



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

September 16, 2026, at 9:00 a.m. Central Time**
Virtual Meeting

WebEx Link:

<https://texasre.webex.com/texasre/j.php?MTID=m1b2e3f3ffba6ee822ec6d3ee551aa6d>

Call-In: +1-855-797-9485

Item	Member Representatives Committee Meeting
1.	Call to Order <i>Curt Brockmann, MRC Chair</i>
2.	<u>Antitrust Admonition*</u> <i>Thad Crow, Communications and Training Coordinator</i>
3.	<u>Approval of May 13, 2026, Meeting Minutes* (Vote)</u> <i>Curt Brockmann, MRC Chair</i>
4.	Special Topics: a. <u>Modernization of Standards, Processes, and Procedures (MSPP)*</u> <i>Alison Oswald, NERC Manager, Standards Development</i> b. A Large Load Perspective* <i>Ali Fenn, Lancium, President</i>
5.	<u>SAR-013 Revisions to Regional Standard BAL-001-TRE-2* (Vote)</u> <i>Rachel Coyne, Executive Chief of Staff</i>
6.	ERCOT Batch Zero Update* <i>Matt Mereness</i>
7.	<u>NSRF Update*</u> <i>Thomas Brinckman</i>
8.	<u>CIPWG Update*</u> <i>Thomas Standifur</i>
9.	NERC Standing Committee Updates: a. NERC Reliability and Security Technical Committee* <i>Venona Greaff</i> b. <u>NERC Compliance and Certification Committee*</u> <i>Frank Owens</i>



10.	NERC Program Area Reports: <i>(Staff may not present on these reports, but will be available to answer questions)</i> a. NERC Program Area Overview <i>Joseph Younger, Senior Vice President and Chief Operating Officer</i> b. Compliance Monitoring and Risk Assessment Report* <i>Kenath Carver, Director, Compliance Assessments</i> c. Enforcement Report and Registration Report* <i>Katie Van Zee, Director, Enforcement and Registration</i> d. Reliability Services Report* <i>David Penney, Director, Reliability Services</i> e. Standards Report* <i>Rachel Coyne, Executive Chief of Staff</i>
11.	Other Business & Future Agenda Items <i>Curt Brockmann, MRC Chair</i>
	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.



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
DRAFT May 13, 2026, Minutes

Member Representatives Committee Meeting
May 13, 2026

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	X	
Imane Mrini	Austin Energy	Municipal		
Stacy Lee	City of College Station	Municipal		X
Rob Robertson	Leeward Renewable Energy	Generation	X	
Truong Le	Acciona Energy	Generation		
Marcus Ellis (proxy for Truong Le)	Acciona Energy	Generation		
Jeremy Carpenter	Tenaska Power Services, Inc.	Load Serving & Marketing		
Adam Cochran (proxy for Jeremy Carpenter)	Tenaska Power Services	Load Serving & Marketing		X
Venona Greaff	Occidental Power Services, Inc.	Load Serving & Marketing	X	
Donte Jackson	CenterPoint Energy Houston Electric, LLC		X	
Robin Manning	NERC Board of Trustees		X	
Brad Collard	Pedernales Electric Cooperative		X	
Manivone Vorabouth	Pedernales Electric Cooperative			X
Christopher Gruning	OPUC		X	
Gordon Drake	ERCOT		X	
Thomas Standifur	Austin Energy		X	



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Thomas Brinkman	CenterPoint Energy Houston Electric, LLC		X	
Mahmood Safi	Vistra Corp.		X	
Crystal E. Ashby	Texas RE Board Chair		X	
Jeffrey A. Corbett	Texas RE Board Vice Chair		X	
Suzanne Spaulding	Texas RE Independent Director		X	
Milton B. Lee	Texas RE Independent Director		X	
Thomas Gleeson	Public Utility Commission of Texas			
Benjamin Barkley	OPUC			
Bridget Headrick	Customized Energy Solutions			X
Holden Mann				X
Jake Pedigo	ERCOT			X
Ken Stell				X
Mike Johnson				X
Gabriel Bailey				X
Jake Clark	Spearmint Energy			X
Dan Roethemeyer				X
Gabriel Mendes	Grid Monitor			X
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	
David Dwyer	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	
Other Texas RE staff members and stakeholders			X	X

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 9:01 a.m. Central Time. Shari Heino made a motion for Daniela Hammons to act as Chair for meeting because Curt Brockmann was attending virtually. Chad Thompson seconded the motion. The motion passed by unanimous voice vote. Troung Le gave his proxy to Marcus Ellis, and Jeremy Carpenter gave his proxy to Adam Cochran. Thad Crow reviewed the antitrust admonition.

3. **Approval of February 25, 2026, and April 23, 2026, MRC Meeting Minutes**

Venona Greaff made a motion to approve February 25, 2026, and April 23, 2026, MRC meeting minutes. Chad Thompson seconded the motion. The Motion passed by unanimous voice vote.

4. **ERCOT Reliability Report – RTC+B**

Gordon Drake presented the ERCOT Reliability Report.

5. **NERC BOT Meeting Update**

Curt Brockmann gave the NERC BOT update, noting that NERC approved a Level 3 Alert in April concerning large loads.

6. **SAR-013 Revision to BAL-001-TRE-2 Update**

Rachel Coyne, Executive Chief of Staff, presented an update on SAR-013 Revisions to BAL-001-TRE-2. She said the Standard Drafting Team met in March and agreed to make changes to the proposed standard. Frank Owens made a motion to post the changes for public comment for 15 days. Venona Greaff seconded the motion. The Motion passed by unanimous voice vote.

7. **Special Topics**

Shari Heino, Chief Risk and Compliance Officer and Vice President, Regulatory Compliance for Brazos Electric Power Cooperative, presented on Brazos Electric's AI Program.

Lance Spross, Director, NERC Compliance for Oncor Electric Delivery, presented on AI Exploration and Application.

8. NSRF Update

Bradley Collard, NSRF Chair, reported on proposed NSRF Charter amendments to add more Vice Chairs to the NSRF. Daniela Hammons made a motion to approve NSRF charter amendments as presented. Frank Owens seconded the motion. The motion passed by unanimous voice vote.

9. CIPWG Update

Thomas Standifur, CIPWG Chair, provided an update on recent CIPWG activities.

10. NERC Reliability Security and Technical Committee Update

Venona Greaff said the RSTC met in March and April. At the March meeting, the committee approved an RSTC work plan and a security guideline, and it discussed a large load action plan. At the April meeting, the committee approved a reliability guideline. Ms. Greaff said the next meeting will be held in June in Arlington, Virginia.

11. NERC Compliance and Certification Committee

Daniela Hammons said that at its last meeting, the CCC discussed facility ratings.

12. NERC Program Area Quarterly Reports

Joseph Younger, Executive Vice President and Chief Operating Officer, gave the NERC Program Area Overview. He discussed issues related to large loads, a project to update Align and the SEL, and the recent ERO Enterprise CMEP Workshop.

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

13. Other Business & Future Agenda Items

None.

The meeting adjourned at 11:09 a.m. Central Time.

Modernization of Standards Processes and Procedures (MSPP) Implementation

Member Representatives Committee Meeting

Alison Oswald
Manager, Standards Development
September 16, 2026

Agenda

- Implementation Areas
- Governance
- Future Timeline

Implementation Areas of Focus

Governance/ Regulatory	ROP	RSTC Charter Revisions	RISC Charter Revisions	RISC Subcommittee Scope Document	Standards Committee Transition
Tools	Comment and Ballot System	Enterprise Document Library	AI Tools	Website Enhancements	Standards Initiation Request and Term Sheet
Pilot	AI Tools • Comment summary • Standard draft	Short-Term Advisory Group • Computational Load	Solicit SARs Biannually	Increase Stakeholder Engagement	Standards Initiation Request and Term Sheet

Governance/Regulatory

What is Changing and Why

Standard Processes Manual (SPM): ROP Appendix 3A

- **To implement most MSPPTF recommendations, including standards development mechanics and responsibilities:**
 - SIR intake process and review coordination; term sheets
 - Standard development responsibilities of the new Reliability Standard Development Subcommittee
 - SME Pool, project teams, and drafting process
 - Comment and balloting processes

Other ROP Sections & Appendices

- **To conform with SPM changes and to address certain high-level MSPPTF recommendations related to standard development mechanics and responsibilities:**
 - Section 300, Reliability Standards Development
 - Removal of SC election procedures (Appendix 3B)
 - RBB segment updates (Appendix 3D)

Standing Committee Charters

- **Issues specifically pertaining to committee governance and authorities:**
 - Provide committees with the new authorities required by the MSPPTF recommendations
 - Outline the creation and governance of the new subcommittee
- *Certain recommendations will be addressed in committee process documents, not the charters**

Draft Revisions to the ROP and Charters

- NERC released draft ROP and Committee Charter revisions on May 18, 2026, for an informal stakeholder comment period through June 17, 2026.
 - NERC also hosted a virtual interactive session, held ad hoc stakeholder meetings, and convened the MSPP Task Force to get further feedback
- Changes in Posted Documents
 - New roles of RSTC, RISC, and RSB
 - RSTC vs RISC roles, RISC vs RSB roles, RSB Composition
 - Standard Processes Manual (SPM)
 - Threshold for initiating requests to modify the SPM
 - Board Waiver authority in SPM
 - Drafting Team Participation on compliance elements (VRF/VSL)
 - Balloting
 - Straw poll thresholds and minimum duration of comment periods
 - Final arbiter over Registered Ballot Body (RBB) disputes

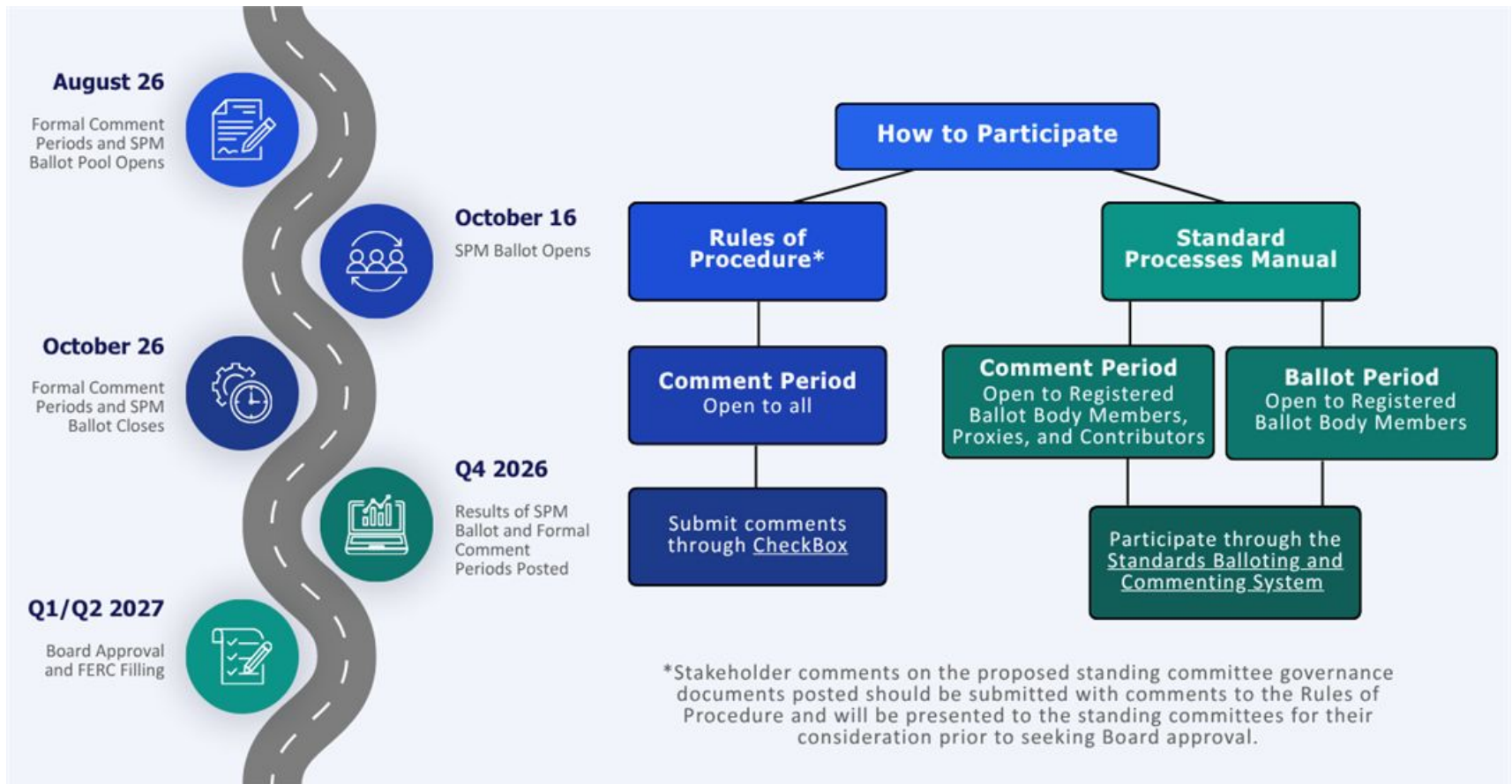
Next Steps

Timeline

Modernization of Standards Processes and Procedures

February - June 2026	July - September 2026	September - January 2026	Q1/Q2 2027	Q3/Q4 2027
- Draft ROP revisions - Post ROP for informal comment period - Hold industry workshop to gather feedback on ROP revisions - Form Short-Term Advisory Group - Create Standards Initiation Request and Term Sheet templates	- Approve SPM for posting by SC - Post ROP changes and charter revisions for formal 60-day comment period - Identify additional projects and pilots as SARs are submitted	- Additional comment or ballot period for ROP and/or SPM revisions as needed; or prepare board presentation - Respond to formal posting comments - File Phase 1 Computational Loads and disband advisory group	- Adopt revised ROP and file with FERC - Establish subcommittee and launch SME Pool - Proceed with Standing Committees charter revisions - Present Standing Committee charter revisions to Board - Implement MSPP standards process	- Create RISC Subcommittee - Hold first standards workshop with RISC subcommittee - Transfer existing standards development projects

MSPP Formal Comment Periods and Ballot Roadmap

NERC



NERC

Discussion



MEMORANDUM

To: Texas RE Member Representatives Committee
From: Rachel Coyne, Executive Chief of Staff
Date: September 16, 2026
Re: Item 05 – Status Update for Project SAR-013: Revisions to Regional Standard BAL-001-TRE-2

Texas RE is requesting the MRC's approval to provide the final Work Product for Project SAR-013: Revisions to Regional Standard BAL-001-TRE-2 to the Texas RE Board for action.

