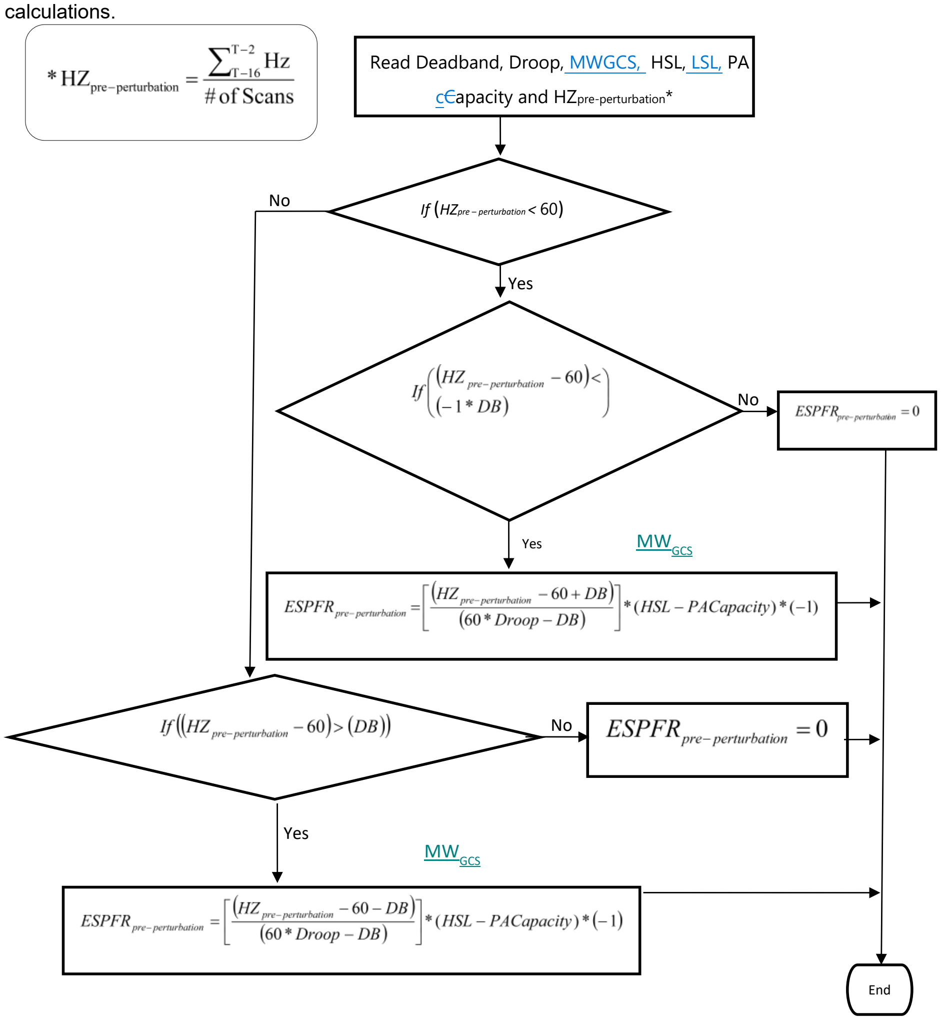
For high frequency events:

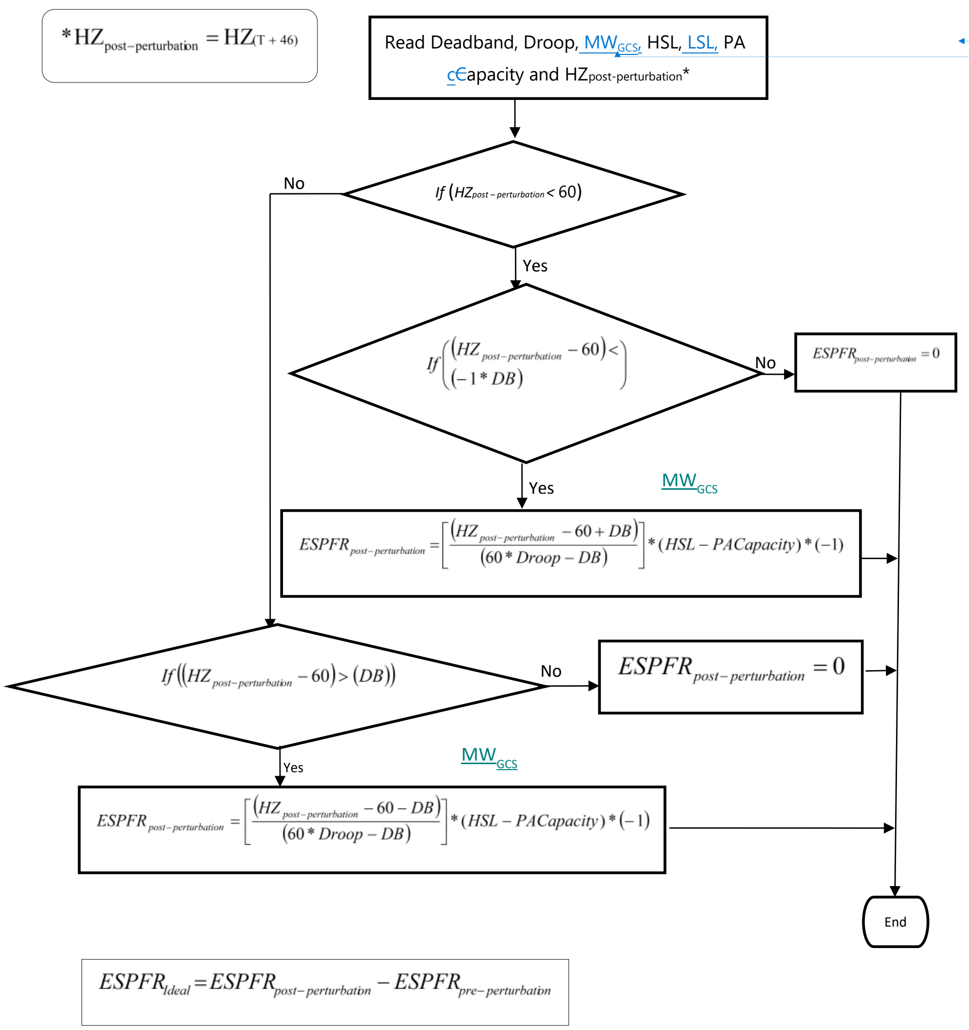
$$ASPFR_{Adj} = Minimum(MW_{T+46} : MW_{T+60}) - MW_{pre\text{-perturbation}} - Ramp\ Magnitude_{Sustained}$$

End

Expected Sustained Primary Frequency Response Calculation

Use the droop and deadband as required by R6. For Combined Cycle Facility evaluation as a single resource (includes MW production of the steam turbine generator), the EPFR will use 5.78% droop in all calculations.





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Adjustment for Steam Turbine

Read K(Limiting Factor), Throttle Pressure curve breakpoints, MW_{GCS}~~HSL~~, $MW_{pre-perturbation}$ and

$$\%\ Steam\ Flow = \frac{MW_{post-perturbation}}{(HSL - PACapacity)}$$

MW_{GCS}

$$Steam\ Flow\ Change\ Factor = \frac{\%\ Steam\ Flow}{0.5}$$

$$MW_{Adjustment} = ESPFR_{Ideal} * \frac{K}{Rated\ Throttle\ Pressure} * (HSL - PACapacity) * Steam\ Flow\ Change\ Factor * (-1)$$

MW_{GCS}

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Throttle Pressure = Interpolation of Pressure curve at $MW_{pre-perturbation}$

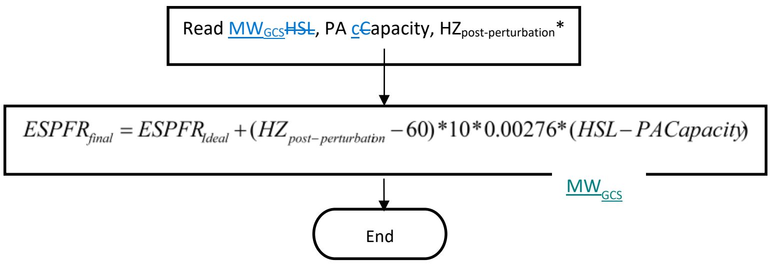
$$ESPFR_{final} = \left(ESPFR_{Ideal} + MW_{Adjustment}\right) * \frac{\text{Throttle Pressure}}{\text{Rated Throttle Pressure}}$$

End

$MW_{post-perturbation} = \text{Maximum}\ (MW_{T+46} : MW_{T+60})$ for low frequency events.

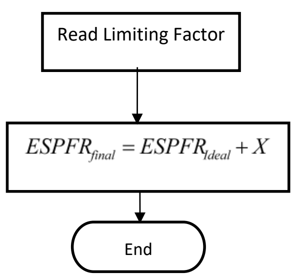
$MW_{post-perturbation} = \text{Minimum}\ (MW_{T+46} : MW_{T+60})$ for high frequency events.

Adjustment for Combustion Turbines and Combined Cycle Facilities



0.00276 is the MW/0.1 Hz change per MW of c~~C~~apacity and represents the MW change in generator output due to the change in mass flow through the combustion turbine due to the speed change of the turbine during the post-perturbation measurement period. (This factor is based on empirical data from a major 2003 event as measured on multiple combustion turbines in ERCOT.)

Adjustment for Other Units

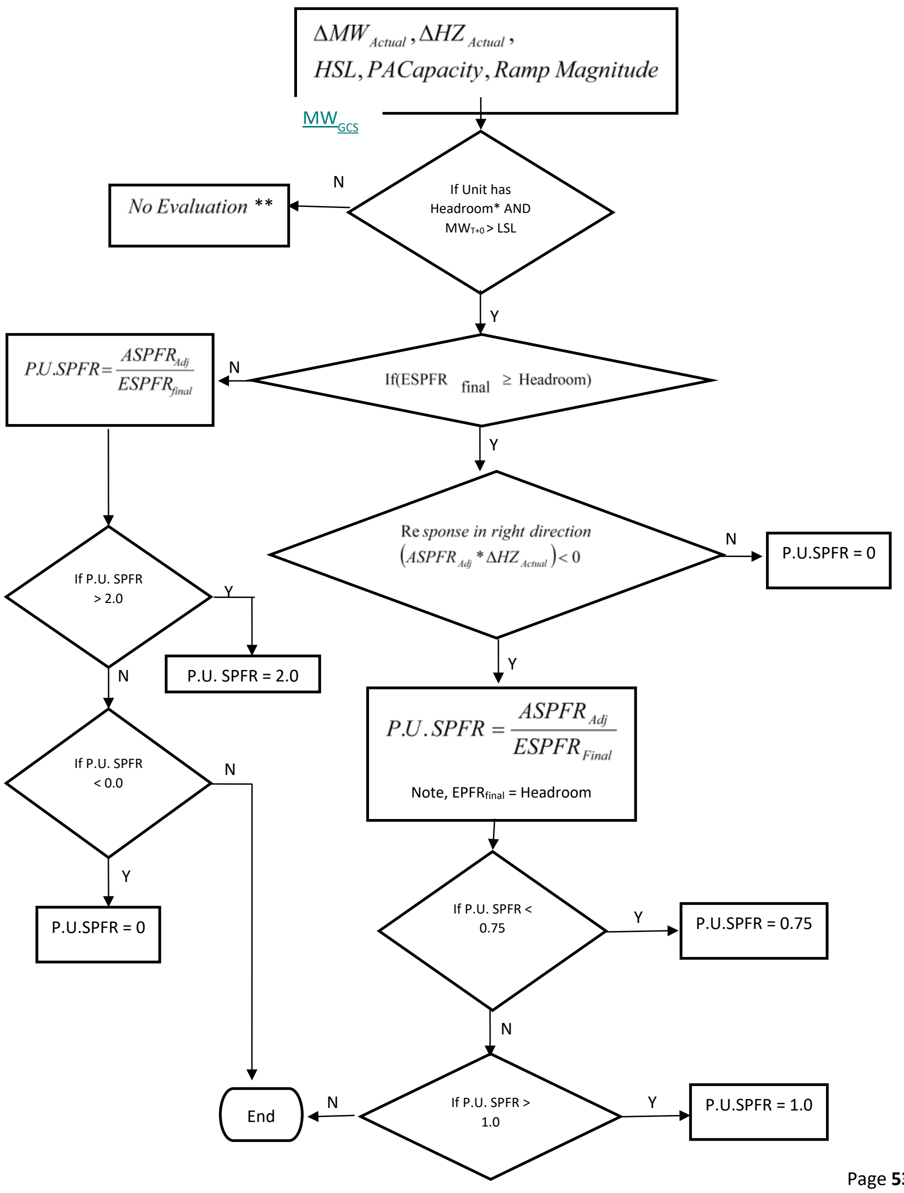


$* HZ_{Actual} = HZ_{(T + 46)}$

This adjustment Factor X will be developed to properly model the delivery of PFR due to known and approved technical limitations of the resource. X may be adjusted by the BA and may be variable across the operating range of a resource.

P.U. Sustained Primary Frequency Response Calculation

$*HZ_{Actual} = HZ_{(T+46)}$


$\Delta MW_{Actual}, \Delta HZ_{Actual},$
$HSL, PACapacity, Ramp\ Magnitude$
MW_{GCS}
If Unit has Headroom* AND MW_{T+0} > LSL
N
No Evaluation **
Y
If(ESPFR final ≥ Headroom)
N
$P.U.SPFR = \frac{ASPFR_{Adj}}{ESPFR_{final}}$
Y
Response in right direction $(ASPFR_{Adj} * \Delta HZ_{Actual}) < 0$
N
P.U.SPFR = 0
Y
$P.U.SPFR = \frac{ASPFR_{Adj}}{ESPFR_{Final}}$
Note, $EPFR_{final}$ = Headroom
If P.U. SPFR > 2.0
Y
P.U. SPFR = 2.0
N
If P.U. SPFR < 0.0
N
Y
P.U.SPFR = 0
If P.U. SPFR < 0.75
Y
P.U.SPFR = 0.75
N
If P.U. SPFR > 1.0
Y
P.U.SPFR = 1.0
N
End

*Check for adequate up headroom, low frequency events. Headroom must be greater than either X~~5~~MW or 2% of ~~(HSL less PA Capacity)~~ (MW_{GCS} less PA capacity), whichever is larger. If a unit does not have adequate up headroom, the unit is considered operating at full capacity and will not be evaluated for low frequency events, where X is 5 MW for generating unit/generating facility and 3 MW for BESS.

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Check for adequate down headroom, high frequency events. Headroom must be greater than either X~~5~~MW or 2% of (MW_{GCS} less PA capacity)~~(HSL less PA Capacity)~~, whichever is larger. If a unit does not have adequate down headroom, the unit is considered operating at low capacity and will not be evaluated for high frequency events, where X is 5 MW for generating unit/generating facility and 3 MW for BESS.

For low frequency events:

MW_{GCS}

$$\boxed{Headroom = HSL - PACapacity - MW_{T-2}}$$

For high frequency events:

$$\boxed{Headroom = MW_{T-2} - LSL}$$

**No further evaluation is required for Sustained Primary Frequency Response. This event will not be included in the Rolling Average calculation of either Initial or Sustained Primary Frequency Response.

T = Time in Seconds

Revision History

Version	Date	Action	Change Tracking
1	7/25/2011	Approved by SDT and submitted to Texas RE RSC for approval to post for regional ballot	
1.1	12/7/2012	Approved by SDT for submission to Texas RE RSC for approval to post for second regional ballot.	Changed sustained measure from average over event recovery period to point at 46 seconds after FME, and other changes to respond to field trial results, comments, and corrections.
1.1	3/6/2013	Texas RE RSC approves submittal to Texas RE Board	
1.1	4/23/2013	Texas RE Board approves submittal to NERC and FERC	
1.1	9/18/2013	NERC and Texas RE file Petition for approval to FERC	
1.1	1/16/2014	Approved by FERC	
1.2	5/21/2015	Texas RE Board approves revisions to Attachment 2 Primary Frequency Response Reference Document	For clarification and consistency of the equations used in the Attachment, changes performed to: - "T" in the equations refers to the start of the Frequency Measurable Event. - "T-2" nomenclature utilized for clarity rather than "t(-2)" (applicable to numerous equations) - Removed floating x in $EPFR_{final}$ for Steam Turbine equation - Corrected sign convention for Expected Sustained Primary Frequency Response to match the calculation for expected primary frequency response. Corrected Adjusted MW for $ESPFR_{final}$ for Steam Turbine by multiplying -1 to calculate proper value. - On Steam Flow Change Factor removed floating x and reinserted PA c~~C~~apacity. - Clarified Footnote 5 for scenario of high frequency event for setting LSL as operating margin (similar to HSL for low frequency events). - Clarified in flowcharts for both P.U. Initial Primary & Sustained

			Frequency Response Calculations: ○ Unit needs to have Headroom and be above LSL to be scored. ○ Cap $EPFR_{final}$ at value of Headroom on unit - Per RSC 5/11/2015, all references to "Final" were changed to "final". - Per RSC 5/11/2015, P.U.PFR and P.U.S.PFR removed italics in flowcharts.
1.3	11/14/2016	RSC approves minor changes to Attachment 2 Primary Frequency Response Reference Document	Replaced Reliability Standards Committee with Members Representative Committee to conform with changes to the Texas RE bylaws and regional standards development process.
1.3	12/07/2016	Texas RE Board approves minor changes to Attachment 2 Primary Frequency Response Reference Document.	Replaced Reliability Standards Committee with Members Representative Committee to conform with changes to the Texas RE bylaws and regional standards development process.
2.0	12/11/2019	Texas RE Board approves changes to the Attachment.	Removed the requirement for Governor droop and deadband settings for Steam turbines of combined cycle resources. Edited Requirements R9.3 and R10.3 to reflect the current process for submitting an exclusion request. Removed Attachment 1, which is the implementation plan for Regional Standard BAL-001-TRE-1. Changed numbering on Attachment 2 to Attachment 1
3.0	TBD		[Description of Changes to reference document]

Implementation Plan

SAR-013 Project to revise Regional Standard BAL-001-TRE-2
Regional Standard BAL-001-TRE-3

Applicable Standard(s)
Regional Standard BAL-001-TRE-3

Requested Retirement(s)
Regional Standard Regional Standard BAL-001-TRE-2

Prerequisite Standard(s)
None

Revision(s) to Glossary of Terms
None

Applicable Entities

- Balancing Authority (BA)
- Generator Owners (GO)
- Generator Operators (GOP)
- Exemptions:
    - Existing generating facilities regulated by the U.S. Nuclear Regulatory Commission are exempt from Standard BAL-001-TRE-2.
    - Generating units/generating facilities while operating in synchronous condenser mode are exempt from Standard BAL-001-TRE-2.
    - Any generators that are not required by the BA to provide primary frequency response are exempt from this standard.

Effective Date
This regional standard shall become effective on the first day of the first calendar quarter after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Retirement Date
Regional Standard BAL-001-TRE-2 shall be retired immediately prior to the effective date of Regional Standard BAL-001-TRE-3 in the particular jurisdiction in which the revised regional standard is becoming effective.

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Description of Changes to Regional Standard BAL-001-TRE-2
Project SAR-013

General Changes

- Revised BAL-001-TRE-2 to BAL-001-TRE-3

BAL-001-TRE-3 Section	Description	Rationale
A 6 Background	Corrected the typo “measurable” to measurable”	Corrected a typo.
A 6 Background	Added “battery energy storage system (BESS)” to the last sentence.	This revision fulfills one of the objectives of the SAR.
Requirement R2	Added BESS to generating unit/generating facility	This revision fulfills one of the objectives of the SAR.
Requirement R2 Footnote 1	Added BESS to generating unit/generating facility	This revision fulfills one of the objectives of the SAR.
Requirement R2 Footnote 1	Added “Attachment 1” to Primary Frequency Response Reference Document.	This revision specifies the Primary Frequency Response Reference Document is in Attachment 1. It is also to be consistent with Requirements R6, R9, and R10.
Requirement Part 2.3	Added BESS to generating unit/generating facility	This revision fulfills one of the objectives of the SAR.
M2	Added BESS to generating unit/generating facility	This revision fulfills one of the objectives of the SAR.
M3	Removed the “per” that should not have been there.	Corrected a typo
Requirement Part 6.1	Added “Generating Units that are not qualified to provide Operating Reserves” to Table 6.1.	This revision fulfills one of the objectives of the SAR.
Requirement Part 6.1 Footnote 2	Added footnote 2: “Refers to ancillary service qualification criteria as required by the Balancing Authority.	This revision fulfills one of the objectives of the SAR.

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BAL-001-TRE-3 Section	Description	Rationale
Requirement Part 6,.3	Added Primary Frequency Response Reference Document to Attachment 1.	This aligns with footnote 1.
Requirement Part 6.1 Footnote 3	Added footnote 3: "Only with prior approval from the Balancing Authority"	This revision fulfills one of the objectives of the SAR.
Table 1 Asterisk	Changed the asterisk to footnotes 4 and 5: "Requirements R6.1, R6.2, and R6.3 are not applicable to steam turbine(s) of a combined cycle resource.	This revision makes the footnotes consistent.
Requirement Part 6.2 Table 6.2	Added BESS – 5%	This revision fulfills one of the objectives of the SAR. A 5% droop for BESS was to match the requirements of existing generation units.
Requirement R7	Added BESS to generating unit/generating facility	This revision fulfills one of the objectives of the SAR.
M7	Added BESS to generating unit/generating facility	This revision fulfills one of the objectives of the SAR.
Requirement R9	Added BESS to generating unit/generating facility	This revision fulfills one of the objectives of the SAR.
Requirement R9	Added Primary Frequency Response Reference Document to Attachment 1.	This aligns with footnote 1.
Requirement Part 9.2	Added BESS to generating unit/generating facility	This revision fulfills one of the objectives of the SAR.
Requirement Part 9.3	Added BESS to generating unit/generating facility	This revision fulfills one of the objectives of the SAR.
M9	Added BESS to generating unit/generating facility	This revision fulfills one of the objectives of the SAR.
Requirement R10	Added BESS to generating unit/generating facility	This revision fulfills one of the objectives of the SAR.
Requirement R10	Added Primary Frequency Response Reference Document to Attachment 1.	This aligns with footnote 1.

BAL-001-TRE-3 Section	Description	Rationale
Requirement Part 10.2	Added BESS to generating unit/generating facility	This revision fulfills one of the objectives of the SAR.
Requirement Part 10.3	Added BESS to generating unit/generating facility	This revision fulfills one of the objectives of the SAR.
M10	Added BESS to generating unit/generating facility	This revision fulfills one of the objectives of the SAR.
Section C 1.1	Added abbreviation for Compliance Enforcement Authority (CEA)	This change makes it consistent with other NERC Reliability Standards.
Section C 1.2	Revised this section to include more detail on when the reset time frame will occur.	This revision fulfills one of the objectives of the SAR.
Violation Severity Levels	Corrected formatting for R4	Format correction.
Standard Attachments	Changed font to size 12 to match the rest of the document.	Format correction.
Standard Attachments 1. a	Added comma after R9	Corrected a typo

Attachment 1

General
- Changed font size from 11pt to 12pt
- Removed capitalization from "capacity" as it is not defined in the NERC Glossary.

Attachment 1 Section	Description	Rationale
I. Introduction	Added BESS to the description of High Sustained Limit.	This revision fulfills one of the objectives of the SAR.
I. Introduction	Revised description of Low Sustained Limit (LSL)	Definition was modified to capture the charging side of the operation curve for BESS units.
I. Introduction	Added description for Maximum Megawatt Governor Control System (MW_{GCS})	Captures the available range of MW response for performance calculations.
I. Introduction	Added description for Design Settings versus Real-time Evaluation	To clarify the difference in expectation in minimum design requirements vs operational settings and evaluation.
I. Introduction	Revised Footnote 1 to indicate that the spreadsheets are found on Texas RE's public website, rather than a specific link.	This will not need to be updated if the link changes.
II Initial Primary Frequency Response Calculations Requirement R9	Included the revised language for Requirement R9.	To be consistent with the Regional Standard.
Initial Primary Frequency Response Performance Calculation Methodology	Changed Primary Frequency Response to the acronym (PFR).	The acronym is described in the Introduction paragraph.

Initial Primary Frequency Response Performance Calculation Methodology	Changed Actual to lower case (actual).	This is not a NERC Glossary term.
Initial Primary Frequency Response Performance Calculation Methodology	Changed Final Expected to lower case (final expected).	This is not a NERC Glossary term.
Actual Primary Frequency Response	Changed Adjusted Actual to lowercase (adjusted actual).	This is not a NERC Glossary term.
Actual Primary Frequency Response	Changed Actual to lowercase (actual)	This is not a NERC Glossary term.
Expected Primary Frequency Response (EPFR)	Changed Expected to lowercase (expected).	This is not a NERC Glossary term.
Expected Primary Frequency Response (EPFR)	Revised equations for Expected Primary Frequency Response to change HSL to MW_{GCS}	Equation was revised to align with the definition of MW_{GCS}
Expected Primary Frequency Response (EPFR) - Pre-perturbation Average Hz	Pre-perturbation Average Hz – Removed capitalization of net dependable capacity.	This term is not defined in the NERC Glossary.

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Expected Primary Frequency Response (EPFR) - Pre-perturbation Average Hz	Removed capitalization of combined cycle.	This term is not defined in the NERC Glossary.
Expected Primary Frequency Response (EPFR) - Pre-perturbation Average Hz	Removed sentence: "The Capacity for wind powered generators is the real time HSL of the wind plant at the time the FME occurred."	The pre-perturbation Average Hz is different than capacity for wind. Statement is no longer needed due to updated definition of MW_{GCS}.
$EPFR_{final}$ for Combustion Turbines and Combined Cycle Facilities	Revised equations for $EPFR_{final}$ for combustion turbines, combined cycle facilities and steam turbines to change HSL to MW_{GCS}	The equations were revised to align with the definition of MW_{GCS} .
$EPFR_{final}$ for Steam Turbine	Revised equations for $EPFR_{final}$ for combustion turbines, combined cycle facilities and steam turbines to change HSL to MW_{GCS}	The equations were revised to align with the definition of MW_{GCS}.
$EPFR_{final}$ for Steam Turbine	Removed capitalization on rated throttle pressure.	This term is not defined in the NERC Glossary.
$EPFR_{final}$ for Steam Turbine	Removed capitalization on pressure.	This term is not defined in the NERC Glossary.
$EPFR_{final}$ for Steam Turbine	Removed capitalization on steam flow change factor.	This term is not defined in the NERC Glossary.
III. Sustained Primary Frequency Response Calculations	Included the revised language for Requirement R10.	To be consistent with the Regional Standard.

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Sustained Primary Frequency Response Performance Calculation Methodology	Changed Per Unit Sustained to lowercase (per unit sustained)	This term is not defined in the NERC Glossary.
Sustained Primary Frequency Response Performance Calculation Methodology	Changed Primary Frequency Response to the acronym (PFR).	The acronym is described in the Introduction paragraph.
Sustained Primary Frequency Response Performance Calculation Methodology	Changed Final Expected to lowercase (final expected).	This term is not defined in the NERC Glossary.
	Changed Frequency Measurable Event to acronym (FME).	The acronym is described in the Introduction paragraph.
Sustained Primary Frequency Response performance requirement	Changed Primary Frequency Response to the acronym (PFR).	The acronym is described in the Introduction paragraph.
Sustained Primary Frequency Response performance requirement	Changed Frequency Measurable Event to acronym (FME).	The acronym is described in the Introduction paragraph.

Expected Sustained Primary Frequency Response (*ESPFR*) Calculations	Changed Expected Sustained to lower case (expected sustained)	This term is not defined in the NERC Glossary.
Expected Sustained Primary Frequency Response (*ESPFR*) Calculations	Changed Primary Frequency Response to the acronym (PFR).	The acronym is described in the Introduction paragraph.
Expected Sustained Primary Frequency Response (*ESPFR*) Calculations	Changed High Sustainable Limit to the acronym (HSL)	The acronym is described in the Introduction paragraph.
Expected Sustained Primary Frequency Response (*ESPFR*) Calculations	Changed Low Sustainable Limit (LSL) to the acronym.	The acronym is described in the Introduction paragraph.
Expected Sustained Primary Frequency Response (*ESPFR*) Calculations	Removed capitalization from power augmentation capacity.	This term is not defined in the NERC Glossary.
Establishing the Ideal Expected Primary Frequency Response	Removed capitalization from expected sustained.	This term is not defined in the NERC Glossary.
Establishing the Ideal Expected Primary Frequency Response	Changed Primary Frequency Response to the acronym (PFR).	The acronym is described in the Introduction paragraph.

Establishing the Ideal Expected Primary Frequency Response	Revised calculations for establishing the ideal Expected Sustained Primary Frequency Response	Equations were revised to align with the definition of MW_{GCS}
Establishing the Ideal Expected Primary Frequency Response	Changed net dependable capacity to the acronym (NDC).	The acronym is described previously.
Establishing the Ideal Expected Primary Frequency Response	Removed the sentence: The capacity for wind powered generators is the real-time HSL of the wind plant at the time the FME occurred.	The pre-perturbation Average Hz is different than the capacity for wind. Statement is no longer needed due to updated definition of MW_{GCS}
Establishing the Ideal Expected Primary Frequency Response	Changed HSL to $MW_{GCS.}$	Equation was revised to align with the definition of MW_{GCS}
$ESPFR_{final}$ for Combustion Turbines and Combined Cycle Facilities	Revised equations for $EPFR_{final}$ for Combustion Turbines and Combined Cycle Facilities to change HSL to MW_{GCS}	Equation was revised to align with the definition of MW_{GCS}
$ESPFR_{final}$ for Steam Turbine	Revised equations for $EPFR_{final}$ for Steam Turbine to change HSL to MW_{GCS}	Equation was revised to align with the definition of MW_{GCS}
$ESPFR_{final}$ for Steam Turbine	Changed rated throttle pressure to lowercase.	This term is not defined in the NERC Glossary.
$ESPFR_{final}$ for Steam Turbine	Changed pressure to lowercase.	This term is not defined in the NERC Glossary.
$ESPFR_{final}$ for Steam Turbine	Changed minimum throttle pressure to lowercase.	This term is not defined in the NERC Glossary.