During the May 13, 2026, meeting, I requested the MRC approve the revised draft Regional Standard BAL-001-TRE-3 and the implementation plan be posted for an additional 45-day comment period, with an additional ballot occurring during the last 15 days of the comment period. The ballot did pass. The standard drafting team (SDT) met on July 20, 2026, to determine next steps. A final ballot was conducted from July 20 – August 4, 2026, which passed as well.

The following documents are included in the MRC's packet for consideration to provide to the Board for action:

- Proposed Regional Standard BAL-001-TRE-3_Clean
- Proposed Regional Standard BAL-001-TRE-3_Redline to Last Posted
- Proposed Regional Standard BAL-001-TRE-3_Redline to Last Approved
- Proposed Implementation Plan_Clean
- Proposed Implementation Plan_Redline to Last Posted
- Description of Revisions
- Updated Work Plan
- Additional Ballot Results
- SDT's Response to Comments
- Final Ballot Results

Upon the receipt from the MRC, the Board may take action on approving Regional Standard BAL-001-TRE-3 be sent to NERC.

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



TEXAS RE

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

**Member Representatives Committee
Meeting
September 16, 2026**



Standard Authorization Request

Public

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 (SDT)

Public

SDT Member	Development Sector(s)
Jose Luis Hinojosa, ERCOT (Chair)	System Coordination and Planning
Chad Mulholland, NRG Energy (Vice Chair)	Generation
Arthur Mayclin, Calpine	Generation
Stewart Rake, Luminant	Generation
Frank Owens, Rayburn Electric Cooperative, Inc.	Cooperative Utility
Juan M. Gomez Gonzalez, CPS Energy	Municipal Utility Transmission and Distribution Generation
Mark Prosperi-Porta, Acciona Energy North America (BT Cunningham Storage, LLC.)	Generation



Project Recap

Public

**6/28/2024 –
SAR Receipt**

**11/6/2025 –
Initial
Comment
Period and
Ballot**

**6/29/2026 –
Additional
Comment
Period and
Ballot**

**8/4/2026 –
Final Ballot**



SAR-013 Project Activity (May 2026 – August 2026)

Public

May 13, 2026 – MRC approved for additional comment and ballot period

May 14 – June 29, 2026 – Additional Comment Period (Ballot last 15 days)

July 20, 2026 – SDT Meeting

July 20 – August 4, 2026 – Final Ballot

Texas RE MRC and Board Consideration



Board Packet

Public

- **Proposed Regional Standard BAL-001-TRE-3_Clean**
- **Proposed Regional Standard BAL-001-TRE-3_Redline to Last Posted**
- **Proposed Regional Standard BAL-001-TRE-3_Redline to Last Approved**
- **Proposed Implementation Plan_Clean**
- **Proposed Implementation Plan_Redline to Last Posted**
- **SDT's Response to Comments**
- **Description of Revisions**
- **Updated Work Plan**
- **Ballot Results**
- **SDT's Responses to Comments**

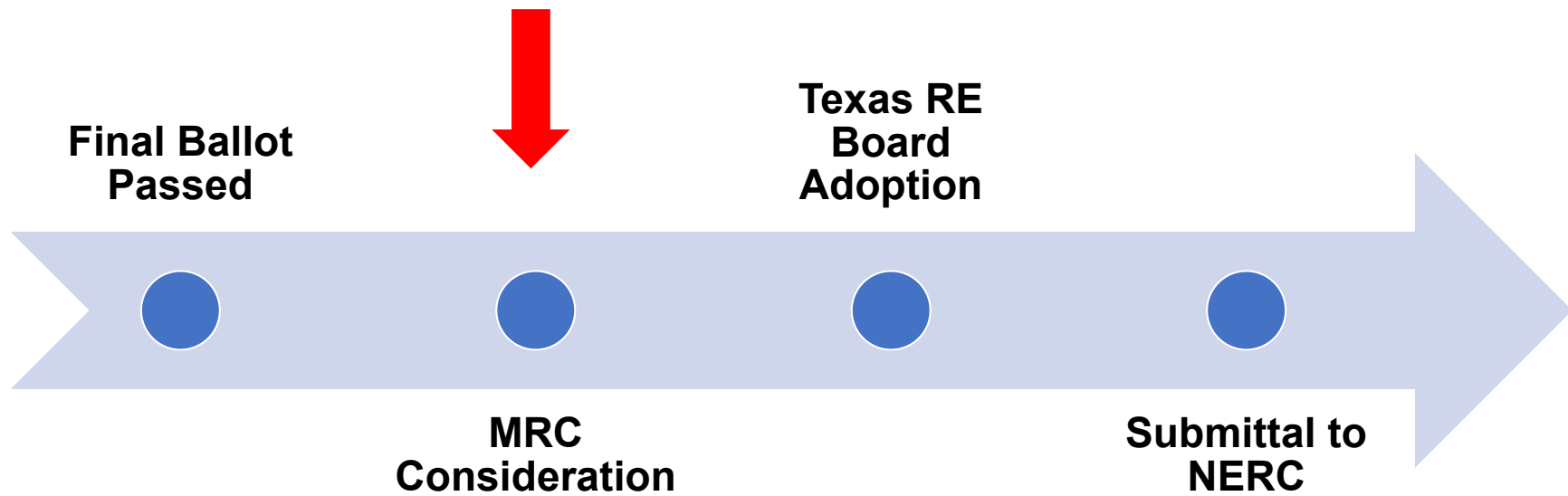


Requesting the MRC approve the final Work Product to be provided to the Texas RE Board for action.



Next Steps

Public



BAL-001-TRE-3 — Primary Frequency Response in the ERCOT Region

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

BAL-001-TRE-3 — Primary Frequency Response in the ERCOT Region

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 terms “resource” and “generating unit/generating facility” refers to any resource capable of providing energy to the ERCOT region. Examples include, but are not limited to, the following:

- Hydro
- Combustion Turbine (Simple Cycle and Single-Shaft Combined Cycle)
- Steam Turbine
- Diesel
- Battery Energy Storage System (BESS)
- DC Tie Providing Ancillary Services

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 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%.

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. This reference document is a Texas RE-controlled document that is subject to revision by the Texas RE Board of Directors.

BAL-001-TRE-3 — Primary Frequency Response in the ERCOT Region

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

BAL-001-TRE-3 — Primary Frequency Response in the ERCOT Region

combined Frequency Response performance was less than the IMFR, per Requirement R5.

- R6.** Each Generator Owner shall set its Governor parameters, as set forth in Requirement R6, Parts 6.1, 6.2, and 6.3. Requirement R6, Parts 6.1, 6.2, and 6.3 are not applicable to steam turbine(s) of a combined cycle resource.

- 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/generating facilities that are not qualified ² to provide Operating Reserves and have obtained prior written approval from the Balancing Authority to widen their deadband settings	+/- 0.036 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
Combustion Turbine (Combined Cycle)	4%
All other generating units/generating facilities	5%

- 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.

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

BAL-001-TRE-3 — Primary Frequency Response in the ERCOT Region

Where

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

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

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
 - Written approval from the Balancing Authority to widen generating units'/generating facilities' deadband settings to +/- 0.036 Hz
- R7.** Each Generator Owner shall operate each generating unit/generating facility that is connected to the interconnected transmission system with the Governor in service and responsive to frequency when the generating unit/generating facility 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 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]*

BAL-001-TRE-3 — Primary Frequency Response in the ERCOT Region

- 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, 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 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 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 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, 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]*

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- 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 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 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 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 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). After CEA consultation with the BA, and 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 CEA 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 CEA 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 CEA 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

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non-compliance until found compliant, or for the duration specified above, whichever is longer.

The CEA 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.

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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 $\leq 20\%$ outside setting range specified in R6.	Any Governor parameter setting was $> 20\%$ and $\leq 30\%$ outside setting range specified in R6.	Any Governor parameter setting was $> 30\%$ and $\leq 40\%$ 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.

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	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 $\geq$ 0.65.	A Generator Owner's rolling average initial Primary Frequency Response performance per R9 was < 0.65 and $\geq$ 0.55.	A Generator Owner's rolling average initial Primary Frequency Response performance per R9 was < 0.55 and $\geq$ 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 $\geq$ 0.65.	A Generator Owner's rolling average sustained Primary Frequency Response performance per R10 was < 0.65 and $\geq$ 0.55.	A Generator Owner's rolling average sustained Primary Frequency Response performance per R10 was < 0.55 and $\geq$ 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

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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 Primary Frequency Response (PFR) performance score.

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			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.

Attachment 1

Primary Frequency Response Reference Document

**Texas Reliability Entity, Inc.
BAL-001-TRE-3
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 available¹ 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.

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

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

High Sustained Limit (HSL) for a generating unit/generating facility: 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.

Low Sustained Limit (LSL) for a generating unit/generating facility: The limit established by the GO/GOP, continuously updatable in Real-Time, that describes the minimum sustained energy capability of a generating unit/generating facility. 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 MW_{GCS} is calculated from HSL to LSL for BESS and HSL to 0 for all other all generator types.

Design Settings versus real-time Evaluation: Settings and verifications (Requirement 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.

In this Regional Standard the terms “resource” and “generating unit/generating facility” refers to any resource capable of providing energy to the ERCOT region. Examples include, but are not limited to, the following:

- Hydro
- Combustion Turbine (Simple Cycle and Single-Shaft Combined Cycle)
- Steam Turbine
- Diesel
- Battery Energy Storage System (BESS)
- DC Tie Providing Ancillary Services

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, 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.

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9.2 If a generating unit/generating facility 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 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.

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

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

The adjusted actual PFR ($APFR_{Adj}$) and the final expected PFR ($EPFR_{final}$) are calculated

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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 (APFR_{adj})

The adjusted actual Primary Frequency Response (APFR_{adj}) 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 actual PFR number that is used to calculate P.U.PFR is adjusted for the ramp magnitude of the generating unit/generating facility 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

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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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-perturbation} and the EPFR_{pre-perturbation}.

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

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

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

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

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

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

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

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

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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

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

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

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

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

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

Where:

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

Where:

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

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

Throttle Pressure = Interpolation of Pressure curve at MW_{pre-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 BESS with capacity that is not expected to provide PFR

$$EPFR_{final} = \text{Minimum} (EPFR_{ideal}, MW_{GCS} - \text{capacity not expected to provide PFR})$$

BESS may, in real time, be required to reserve capacity for providing non-proportional frequency response. When this occurs, the expected MW response from the BESS shall be limited to exclude this capacity. The BA will utilize system data to determine when capacity should be excluded from the calculations.

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.

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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, based on participation in at least eight FMEs. See Attachment 1: Primary Frequency Response Reference Document for specific calculations.

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 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 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.

Sustained Primary Frequency Response performance requirement:

The standard requires an average performance over a period of 12 months (including at least

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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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)

$$P.U.SPFR_{Resource} = \frac{Actual\ Sustained\ Primary\ Frequency\ Response_{Adj}}{Expected\ Sustained\ Primary\ Frequency\ Response_{Final}}$$

$P.U.SPFR_{Resource}$ 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.

Actual Sustained Primary Frequency Response (ASPFR) Calculations

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

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 ($ASPFR_{Adj}$)

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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 Measurable 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:

$$RampMW Sustained = (MW_{T-4} - MW_{T-60}) \times 0.821$$

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

$$\frac{46 \text{ seconds}}{56 \text{ seconds}} \text{ or } 0.821.$$

on its ramp to $T+46$ unencumbered by the FME. The modifier is

Expected Sustained Primary Frequency Response (ESPFR) Calculations

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, HSL/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 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 $EPFR_{pre-perturbation}$. The $EPFR_{pre-perturbation}$ is the same $EPFR_{pre-perturbation}$ value used in the Initial measure of R9.

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

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

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

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

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

Capacity and 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. 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

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

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

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

Where:

$$MW_{Adj} = ESPFR_{ideal} \times \frac{K}{\text{Rated Throttle Pressure}} \times (MW_{GCS} - PA \text{ Capacity}) \times \text{Steam Flow Change Factor} \times -1$$

Where:

BAL-001-TRE-3 — Primary Frequency Response in the ERCOT Region

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

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

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

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 BESS with capacity that is not expected to provide PFR

$$ESPFR_{\text{final}} = \text{Minimum} (ESPFR_{\text{ideal}}, MW_{\text{GCS}} - \text{capacity not expected to provide PFR})$$

BESS may, in real time, be required to reserve capacity for providing non-proportional frequency response. When this occurs, the expected MW response from the BESS shall be limited to exclude this capacity. The BA will utilize system data to determine when capacity should be excluded from the calculations.

ESPFR_{final} for Other Generating Units/Generating Facilities

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

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

BAL-001-TRE-3 — Primary Frequency Response in the ERCOT Region

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 and additional capacity not expected to provide PFR) or within 5 MW (whichever is greater), or a BESS is operating within 2% or 3 MW of its MW_{GCS} less capacity not expected to provide PFR 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 ($Hz_{Post-perturbation} < 60$ if:

$$MW_{pre-perturbation} \geq \min[(MW_{GCS} - PA \text{ Capacity} - \text{capacity not expected to provide PFR}] \times .98), (MW_{GCS} - PA \text{ Capacity} - \text{capacity not expected to provide PFR}] - Y \text{ MW})]$$

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

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

$$MW_{pre-perturbation} \leq \max[(LSL + (MW_{GCS} - PA \text{ Capacity} - \text{capacity not expected to provide PFR}] \times 0.02)), (LSL + Y \text{ MW})]$$

then PFR is not evaluated for this FME where Y 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

BAL-001-TRE-3 — Primary Frequency Response in the ERCOT Region

- additional capacity not expected to provide PFR) and greater than 3 MW;
and
 - c. The Expected Primary Frequency Response_{final} is greater than the generating unit/generating facility's available frequency responsive capacity⁴; and
 - d. The generating unit/generating facility's 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 and additional capacity not expected to provide PFR) 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-3**

BAL-001-TRE-3 — Primary Frequency Response in the ERCOT Region

Primary Frequency Response Measurement and Rolling Average Calculation – Initial Response

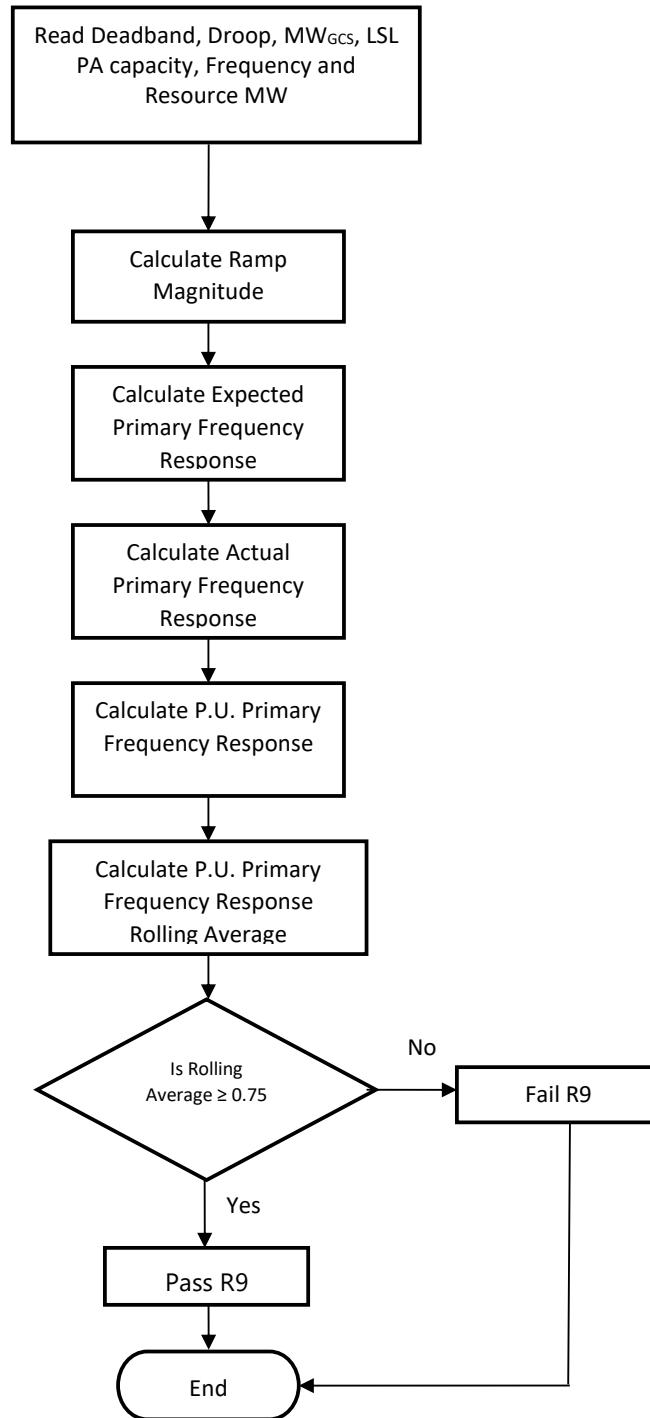
PA = Power Augmentation

HSL = High Sustained Limit

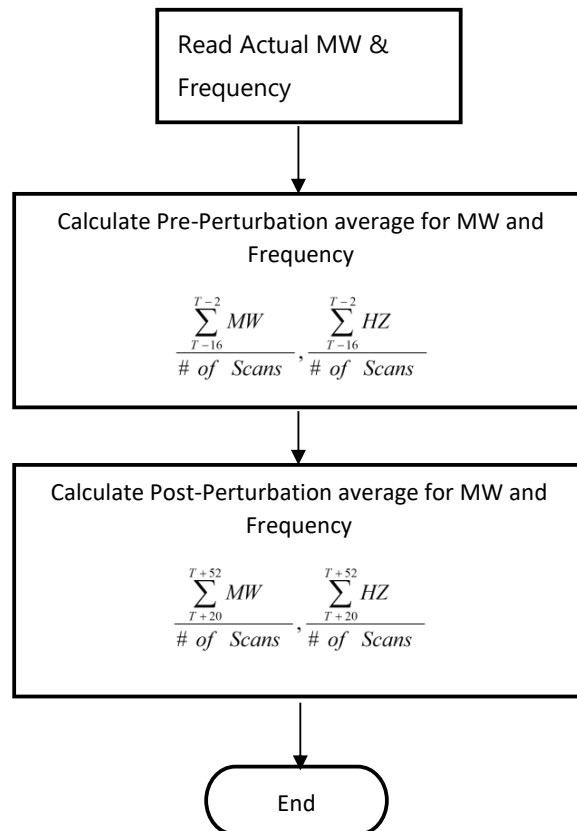
LSL = Low Sustained Limit

MW_{GCS} = maximum megawatt control range of the Governor control system

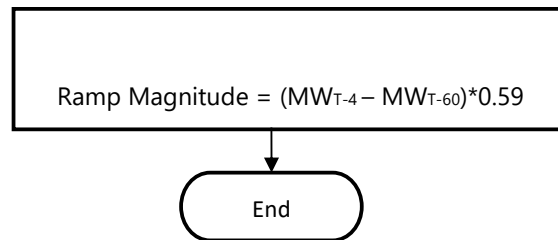
BAL-001-TRE-3 — Primary Frequency Response in the ERCOT Region



BAL-001-TRE-3 — Primary Frequency Response in the ERCOT Region

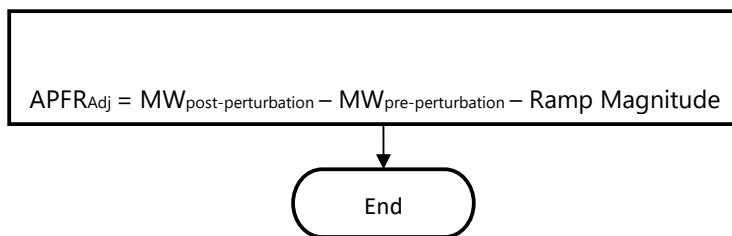
Pre/Post-Perturbation Average MW and Average Frequency Calculations

Ramp Magnitude Calculation



(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.

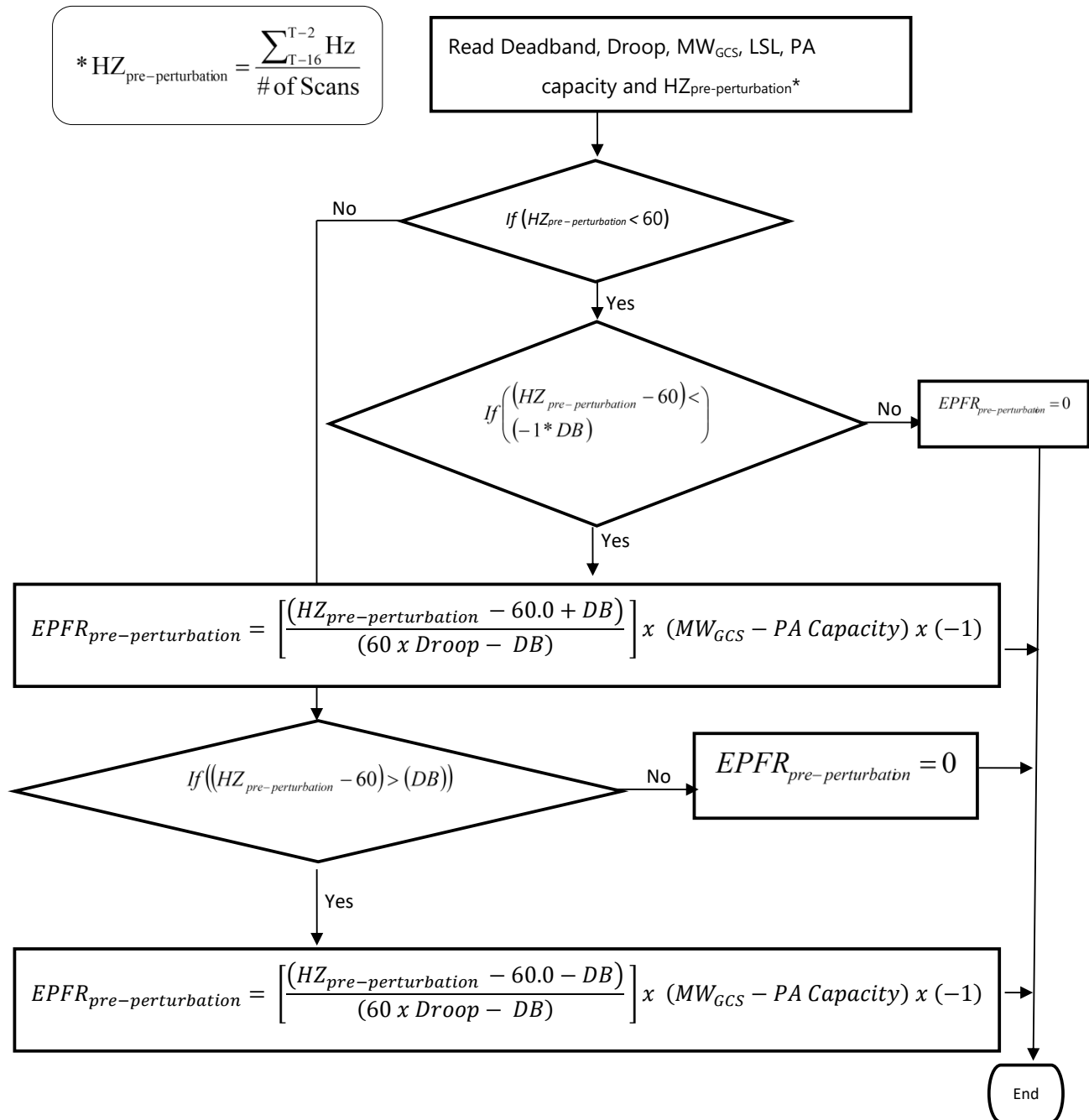
Actual Primary Frequency Response (APFRA_{Adj})



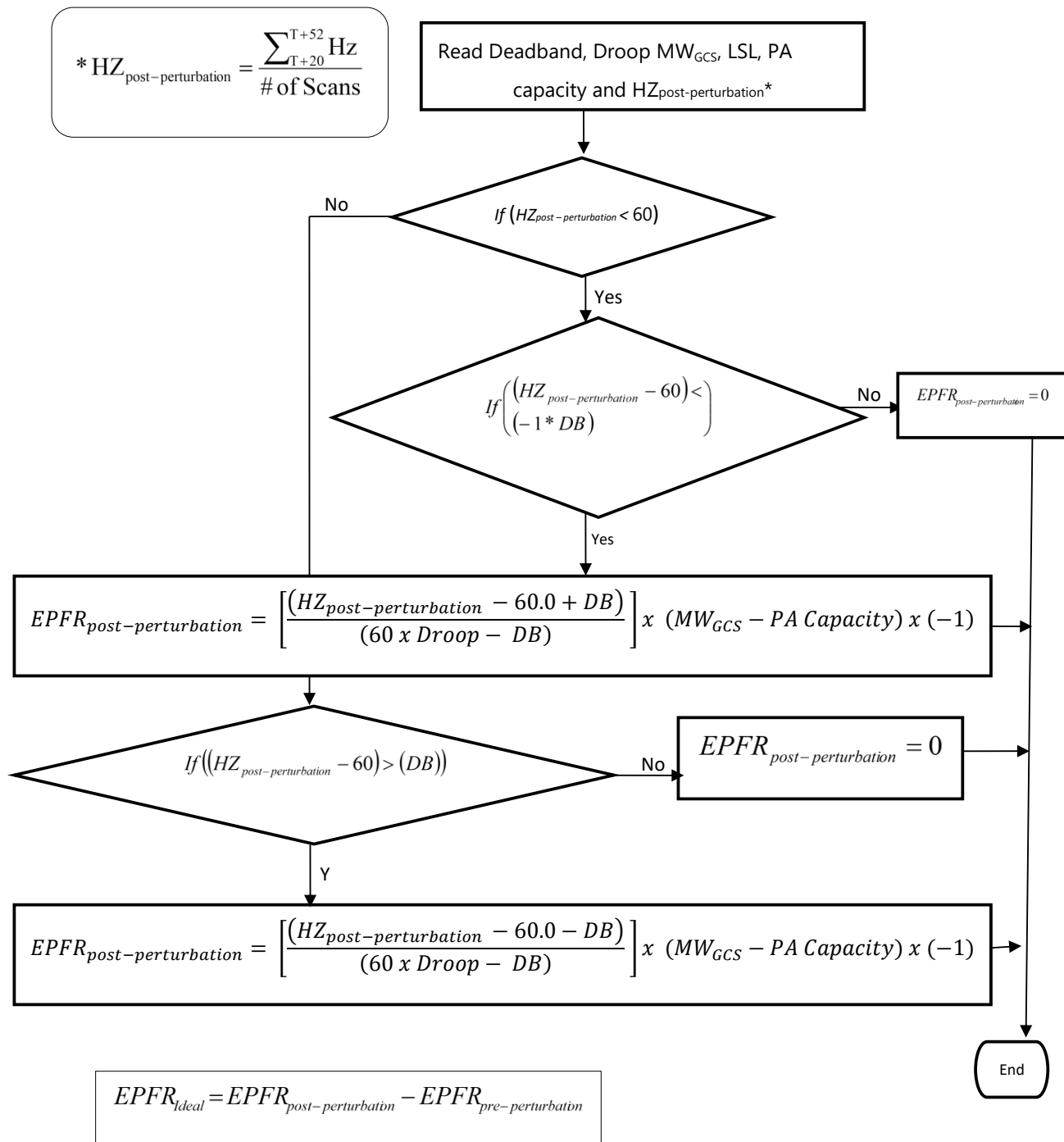
BAL-001-TRE-3 — Primary Frequency Response in the ERCOT Region