IV. Limits on Calculation of Primary Frequency Response Performance (Initial and Sustained):	Changed HSL to MW_{GCS} Added “or a BESS is operating within 2% or 3MW of its MW_{GCS}	Equations were revised to align with the definition of MW_{GCS} 3 MW or 2% limit was the agreed limit for BESS units to be excluded from evaluation.
IV. Limits on Calculation of Primary Frequency Response Performance (Initial and Sustained):	Revised equations to change HSL to MW_{GCS}	Equation was revised to align with the definition of MW_{GCS}
IV. Limits on Calculation of Primary Frequency Response Performance (Initial and Sustained):	Added “where X is 5 MW for generating units/generating facility and 3 MW for BESS”	This language aligns with ERCOT Operating Guides.
IV. Limits on Calculation of Primary Frequency Response Performance (Initial and Sustained):	Changed Primary Frequency Response to the acronym (PFR).	The acronym is described in the Introduction paragraph.

Final Expected Primary Frequency Response ($EPFR_{final}$) is greater than Operating Margin:	Changed HSL to MW_{GCS}	Equation was revised to align with the definition of MW_{GCS}
Final Expected Primary Frequency Response ($EPFR_{final}$) is greater than Operating Margin:	Added "or a BESS is operating within 2% or 3MW of its MW_{GCS}	3 MW or 2% limit was the agreed limit for BESS units to be excluded from evaluation
Final Expected Primary Frequency Response ($EPFR_{final}$) is greater than Operating Margin:	Added: The BESS's pre-perturbation operating margin (appropriate for the frequency deviation direction) is greater than 2% of its (MW_{GCS} less PA Capacity) and greater than 3 MW; and	3 MW or 2% limit was the agreed limit for BESS units to be excluded from evaluation
Final Expected Primary Frequency Response ($EPFR_{final}$) is greater than Operating Margin:	Changed HSL to MW_{GCS}.	revised to align with the definition of MW_{GCS}

Final Expected Primary Frequency Response ($EPFR_{final}$) is greater than Operating Margin:	Changed initial and sustained to lower case.	These terms are not defined in the NERC Glossary.

Attachment A

- Added LSL = Low Sustained Limit
- Added MW_{GCS} = maximum megawatt control range of the Governor control system
- Made conforming changes to the flowcharts to align with Attachment 1
- Removed capitalization from “capacity” as it is not defined in the NERC Glossary.

Attachment B

- Made conforming changes to the flowcharts to align with Attachment 1
- Removed capitalization from “capacity” as it is not defined in the NERC Glossary.

ERCOT IBRWG Update

Julia Matevosyan
Associate Director and Chief Engineer
ESIG

ESIG
ENERGY SYSTEMS INTEGRATION GROUP

09/17/2025

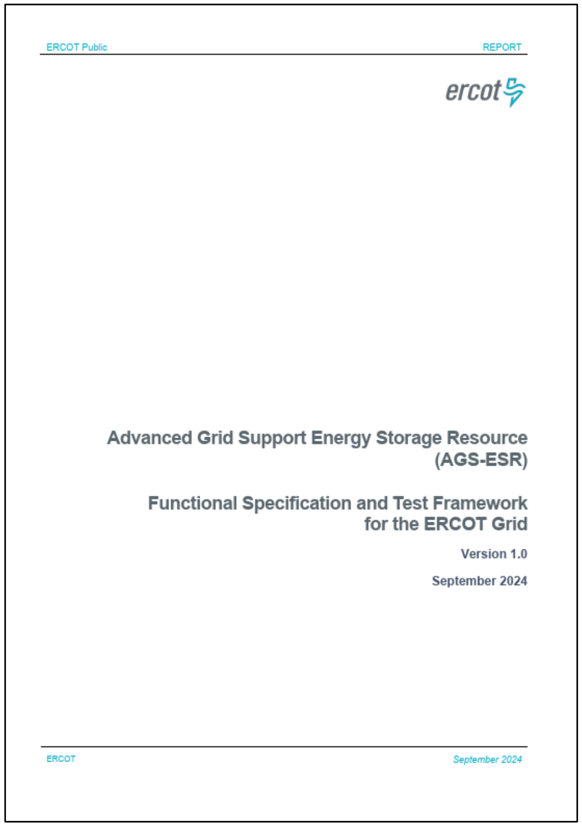
IBRWG Background Information

- Scope reviewed and approved at April 2025 ROS meeting https://www.ercot.com/calendar/04032025-ROS-Meeting-_-Webex.
- More than 100 attendees at peak of each IBRWG meeting both ERCOT and outside stakeholders.
- Discussing performance of IBRs, changing NERC standards related to IBRs (presented by TRE) and any new performance requirements that ERCOT may need as the system and technology continue evolving.
- On average about two ERCOT's Revisions Requests (RRs) per year are going though IBRWG.
- Other topics being discussed:
  - Changes to DWG Procedure Manual related to IBR modeling (jointly with DWG)
  - ERCOT IBR-related events
  - IBR limitations/issues to perform in accordance with specific ERCOT requirements and potential mitigation
  - New IBR technology developments and changes to IBR interconnection requirements/standards in North America (NERC and other ISO areas) and globally
  - Any large IBR related performance events outside of ERCOT

Public

Advanced Grid Support (AGS) from Energy Storage Resources (ESR)

- In summer 2023 ERCOT presented a benefit analysis of grid forming IBRs for the system.
- In summer 2024 ERCOT presented a set of simulation-based tests to be applied to ESRs to qualify as those with AGS.
- As the next step, the tests were drafted into Dynamic Working Group's (DWG) Procedure Manual and discussed at both IBRWG and DWG.
- OEMs with commercial AGS ESR products presented at IBRWG, reflecting on ERCOT's testing requirements and provided comments to the draft of DWG Procedure Manual.
- DWG Procedure Manual Approved by ROS in May 2025.
- Now, if any Interconnecting Entity would like to install AGS ESR these tests apply (as a part of ERCOT Model Quality Test).
- The tests were also built into DMView and PMView tools, in June 2025.


ERCOT Public REPORT

ercot

Advanced Grid Support Energy Storage Resource (AGS-ESR)

Functional Specification and Test Framework for the ERCOT Grid

Version 1.0

September 2024

ERCOT September 2024

Public

Advanced Grid Support from Energy Storage Resources

- In fall 2024 NOGRR 727 and PGRR 121 requiring all future ESRs to have AGS capability were also developed and entered the stakeholder process.
- NOGRR 727 and PGRR 121 on the agenda at the August 2025 TAC for vote with Urgent status.
- Market/Incentives proposal is still under discussion: NPRR 1278 to create the Advanced Grid Support Service, introducing market mechanisms to incentivize AGS in ESRs.

Reactive Power at 0 MW

- NOGRR 245 introduced wholesale reference to IEEE2800 Clause 5 (Reactive capability, incl. down to 0 MW, during normal operation) in ERCOT's Nodal Operating Guide Voltage Rider-Through (VRT) section (Section 2.9.1).
- This created ambiguity with existing ERCOT Protocols (Sec. 3.15), which require reactive support at output ≥10%.
- Sect. 3.15 also requires utilization of reactive capability at lower output levels, if available, when an IBR is online.
- Combined with wholesale adoption of IEEE2800 Clause 5 through NOGRR245, this seems to have introduced a requirement for all future IBRs (SGIA signed after 08/01/24) to have and utilize reactive capability down to 0 MW output.
- However, with Clause 5 (relates to normal operation) being referenced in VRT Section there is lack of clarity, which may lead to cost/risk for IBR developers – plants may lock in different designs and then face future compliance disputes.
- OEM brought this issue at June IBRWG meeting.
- IBRWG leadership, the OEM and some interested REs met offline in July to discuss.
- As of August, IBRWG meeting, ERCOT is reviewing with their legal deciding on Next Steps.

Reactive Power at 0 MW – Potential Next Steps

- Clarify whether ERCOT requires or does not require reactive power capability below 10% output.
- Resolve mismatch by placing Clause 5 reference in the more appropriate section of the ERCOT Nodal Protocols(Section 3.15).
- Provide guidance on:
  - Utilization of reactive capability (i.e. capability vs performance) and
  - IBR plant vs inverter capability requirements (there's lack of clarity on this in IEEE 2800 language)
- Preferably (requested by OEMs), define duration, ambient conditions, and system need before finalizing.

PRF/VRT Coordination Issues

- At July IBRWG, ERCOT brought up a coordination issue between voltage-ride through mode and primary frequency response of IBRs. This issue is seen from both wind and solar facilities, as shown in ERCOT's presentation.
- The issue results in unexpected PFR responses during recovery period after VRT events.
- The reasons are two-fold:
  - Instantaneous (erroneous) detection of under- or over- frequency spikes during fault conditions results in unexpected/undesirable PFR response after the fault is cleared and/or
  - Active power set point to which PFR droop is applies is that during or shortly after the fault (i.e. reduced active power production) and not pre-disturbance output – results in delayed active power recovery, and/or incorrect response (not as expected) to real frequency events that may follow an initial fault event
- Inverter and power plant controller OEMs are presenting at Aug and Sept IBRWG.
- ERCOT will then be deciding on recommendations related to frequency event detection for PFR, mode prioritization between VRT and PFR, and active power set point to which PFR is applied.

Two ESIG Trainings – Nov and Dec 2025

ESIG

ESIG Interconnection Studies Short Course

WHEN: November 17-19, 2025

WHERE: Manatee Lagoon, 6000 N Flagler Dr, West Palm Beach, FL 33407

MORE DETAILS:

This 3-day in-person training is intended to enhance the knowledge and ability of the current workforce through coursework focused on best practices for performing the study work necessary to interconnect inverter-based resources to the bulk power system reliably. Training participants will learn practical methods and best practices that can be leveraged into enhanced study practices across the industry. These training modules will focus on the expected day-to-day needs of engineers performing interconnection studies, model quality tests, or inverter-based resource model and simulation work as well as managing study practices within their organization.

EXPRESS INTEREST - INTERCONNECTION STUDIES SHORT COURSE

ESIG Electromagnetic Transient Training

WHEN: December 16 - 19, 2025

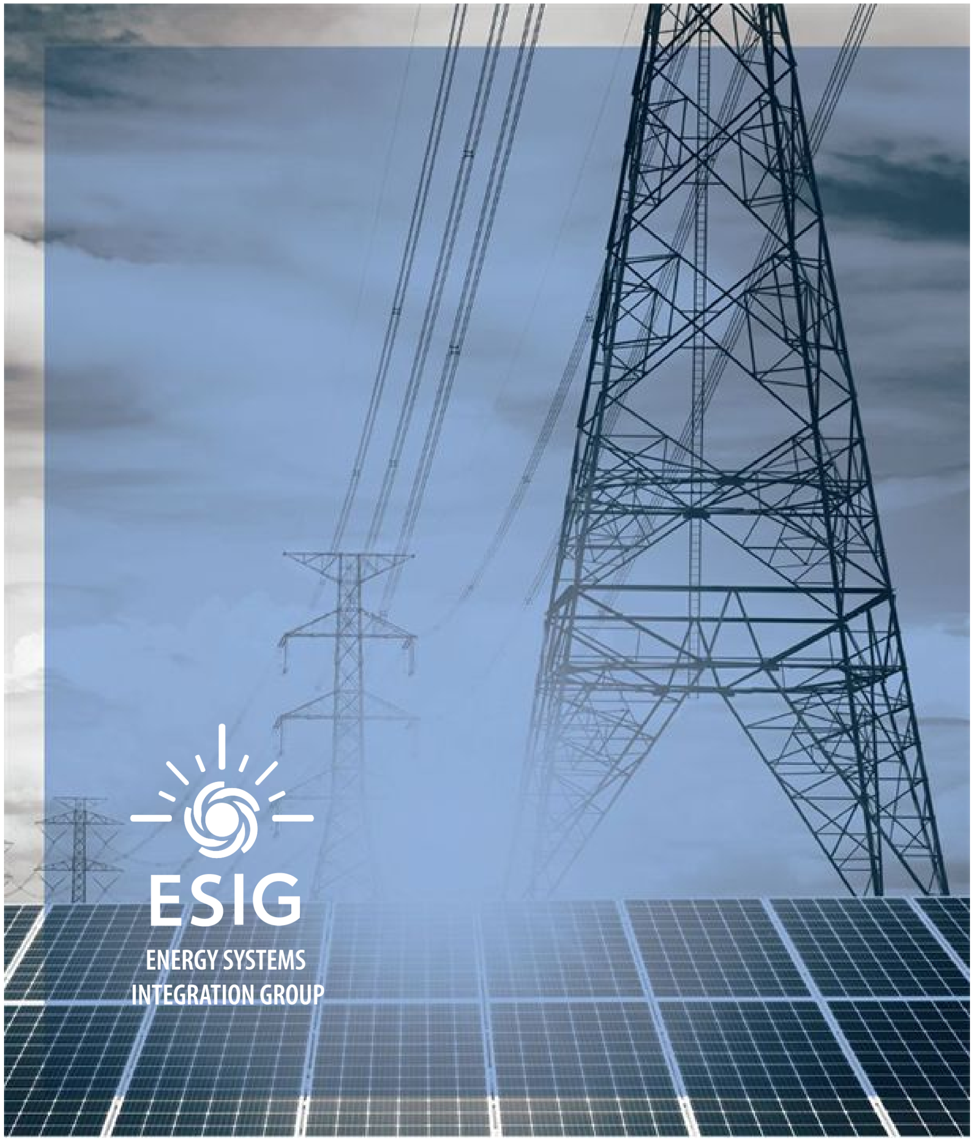
WHERE: Texas RE's Rio Grande Room, Austin, Texas

MORE DETAILS:

This 3-day in-person training is intended to enhance the knowledge and ability of the current workforce through coursework focused on performing EMT simulations in the current interconnection and planning paradigm. Training participants will learn practical methods and best practices that can be leveraged into enhanced study practices across the industry. These training modules will focus on the expected day-to-day needs of engineers performing EMT analysis as well as managing EMT study practices within their organization.

EXPRESS INTEREST - EMT TRAINING

Thanks to NextEra and Texas RE for hosting at their facilities!



THANK YOU

Julia Matevosyan

julia@esig.energy

Public

Avoiding Issues Related to the Iberian Outage in ERCOT

Dan Woodfin
Vice President, System Operations

Texas RE MRC Meeting
September 17, 2025

Overview

- This presentation is not intended to be a deep-dive into the Iberian Peninsula blackout
- Instead, it is intended to provide an overview of the ERCOT requirements and activities that are intended to prevent and lessen, and to mitigate the conditions that could result in a similar type of event, and to recover from such an event were it to occur
- Outline:
  - Background on Iberian Peninsula Blackout
  - Preventing
  - Mitigating
  - Recovering
  - ERCOT Strategies Related to Specific Findings of the Red Electrica Report

ERCOT, Spain, & Portugal Comparison

ERCOT

- ~ 85,000 MW Peak Demand
- ~ 54,000 miles of high-voltage transmission (345, 138, & 69 kV)
- ~170,000 MW of installed capacity
- No synchronous connections

Spain and Portugal (Combined)

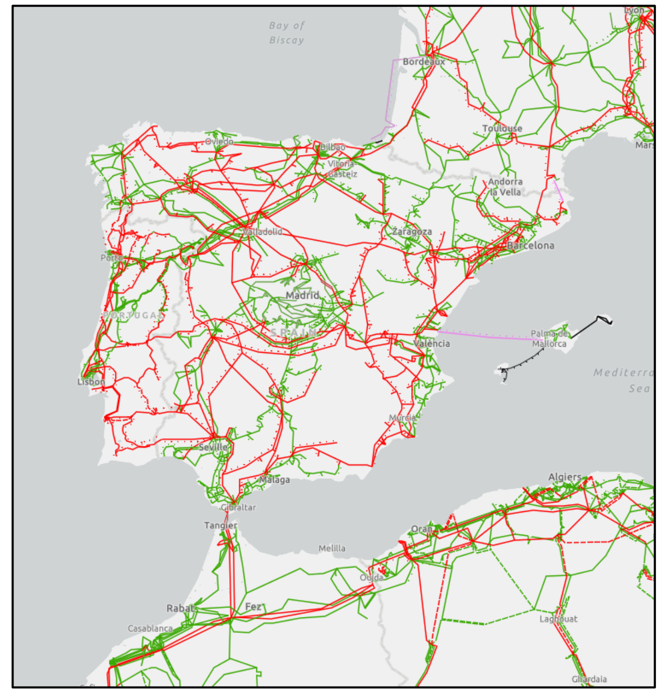
- ~ 50,000 MW Peak Demand
- ~ 31,000 miles of high-voltage transmission (400, 220, & 150 kV)
- ~ 150,000 MW of installed capacity
- Synchronous interconnections to France and Morocco (2,800 & 1,500 MW, respectively)

Energy Mix	ERCOT (2024)	Spain (2023)	Portugal (2023)
Natural Gas	44.2%	22.5%	21.3%
Oil	0.0%	3.3%	2.5%
Wind	24.2%	22.5%	26.9%
Coal	12.6%	1.6%	0.0%
Solar	10.4%	16.9%	11.2%
Nuclear	8.4%	19.9%	0.0%
Hydro	0.1%	10.9%	29.6%
Biofuels	0.1%	1.8%	7.1%
Other	-0.1%	0.7%	1.4%

Source: International Energy Agency (IEA)

April 28 Iberian Blackout Issues

- Localized and inter-area oscillations
- Actions taken to control oscillations (putting additional lines in service and decreasing transfers) raised voltages
- Inverter-based resource reactive requirements proportional to real power and not set for voltage control
- Need for dynamic reactive support
- Lack of high-voltage ride through
- Further loss of generation and system collapse
- Rapid Black Start implementation



Initial Lessons Learned for ERCOT

- ERCOT has several existing processes in place and initiatives underway that would:
  - Prevent or lessen the magnitude and number of large power imbalances
  - Mitigate the impact of a large imbalance if it were to occur
  - Recover from the effects of a collapse due to a large imbalance

Preventing Large Power Imbalances

ERCOT has implemented many processes over the last decade to mitigate the simultaneous loss of multiple generation sites

- Identification of Generic Transmission Constraints (GTCs) limit the output from units in an area to the amount that would be stable following a fault on the system
  - Identifying these situations has required increased study capability and personnel, more accurate dynamic models of the generators, etc.
  - Online stability studies to allow identification and quantification of stability issues rather than depending on offline studies
- NOGRR 245 to reinforce IBR ride-through capability for existing units and improve that capability for future units – to limit the number of generators that trip due to a single fault
- Project to install synchronous condensers at key locations across West Texas to limit the number of generators that are affected by a single fault
- Improved event analysis and data collection from smaller events such as IBR ride-through failures and generation/load oscillations

Preventing Large Power Imbalances

ERCOT has been working on additional initiatives to reduce the potential for loss of generation and large loads

- Current proposal to require grid-forming capability for all future Energy Storage Resources (NOGRR272/PGRR121)
- ERCOT is investigating ride-through capabilities and requirements for large electronic loads
- Current studies to establish System Operating Limits for large electronic load lost for any single contingency

Mitigating the Impact of Large Power Imbalances

- ERCOT procures enough frequency-responsive Ancillary Services (Responsive Reserve Service (RRS)) to withstand the simultaneous loss of two largest units and keep the frequency above 59.3 Hz
  - All Resources (including renewables) are required to have primary frequency response (PFR) capability; RRS is procured to ensure sufficient headroom is available for the PFR response (RRS can also be provided by load resources on underfrequency relays)
  - The amount of RRS that is needed to protect against this generation loss varies based on the inertia on the system; more RRS is procured when inertia is expected to be lower
  - This also protects against smaller outages or simultaneous outages of multiple units up to this magnitude (~2800MW)
  - Procure enough ERCOT Contingency Reserve Service to restore RRS within 15 minutes to prepare for another loss

Mitigating Large Power Imbalances – UFLS “Safety Net”

ERCOT implemented an Under-Frequency Loadshed Scheme (UFLS) program reduce up to 25% of system load automatically to serve as a safety net for larger generation losses

- For many years, this UFLS program included 3 stages; after winter storm Uri, this was adjusted to 5 stages over the same frequency range
- An “anti-stall” system is also being added to restore frequency if frequency stays below 59.5 Hz for an extended period

Frequency Threshold	Minimum Requirement	Delay to Trip
59.3 Hz	At least 5% of the TO Load	At least six cycles but no more than 30 cycles
59.1 Hz	A total of at least 10% of the TO Load	At least six cycles but no more than 30 cycles
58.9 Hz	A total of at least 15% of the TO Load	At least six cycles but no more than 30 cycles
58.7 Hz	A total of at least 20% of the TO Load	At least six cycles but no more than 30 cycles
58.5 Hz	A total of at least 25% of the TO Load	At least six cycles but no more than 30 cycles

Recovering: Black Start Improvements

- If a blackout affects all or a large portion of a power system, special tools and procedures (Black Start) are used to re-energize the area
- ERCOT conducts annual Black Start Training with required Market Participants
  - Simulates a blackout event
  - Participants utilize Black Start tools and procedures to simulate the restoration of the grid
  - Next Black Start Training will be in October 2025
- ERCOT is actively reviewing the use of *temporary* synchronous ties to facilitate Black Start
  - Following Winter Storm Uri, ERCOT worked with Texas A&M to determine potential locations where temporary synchronous ties could form a Black Start "peninsula" to more quickly restore ERCOT load and generation following a blackout
  - The Iberian event emphasized the benefit of this initiative

Specific Strategies Related to Red Eléctrica Findings

Findings	Spain	ERCOT
Oscillations	• Leading up to the event, oscillations were observed from a photovoltaic plant • Actions that were taken to mitigate the oscillation increased system voltage and reduced the system's voltage control flexibility	• Identify and implement Generic Transmission Constraints (GTCs) to maintain stable operations of impacted Resources • ERCOT synchronous Generation Resources (GRs) are required to install Power System Stabilizers to provide oscillation dampening support • ERCOT has some streaming PMUs and tools to diagnose oscillations • ERCOT has ordered generators offline until they fix the source of their oscillations

Specific Strategies Related to Red Eléctrica Findings

Findings	Spain	ERCOT
Voltage Control	• Only conventional generators are required to comply with dynamic voltage control requirements • Other resource types, including renewables, are operated at constant power factor control • Some generation failed to comply with its voltage control obligations	• All GRs and Energy Storage Resources (ESR) are required to provide dynamic voltage support • ERCOT/VPWG routinely review and assess resources' voltage control performance • GR and ESR automatic voltage regulation (AVR) response to a change in voltage is tested every five years • IBR reactive requirement is ±.95 based on max output

Specific Strategies Related to Red Eléctrica Findings

Findings	Spain	ERCOT
Voltage Ride-Through	• Some generators tripped without meeting ride through requirements due to insufficient margin (set protection at the ride through profile) or without enough time delay	• GRs and ESRs are required to meet voltage and frequency ride through requirements. These are minimum operational requirements, not protection set-points • NOGRR245 will reinforce IBR ride-through capability for existing units and improves capability for future units, but is not yet implemented

Questions?

NERC Standards Review Forum Update

Texas RE Member Representatives Committee

September 17, 2025

Chris Seaman, Rayburn Electric Cooperative

Chair

Brad Collard, Pedernales Electric Cooperative

Vice-Chair

Rachel Coyne, Texas RE

Texas RE Facilitator

Recent NSRF Meetings

- 05/15/2025 – Hybrid
- 06/26/2025 – Remote
- 07/24/2025 – Remote
- 08/21/2025 – Remote

Open sessions are hosted by Texas RE.

Hybrid session was hosted at ERCOT - Met Center

Closed sessions are hosted by Pedernales Electric Cooperative.

Standards Report

Standards Report

- Newly Effective Reliability Standards
  - 07/1/2025
    - *TOP-003-6.1: Transmission Operator and Balancing Authority Data and Information Specification and Collection*
    - *IRO-010-5: Reliability Coordinator Data and Information Specification and Collection*

Standards Report

- <u>Effective Dates for Upcoming Reliability Standards:</u>
  - 10/1/2025
    - *TOP-002-5: Operations Planning*
  - 04/01/2026
    - *TPL-008-1: Transmission System Planning Performance Requirements for Extreme Temperature Events*

**Refer to Implementation Plan for staggered timeframes of fully enforceable Standard.*

Ongoing NERC Reliability Standard Projects

High Priority Projects

1. 2020-06 Verification of Models and Data for Generators IBR
2. 2021-01 System Model validation with IBRs IBR
3. 2022-02 Uniform Modeling Framework for IBR IBR
4. 2023-06 CIP-014 Risk Assessment Refinement
5. 2024-01 Rules of Procedure Definitions Alignment IBR
6. 2024-02 Planning Energy Assurance
7. 2025-03 FERC Order 901 Operational Studies*
8. 2025-04 FERC Order 901 Planning Studies*

*New projects approves at the August SC meeting

IBR – Inverter-based resource and/or distributed energy resource projects

SPM – Standards Committee has approved a waiver to the Standards Procedure Manual timelines

Continues

High Priority Projects

Continued

1. 2024-03 Revisions to EOP-012-2 (Rule 321, 45-day comment period, no ballot) SPM

Filed, awaiting FERC approval (as of the day this presentation was submitted)

IBR – Inverter-based resource and/or distributed energy resource projects

SPM – Standards Committee has approved a waiver to the Standards Procedure Manual timelines

Medium Priority Projects

1. 2024-04 EMT Modeling [IBR]
2. 2023-01 EOP-004 IBR Event Reporting [IBR]

IBR – Inverter-based resource and/or distributed energy resource projects

SPM – Standards Committee has approved a waiver to the Standards Procedure Manual timelines

Low Priority Projects

1. 2017-01 Modifications to BAL-003 Phase 2
2. 2019-04 Modifications to PRC-005-6
3. 2021-02 Modifications to VAR-002-4.1 IBR
4. 2021-08 Modifications to FAC-008
5. 2023-05 Modifications to FAC-001 and FAC-002 IBR
6. 2023-07 Transmission Planning Performance for Extreme Weather SPM
7. 2023-08 Modifications of MOD-031 Demand and Energy Data IBR

IBR – Inverter-based resource and/or distributed energy resource projects

SPM – Standards Committee has approved a waiver to the Standards Procedure Manual timelines

Recent NERC Filings

- RR25-1-000: ROP Appendix 4E Compliance Filing
- RR25-4-000: Joint Petition for Approval of Revised RDAs
- RD25-7-000: Reply Comments re: EOP-012-3
- RR23-4-000: Compliance Filing Regarding 2023 Revisions to the NERC ROP for Reliability Standards
- RD22-4-001: Inverter-Based Resources Work Plan Progress Update (2 filings)
- EL25-49-000: Comments on Large Loads

Recent FERC Orders/Rules

- RM25-3-000 Order Approving IBR Ride-through Standards
- RR25-1-000: Order Approving Revisions to Appendix 4E of the NERC ROP

Recent Discussion Topics

- EOP-005-3 System Restoration from Blackstart Resources – Rashida Caraway
- Texas RE – Chief Engineer Report (Recurring)- Mark Henry
- MOD-026 – NERC Alert and other activities – Alan Castellanos
- IBR Risks – Jeff Hargis
- Project 2020-06 SDT Update - SDT
- Qualified Change Definition and SOL Methodology Update Process – ERCOT
- NERC IRO-010/TOP-003 Mapping Document and CFR Update - ERCOT
- FAC-008 Best Practices and Workbook Management – Tyler Espino
- FERC Order 901 Milestone 3 Update – Mark Henry
- FAC-002-4 Facility Interconnection Studies with IBR focus– Nick Hayes

Continues

Closed Session Topics

- Open Session Carry Over
- ERCOT Updates
  - TOP-003/IRO-010 Mapping document and information/data specification
  - Qualified Change Definition and SOL Methodology Update Process
- EOP-011/012 Weatherization
- PRC-004/PRC-027 Best Practices
- Other Discussion Items – Industry experiences, best practices and lessons learned with internal controls

Upcoming NSRF Meetings

Future Scheduled Meeting Dates (meetings are typically held on the 3rd or 4th Thursday of each month except as noted; no meeting is held in December):

- September 18, 2025 (Hybrid at Rayburn EC Campus, Rockwall, TX)
- October 23, 2025
- November 20, 2025 (Hybrid)(Leadership determination and meeting dates for 2026)

Questions or Comments?

Thank you!