Expected Primary Frequency Response Calculation

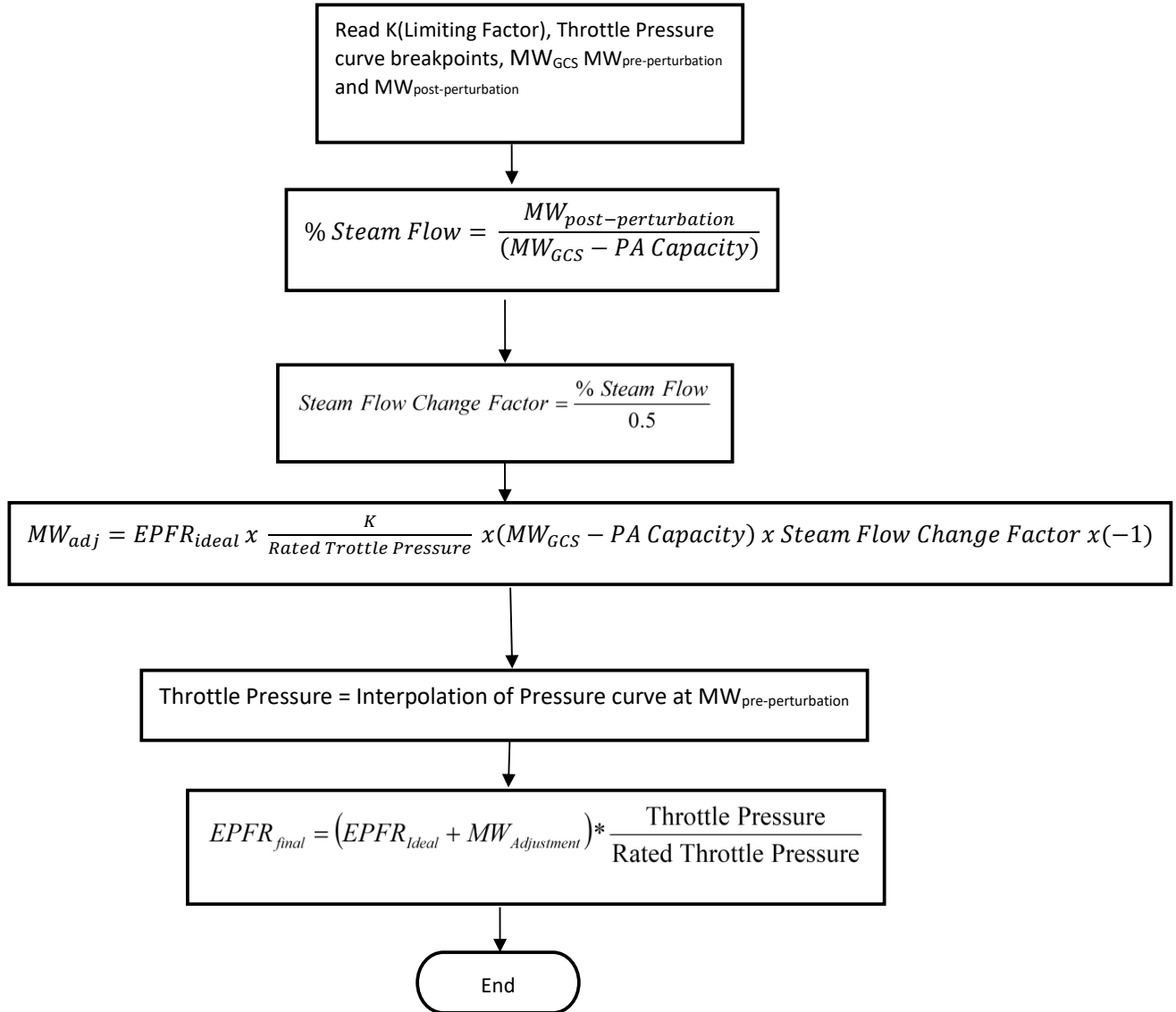
Use the maximum droop and maximum deadband as required by R6. For Combined Cycle Facility evaluation as a single resource (includes MW production of the steam turbine generator), the EPFR will use 5.78% droop in all calculations.



BAL-001-TRE-3 — Primary Frequency Response in the ERCOT Region

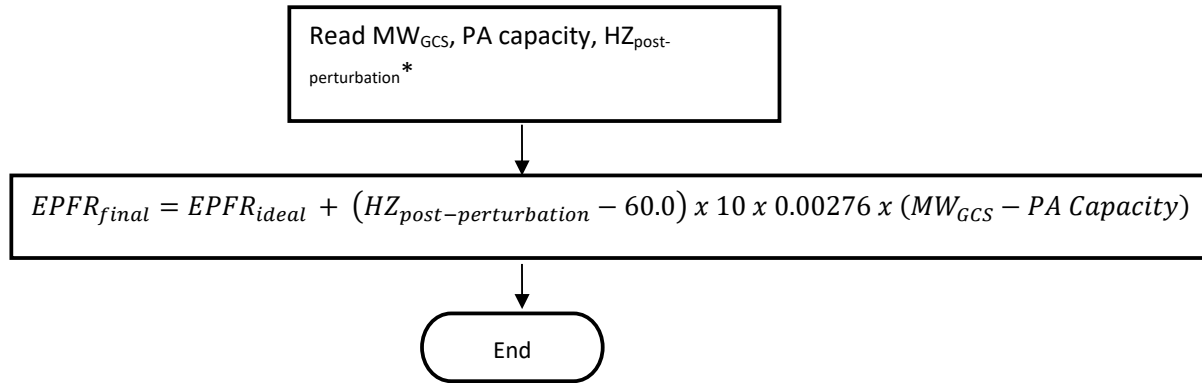


Adjustment for Steam Turbine



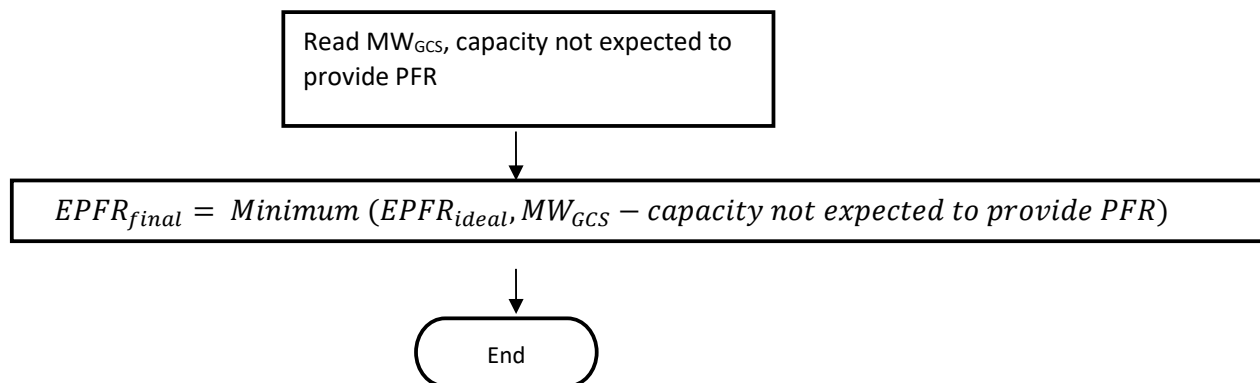
BAL-001-TRE-3 — Primary Frequency Response in the ERCOT Region

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.)

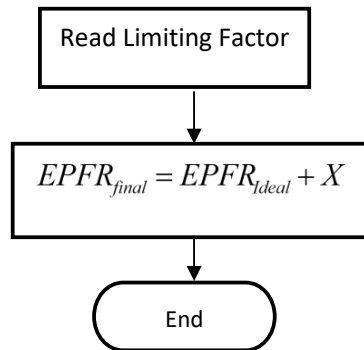
Adjustment for BESS with capacity that is not expected to provide PFR



BESS may, in real time, be required to reserve capacity for providing non-proportional frequency response. When this occurs, the expected MW response from the BESS shall be limited to exclude this capacity. The BA will utilize system data to determine when capacity should be excluded from the calculations.

BAL-001-TRE-3 — Primary Frequency Response in the ERCOT Region

Adjustment for Other Units

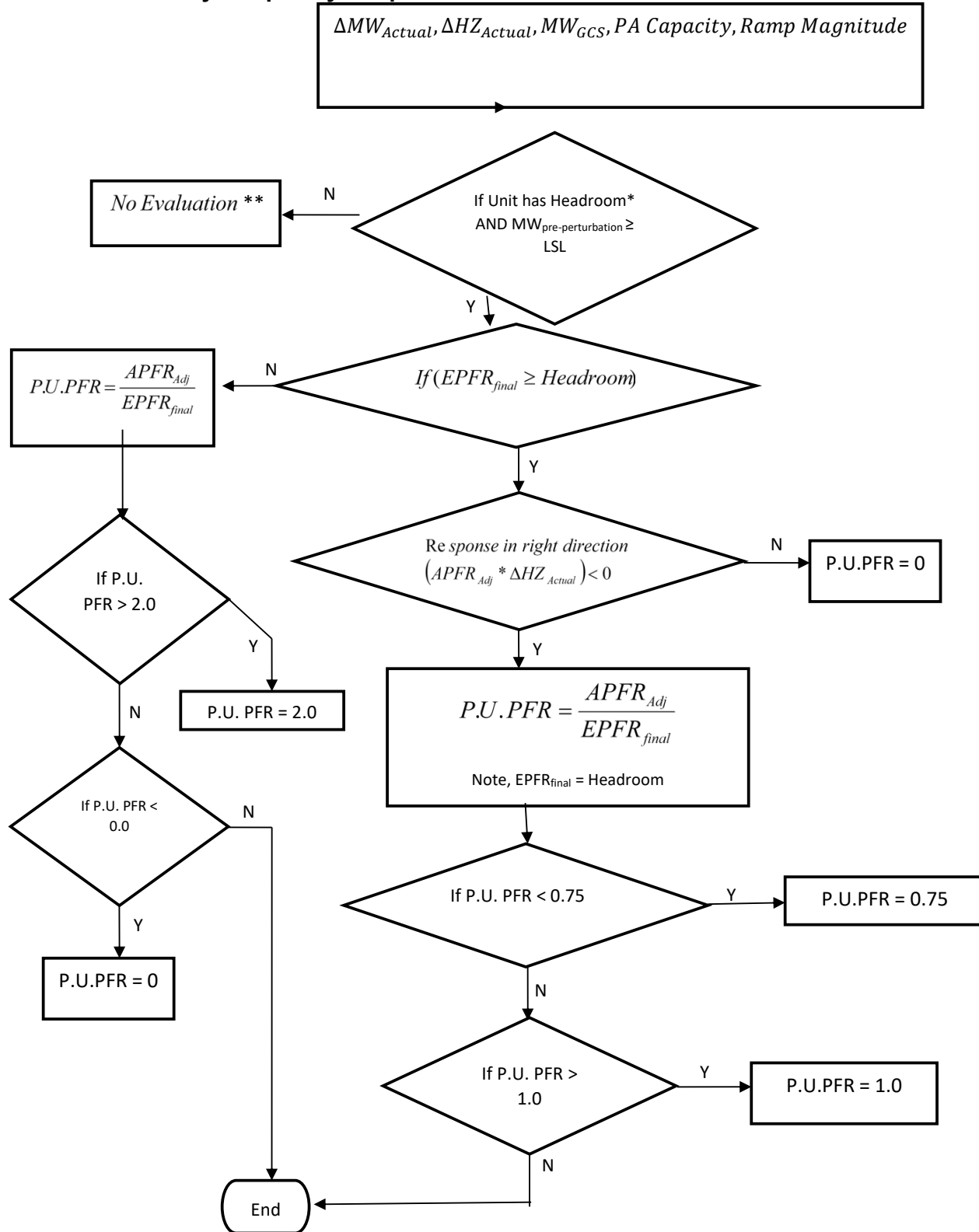


$$* \text{HZ}_{\text{post-perturbation}} = \frac{\sum_{T+20}^{T+52} \text{HZ}_{\text{Actual}}}{\# \text{ of Scans}}$$

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.

BAL-001-TRE-3 — Primary Frequency Response in the ERCOT Region

P.U. Initial Primary Frequency Response Calculation



BAL-001-TRE-3 — Primary Frequency Response in the ERCOT Region

*Check for adequate up headroom, low frequency events. Headroom must be greater than either XMW or 2% of (MW_{GCS} less PA capacity and additional capacity not expected to provide PFR), 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 and additional capacity not expected to provide PFR), 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:

$$\text{Headroom} = HSL - PA \text{ Capacity} - \text{capacity not expected to respond with PFR} - MW_{T-2}$$

For high frequency events:

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

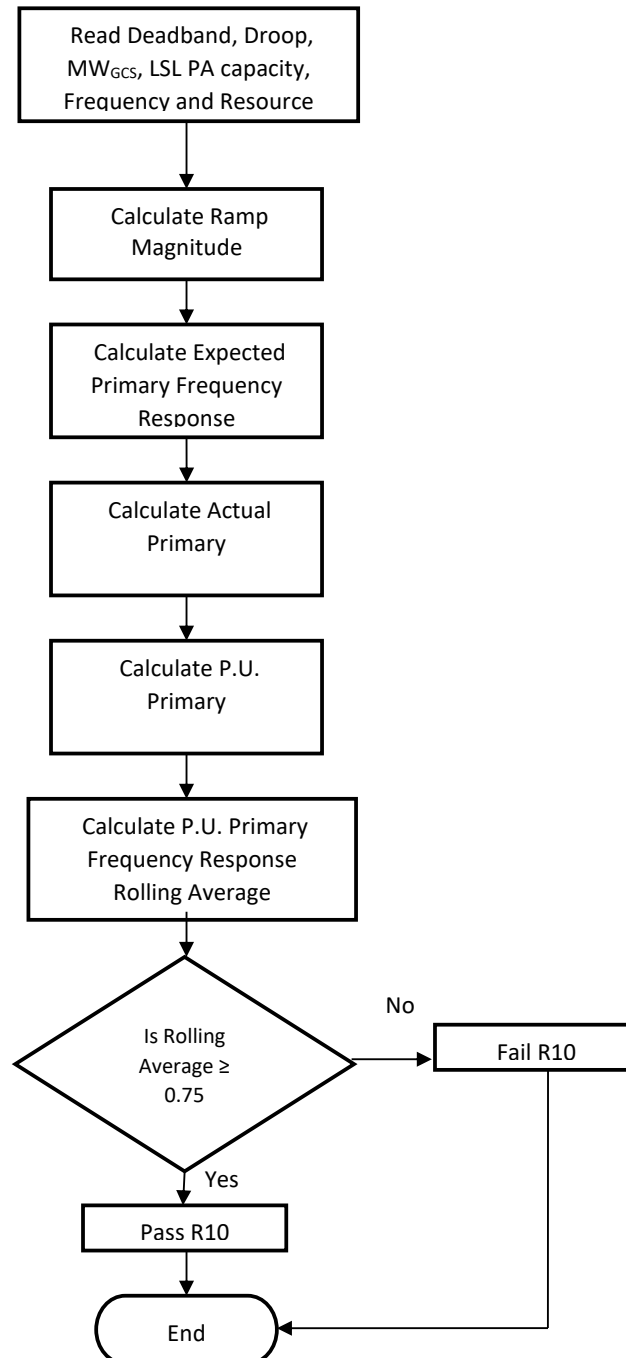
**No further evaluation is required for Sustained Primary Frequency Response. This event will not be included in the Rolling Average calculation of either Initial or Sustained Primary Frequency Response.

T = Time in Seconds

**Attachment B to
Primary Frequency Response Reference Document**

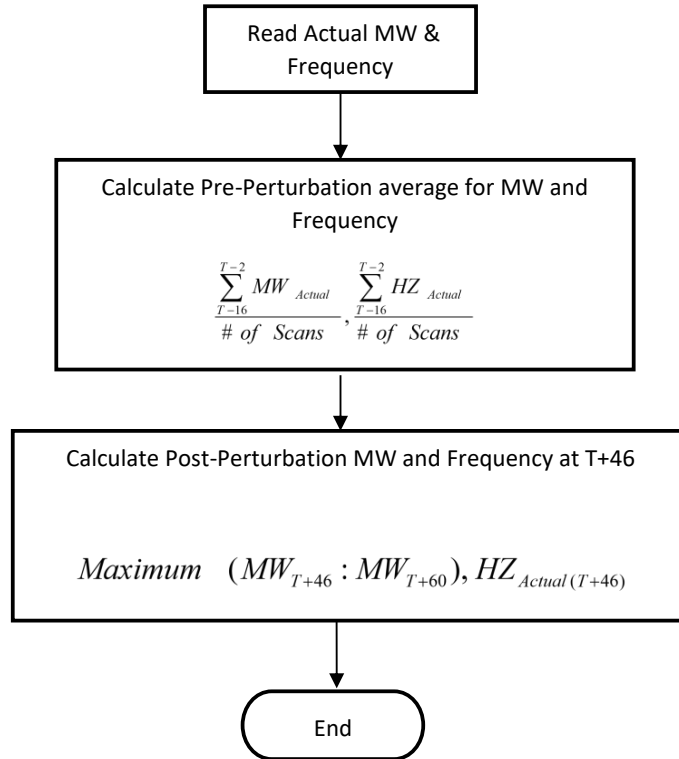
**Sustained Primary Frequency Response Methodology for
BAL-001-TRE-3**

Primary Frequency Response Measurement and Rolling Average Calculation—Sustained Response



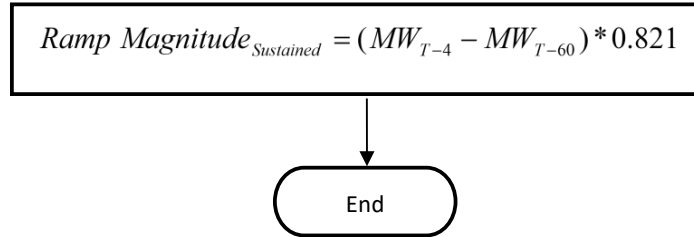
BAL-001-TRE-3 — Primary Frequency Response in the ERCOT Region

Pre/Post-Perturbation Average MW and Average Frequency Calculations



BAL-001-TRE-3 — Primary Frequency Response in the ERCOT Region

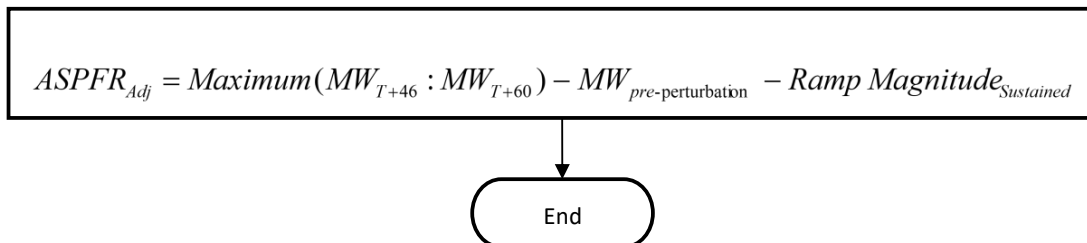
Ramp Magnitude Calculation - Sustained



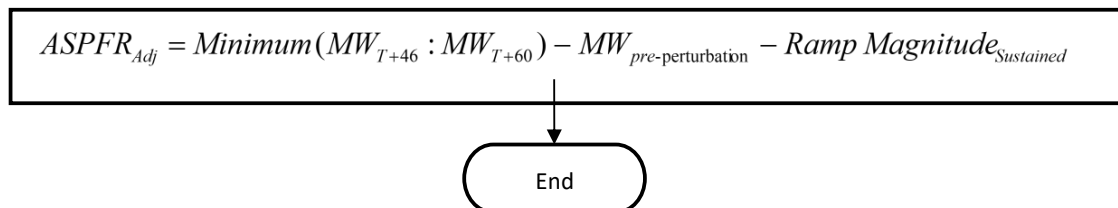
(MWT-4 – MWT-60) represents the MW ramp of the generator resource/generator facility for a full minute prior to the event. The factor 0.821 adjusts this full minute ramp to represent the ramp the generator would have changed the system had it been allowed to continue on its ramp to T+46 unencumbered.

Actual Sustained Primary Frequency Response (ASPFRadj)

For low frequency events:



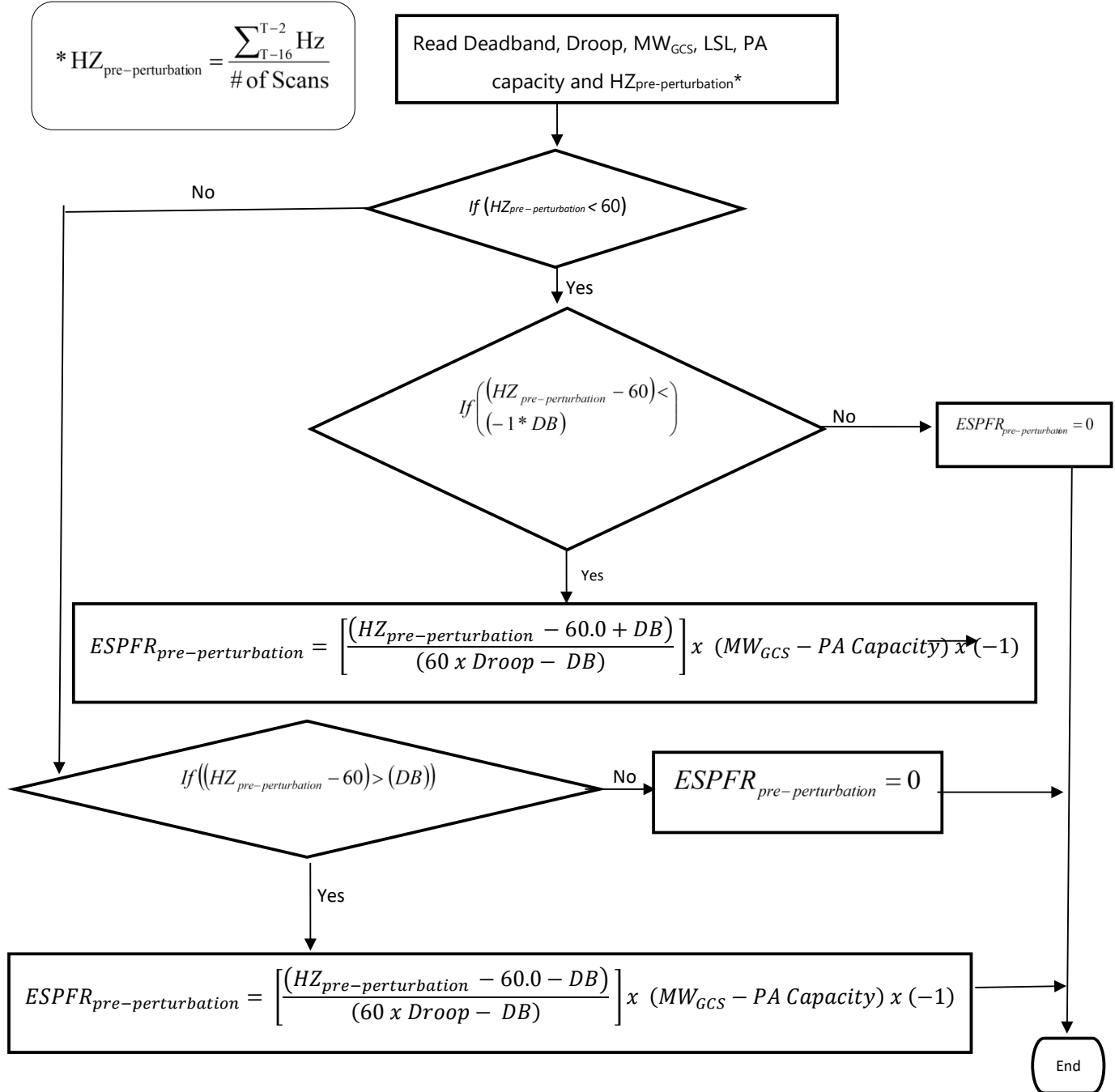
For high frequency events:



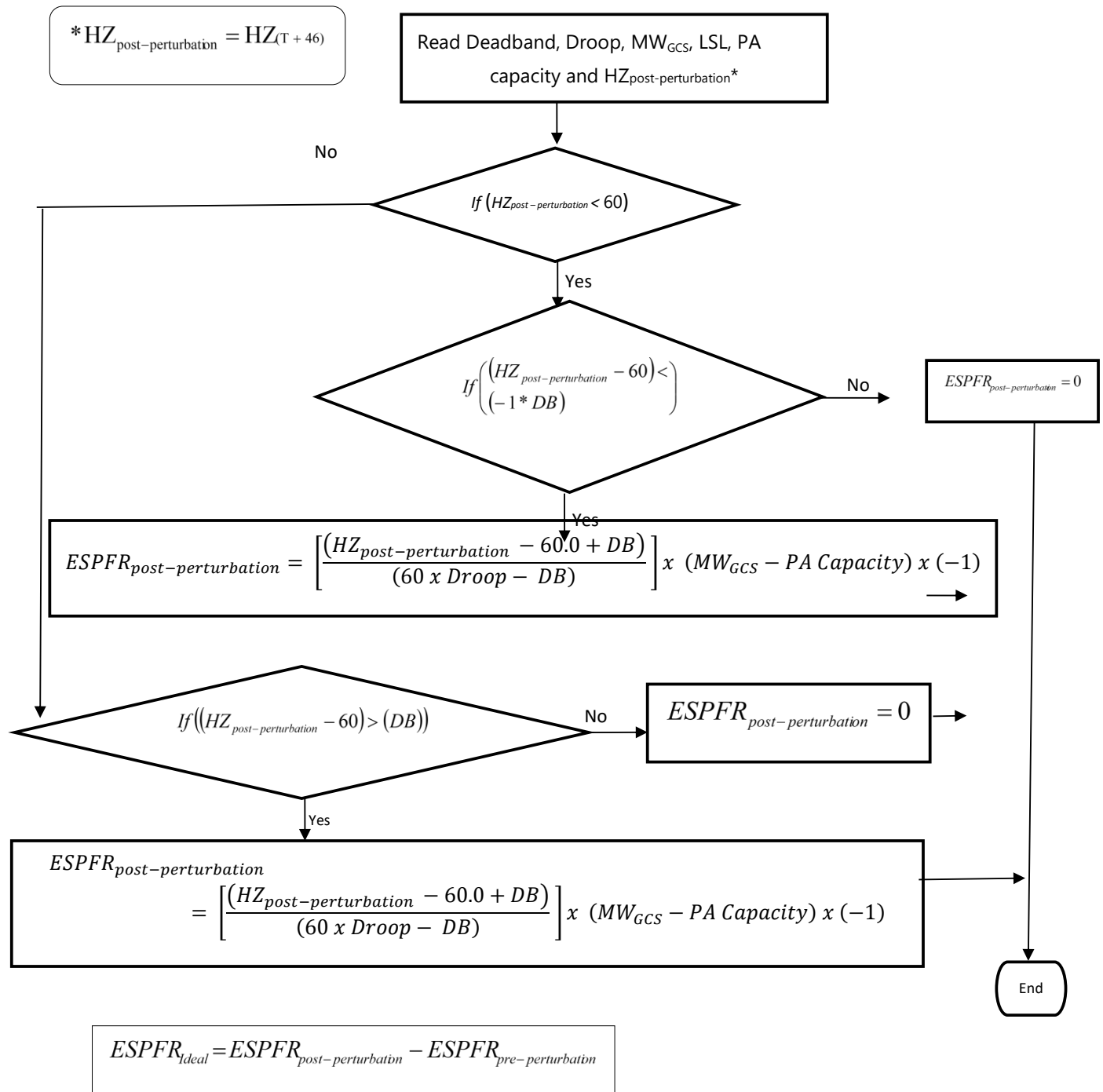
BAL-001-TRE-3 — Primary Frequency Response in the ERCOT Region

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.