ERCOT CIP WORKING GROUP UPDATE

For the Texas RE – Member Representatives Committee (MRC)
September 17, 2025

Trevor Tidwell, TNMP
CIPWG Chair

Thomas Standifur, Austin Energy
CIPWG Vice Chair

- June 6th – Virtual Only
- August 1st @ Texas Tech's Innovation Hub
- September 5th – Virtual Only

RECENT MEETINGS

- E-ISAC briefing
- PUCT
  - Paragon – Update and poll question on training opportunities
  - Paragon – 3rd Quarter Meeting
  - Paragon – Update on next round of Technical Courses
- Ask Texas RE
  - CIP-003-8 R2 Section 2 (Physical Security Controls)
  - CIP-003-8 R2 Section 5 (TCAs & RM)
  - CIP-010-4 R1
  - Question about CIP-012-2
- FBI – Texas Energy Working Group September 9th-10th in Dallas
- Stepping down at the end of the year

OPEN SESSION TOPICS SUMMARY

Public

- Dr. Stephen Bayne – Introduction to Critical Infrastructure Security Institute (CISI) and their ten strategic research pillars (subset of 16 critical infrastructure sectors)
- Reese Technology Center
  - GLEAMM (Global Laboratory for Energy Asset Management and Manufacturing) – A true microgrid that disconnect from local utility to perform research including EMP testing.
  - Setting up a lab for cyber-physical testing. This includes researching what would be necessary to develop hardware bill of materials (HBOMs).
- Dr. Jacob Stephens – Overview of pulsed power work (e.g. EMP)
- Dr. Ranadip Pal – Overview of AI research
- Dr. Benda Connor – Overview of applied research including research to accelerate the critical infrastructure operator's business case to deploy a private cellular network with triple value proposition.
- Dr. Shane Walker – Overview of water supply, the energy-water nexus, and cybersecurity for water systems

PRE-CIPWG BRIEF & TOUR BY TEXAS TECH'S CRITICAL INFRASTRUCTURE SECURITY INSTITUTE (CISI)

Public

Public


OPAL-RT TECHNOLOGIES
OPAL-RT TECHNOLOGIES

Public

- Chuck Bondurant, Director of Critical Infrastructure Security and Risk Management, PUCT
- Dr. Stephen Bayne, Executive Director, CISI
- Dr. Kay Tindle, Associate Executive Director of Strategy & Innovation, CISI
- Dr. Brenda Connor, Senior Technical Managing Director, CISI
- Dr. Argenis Bilbao, Senior Director, GLEAMM
- Dr. Jacob Stephens, Professor, ECE – Pulsed Power
- Dr. Ranadip Pal, Professor, ECE – Cybersecurity
- Dr. Shane Walker, Director, Texas Produced Water Consortium
- Melissa Miller, Executive Associate, CISI

THANKS

- Standards typically tracked during the open sessions

  HIGH PRIORITY

  - **2025-02 Internal Network Security Monitoring Standard Revision (CIP-015-2)**
    - Comments on SAR closed on 8/15/2025. Initial posting expected in November.

  MEDIUM PRIORITY

  - **2021-03 CIP-002 Transmission Owner Control Centers**
    - Comments on SAR closed on 7/9/2025
  - 2023-09 Risk Management for Third-Party Cloud Services
    - Nothing in the three-month outlook as of 9/1/2025.

  LOW PRIORITY

  - 2022-05 Modifications to CIP-008 Reporting Threshold
    - Possible informal comment period starting week of September 15th.

  WITH FERC

  - **2023-03 Internal Network Security Monitoring (INSM) under docket number RM24-7-000. Approved on 6/26/2025 and Order No. 907-A issued on 8/21/2025 to clarify the scope of "CIP-networked environment".**
  - 2016-02 Modifications to CIP under docket number RM24-8-000. **Errata filed by NERC on 5/20/2025.**
  - 2021-03 CIP-002 Transmission Owner Control Centers under docket number RM25-7-000
  - 2023-04 Modification to CIP-003 under docket number RM25-8-000

OPEN SESSION
CIP STANDARDS TRACKED

Public

- None

OPEN SESSION
NERC REPORTS, GUIDELINES, WHITE PAPERS TRACKED

CLOSED SESSION TOPICS SUMMARY

- Security Topics
  - E-ISAC briefing (August)
- Compliance Topics
  - Audit experience share
  - Peer share
  - Peer check
- Administrative
  - November CIPWG logistics and agenda

Public

ANY QUESTIONS?

NERC Reliability and Security Technical Committee Update

For the Texas RE – Member Representatives Committee (MRC)

Sep 17, 2025

Venona Greaff, Oxy
At-Large

David Grubbs, City of Garland / Garland Power & Light
State/Municipal Utility

Drew Bosner, ERCOT
ISO

NERC RSTC – June 10-11, 2025

- RSTC High Priority Work Plan Items Status Updates
  - White Paper: Case Study on Adoption of EMT Modeling and Studies in Interconnection and Planning Studies for BPS-connected IBRs (#4)
  - White Paper: Risk Profiles and Prioritization on Motor Vehicle Electrification (#1)
  - Reliability Guideline: Recommended Approach to Interconnection Studies for BPS-Connected Inverter-Based Resources (#8)
  - Reliability Guideline: BPS-Connected IBR Commissioning Best Practices (#24)

RSTC HIGH PRIORITY

NERC RSTC – June 10-11, 2025

- RSTC High Priority Work Plan Items - LLTF
  - White Paper: Characteristics and Risks of Emerging Large Loads (LLTF #1)
  - White Paper: Assessment of gaps in existing practices, requirements, and Reliability Standards for Emerging Large Loads (LLTF #2)
  - Reliability Guideline: Risk Mitigation for Emerging Large Loads (LLTF #3)

RSTC HIGH PRIORITY

NERC RSTC – June 10-11, 2025

- Approved
  - RSTC Notional Work Plan Process
  - White Paper: Case Study on Adoption of EMT Modeling and Studies in Interconnection and Planning Studies for BPS–connected IBRs

    RSTC HIGH PRIORITY
  - White Paper: EMT Analysis in Operations Planning for BPS-Connected IBRs

NERC RSTC – June 10-11, 2025

- Request for RSTC Comments:
  - Large Loads Task Force (LLTF) White Paper #2: Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Loads
  - White Paper: Electric Vehicle Risk Profiles and Prioritization
  - White Paper: Modeling DER Aggregators and DERMS
  - FERC Order 901: Standard Authorization Request (SAR) – Planning Studies and Operational Studies

NERC RSTC – June 10-11, 2025

- Endorsed:
  - SAR – PRC-006 –White Paper: Electric Vehicle Risk Profiles and Prioritization
- Accept to Post for 45-Day Comment Period:
  - Security Guideline: Primer for Cloud and BCSI Protection
  - Security Guideline: Vendor Incident Response
  - Security Guideline: Supply Chain Procurement Language

NERC RSTC – June 10-11, 2025

- Combined Meeting of RISC, RSTC, and SC
  - Standing Committee Governance
  - Panel Discussion – Standing Committees
    - Teresa Mogensen, RISC Chair
    - Rich Hydzik, RSTC Chair
    - Todd Bennett, SC Chair
  - Modernizing Standards Processes and Procedure Task Force (MSPPTF) Update

NERC RSTC – July 22, 2025
Conference Call

- Approved
  - RSTC HIGH PRIORITY White Paper: Characteristics and Risks of Emerging Large Loads
  - Reference Document: Balancing Authority Area Footprint Change Tasks
- Informational Items
  - CIP Roadmap

Future Meetings

September 10-11, 2025 – Hybrid - TexasRE
December 10-11, 2025 – Virtual

January 20-22, 2026 – Annual Work Plan Summit
March 11-12, 2026 – In-Person
June 10-11, 2026 – Hybrid
Sept 9-10, 2026 – Hybrid
Dec 9-10, 2026 – Virtual

RSTC Newsletter Link
https://www.nerc.com/comm/RSTC/Pages/RSTC-Newsletter.aspx

COMPLIANCE AND CERTIFICATION COMMITTEE

Update to Texas RE Member Representatives Committee
September 2025

- **CCC Meeting** (CCC Agenda Package)
  - Standing Committees Governance
  - Q3 Focused Discussion – Internal Controls
  - NERC Internal Audit Update
  - Future Meeting Dates
    - October 14 – 16, 2025: Southern Company – Birmingham, AL

CIP and O&P Compliance Monitoring and Risk Assessment Report

Member Representatives Committee Meeting

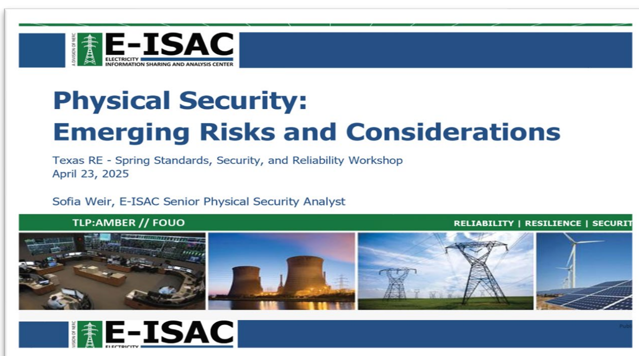
September 17, 2025

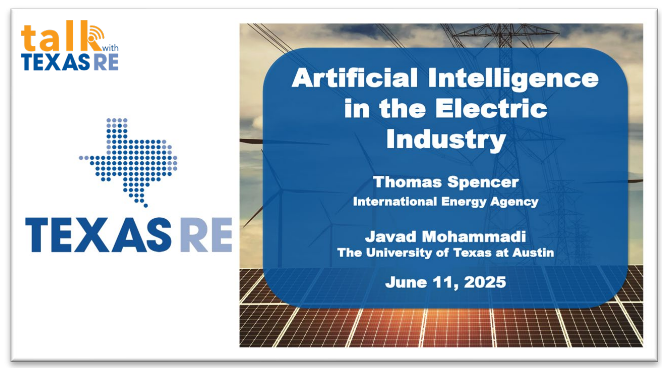
Public

Critical Infrastructure Protection Compliance Monitoring

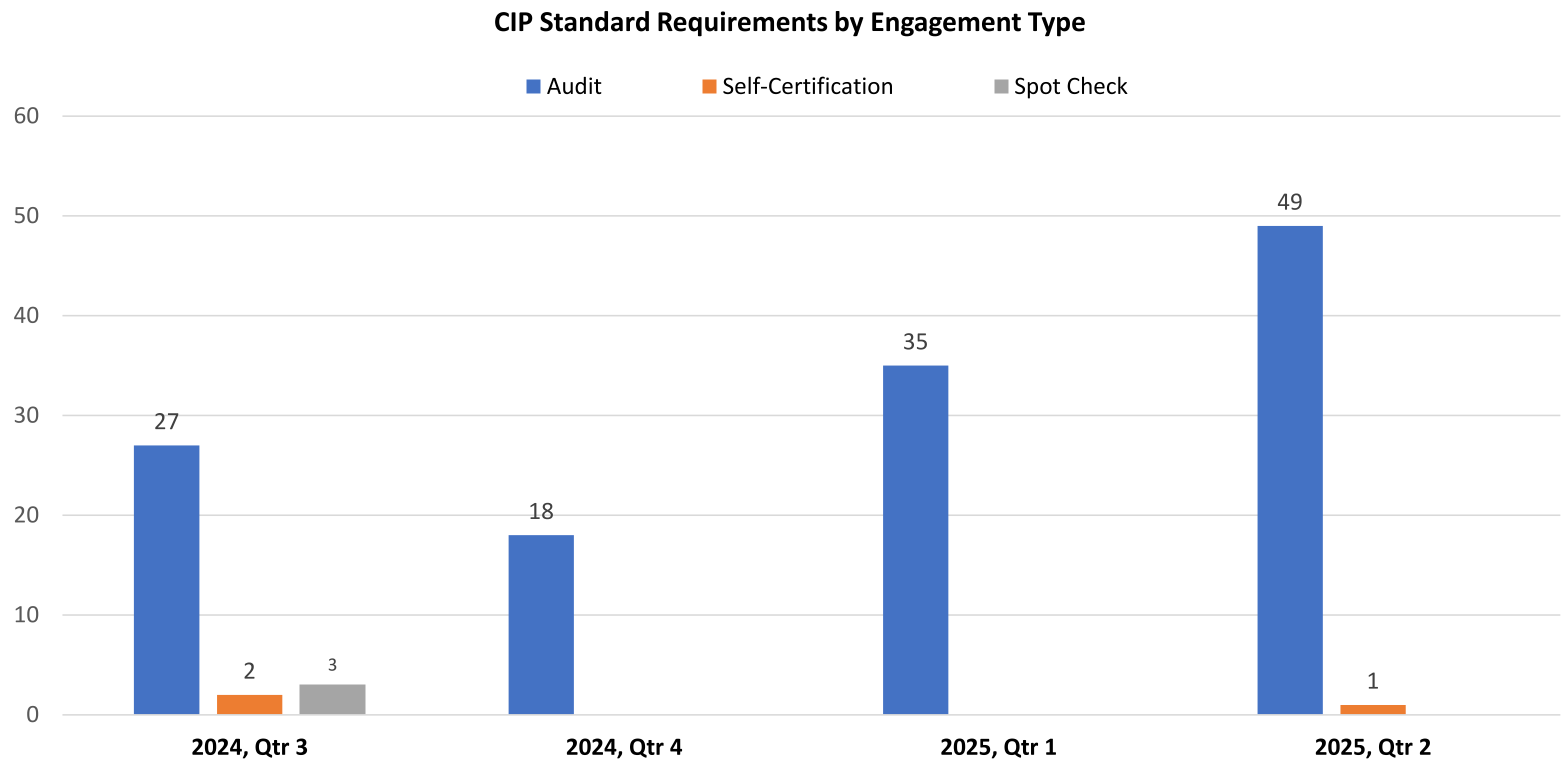
Public

Q2 2025: Workshop, Webinar, Training, and Conference Highlights



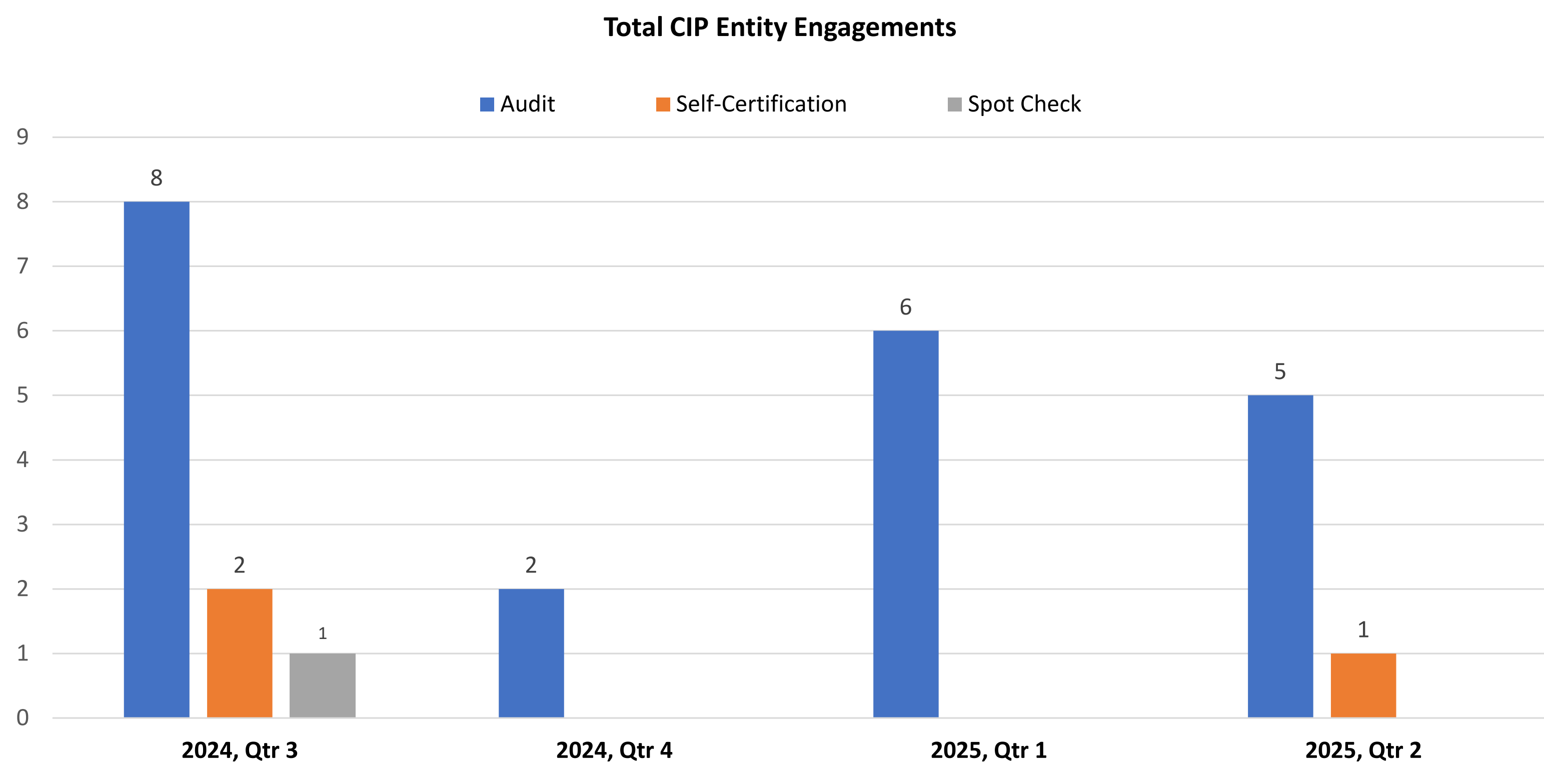


Q2 2025: Total CIP Requirements

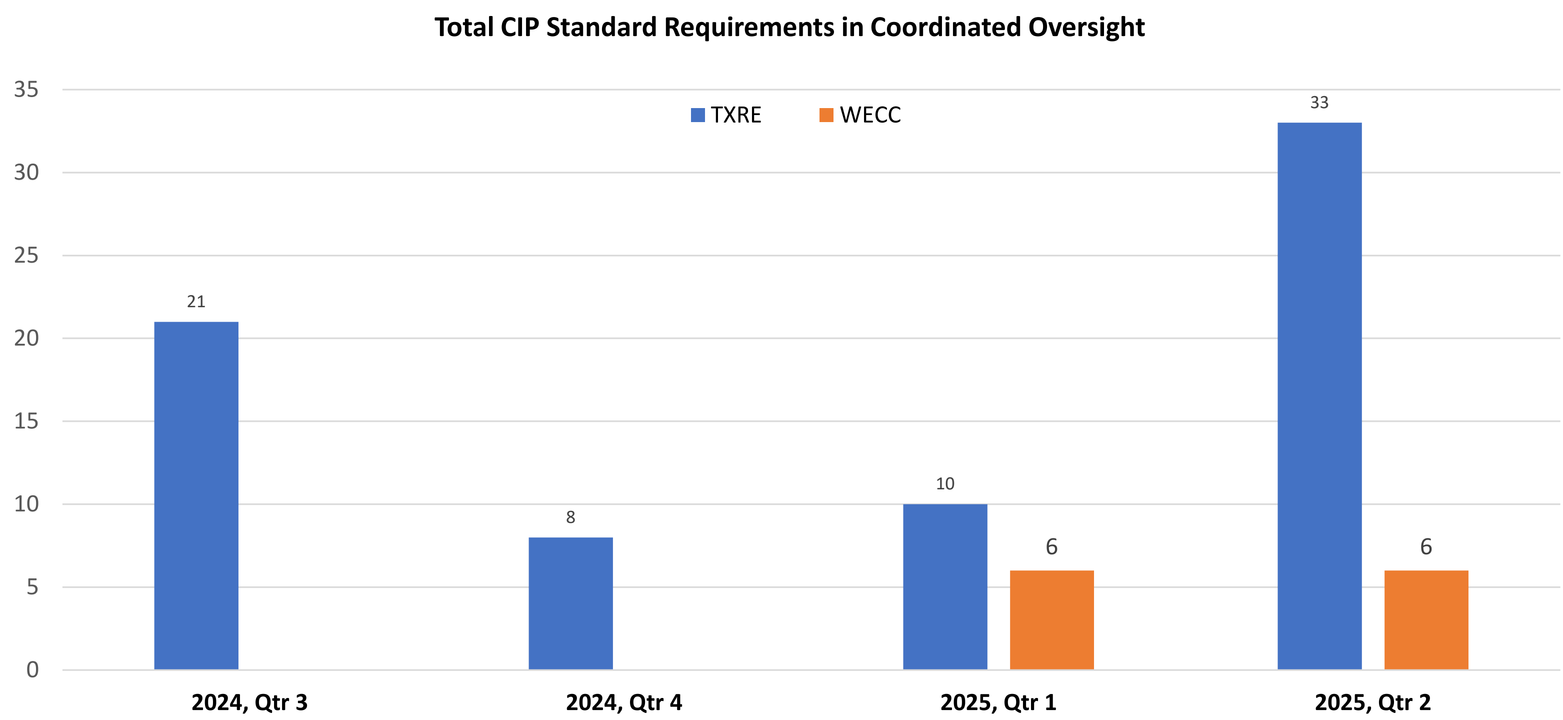


Public

Q2 2025: Total CIP Engagements

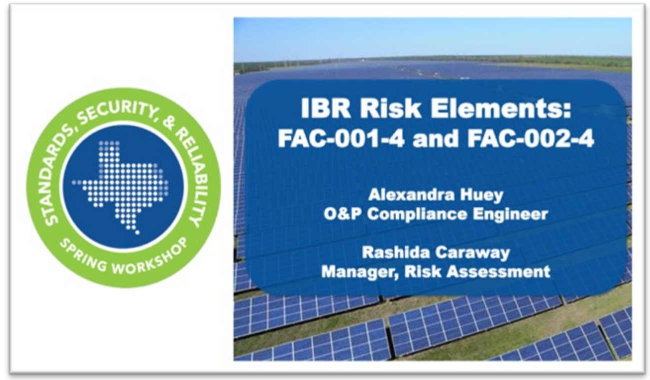


Q2 2025: Total CIP Requirements Coordinated Oversight

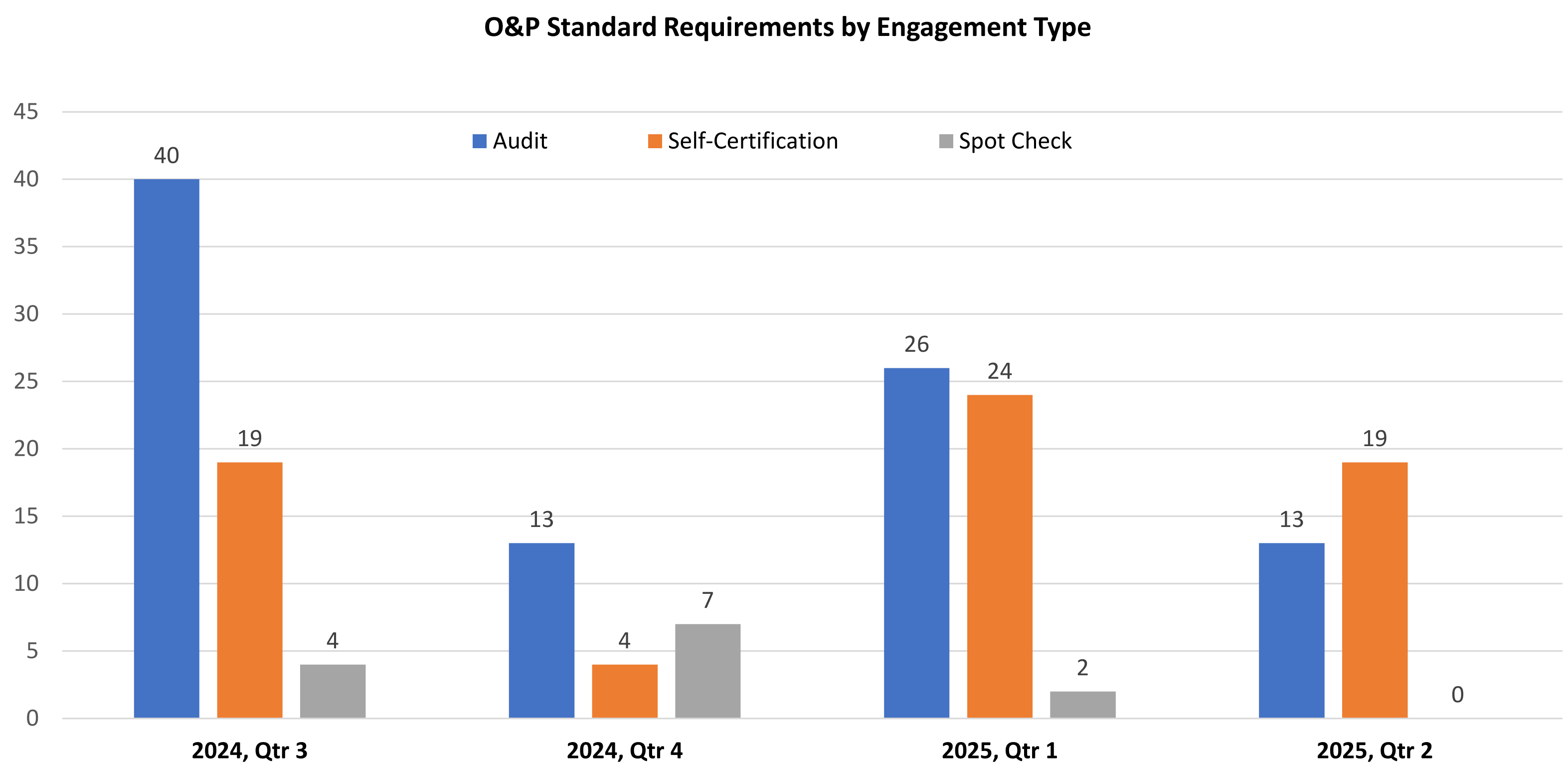


Operations and Planning Compliance Monitoring

Q2 2025: Workshop, Webinar, Training, and Conference Highlights

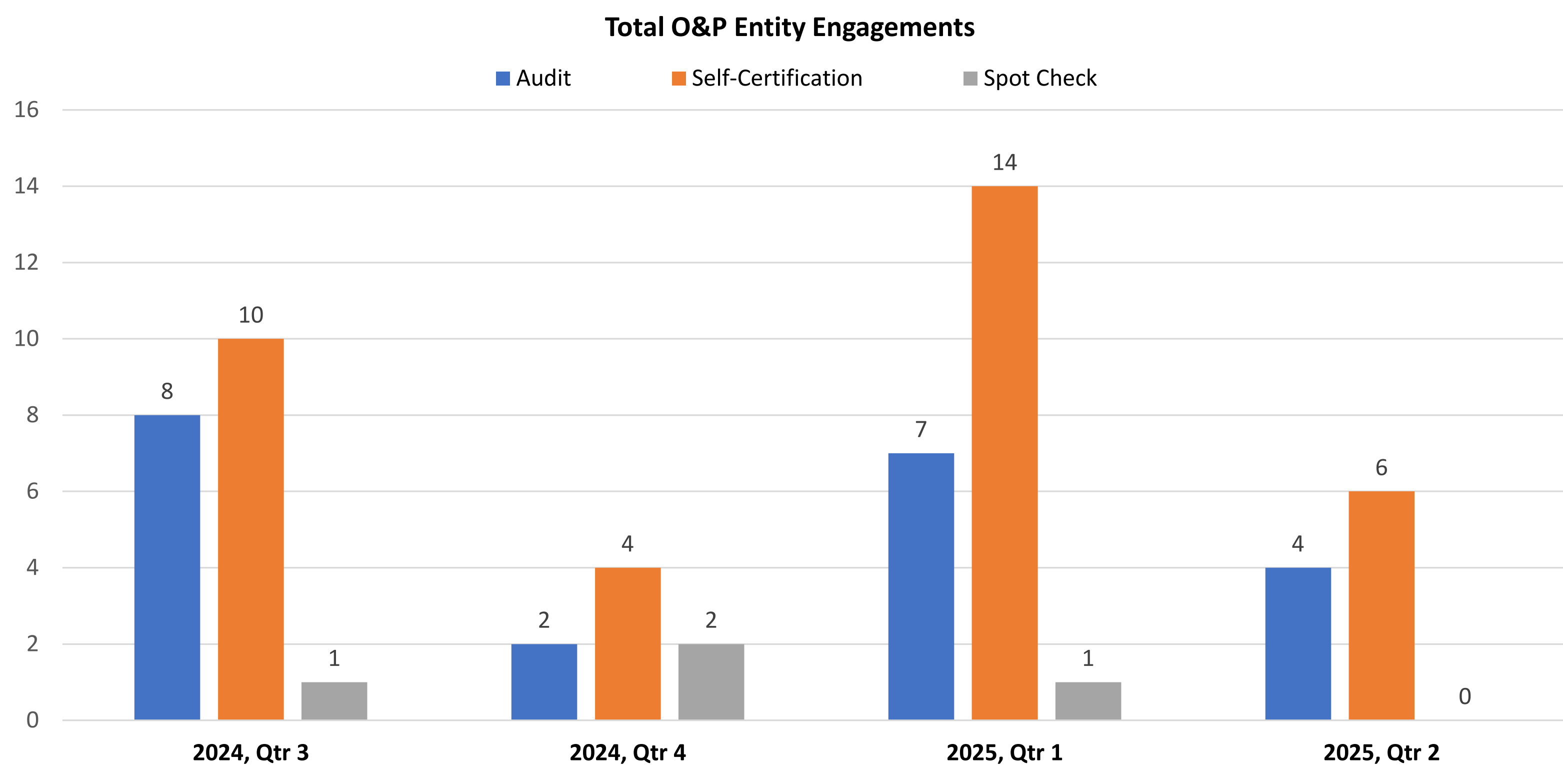


Q2 2025: Total O&P Requirements



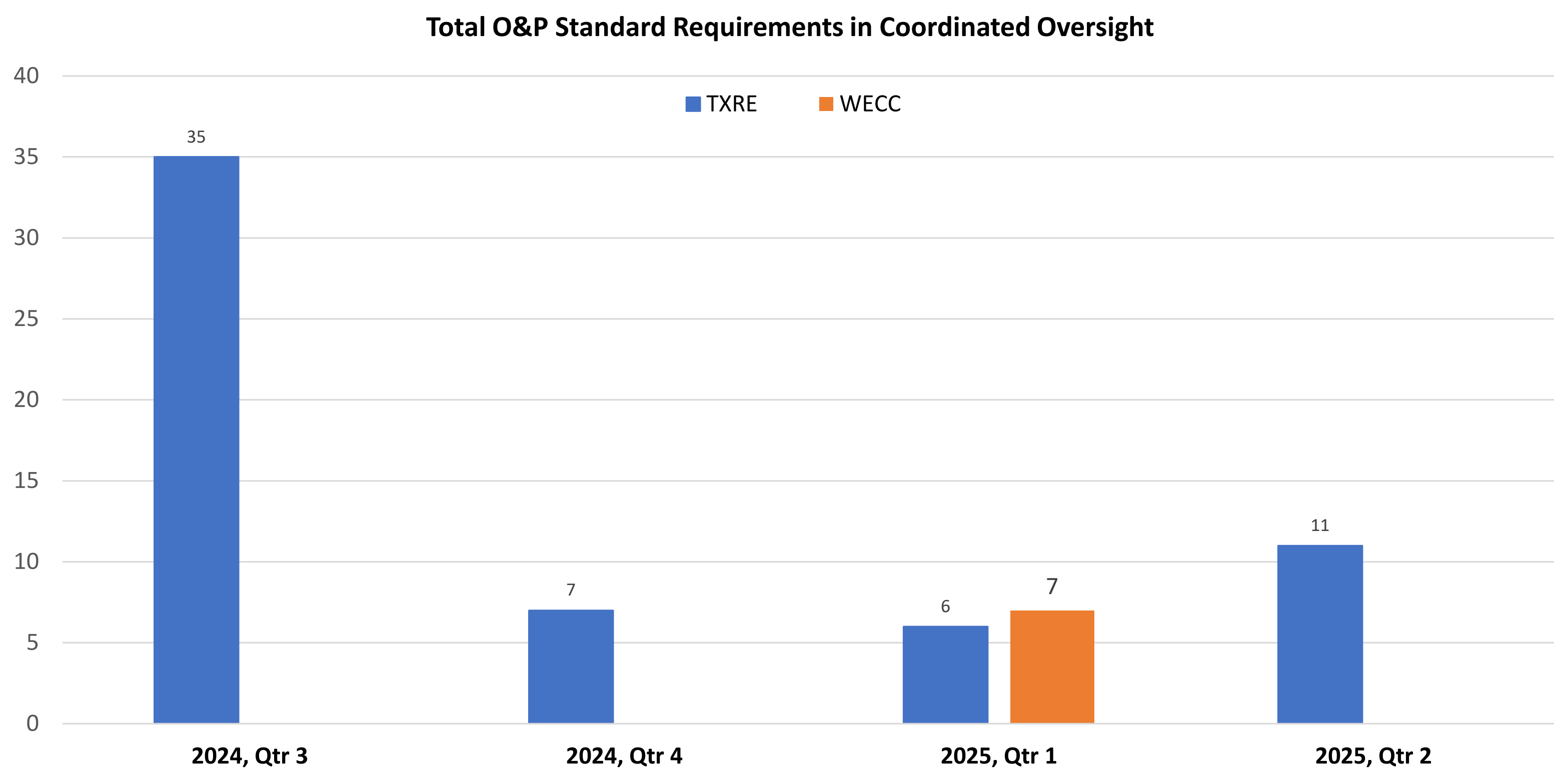
Public

Q2 2025: Total O&P Engagements

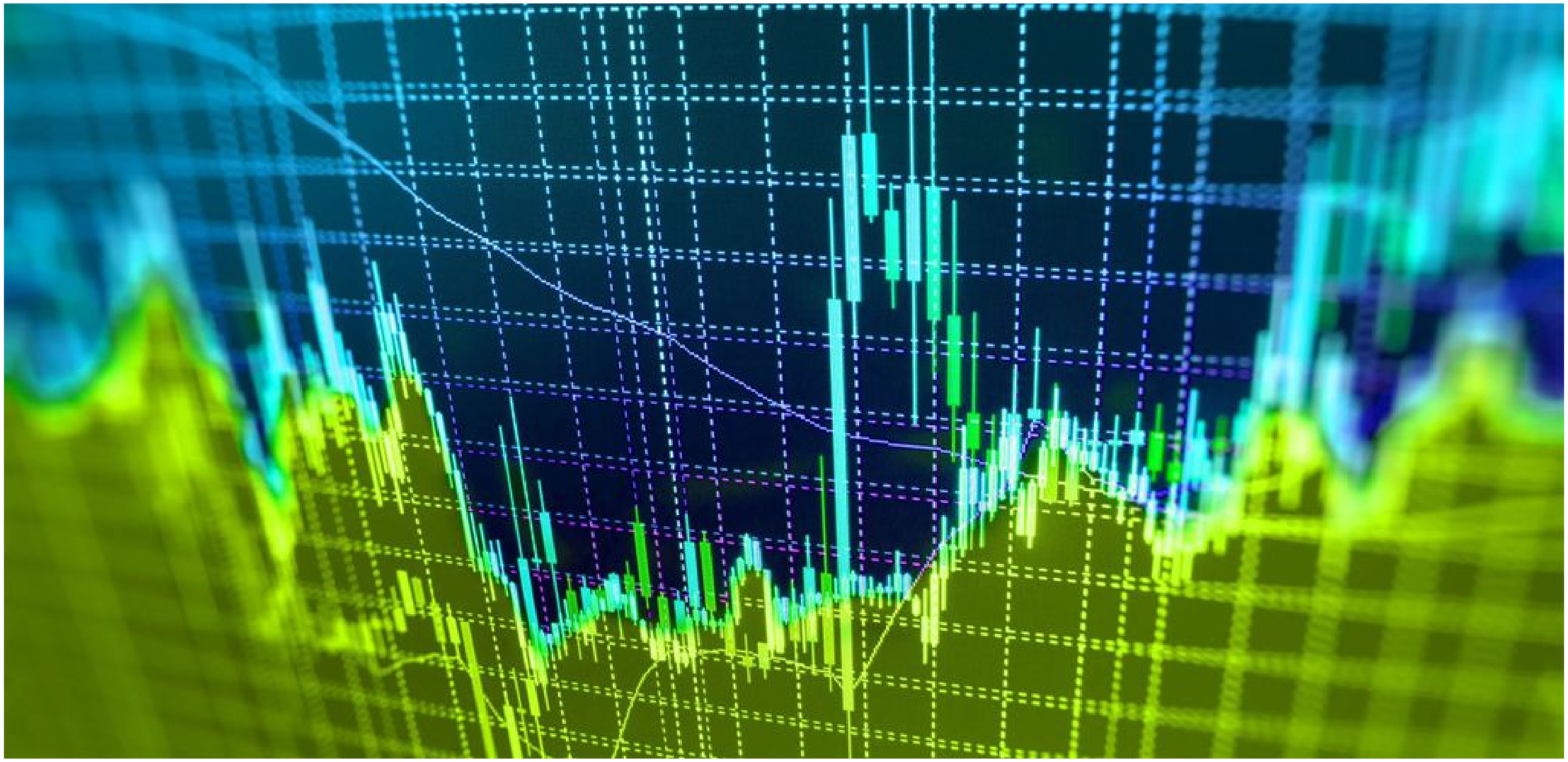


Public

Q2 2025: Total O&P Requirements Coordinated Oversight

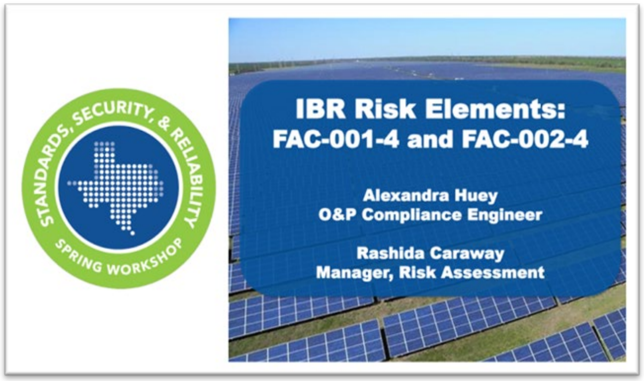


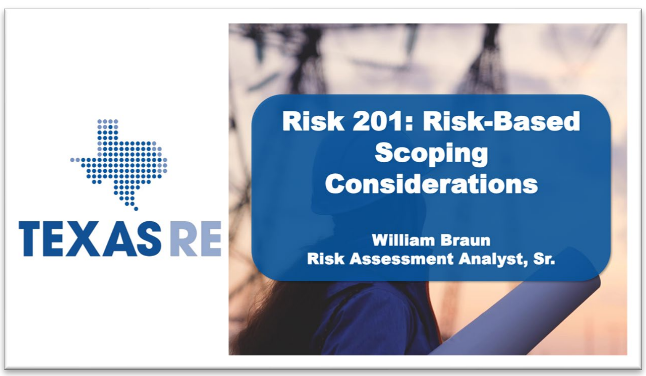
Risk Assessment



Public

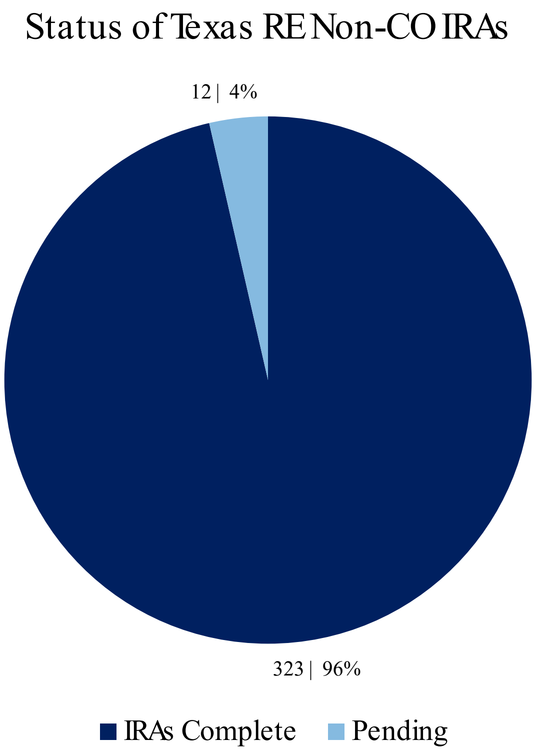
Q2 2025: Workshop, Webinar, Training, and Conference Highlights

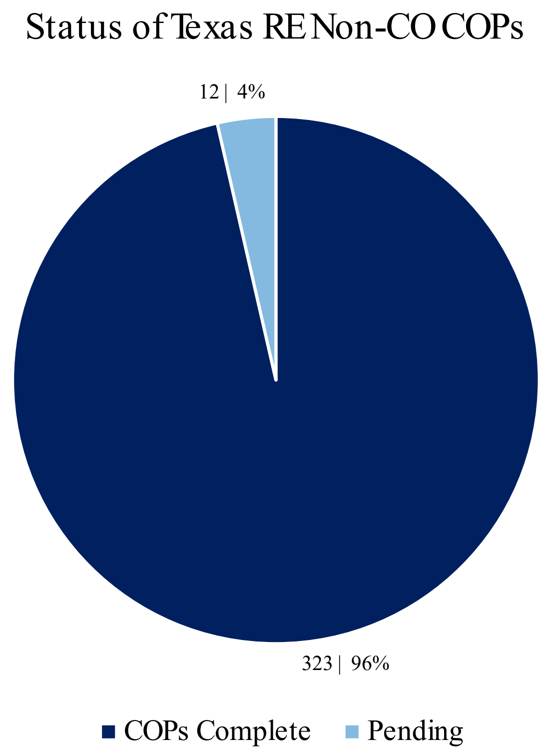




Public

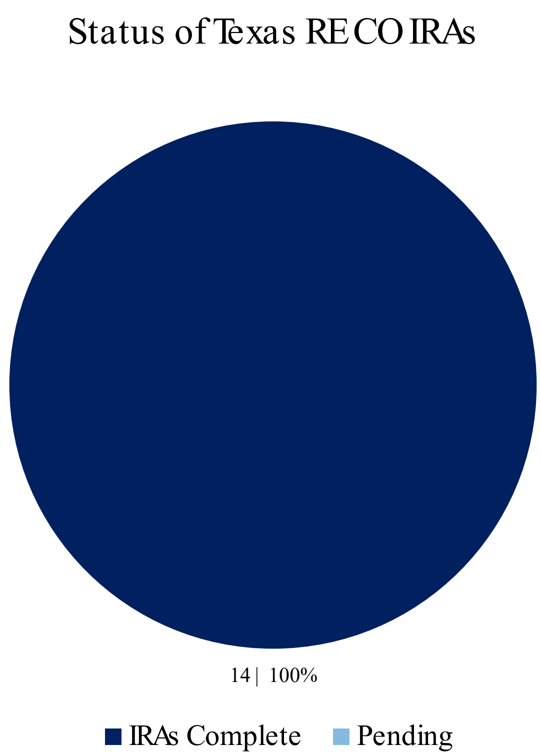
Q2 2025: Texas RE Non-Coordinated Oversight

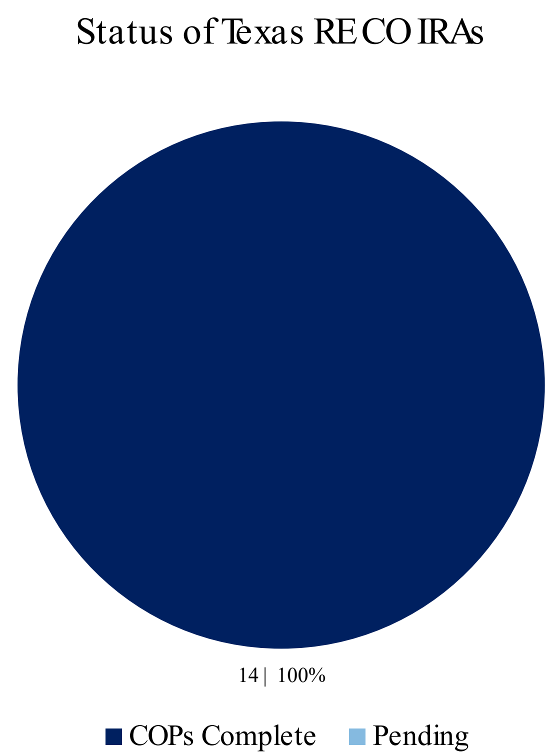




As of June 30, 2025

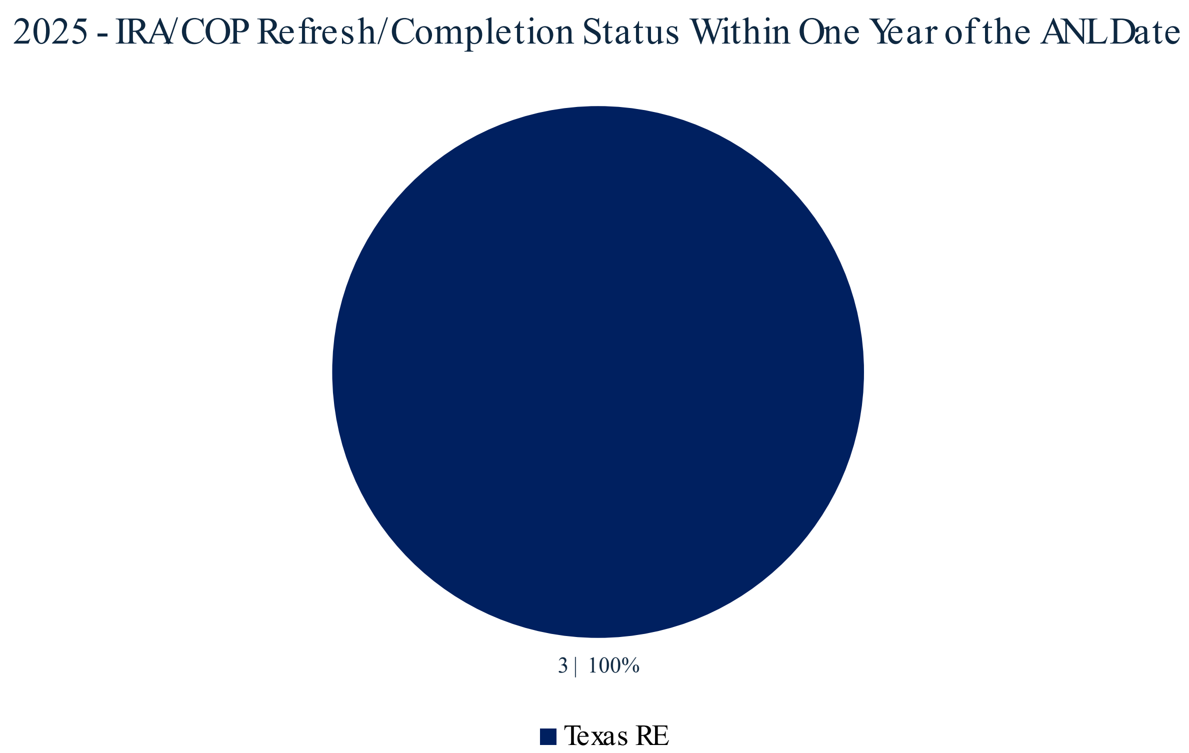
Q2 2025: Texas RE Coordinated Oversight





As of June 30, 2025

Q2 2025: IRA/COP Completed Prior to Audit



As of June 30, 2025

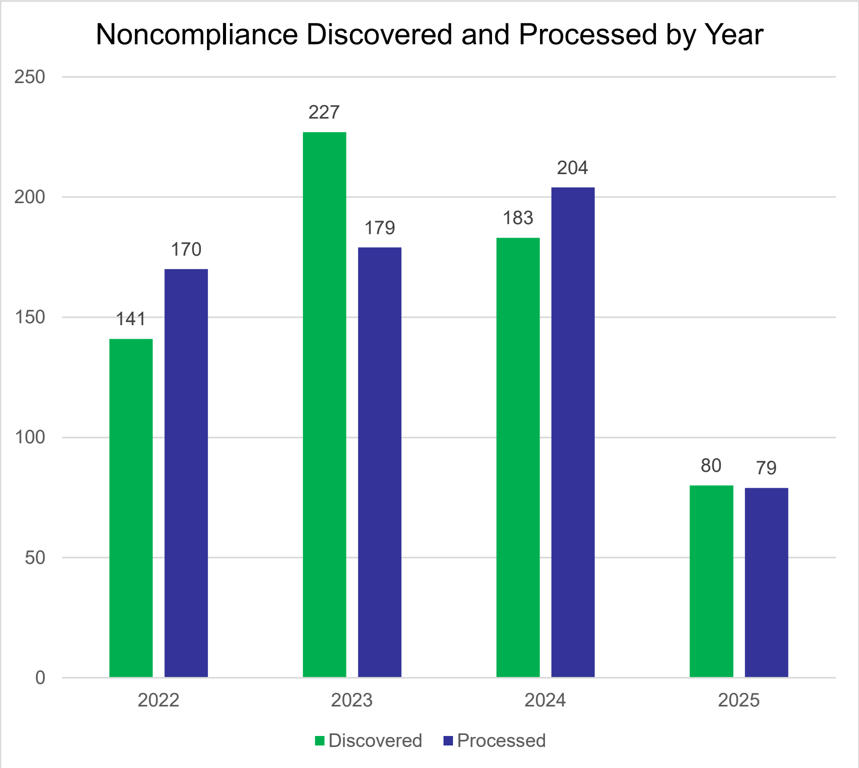
TEXAS RE

Enforcement Report

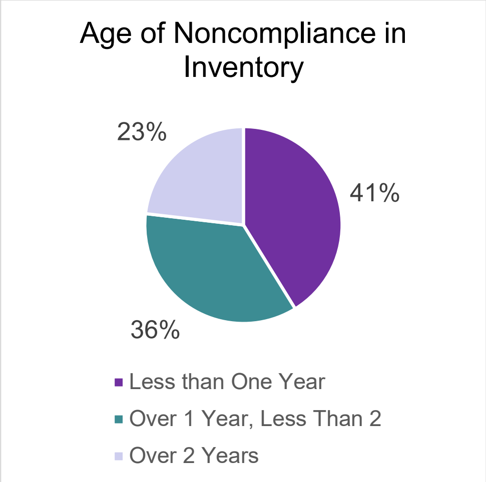
Member Representatives Committee Meeting
September 17, 2025

Public

Enforcement Discovery Dashboard

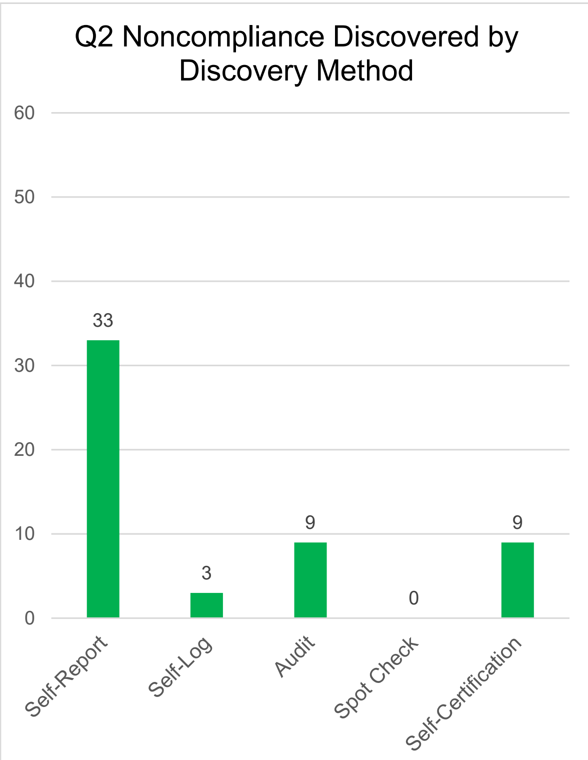


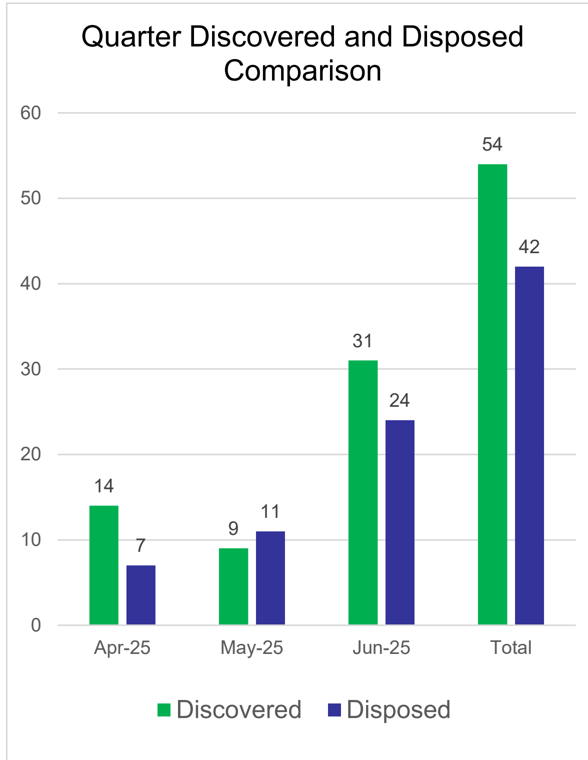
Inventory End of Q2 2025: 216

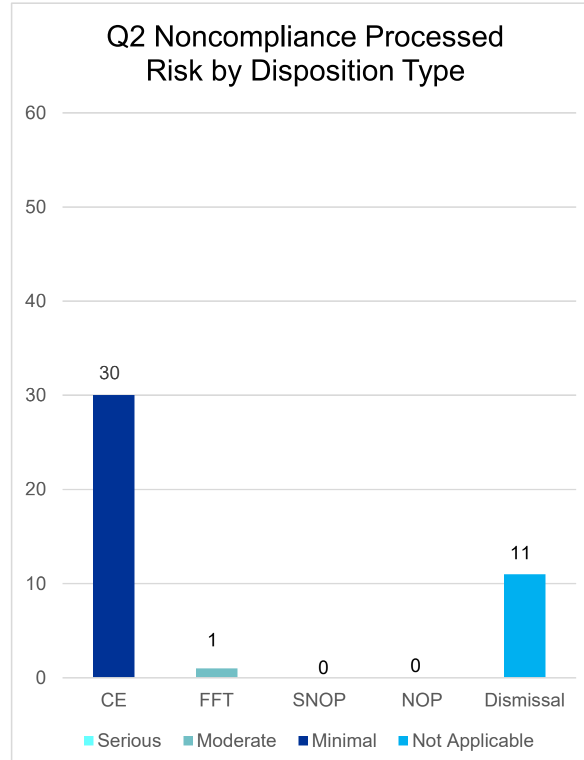


Top Violations Discovered by NERC Standards	
CIP-010	9
CIP-007	8
MOD-025	8
CIP-003	6
PRC-005	6
MOD-026	5
MOD-027	5
CIP-005	4
EOP-012	4
FAC-008	4

Enforcement Quarterly Dashboard







TEXAS RE

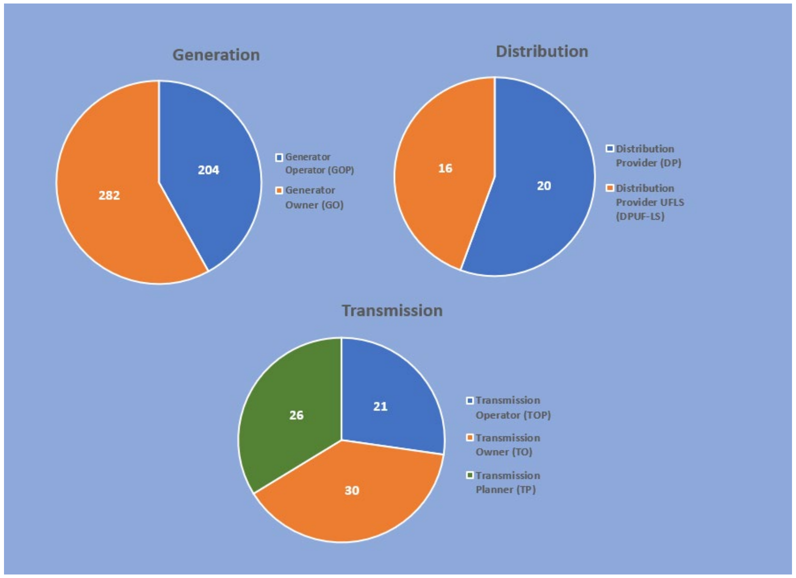
Registration Report

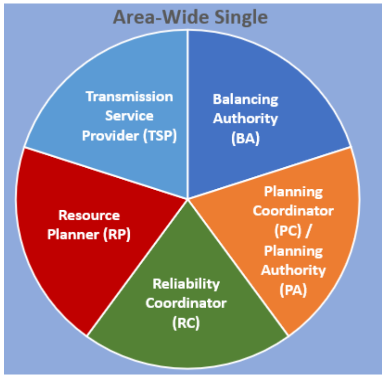
Member Representatives Committee Meeting
September 17, 2025

Public

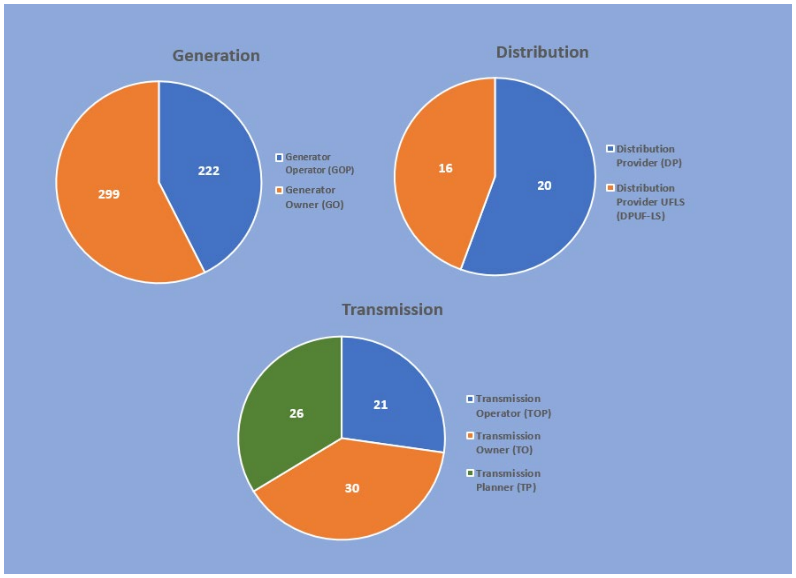
Number of Registered Entities by Function – Texas RE Region