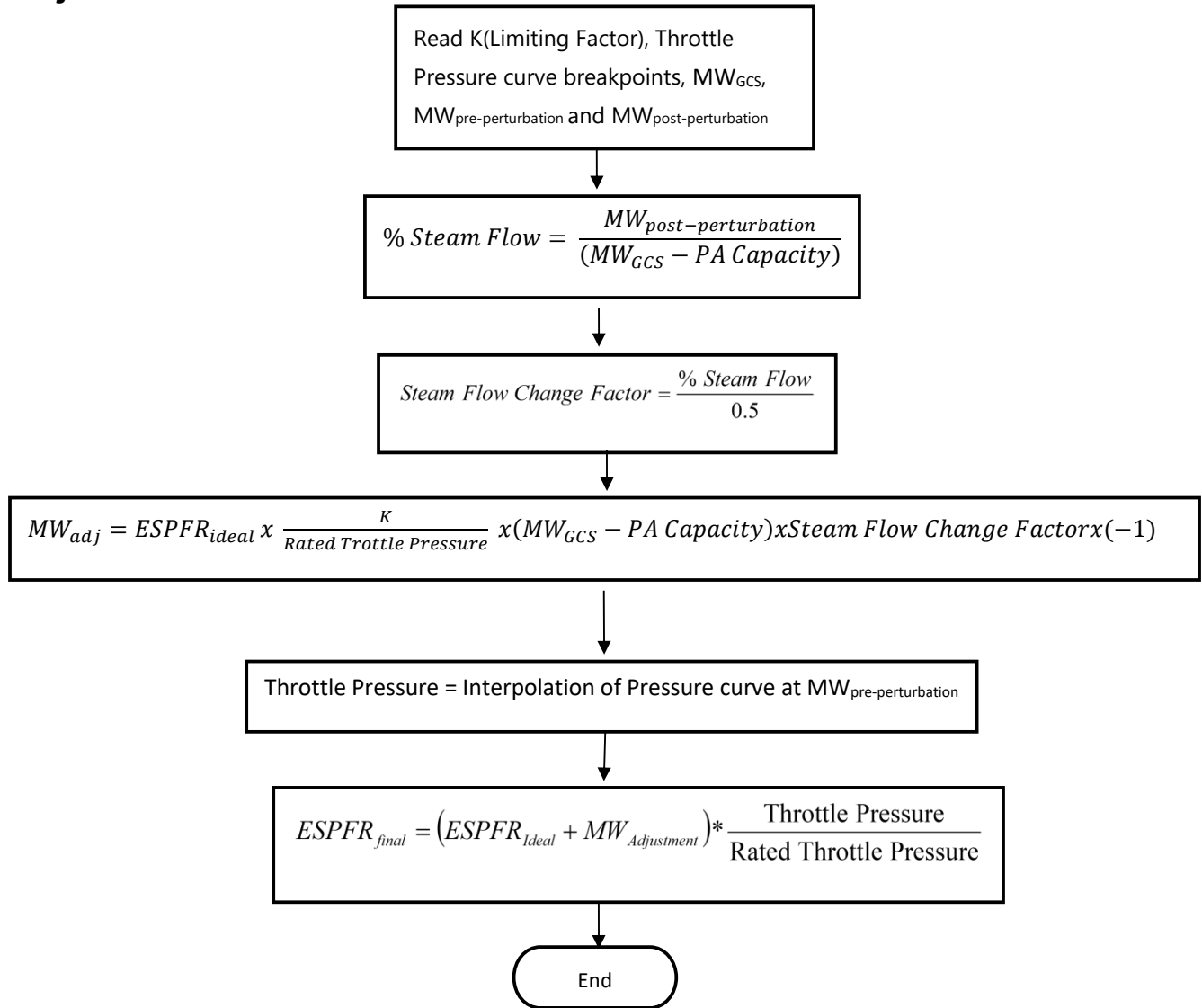


BAL-001-TRE-3 — Primary Frequency Response in the ERCOT Region



BAL-001-TRE-3 — Primary Frequency Response in the ERCOT Region

Adjustment for Steam Turbine

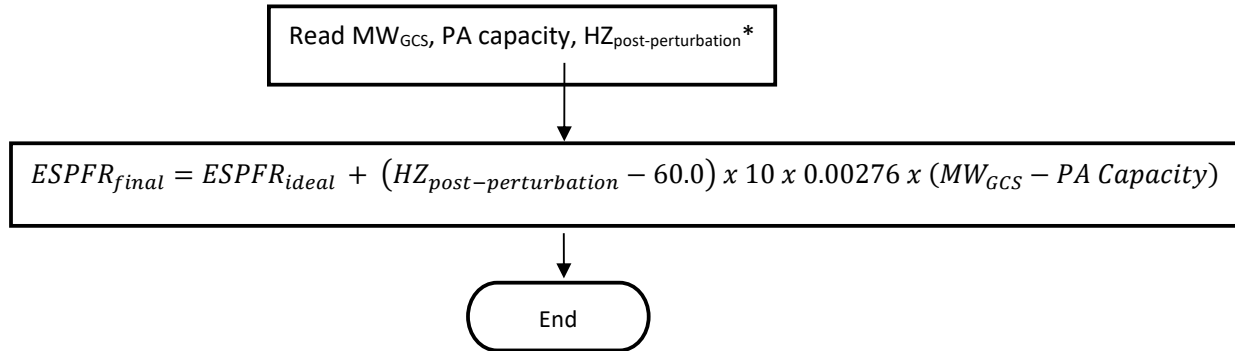


$MW_{post-perturbation}$ = Maximum ($MW_{T+46} : MW_{T+60}$) for low frequency events.

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

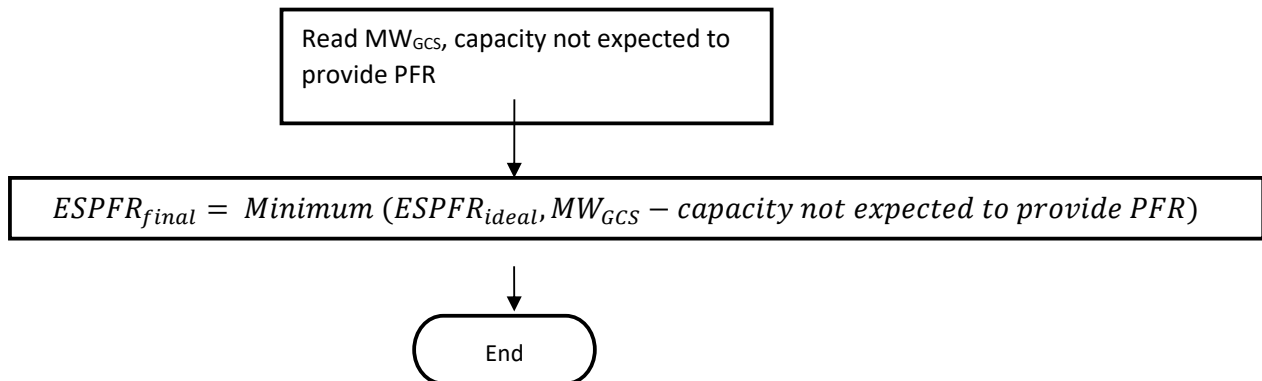
BAL-001-TRE-3 — Primary Frequency Response in the ERCOT Region

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.)

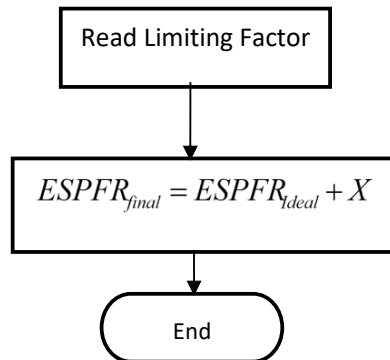
Adjustment for BESS with capacity that is not expected to provide PFR



BESS may, in real time, be required to reserve capacity for providing non-proportional frequency response. When this occurs, the expected MW response from the BESS shall be limited to exclude this capacity. The BA will utilize system data to determine when capacity should be excluded from the calculations.

BAL-001-TRE-3 — Primary Frequency Response in the ERCOT Region

Adjustment for Other Units



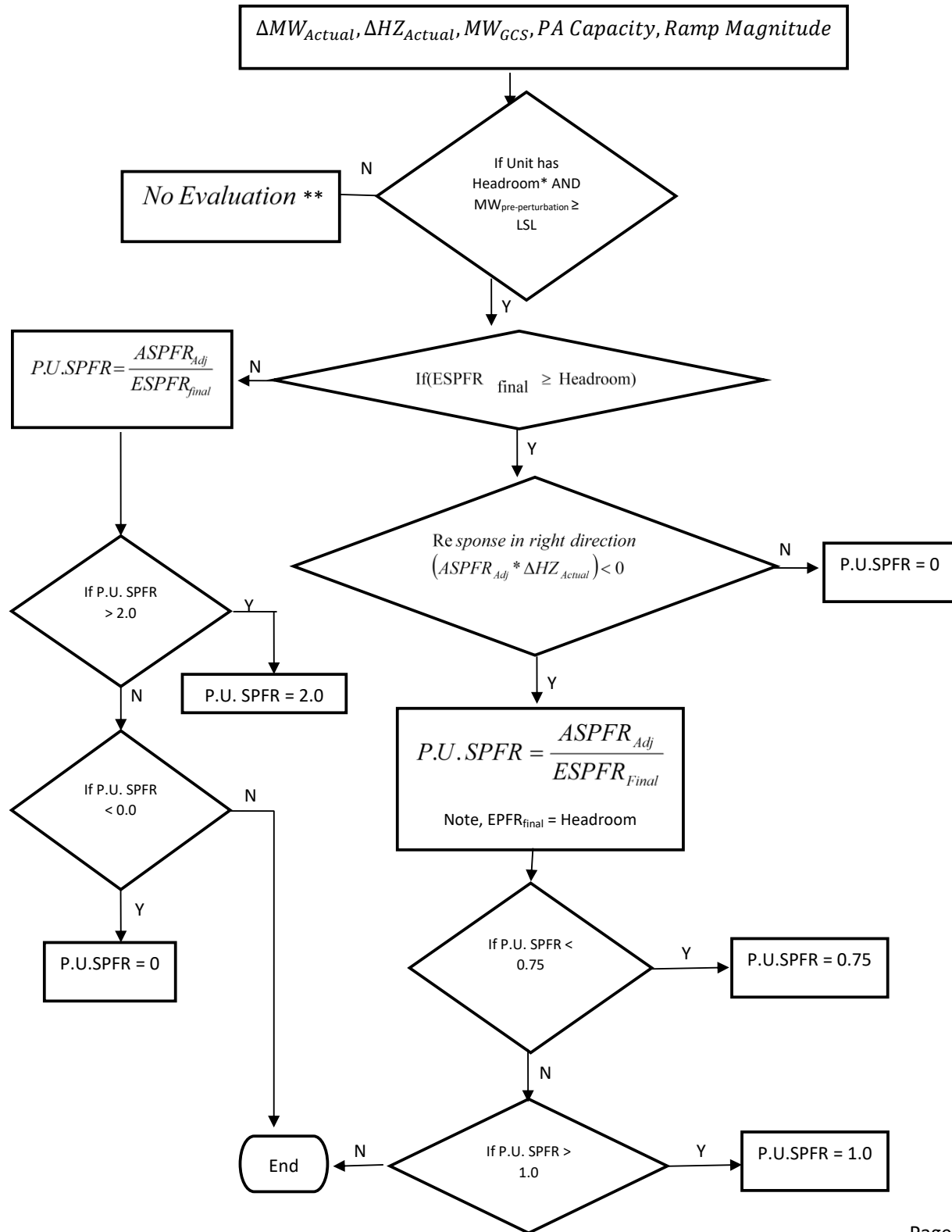
$$* HZ_{Actual} = HZ_{(T + 46)}$$

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

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

BAL-001-TRE-3 — Primary Frequency Response in the ERCOT Region



BAL-001-TRE-3 — Primary Frequency Response in the ERCOT Region

*Check for adequate up headroom, low frequency events. Headroom must be greater than either XMW or 2% of (MW_{GCS} less PA capacity and additional capacity not expected to provide PFR), 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 and additional capacity not expected to provide PFR), 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:

$$\text{Headroom} = HSL - PA \text{ Capacity} - \text{capacity not expected to respond with PFR} - MW_{T-2}$$

For high frequency events:

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

**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

BAL-001-TRE-3 — Primary Frequency Response in the ERCOT Region
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

BAL-001-TRE-3 — Primary Frequency Response in the ERCOT Region

			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		Attachment 1 was updated to align the MW _{GCS} definition and provide calculations for BESS. There is an additional calculation to provide a breakout for expected primary frequency response calculation for BESS and to account for any capacity that is not expected to provide PFR. Several sections were updated to align and

BAL-001-TRE-3 — Primary Frequency Response in the ERCOT Region

			account for capacity not expected to provide PFR for BESS as well. The flowcharts in Attachments A and B to the reference document were also updated to account for BESS expected primary frequency response calculations.
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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 terms “resource” and “generating unit/generating facility” refers to any resource capable of providing energy to the ERCOT region. Examples include, but are not limited to, the following:

- Hydro
- Combustion Turbine (Simple Cycle and Single-Shaft Combined Cycle)
- Steam Turbine
- Diesel
- Battery Energy Storage System (BESS)
- DC Tie Providing Ancillary ServicesIn 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]*

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.

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- 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 (8) FMEs in a 12-month period, its performance shall be based on a rolling eight FME average response.
- 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]*

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~~M5.~~ ~~T.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.

M5.

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~~R7, R6.~~ ~~R6.~~ Each Generator Owner shall set its Governor parameters, as set forth in Requirement R6, Parts 6.1, 6.2, and 6.3 follows. Requirement R6, Parts 6.1, 6.2, and 6.3 are not applicable to steam turbine(s) of a combined cycle resource.

- 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 u Units/ generating facilities that are not qualified ² to provide Operating Reserves and have obtained prior written approval from the Balancing Authority to widen their deadband settings	+/- 0.036 Hz
All Other g Generating u Units/ g Generating f 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
Combustion Turbine (Combined Cycle)	4%
All other generating units/generating facilities	5%
Generator Type	Max. Droop % Setting
Hydro	5%
Combustion Turbine (Simple Cycle and Single-Shaft Combined Cycle)	5%

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

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

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Combustion Turbine (Combined Cycle)	4%
Steam Turbine ⁴	5%
Diesel	5%
BESS	5%
DC Tie Providing Ancillary Services	5%
Variable Renewable (Non-Hydro)	5%

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

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

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

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. ~~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
- Written approval from the Balancing Authority to widen generating units'/generating facilities' deadband settings to +/- 0.036 Hz

R8-R7. ~~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

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

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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. ~~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.

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R8. ~~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]*

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M8. ~~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.

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R9. ~~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.

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- 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 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.

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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, 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 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 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.

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M10. Each Generator Owner shall have evidence that each of its generating units/generating facilities 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). ~~After CEA consultation with the BA, and 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~~ CEA 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~~ CEA 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~~ CEA 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.

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- 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~~CEA 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

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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.

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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 $\leq 20\%$ outside setting range specified in R6.	Any Governor parameter setting was $> 20\%$ and $\leq 30\%$ outside setting range specified in R6.	Any Governor parameter setting was $> 30\%$ and $\leq 40\%$ 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.