359 Registered Entities | 599 Functions
As of August 1, 2024



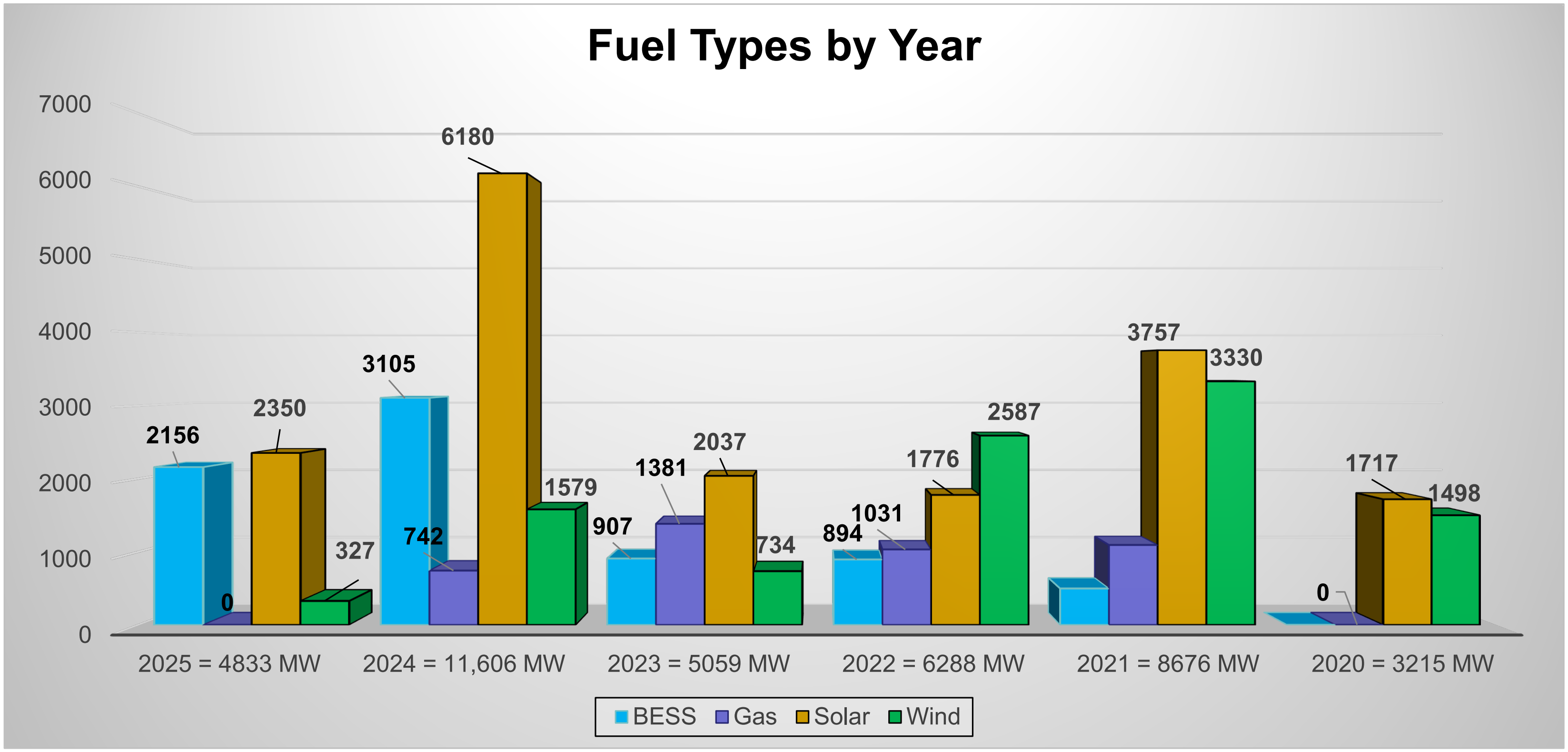


387 Registered Entities | 634 Functions
As of August 1, 2025



Over 20% of all Texas RE registered entities participate in the Coordinated Oversight Program

Registered Generation by Fuel Type



TEXAS RE

Other Registration Activities – CFR and JRO Agreements

Coordinated Functional Registration (CFR)

Voluntary Written Agreement

- A CFR agreement occurs when two or more NERC registered entities divide responsibilities of the NERC Reliability Standards
- Texas RE reviews CFR agreements in the Centralized Organization Registration ERO System (CORES) to ensure there are no gaps or overlaps in responsibility between the parties
- A CFR must be updated when modifications (changes to applicable parties or standards) occur
- A CFR Member Listing is available on NERC's website
  - Texas RE currently has 8 active CFRs
    - 1 GO CFR (MRO is the lead region)
    - 5 GOP CFRs
    - 2 TOP CFRs

Joint Registration Organization (JRO)

Voluntary Written Agreement

- A JRO agreement occurs when an entity is registered for a specific function and accepts all compliance responsibility of all applicable NERC Reliability Standards for itself and on behalf of one or more parties or related entities
- Texas RE reviews and approves JROs in CORES
- A JRO must be updated when any modifications occur
- A JRO Member Listing is available on NERC's website
  - Texas RE currently has 7 active JROs:
    - 2 DP JROs
    - 1 DP UFLS JRO
    - 2 GO JROs
    - 1 GOP JRO
    - 1 TP JRO

Reliability Services Report

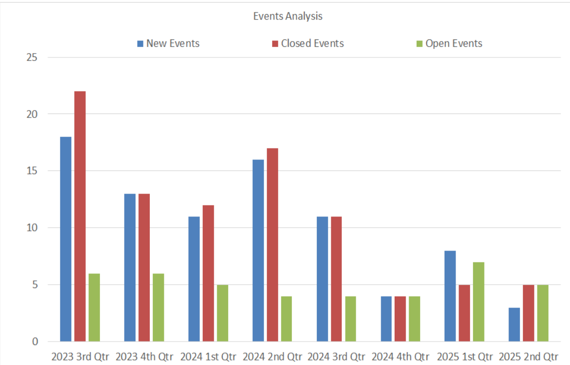
Member Representatives Committee Meeting
September 17, 2025

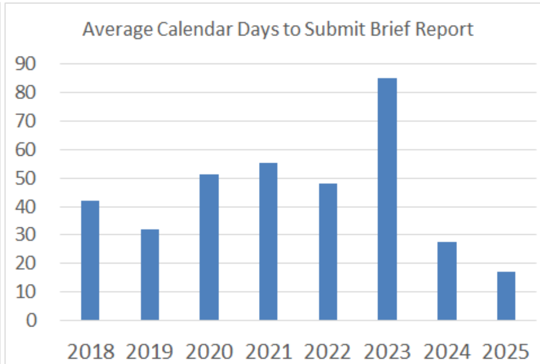
Key Activities in Q2 2025

- Energy adequacy pilot study underway
- 2025 LTRA and SRA in progress
- Texas RE RPRRA published
- NERC State of Reliability report published
- Large Load Task Force

Reliability Services Functional Dashboard as of August 15, 2025

EVENTS ANALYSIS





SITUATIONAL AWARENESS

Through 8/15/2025

Category	OE-417 Submission	EOP-004 Submission
Physical/cyber Threat		
System Separation or Islanding		
Loss of Firm Load		
Public Appeals		
Loss of Monitoring	3	
Control Center Evacuation	1	
Loss of > 50k Customers	3	
Fuel Supply Emergency		
Damage/Destruction of Facility		1
Generation Loss		
Transmission Loss		

PERFORMANCE ANALYSIS

On-Time Section 1600 Reporting Status as of 8/15/2025

	2024 Q3	2024 Q4	2025 Q1	2025 Q2
TADS	100%	100%	100%	98%
GADS	99%	99%	96%	96%
MIDAS	99%	98%	100%	60%
Wind GADS	77%	90%	90%	81%
Solar GADS	82%	74%	80%	77%

>90%
>80% and < 90%
<80%

*** Q2 data due on 8/15 for GADS-Conventional, Wind and Solar

** Q2 data due 8/31 for MIDAS

Q2 data reporting in progress

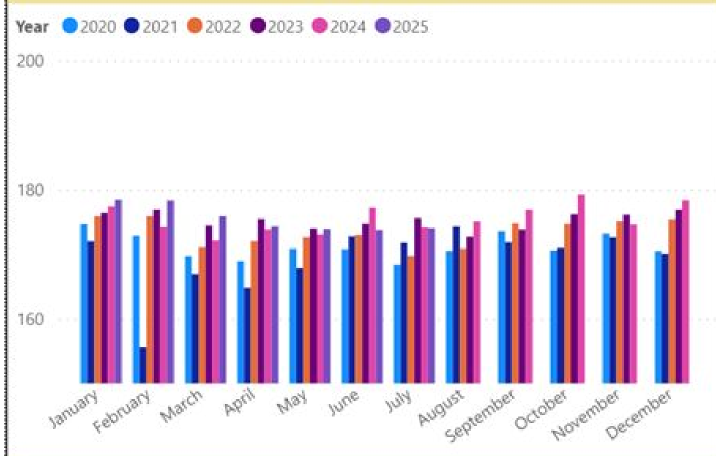
RELIABILITY ASSESSMENTS

Region	LTRA Data Quality	LTRA Timeliness	WRA Quality	WRA Timeliness	SRA Quality	SRA Timeliness
MRO	Data Error in 2024 LTRA					
NPCC						
RF						
SERC						
TEXAS-RE						
WECC						

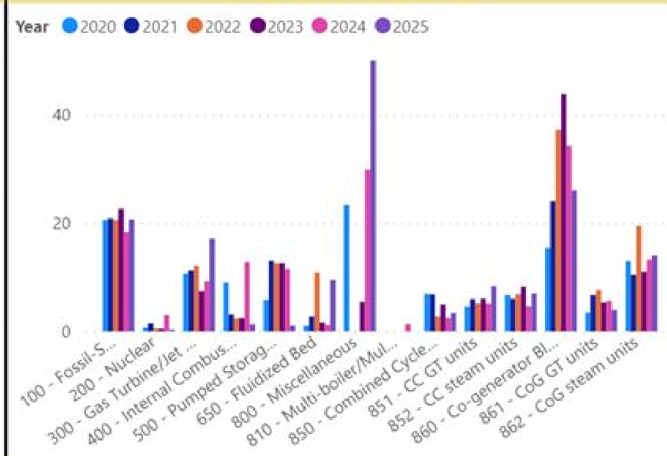
Public

Grid Reliability Dashboard as of August 15, 2025

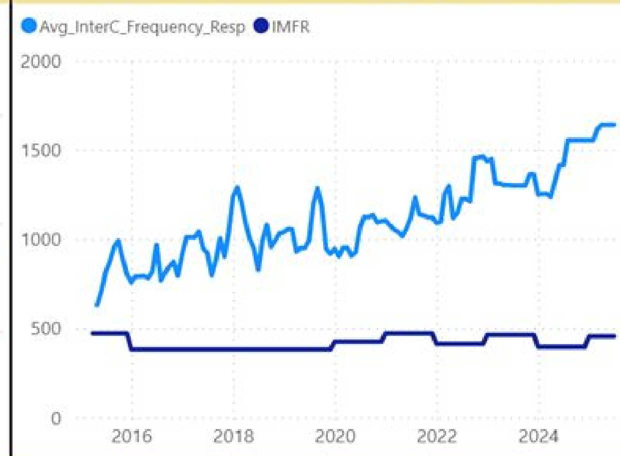
CPS1 by Month



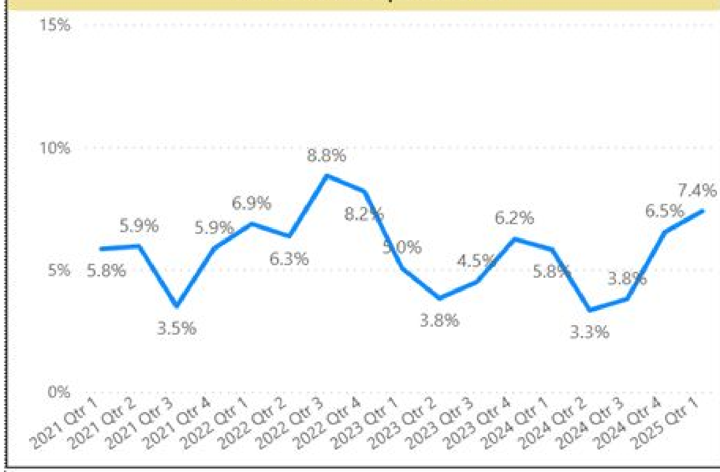
Avg EFOR by Unit Type



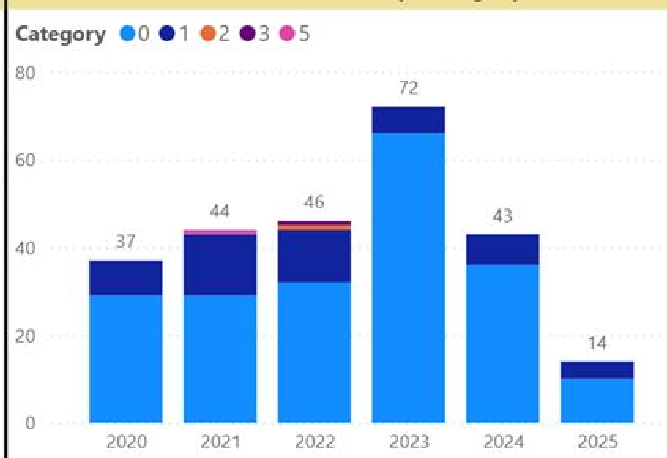
Avg Interconnection Frequency Response



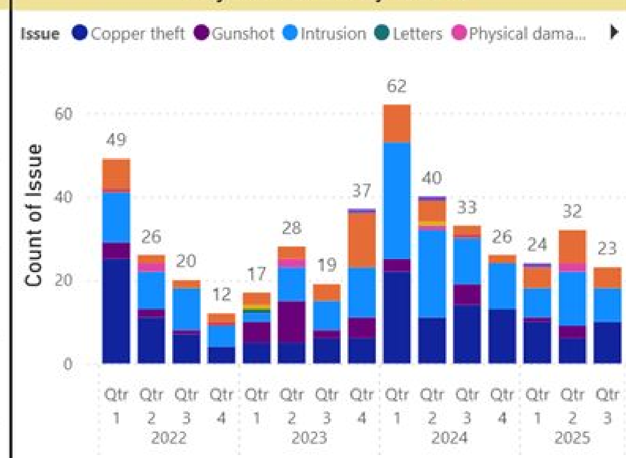
Percent Misoperations



Number of Events by Category



Physical Security Issues



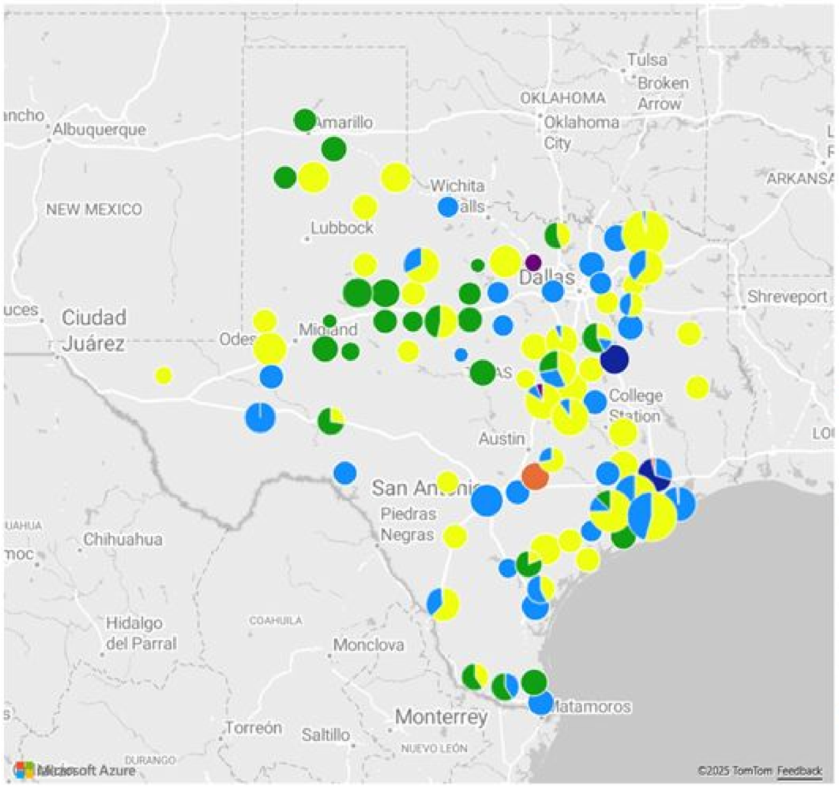
APPENDIX:
RELIABILITY AND PERFORMANCE INDICATORS UPDATE

Public

New Generation Interconnections as of August 1, 2025

New Generation Interconnections

Technology PV BL WT GT IC CC ST



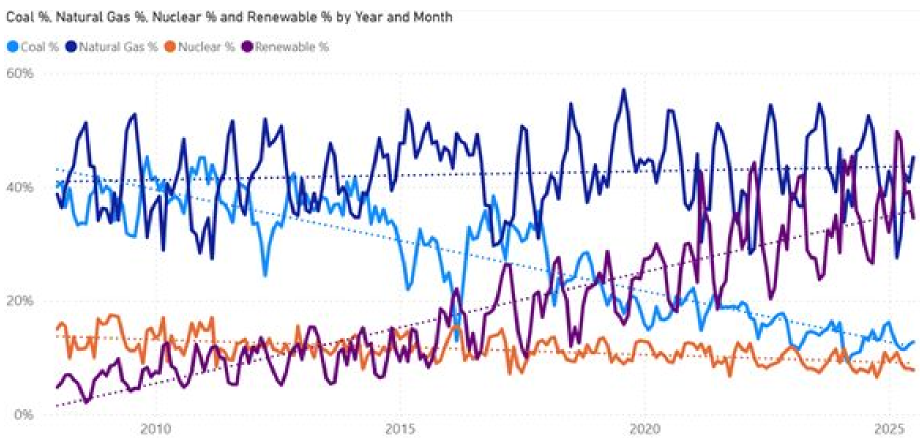
Technology	Year	Count of Capacity (MW)	Sum of Capacity (MW)
WT	2023	1	7.20
CC	2024	2	67.00
PV	2024	1	24.76
WT	2024	4	401.00
BL	2025	42	5,586.17
CC	2025	1	21.00
GT	2025	1	143.70
IC	2025	1	188.40
PV	2025	58	13,468.94
ST	2025	1	14.00
WT	2025	35	4,736.16
BL	2026	27	4,249.83
GT	2026	3	912.00
IC	2026	2	218.40
PV	2026	23	4,969.38
WT	2026	2	313.82
BL	2027	1	201.10
PV	2027	3	523.17
WT	2027	1	259.20
Total		**209**	**36,305.23**

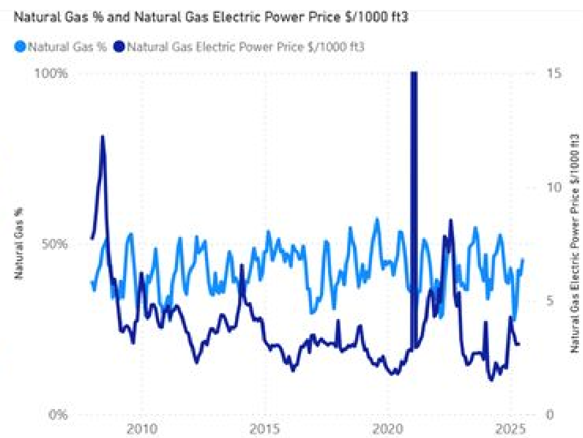
Approved for Synchronization/No COD

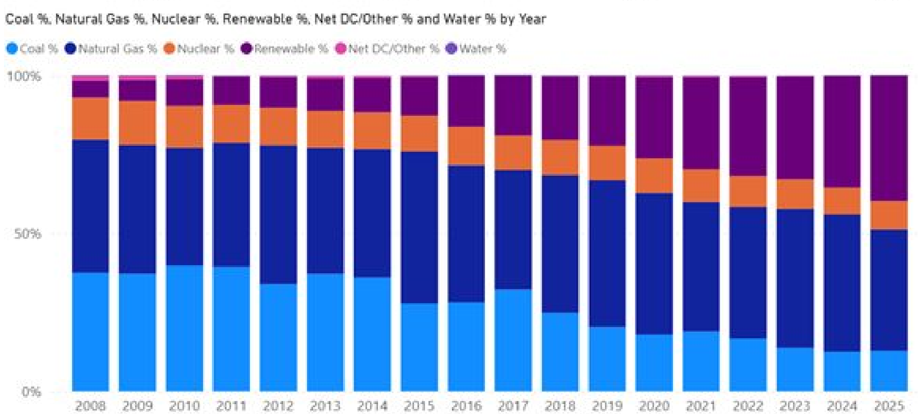
Year	Count of Capacity (MW)	Sum of Capacity (MW)
2017	1	7.30
2018	2	9.30
2019	6	634.10
2020	7	661.50
2021	10	1,703.83
2022	11	2,547.29
2023	11	2,457.74
2024	27	5,027.64
2025	39	7,369.64
Total	**114**	**20,418.34**

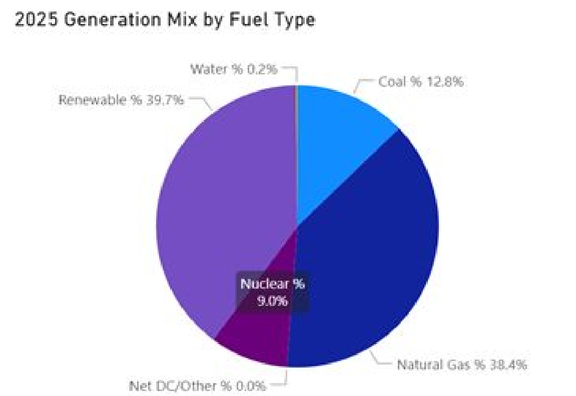
New Generation interconnections with a signed interconnection agreement and meeting all Planning Guide requirements

Generation Mix Trends





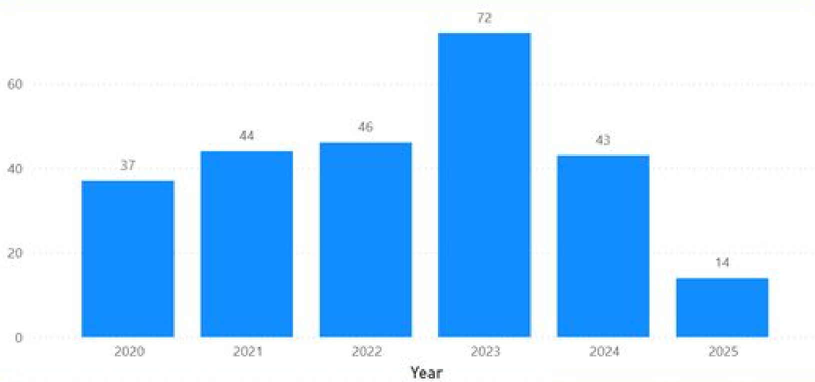




Public

System Events Dashboard as of August 15, 2025

Number of Events by Year



Events By Year and Category

Year	0	1	2	3	5	Total
2020	29	8				**37**
2021	29	14			1	**44**
2022	32	12	1	1		**46**
2023	66	6				**72**
2024	36	7				**43**
2025	10	4				**14**
Total	**202**	**51**	**1**	**1**	**1**	**256**

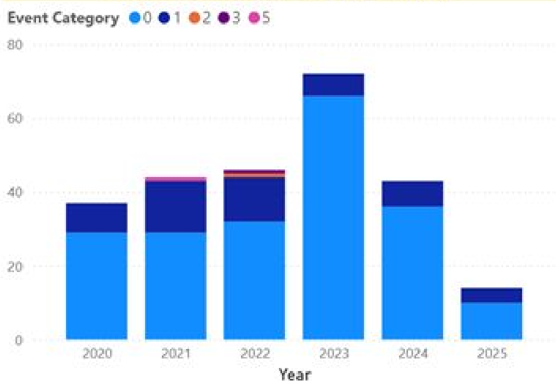
Reports Received

Year	Brief Report	EOP-004	OE-417	Other	Total
2020	8	6	28	2	**44**
2021	18	12	57		**87**
2022	19	7	39	1	**66**
2023	9	17	60		**86**
2024	7	10	41		**58**
2025	3	3	12		**18**
Total	**64**	**55**	**237**	**3**	**359**

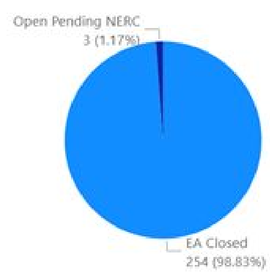
Year

- Select all
- 2010
- 2011
- 2012
- 2013
- 2014
- 2015
- 2016
- 2017
- 2018
- 2019
- 2020
- 2021
- 2022
- 2023
- 2024
- 2025

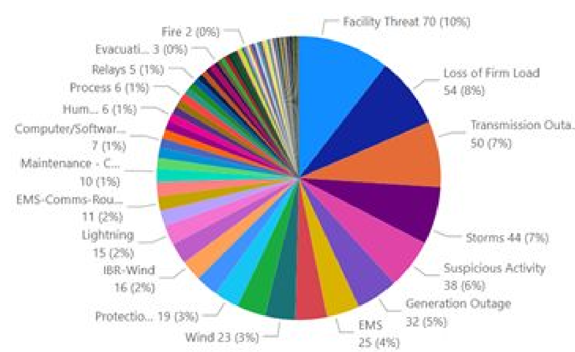
Number of Events by Year and Category



Status of Events



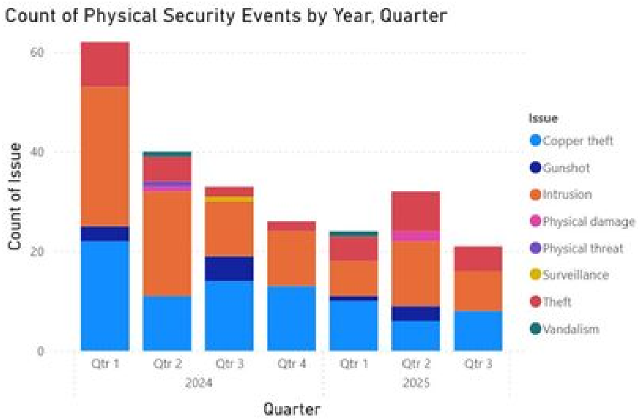
Events by Cause

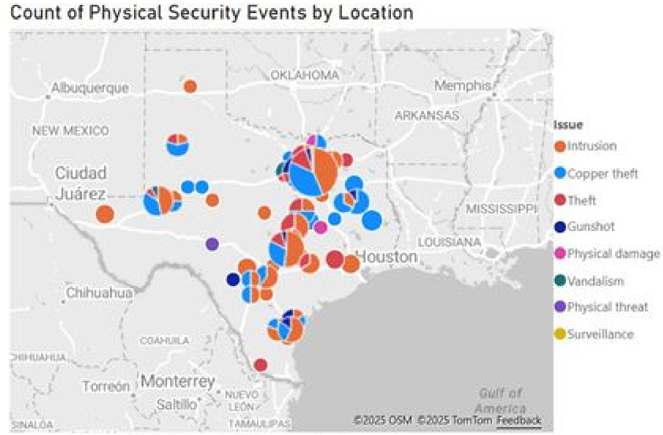


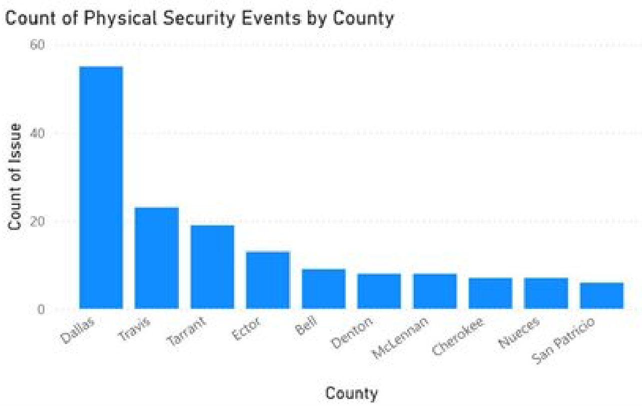
Key 2025 System Events

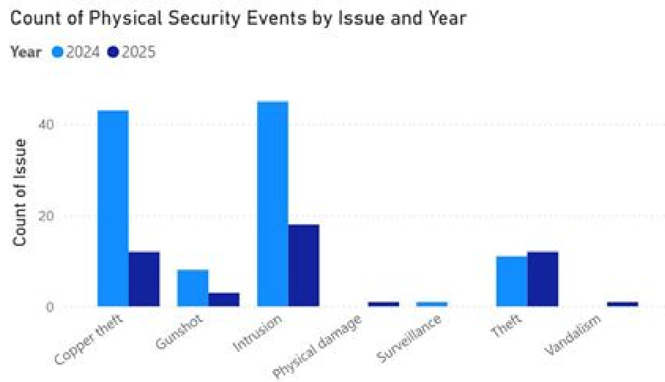
- **Four reported loss of monitoring and control events**
- **Two reported physical security events**