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	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 $\geq$ 0.65.	A Generator Owner's rolling average initial Primary Frequency Response performance per R9 was < 0.65 and $\geq$ 0.55.	A Generator Owner's rolling average initial Primary Frequency Response performance per R9 was < 0.55 and $\geq$ 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 $\geq$ 0.65.	A Generator Owner's rolling average sustained Primary Frequency Response performance per R10 was < 0.65 and $\geq$ 0.55.	A Generator Owner's rolling average sustained Primary Frequency Response performance per R10 was < 0.55 and $\geq$ 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

BAL-001-TRE-3 — Primary Frequency Response in the ERCOT Region

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.

Attachment 1

Primary Frequency Response Reference Document

Texas Reliability Entity, Inc.
 BAL-001-TRE-32
 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 available¹ 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.

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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 MW_{GCS} is calculated from HSL to LSL less any capacity that is not expected to provide PFR for BESS and HSL to 0 for all other all generator types. ~~For all generator types, except BESS, MW_{GCS} is calculated from HSL to 0 while BESS is calculated from HSL to LSL.~~

Design Settings versus real-time Evaluation: Settings and verifications (Requirement 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.

In this Regional Standard the terms “resource” and “generating unit/generating facility” refers to any resource injecting power to serve load capable of providing energy to the ERCOT region. Examples include, but are not limited to, the following:

- Hydro
- Combustion Turbine (Simple Cycle and Single-Shaft Combined Cycle)
- Steam Turbine
- Diesel
- Battery Energy Storage System (BESS)
- DC Tie Providing Ancillary Services
- ~~Battery Energy Storage System (BESS)~~

~~DC Tie Providing Ancillary Services~~ 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.

Commented [JH1]: Removing this call out to align with our discussion with SDT that this should be a static droop value. Calculations modified to show that response should be limited to PFR capacity available.

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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.

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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.

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

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

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

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The adjusted actual PFR ($APFR_{adj}$) and the final expected PFR ($EPFR_{final}$) 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 ($APFR_{adj}$)

The adjusted actual Primary Frequency Response ($APFR_{adj}$) 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 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

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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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 $EPFR_{post-perturbation}$ and the $EPFR_{pre-perturbation}$.

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

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

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

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

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

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

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

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

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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

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

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.

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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

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

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.

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EPFR_{final} for Steam Turbine

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

Where:

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

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Where:

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

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

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

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 BESS with capacity that is not expected to provide PFR

$$EPFR_{\text{final}} = \text{Minimum} (EPFR_{\text{ideal}}, MW_{\text{GCS}} - \text{capacity not expected to provide PFR})$$

BESS may, in real time, be required to reserve capacity for providing non-proportional frequency response. When this occurs, the expected MW response from the BESS shall be limited to exclude this capacity. The BA will utilize system data to determine when capacity should be excluded from the calculations.

EPFR_{final} for Other Generating Units/Generating Facilities

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

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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.

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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

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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.

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 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)

$$P.U.SPFR_{Resource} = \frac{Actual\ Sustained\ Primary\ Frequency\ Response_{Adj}}{Expected\ Sustained\ Primary\ Frequency\ Response_{Final}}$$

$$P.U.SPFR_{Resource} = \frac{Actual\ Sustained\ Primary\ Frequency\ Response_{Adj}}{Expected\ Sustained\ Primary\ Frequency\ Response_{Final}}$$

$P.U.SPFR_{Resource}$ 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.

Actual Sustained Primary Frequency Response (ASPFR) Calculations

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

Where:

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

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

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 ($ASPFR_{Adj}$)

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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 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:

$$RampMW_{Sustained} = (MW_{T-4} - MW_{T-60}) \times 0.821$$

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

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$$\frac{46 \text{ seconds}}{56 \text{ seconds}} \text{ or } 0.821.$$

on its ramp to T+46 unencumbered by the FME. The modifier is

Expected Sustained Primary Frequency Response ($ESPFR$) Calculations

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, HSL/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 power augmentation capacity (PA

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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 $EPFR_{pre-perturbation}$. The $EPFR_{pre-perturbation}$ is the same $EPFR_{pre-perturbation}$ value used in the Initial measure of R9.

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

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

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

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

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

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

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

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

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Capacity and 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. 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

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

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.)

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ESPFR_{final} for Steam Turbine

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

Where:

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

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

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Where:

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

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

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

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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

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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 BESS with capacity that is not expected to provide PFR

$$ESPFR_{final} = \text{Minimum}(ESPFR_{ideal}, MW_{GCS} - \text{capacity not expected to provide PFR})$$

BESS may, in real time, be required to reserve capacity for providing non-proportional frequency response. When this occurs, the expected MW response from the BESS shall be limited to exclude this capacity. The BA will utilize system data to determine when capacity should be excluded from the calculations.

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 and additional capacity not expected to provide PFR) or within 5 MW (whichever is greater), or a BESS is operating within 2% or 3 MW of its MW_{GCS} less capacity not expected to provide PFR 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-perturbation} < 60 if:

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

$$MW_{pre-perturbation} \geq \min[(MW_{GCS} - PA\ Capacity - \text{capacity not expected to provide PFR}) \times .98], (MW_{GCS} - PA\ Capacity - \text{capacity not expected to provide PFR}) - Y\ MW\}$$

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

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For frequency deviations above 60 Hz (HzPost-perturbation > 60, if:

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

$$MW_{pre-perturbation} \leq \max[(LSL + ([MW_{GCS} - PA Capacity - \text{capacity not expected to provide PFR}] \times 0.02)), (LSL + Y MW)]$$

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then PFR is not evaluated for this FME where ~~X~~-Y 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 additional capacity not expected to provide PFR) 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 capacity⁴; 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 and additional capacity not expected to provide PFR) 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 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}.

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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.

**Attachment A to
Primary Frequency Response Reference Document**

**Initial Primary Frequency Response Methodology for
BAL-001-TRE-~~32~~**

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Primary Frequency Response Measurement and Rolling Average Calculation – Initial Response

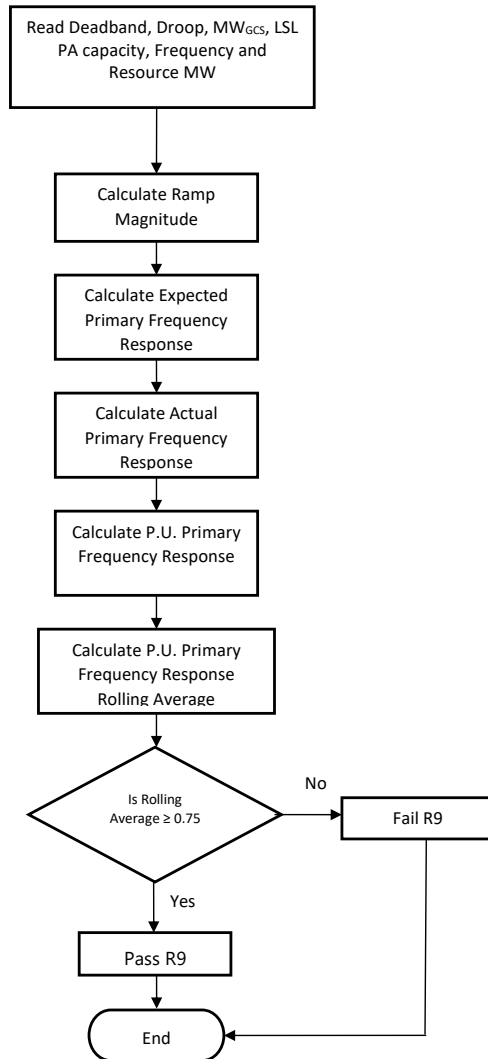
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PA = Power Augmentation

HSL = High Sustained Limit

LSL = Low Sustained Limit

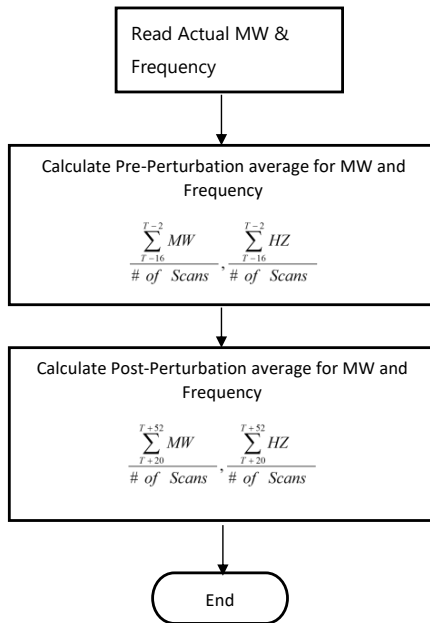
MW_{GCS} = maximum megawatt control range of the Governor control system

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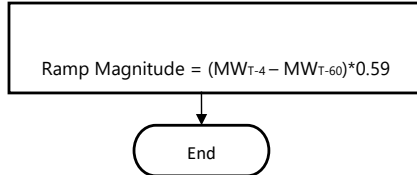
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Pre/Post-Perturbation Average MW and Average Frequency Calculations

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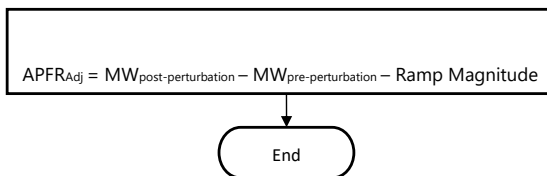
Ramp Magnitude Calculation



(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.

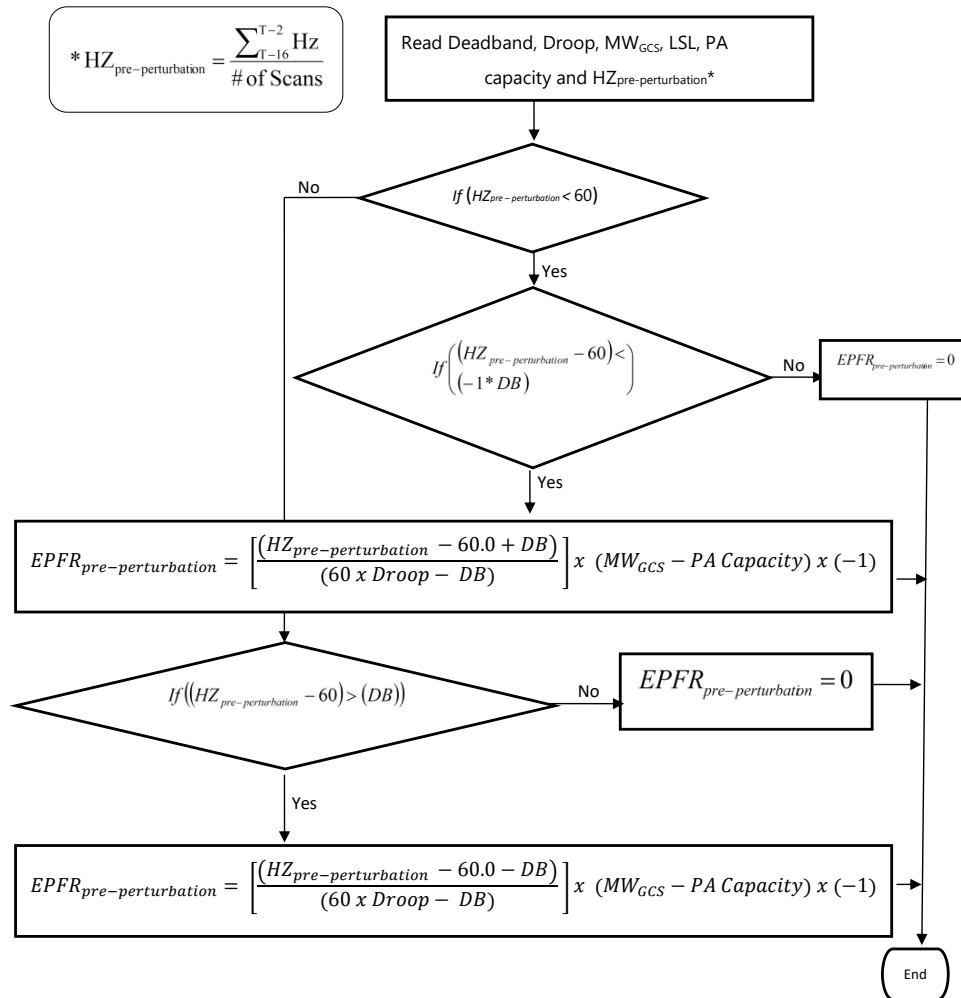
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Actual Primary Frequency Response (APFRA_{Adj})