Infrastructure Protection – 2024-2025



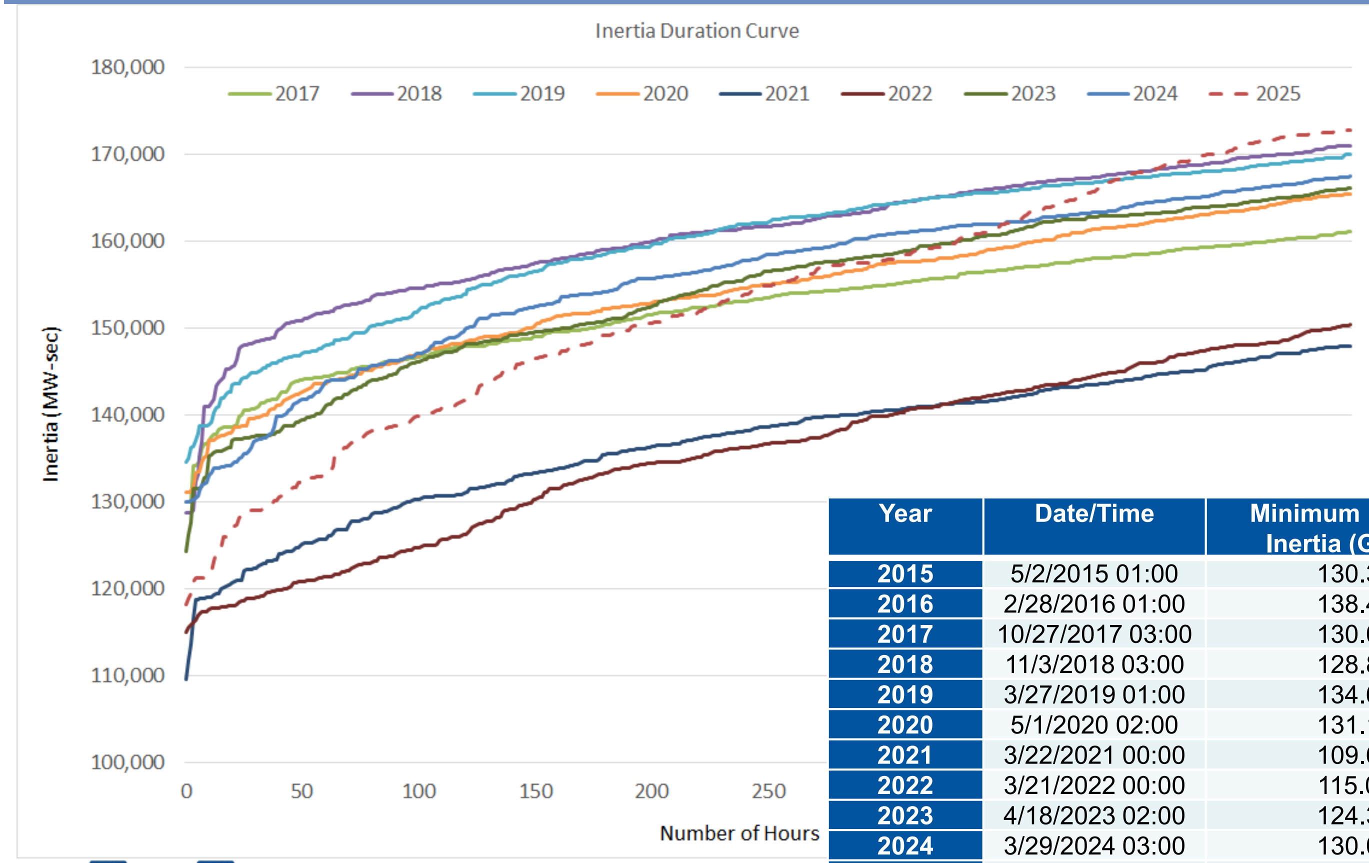






- **Incidents reported to System Security Response Group (SSRG)**
- **Slight downward trending 2024 Q2 to 2025 Q2**

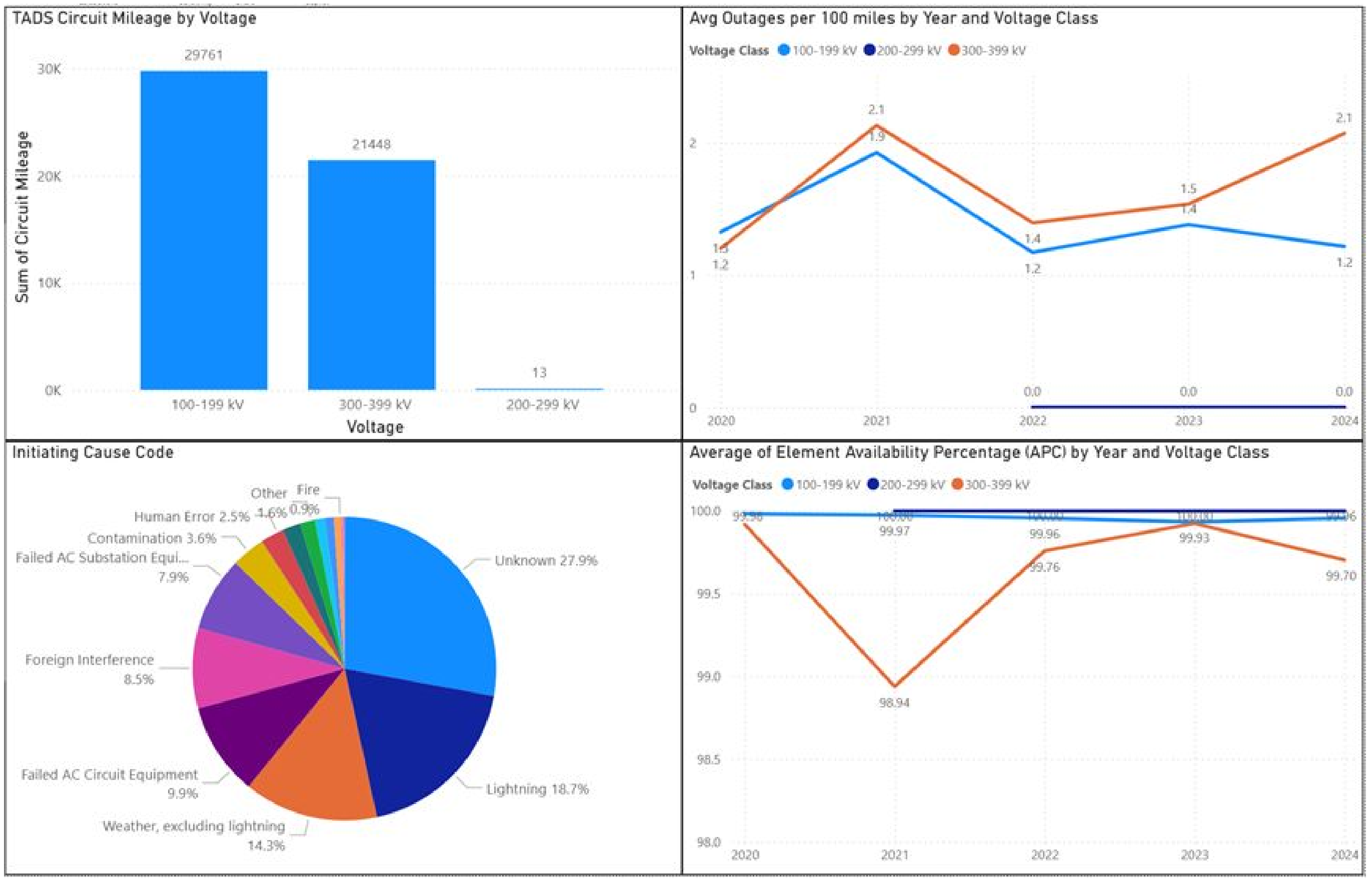
System Inertia as of August 1, 2025



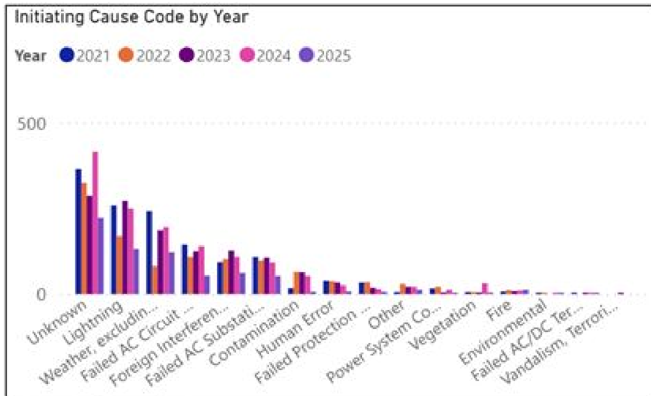
2025 Inertia Duration Curve

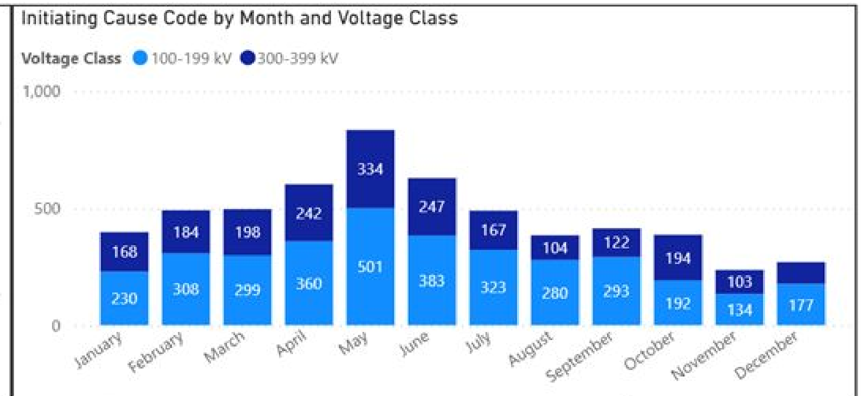
Year	Date/Time	Minimum Hourly Inertia (GW-s)	Load (MW)	Net Load (MW)	IRR %
2015	5/2/2015 01:00	130.3	27,798	20,569	26.1%
2016	2/28/2016 01:00	138.4	26,839	14,797	44.9%
2017	10/27/2017 03:00	130.0	28,443	13,178	53.7%
2018	11/3/2018 03:00	128.8	28,412	13,452	52.7%
2019	3/27/2019 01:00	134.6	29,426	14,645	50.2%
2020	5/1/2020 02:00	131.1	30,273	13,076	56.8%
2021	3/22/2021 00:00	109.6	31,904	10,905	65.8%
2022	3/21/2022 00:00	115.0	33,365	11,445	65.7%
2023	4/18/2023 02:00	124.3	35,798	13,817	61.4%
2024	3/29/2024 03:00	130.0	37,297	11,912	68.1%
2025 YTD	3/18/2025 11:00	**118.3**	48,973	**12,290**	**74.9%**

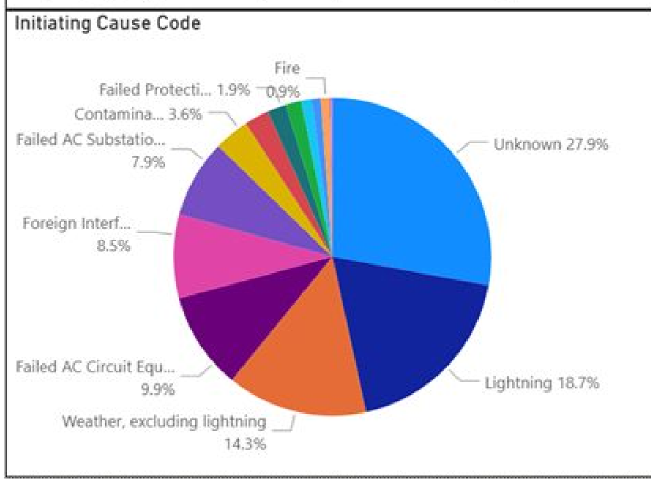
Transmission Performance Dashboard

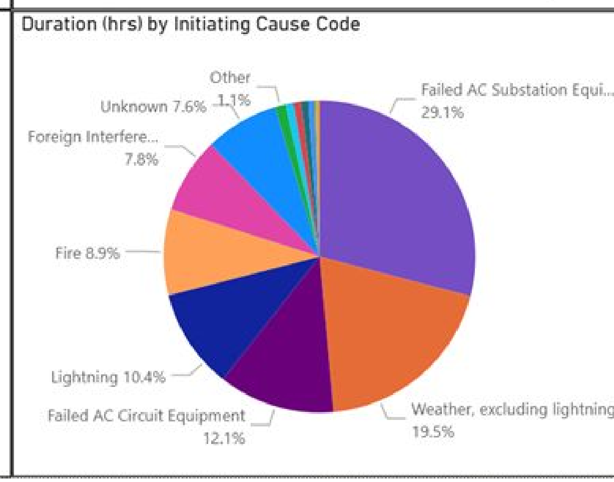


Transmission Performance Dashboard





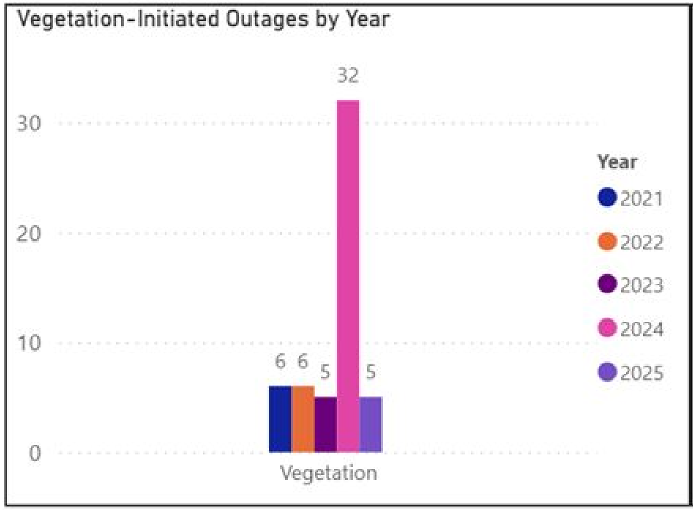


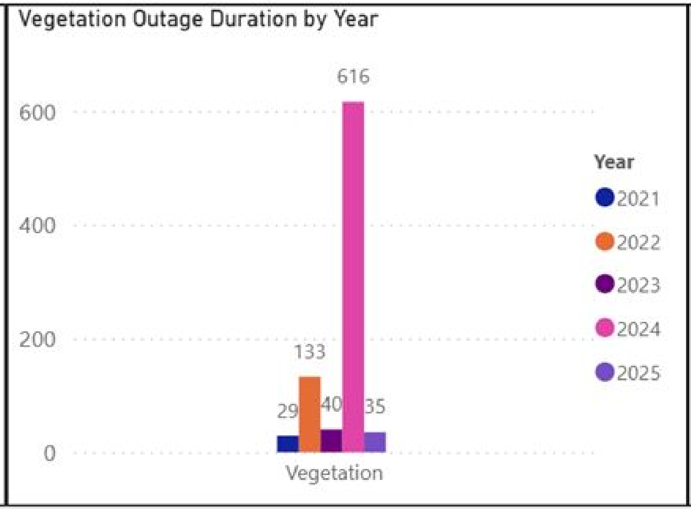


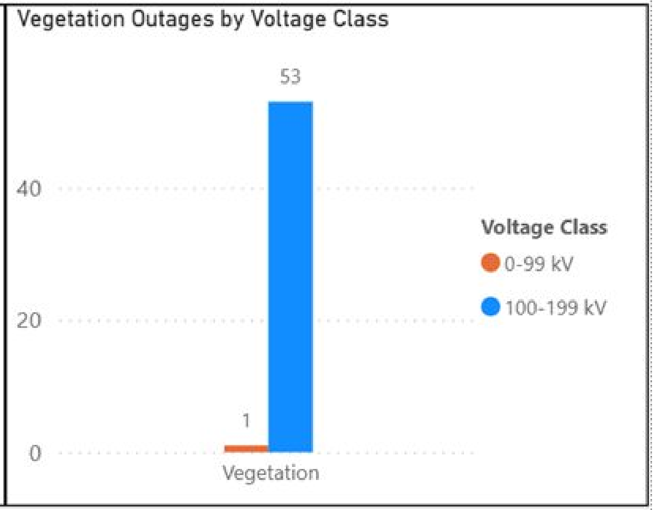
Transmission Event Data by Cause, Month, and Duration

2021 – 2025 YTD

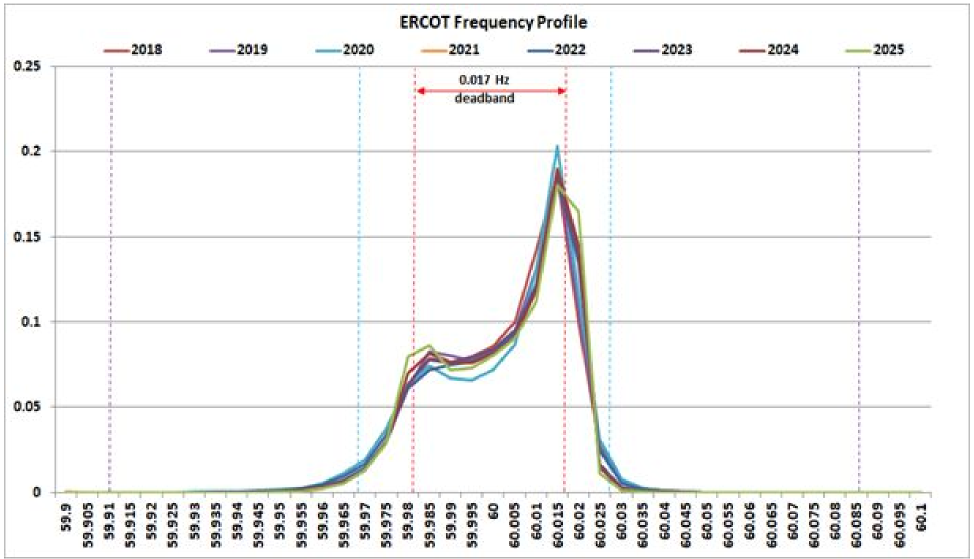
Vegetation Outage Trends – Available Data

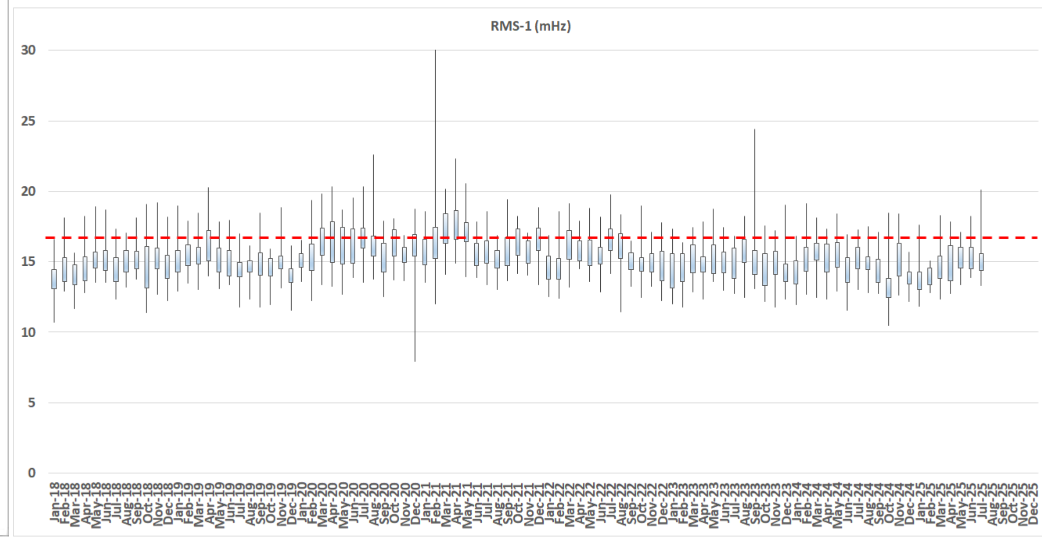






Frequency Control as of August 1, 2025

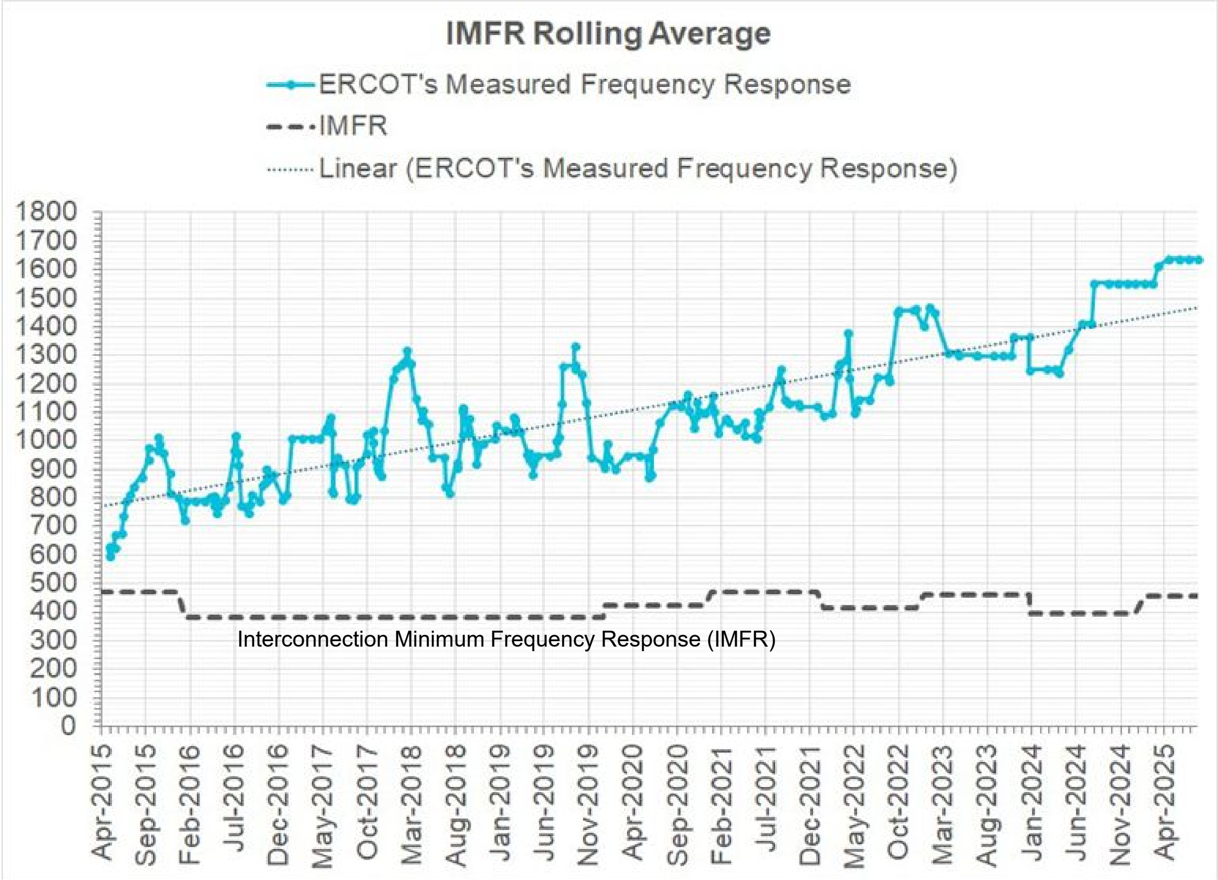




Red dashed line indicated 17 mHz governor dead-band

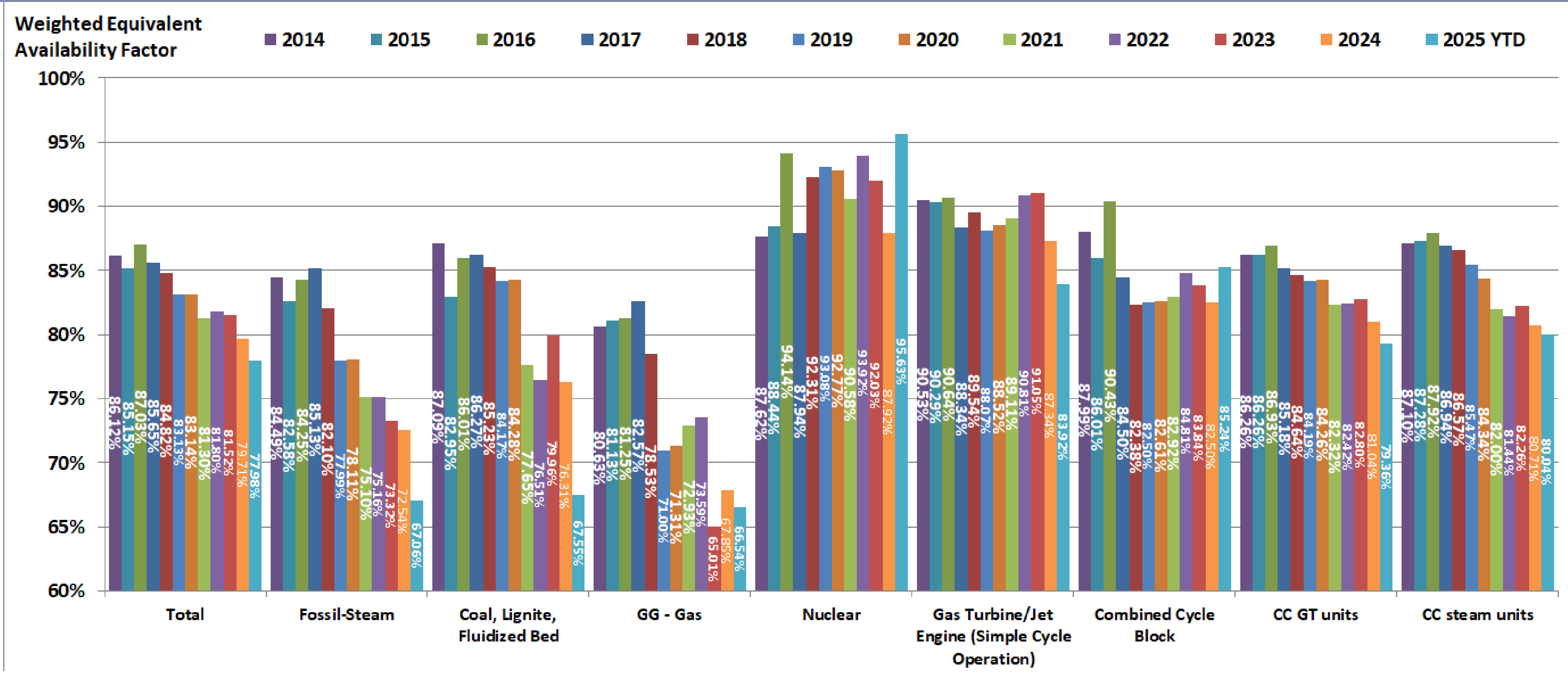
<u>Balancing Authority ACE Limit (BAAL) Exceedances</u>
72 clock-minutes of BAAL Exceedances in 2021
1 clock-minute of BAAL Exceedances in 2022
21 clock-minutes of BAAL Exceedances in 2023
5 clock-minutes of BAAL Exceedances in 2024
0 clock-minutes of BAAL Exceedances in 2025

Primary Frequency Response – BAL-001-TRE



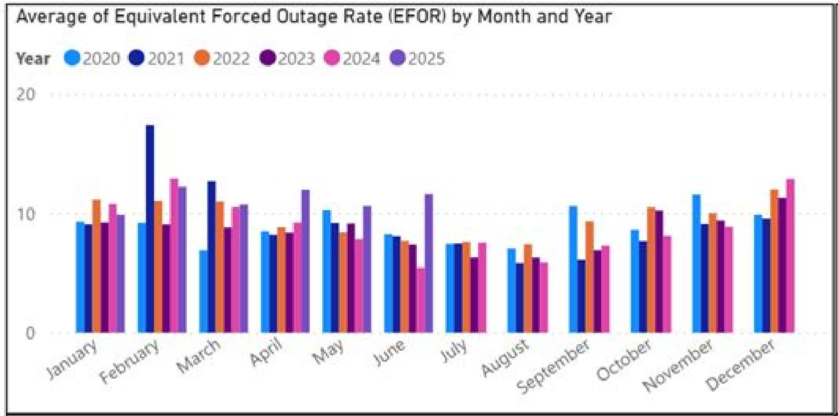
Public

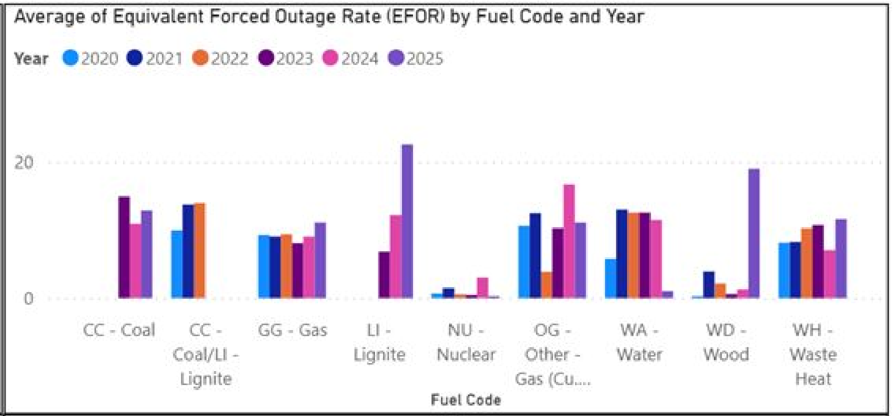
Generation Availability (Conventional)

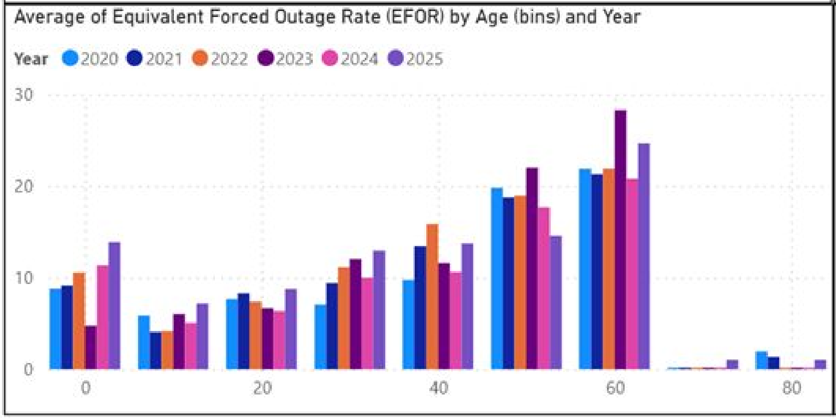


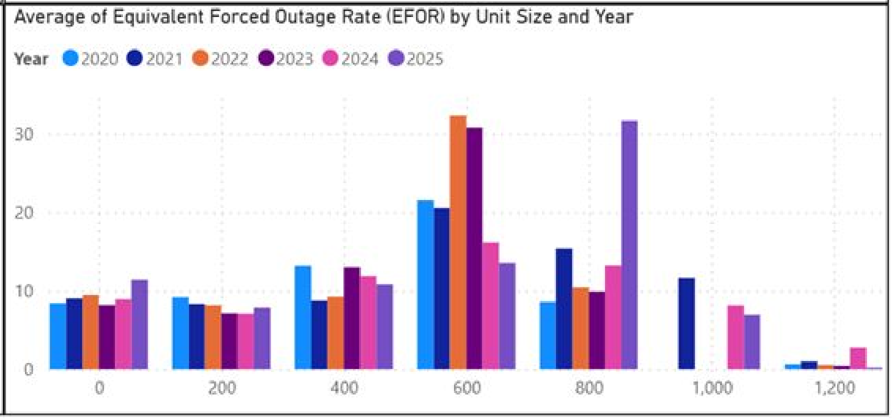
TEXAS RE

Generation Equivalent Forced Outage Rates (Conventional)

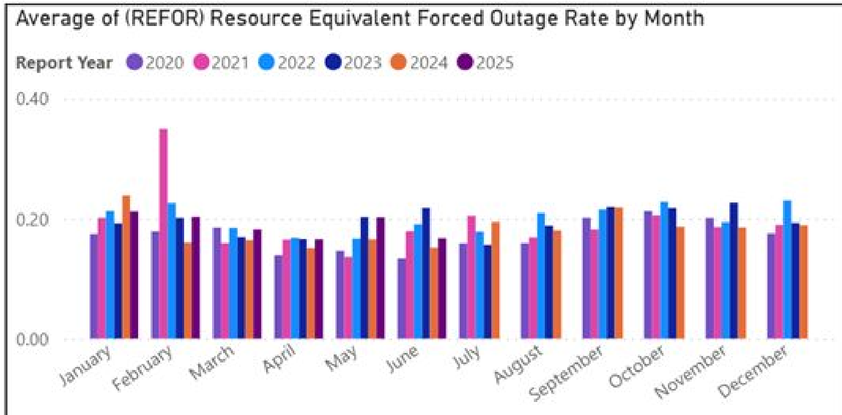


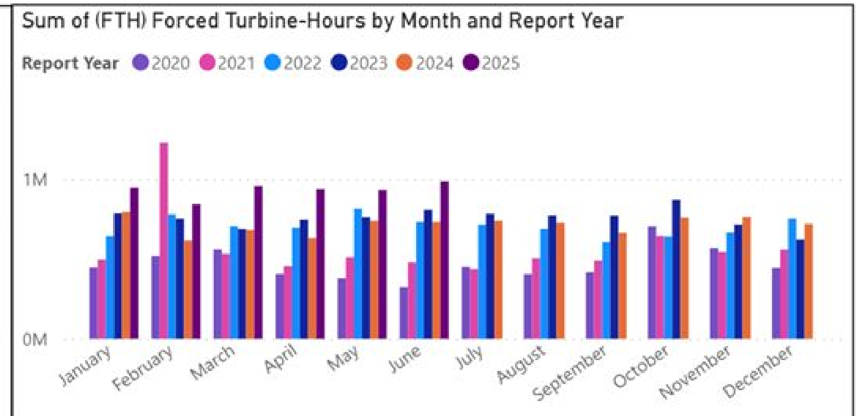


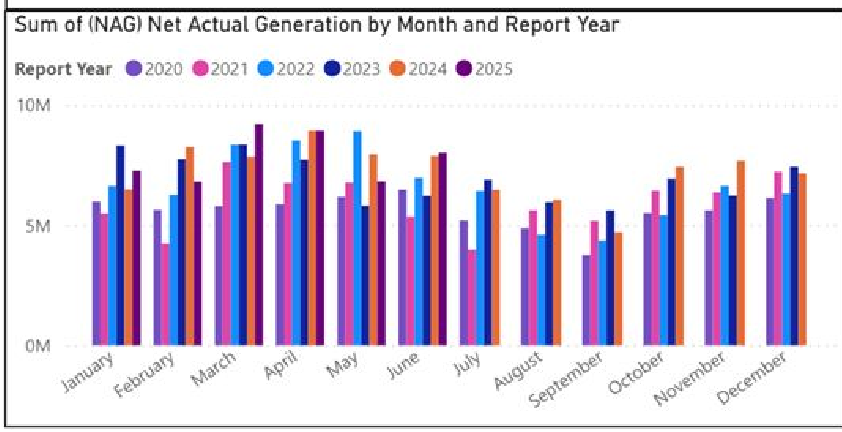


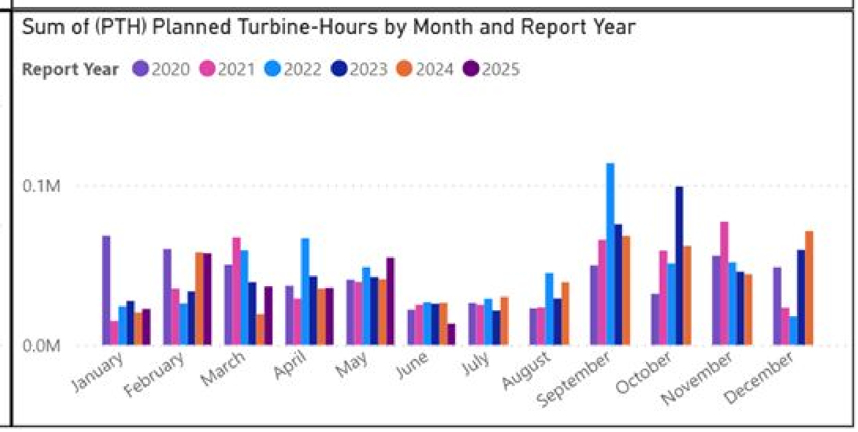


Wind GADS Metrics





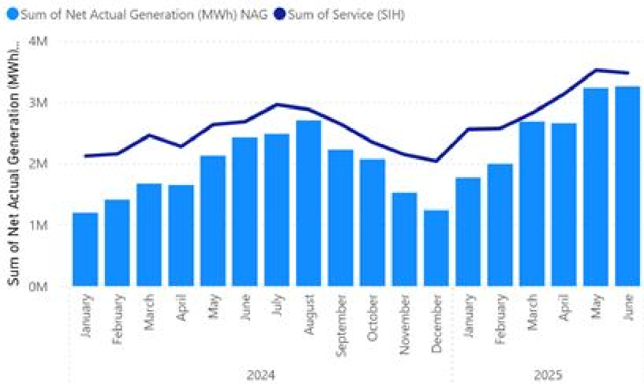




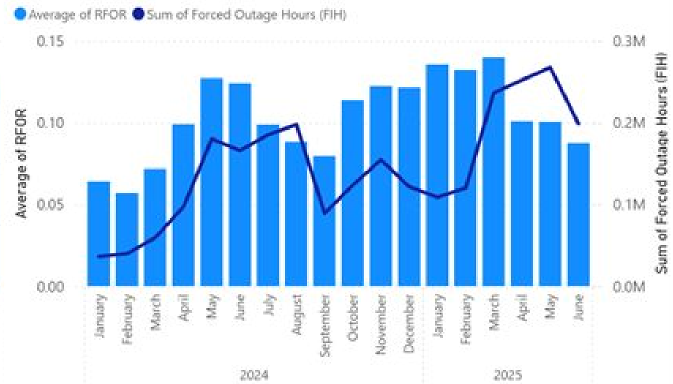
TEXAS RE

Solar GADS Metrics

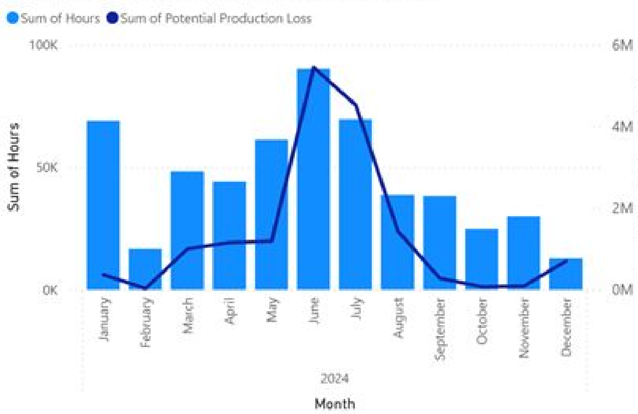
Net Actual Generation (MWh) NAG and Service Hours (SIH) by Month



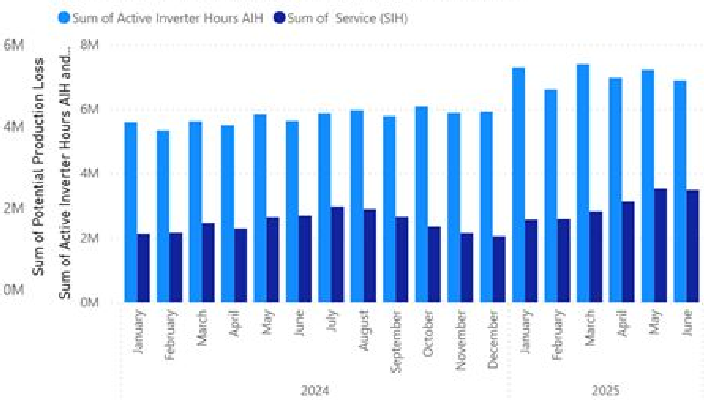
Average Forced Outage Rate and Forced Outage Hours (FIH) by Month



Outage Hours and Potential Production Loss by Month

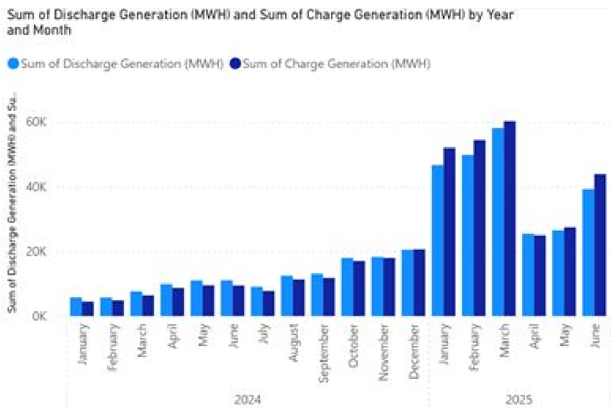


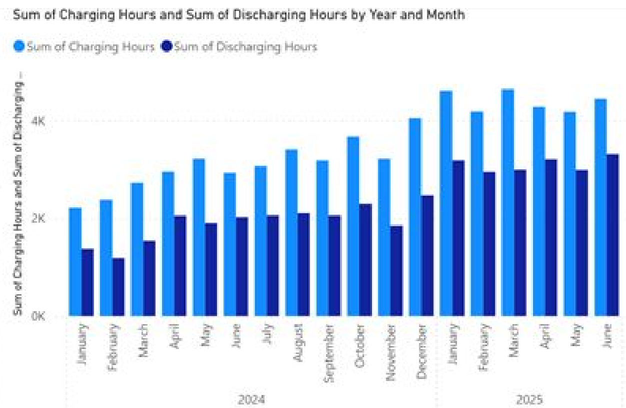
Active Inverter Hours AIH and Service Hours (SIH) by Month

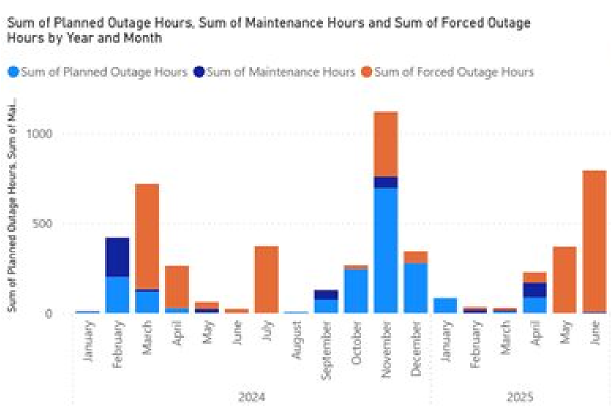


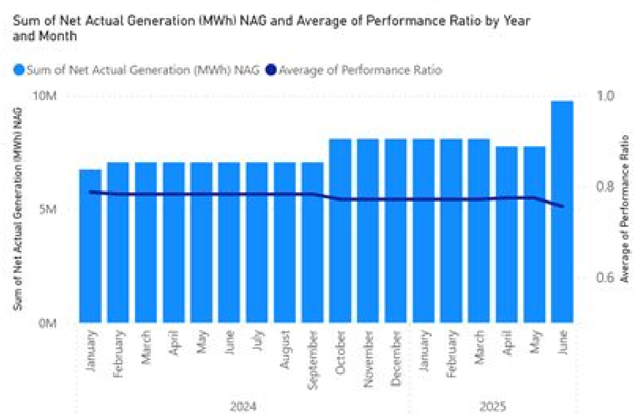
TEXAS RE

BESS GADS Metrics







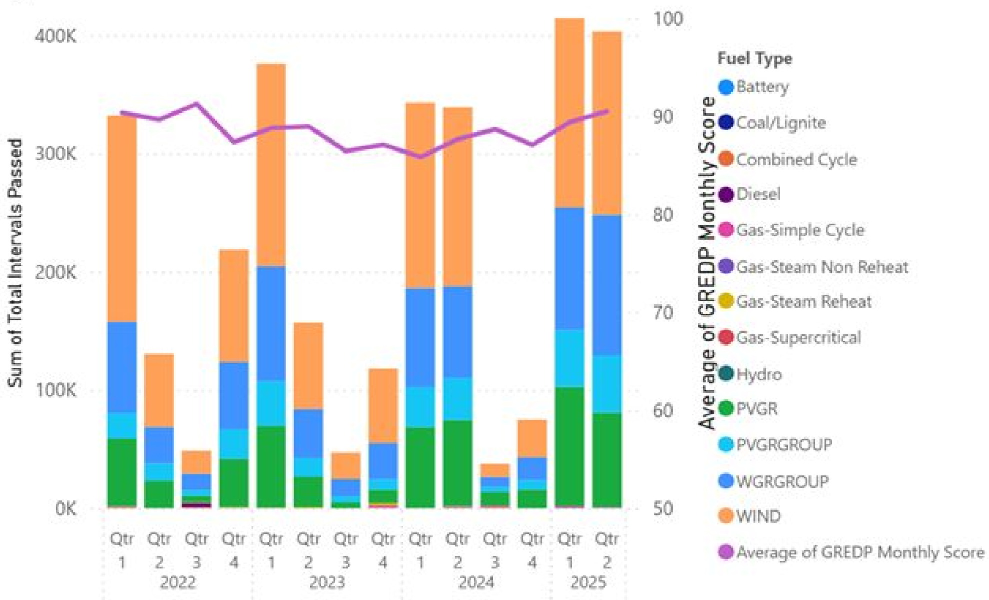


Metrics for Battery Energy Storage System (BESS) facilities co-located with solar or wind generation facilities

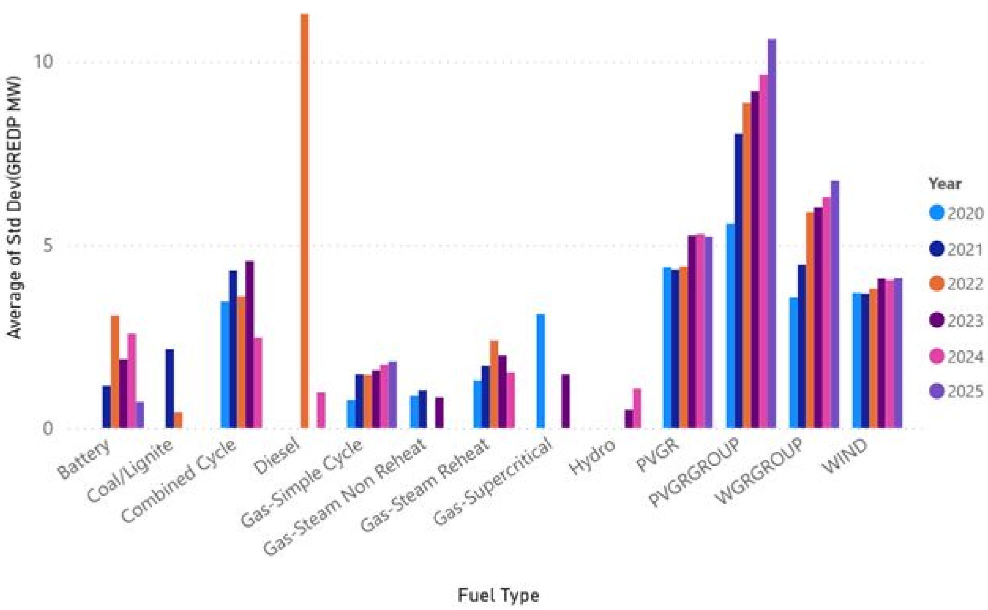
TEXAS RE

GREDP Metrics

Sum of Total Intervals Passed and Average of GREDP Monthly Score by Year, Quarter and Fuel Type



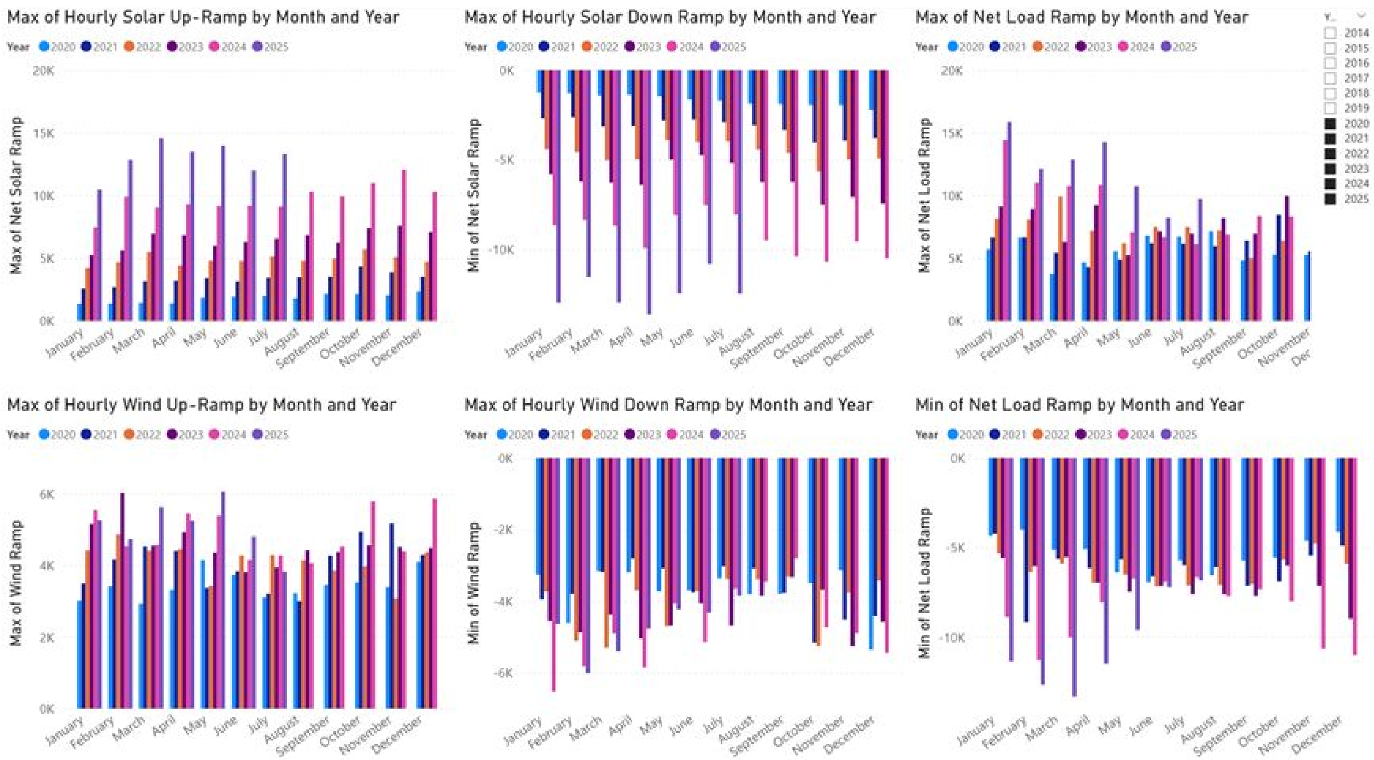
Average of Std Dev(GREDP MW) by Fuel Type and Year



Public

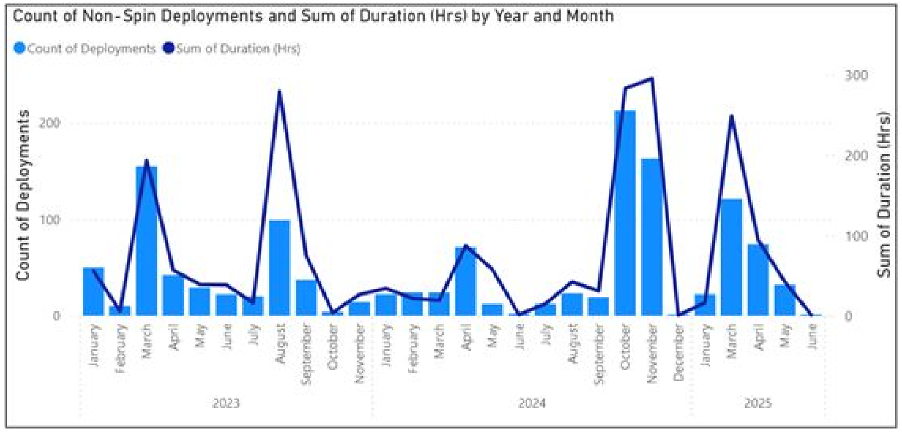
Ramping

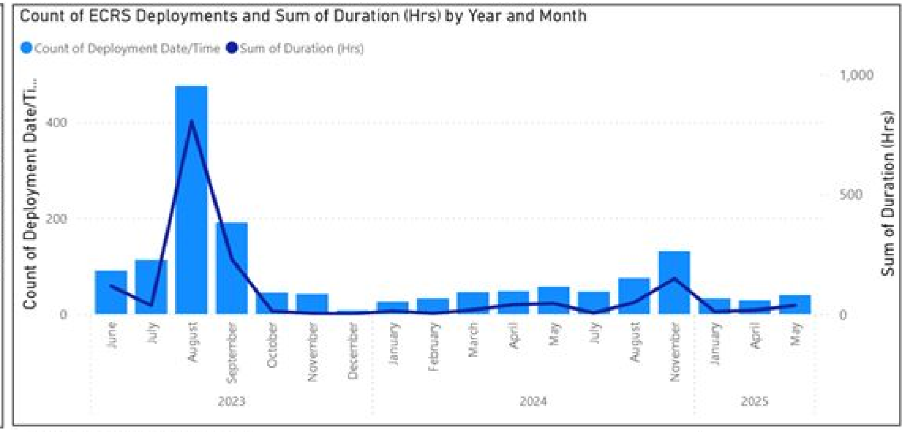
2025 maximum solar up and down ramps now exceeding 13,000 MW per hour

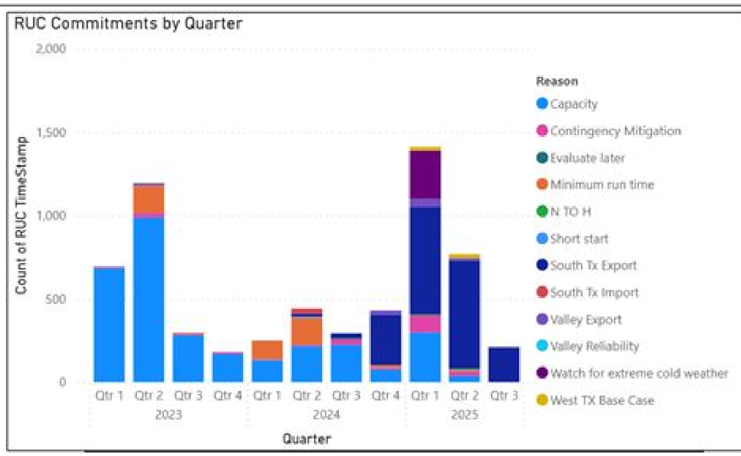


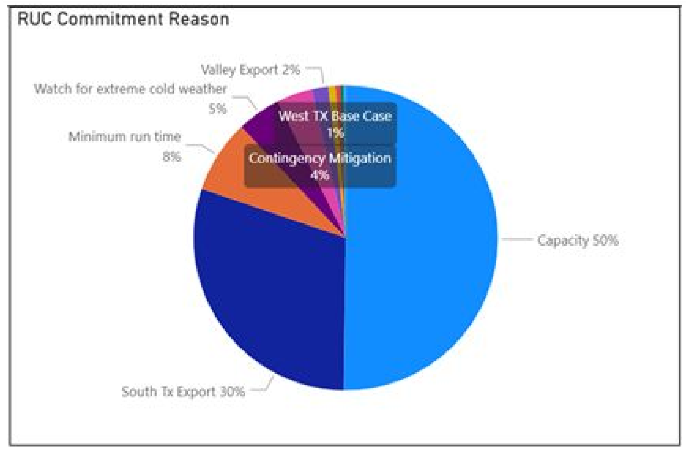
TEXAS RE

Non-Spin RUC and ECRS Deployments as of August 1, 2025





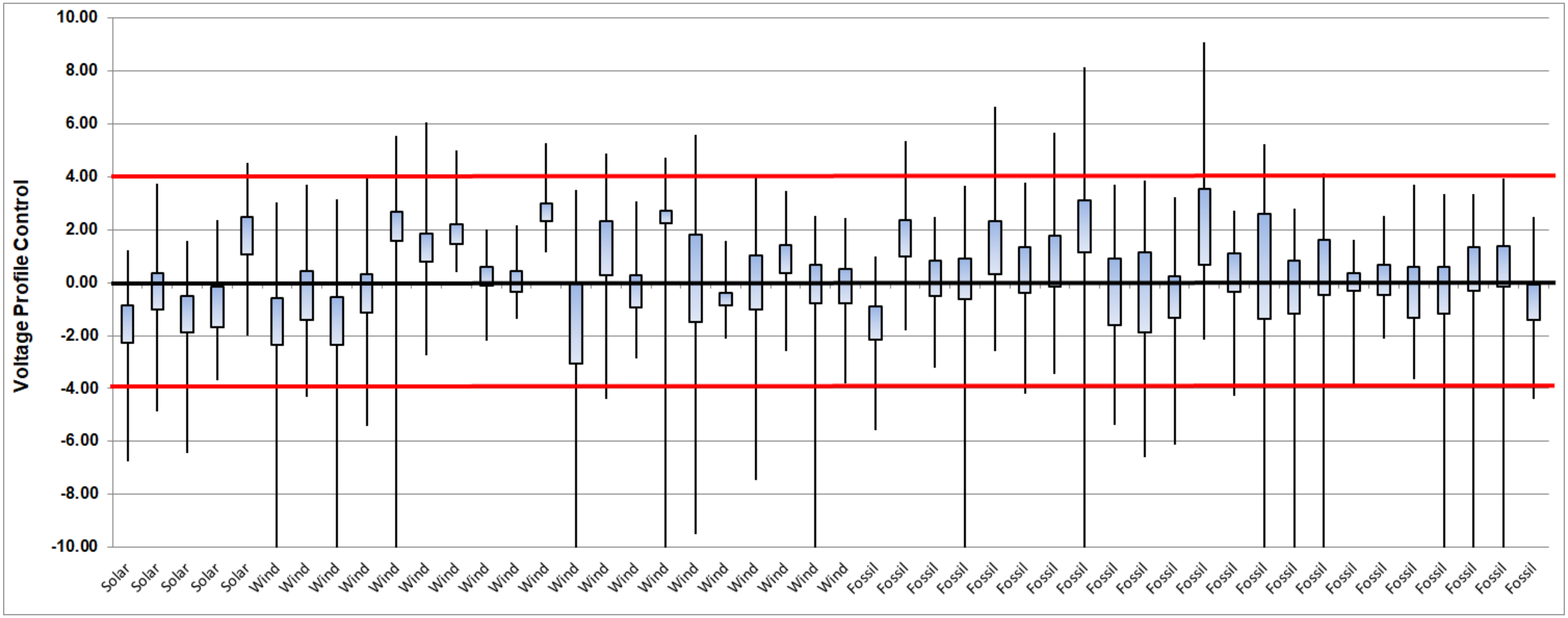




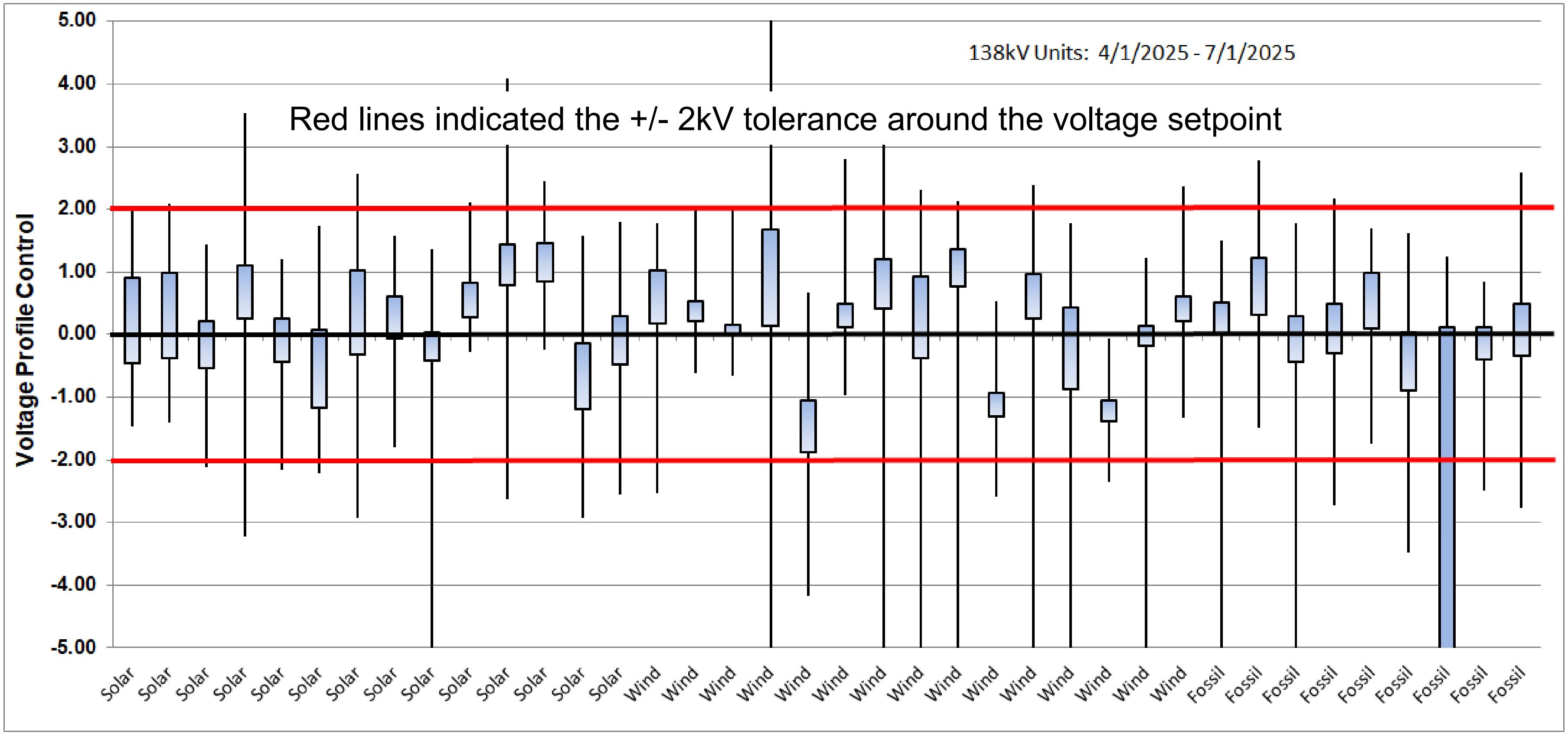
Public

Voltage Control Metrics – 345kV Units for Apr-Jun 2025

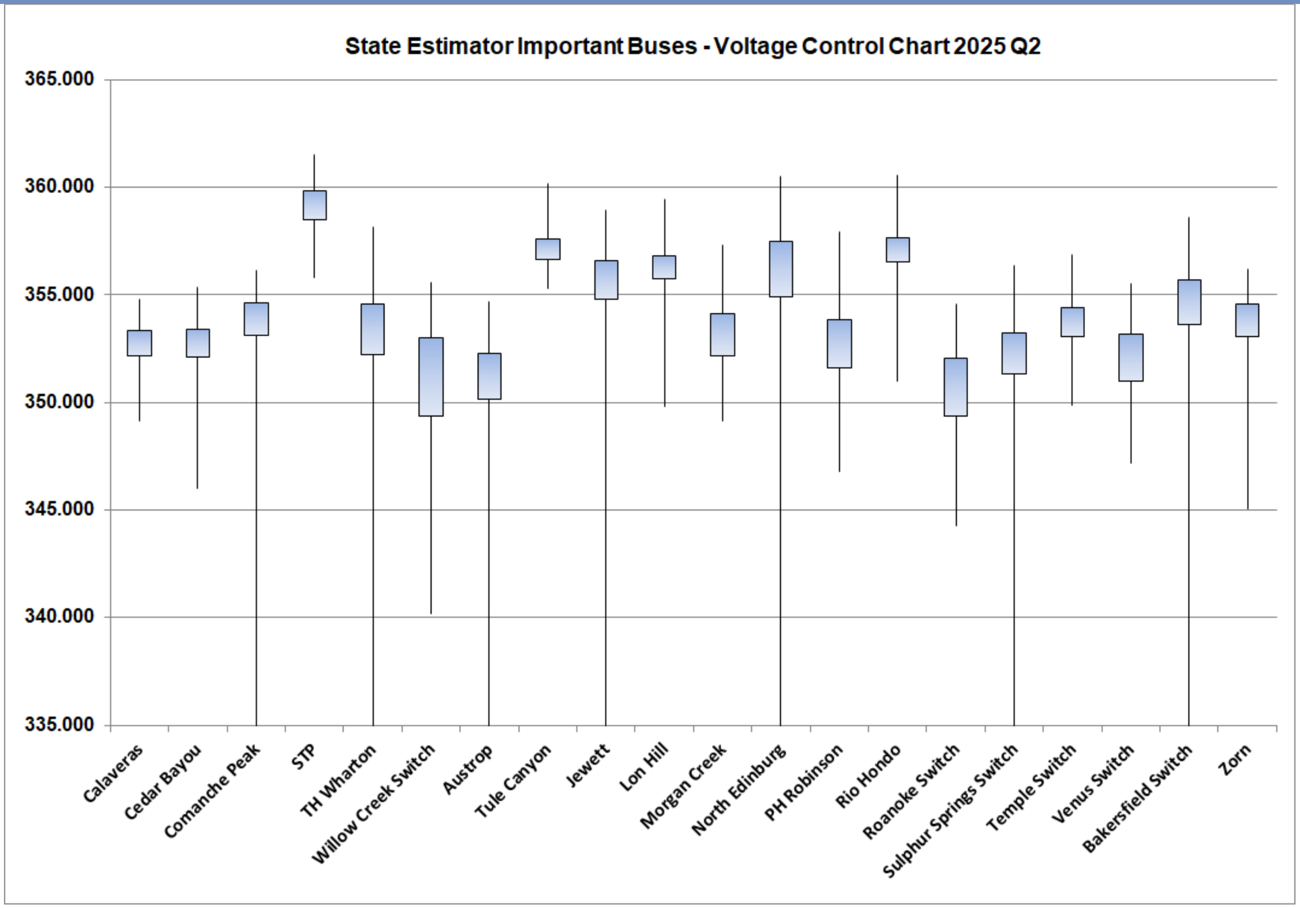
Red lines indicated the +/- 4kV tolerance around the voltage setpoint



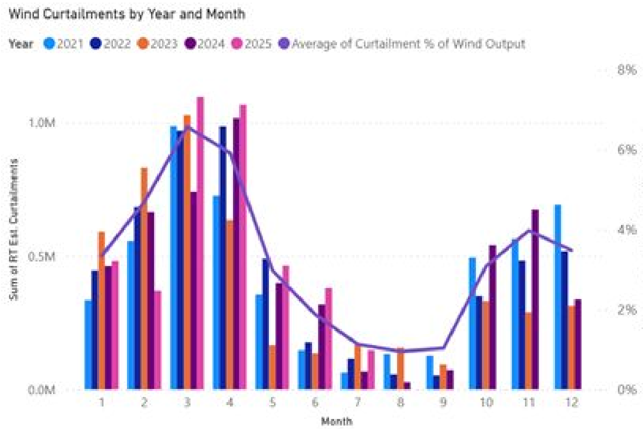
Voltage Control Metrics – 138kV Units for Apr-Jun 2025

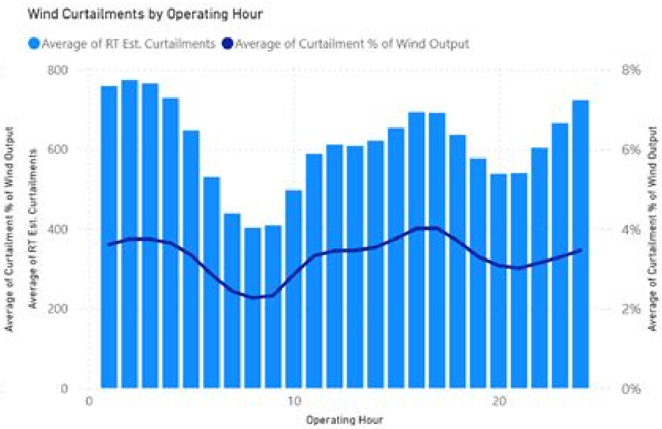


Voltage Control Metrics – State Estimator Important Buses

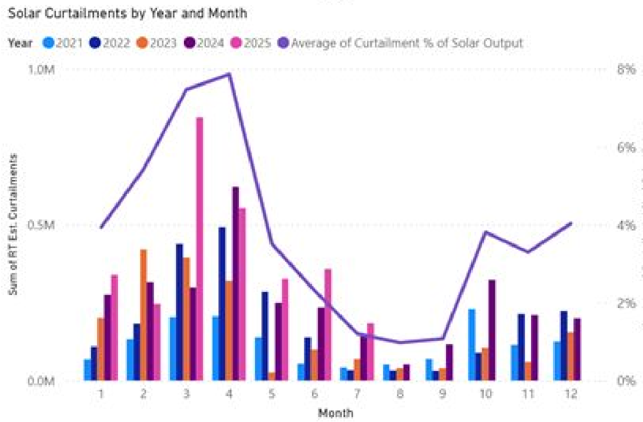


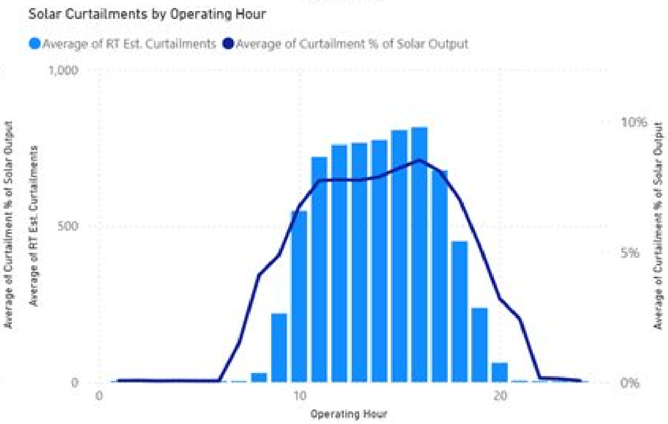
Curtailments as of August 1, 2025



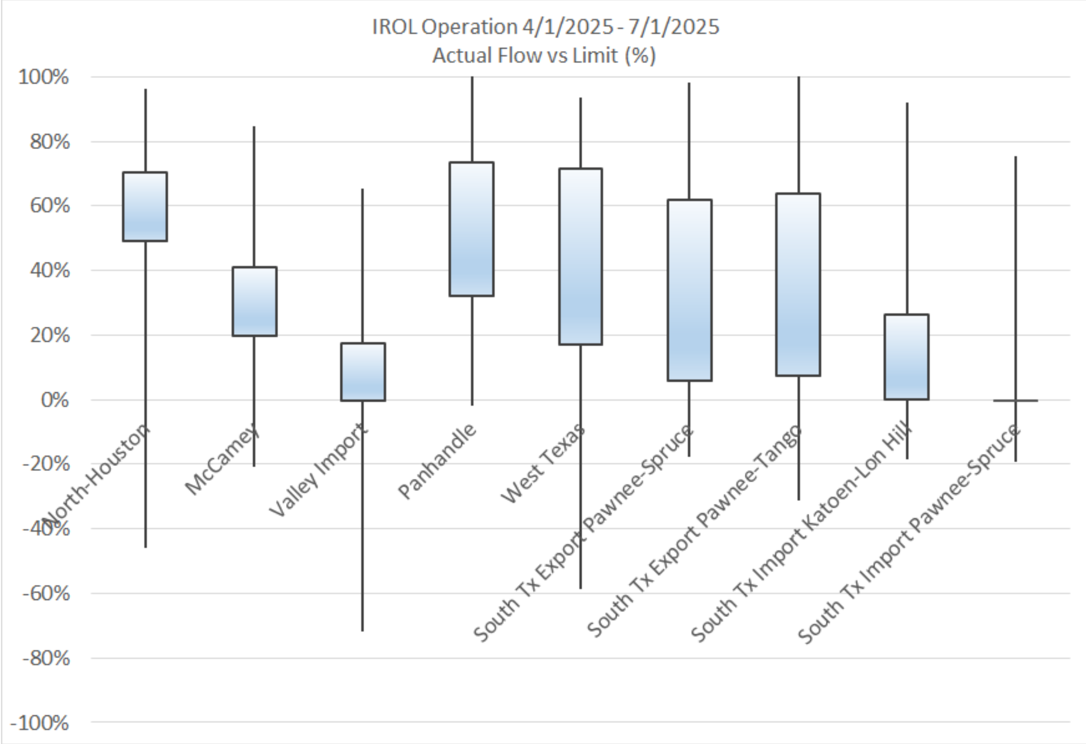


2025 YTD	Wind	Solar
GWHrs	4,008.5	2,850.5
Max Hourly MW Curtailment	8,656	10,826
Avg % of Uncurtailed Output	5.3%	7.0%



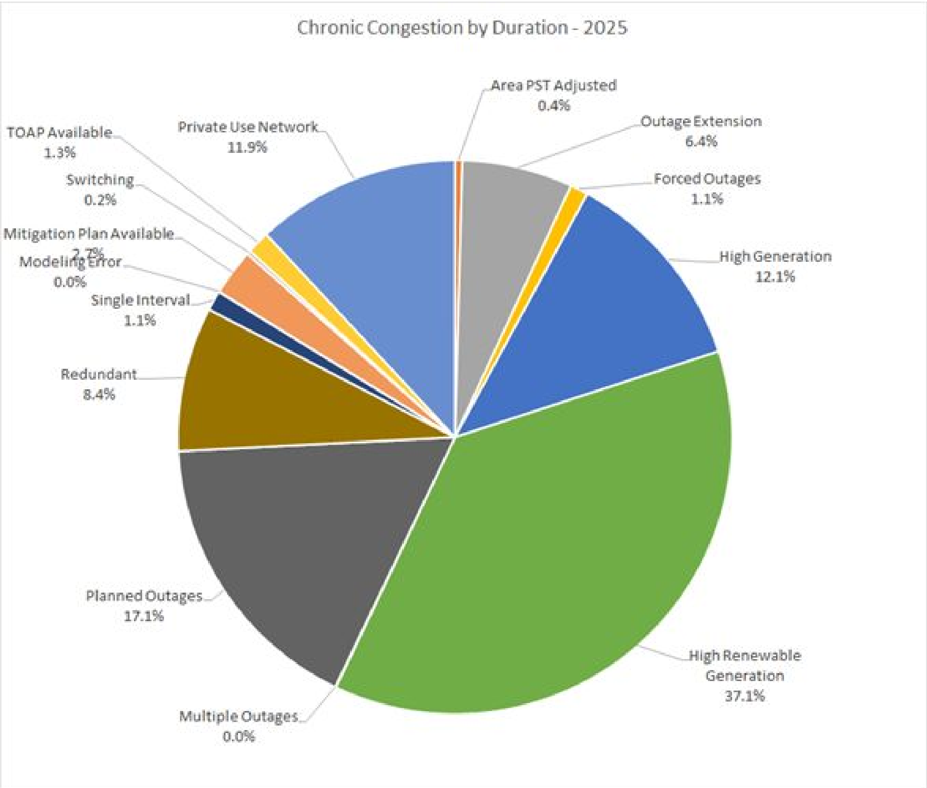


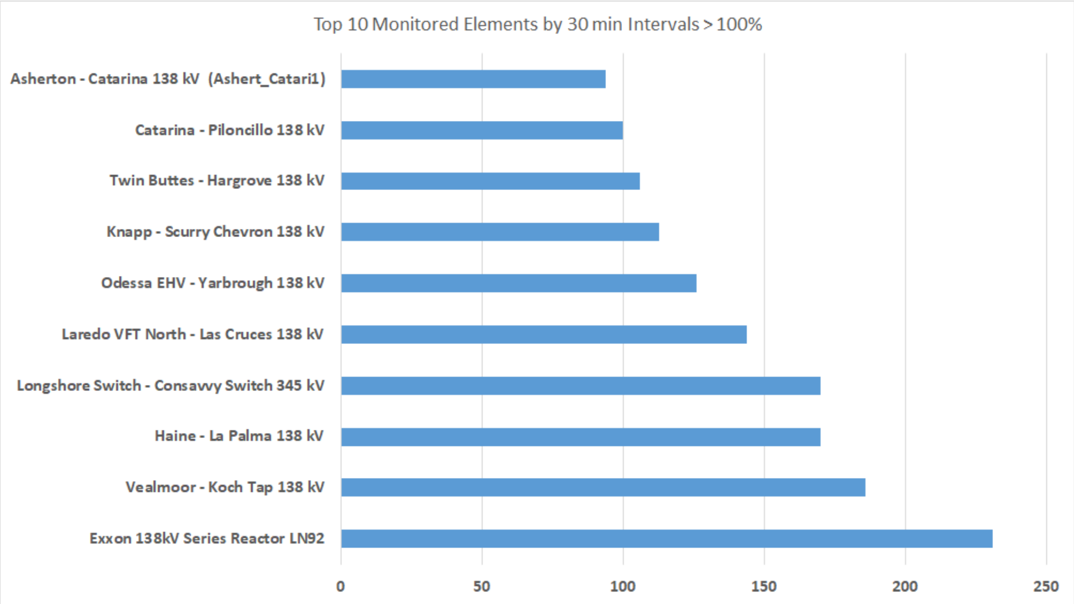
Generic Transmission Constraints



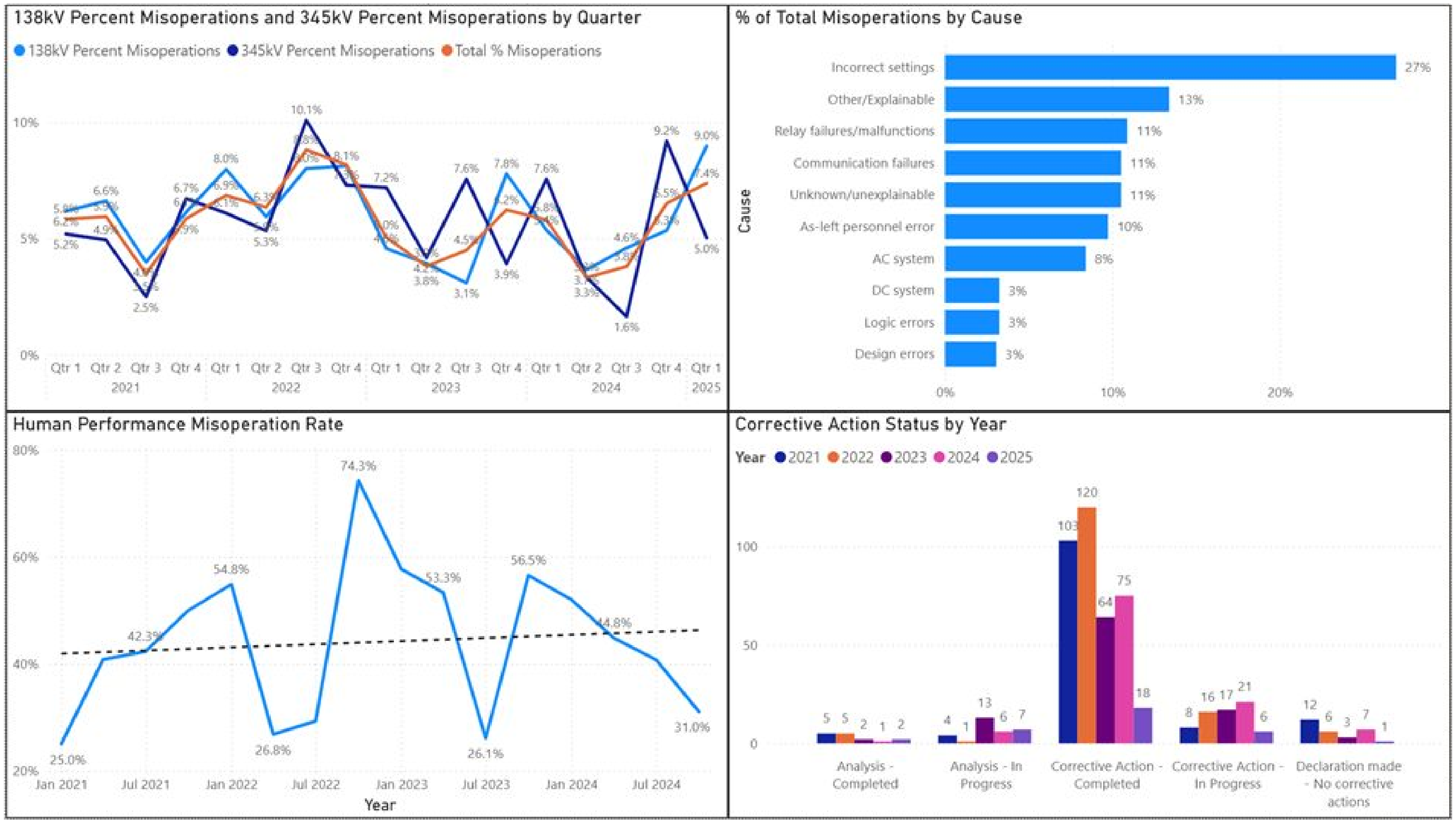
	North-Houston	McCamey	Valley Import	Panhandle	West Texas	South Tx Export Pawnee-Spruce	South Tx Import Pawnee-Spruce	South Tx Export Pawnee-Tango	South Tx Export Katoen-Lon Hill
# Minutes > 90%	25	0	0	934	959	0	315	52	2
# Minutes > 100%	0	0	0	2	0	0	0	5	0

Transmission Congestion as of August 1, 2025



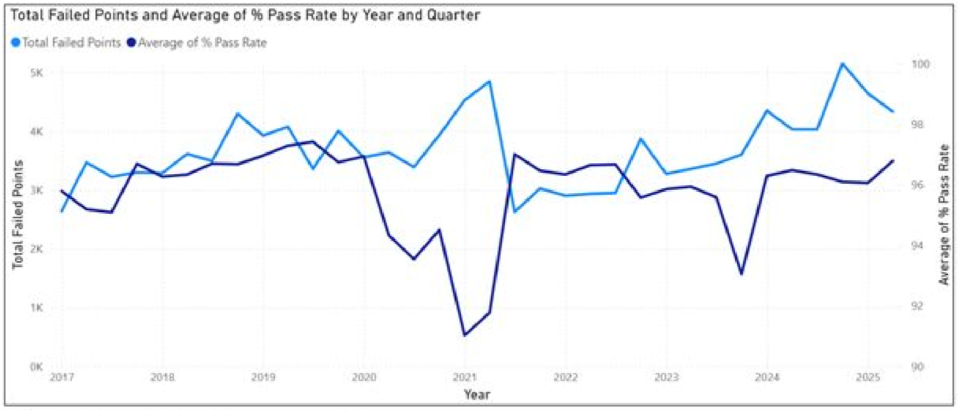


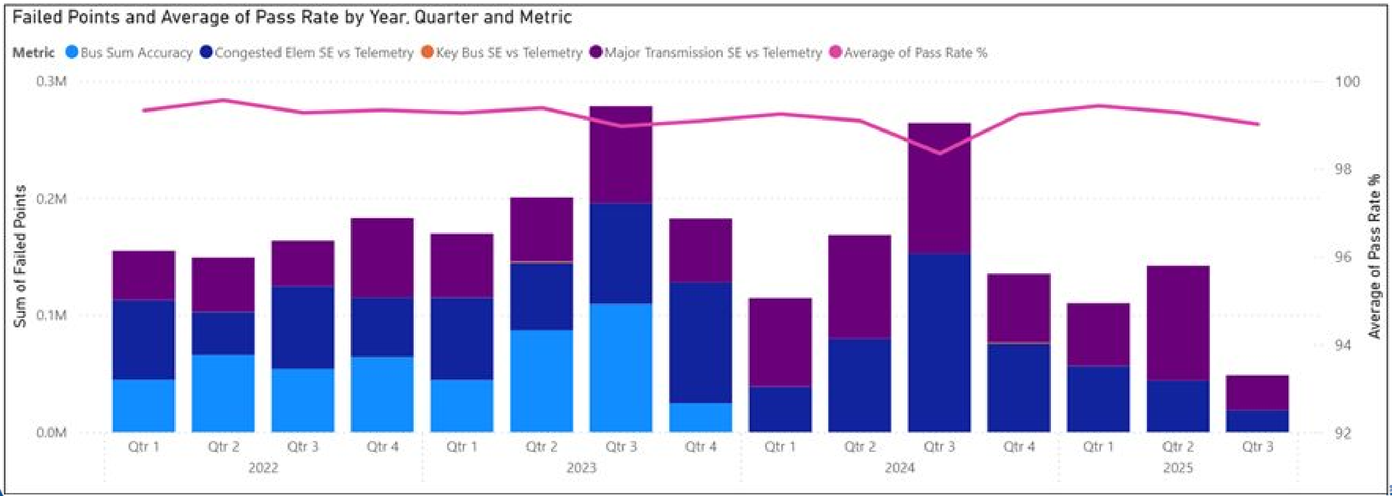
Protection System Misoperations Dashboard



TEXAS RE

Telemetry Availability and Accuracy





Standards Report

Member Representatives Committee Meeting

September 17, 2025

Executive Summary

Texas RE Took Action on 11 NERC Reliability Standards Projects Phases

20 Projects in Active Standards Development

Texas RE Comments Submitted

Project Number	Project Name	Action
2020-06	Verifications of Models and Data for Generators | Definitions, MOD-026-2	Initial Ballots, Additional Ballots
2021-01	System Model Validation with IBRs | MOD-033-3	Initial Ballot, Additional Ballot
2021-03	CIP-002	SAR Comment Period
2022-02	Uniform Modeling Framework for IBR | MOD-032-2, IRO-010-6, TOP-003-8	Initial Ballots, Additional Ballots
2023-06	CIP-014 Risk Assessment Refinement	Additional Ballot
2023-07	Transmission System Planning Performance Requirements for Extreme Weather – Phase II	SAR Comment Period
2025-02	Internal Network Security Monitoring Standard Revision	SAR Comment Period

Public

Recent NERC Filings to FERC

FERC Docket Number	Filing	FERC Submittal Date
RD22-4-001	Inverter-Based Resources Work Plan Progress Update	5/6/2025
FA11-21-000	Compliance Filing in Response to January 2013 Order	5/8/2025
RM24-8-000	Errata and Supplemental Petition of NERC for Approval of CIP Reliability Standards	5/20/2025
RR23-4-000	Compliance Filing Regarding Revisions to the NERC ROP for Reliability Standards	5/28/2025
RD25-7-000	Replay Comments re: EOP-012-2	5/28/2025
RR24-4-002	Compliance Filing Regarding 2024 NERC Performance Assessment	6/16/2025
RR25-4-000	Joint Petition for Approval of Revised RDAs	7/14/2025
RM24-7-002	Request for Clarification of Order 907	7/25/2025
RR25-1-000	ROP Appendix 4E Compliance Filing	7/31/2025
RD22-4-001	IBR Work Plan Filing August 2025 Update	8/4/2025
FA11-21-000	Compliance Filing in Response to January 2013 Order	8/14/2025
RR25-5-000	NERC 2026 Business Plan and Budget	8/22/2025

Public

High Priority Active Projects

- 2020-06 Verifications of Models and Data for Generators (IBR Definitions)
- 2021-01 Modifications to MOD-025 and PRC-019
- 2022-02 Uniform Modeling Framework for IBR
- 2023-06 CIP-014 Risk Assessment
- 2024-01 ROP Definitions Alignment (GO and GOP)
- 2024-02 Planning Energy Assurance
- 2025-02 Internal Network Security Monitoring Standard Revision

Public

Medium Priority Active Projects

- **2021-03 CIP-002**
- **2022-04 EMT Modeling**
- **2023-01 EOP-004 IBR Event Reporting**
- **2023-09 Risk Management for Third-Party Cloud Services**
- **2025-01 Canadian-specific Revisions to EOP-012-3**

Public

Low Priority Active Projects

- 2017-01 Modifications to BAL-003 Phase II
- 2019-04 Modifications to PRC-005-6
- 2021-02 Modifications to VAR-002-4.1
- 2021-08 Modifications to FAC-008
- 2022-05 Modifications to CIP-008 Reporting Threshold
- 2023-05 Modifications to FAC-001 and FAC-002
- 2023-07 Transmission System Planning Performance Requirements for Extreme Weather
- 2023-08 Modifications to MOD-031 Demand and Energy Data