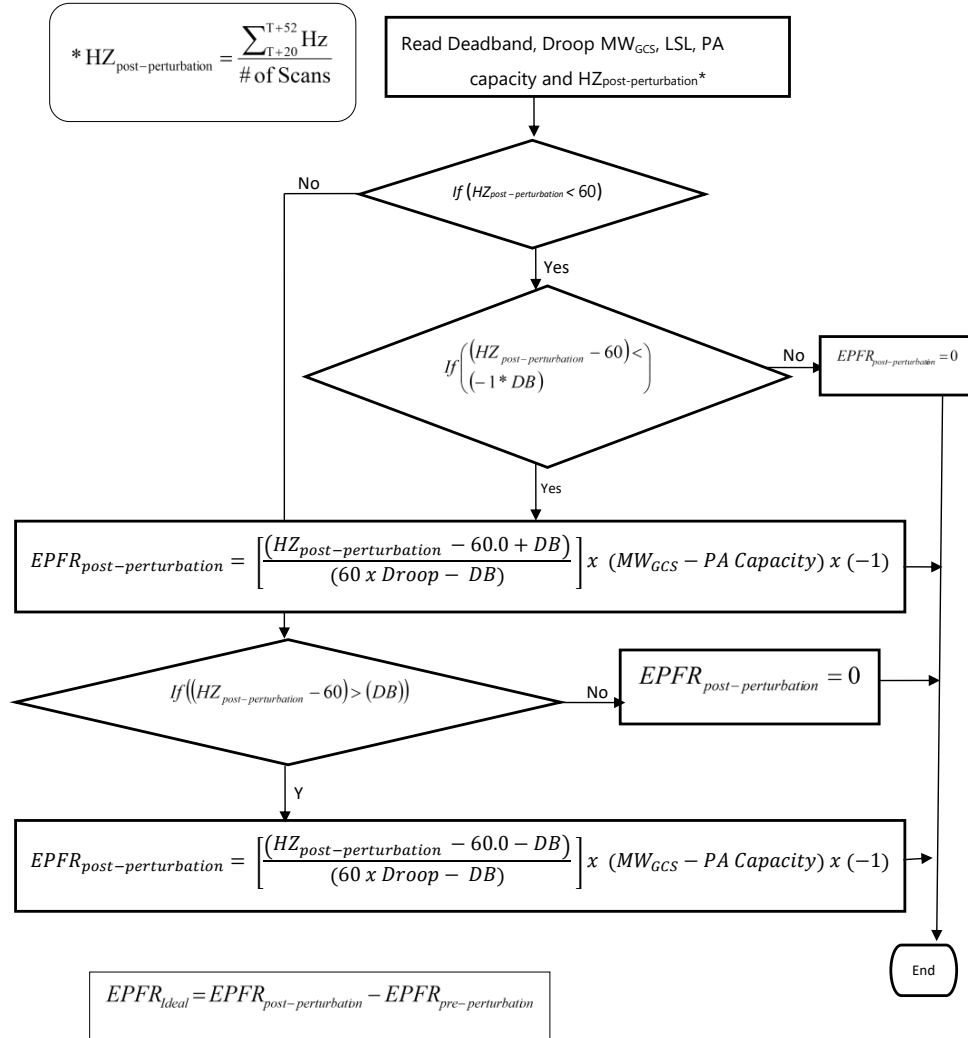


Expected Primary Frequency Response Calculation

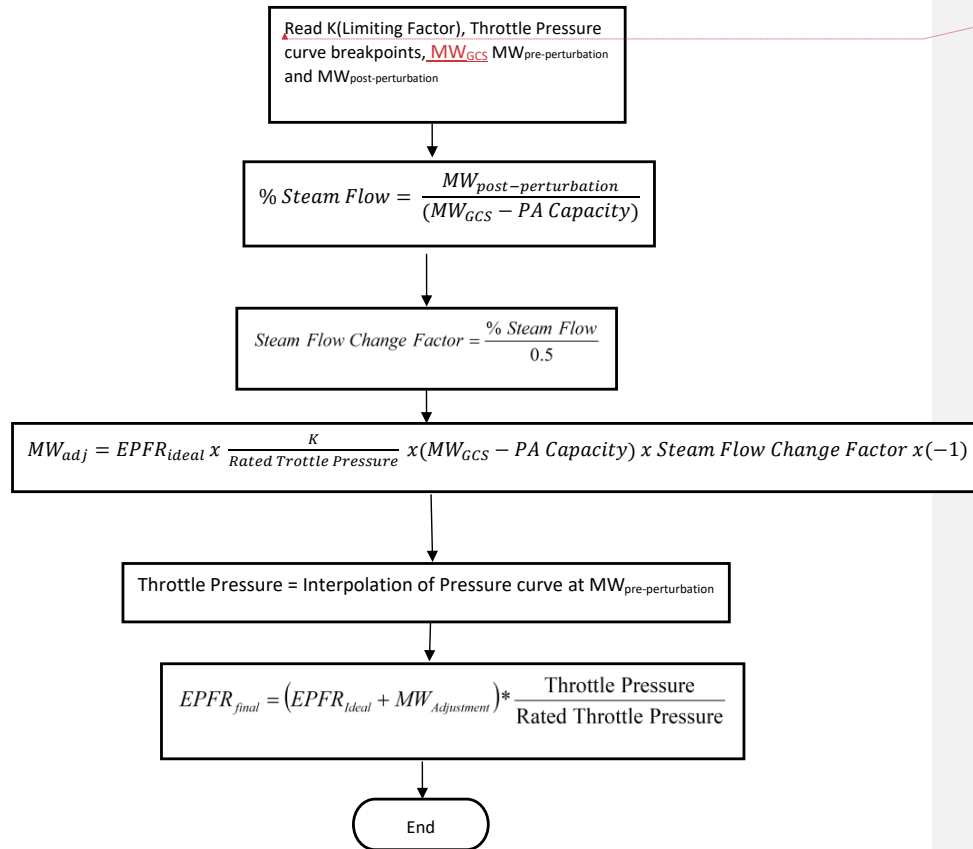
Use the maximum droop and maximum deadband as required by R6. For Combined Cycle Facility evaluation as a single resource (includes MW production of the steam turbine generator), the EPFR will use 5.78% droop in all calculations.



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Adjustment for Steam Turbine

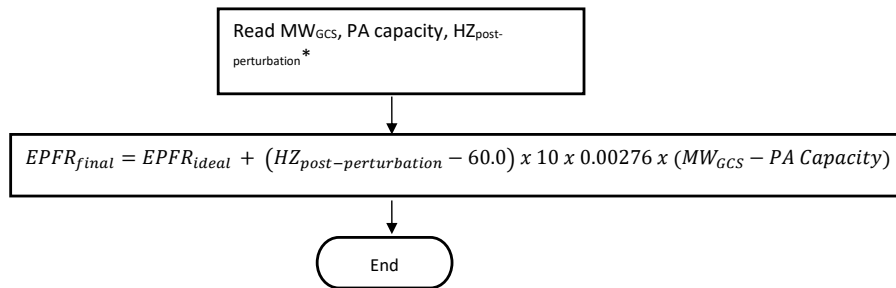


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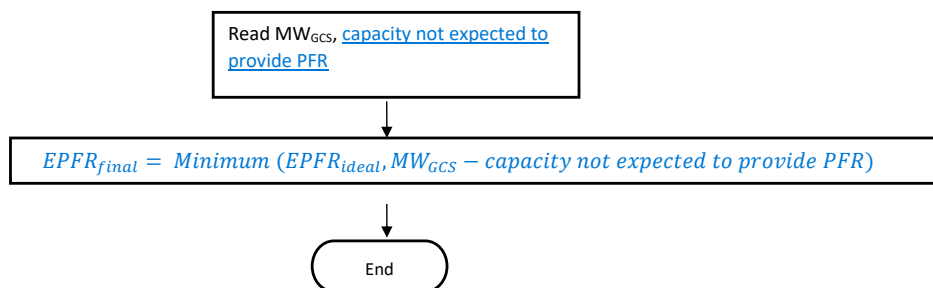
Adjustment for Combustion Turbines and Combined Cycle Facilities

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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.)

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Adjustment for BESS with capacity that is not expected to provide PFR

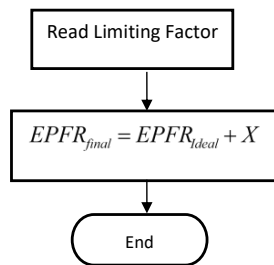
[BESS may, in real time, be required to reserve capacity for providing non-proportional frequency response. When this occurs, the expected MW response from the BESS shall be limited to exclude this capacity. The BA will utilize system data to determine when capacity should be](#)

BAL-001-TRE-32 — Primary Frequency Response in the ERCOT Region

[excluded from the calculations.](#)

Adjustment for Other Units

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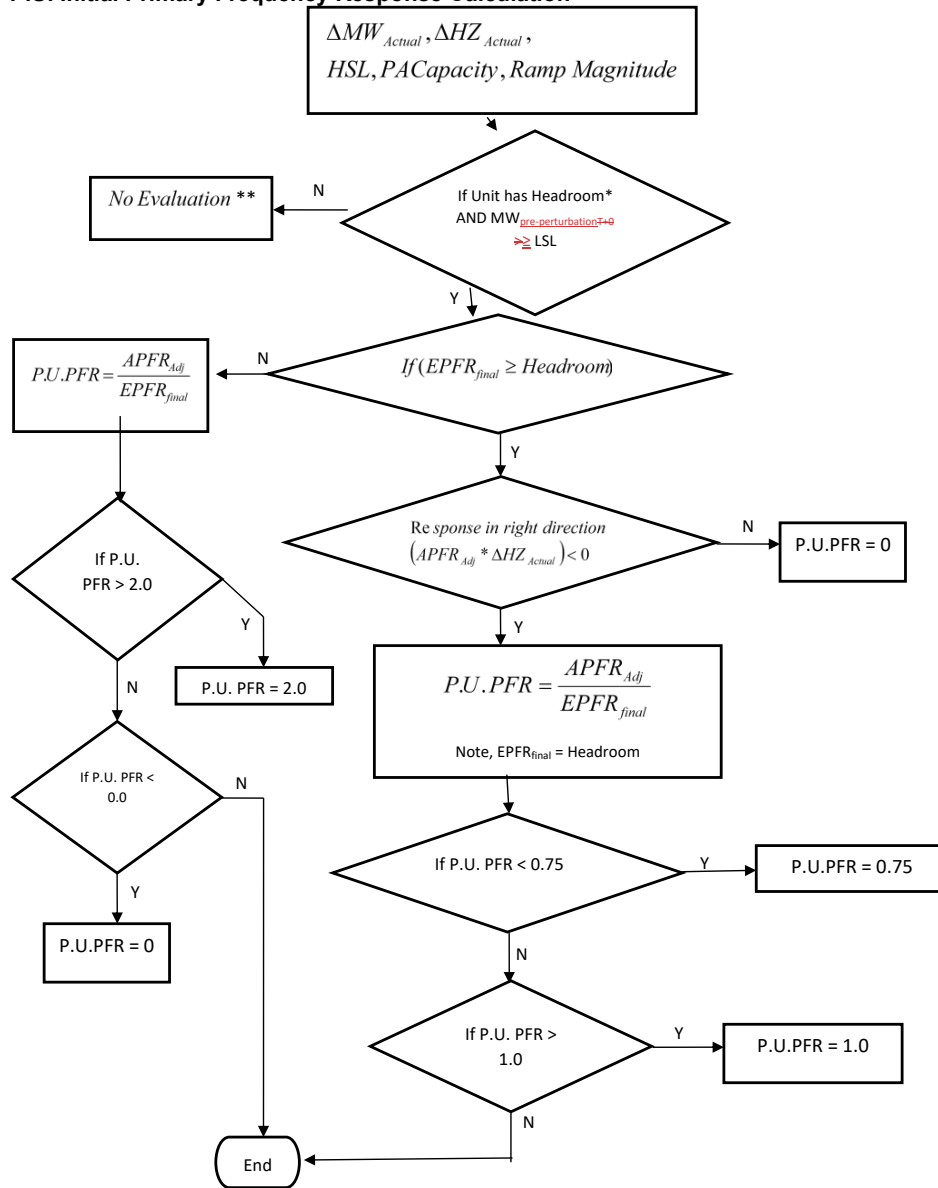
$$* \text{HZ}_{\text{post-perturbation}} = \frac{\sum_{T+20}^{T+52} \text{HZ}_{\text{Actual}}}{\# \text{ of Scans}}$$

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.

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BAL-001-TRE-32 — Primary Frequency Response in the ERCOT Region

P.U. Initial Primary Frequency Response Calculation



BAL-001-TRE-32 — Primary Frequency Response in the ERCOT Region

*Check for adequate up headroom, low frequency events. Headroom must be greater than either XMW or 2% of $(MW_{GCS}$ less PA capacity [and additional capacity not expected to provide PFR](#)), 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 [and additional capacity not expected to provide PFR](#)), 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:

$$\text{Headroom} = MW_{GCS} - HSL - PA \text{ Capacity} - \text{capacity not expected to respond with PFR} - MW_{T-2}$$

For high frequency events:

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

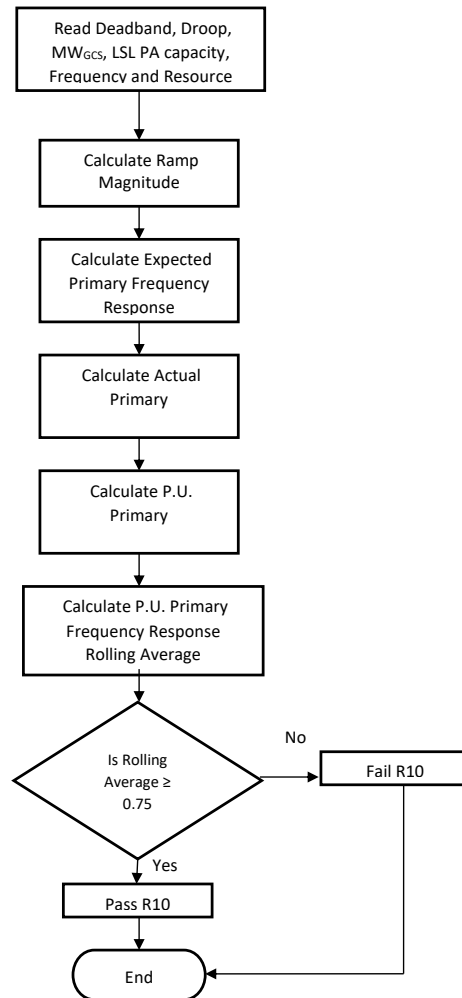
**No further evaluation is required for Sustained Primary Frequency Response. This event will not be included in the Rolling Average calculation of either Initial or Sustained Primary Frequency Response.

T = Time in Seconds

**Attachment B to
Primary Frequency Response Reference Document**

**Sustained Primary Frequency Response Methodology for
BAL-001-TRE-~~23~~**

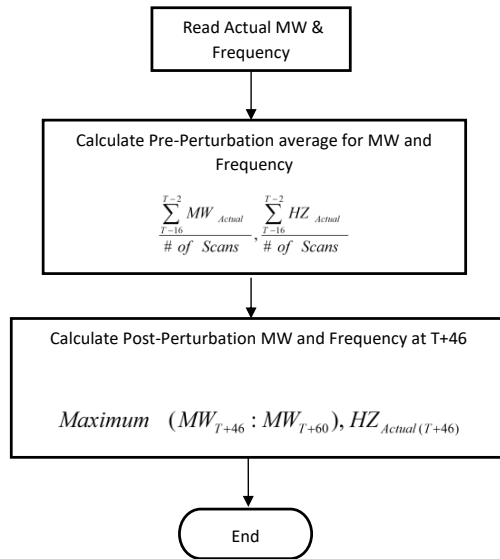
Primary Frequency Response Measurement and Rolling Average Calculation—Sustained Response



BAL-001-TRE-32 — Primary Frequency Response in the ERCOT Region

Pre/Post-Perturbation Average MW and Average Frequency Calculations

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BAL-001-TRE-32 — Primary Frequency Response in the ERCOT Region

Ramp Magnitude Calculation - Sustained

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

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.

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Actual Sustained Primary Frequency Response (ASPFR_{Adj})

For low frequency events:

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

End

For high frequency events:

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

End

BAL-001-TRE-~~32~~ — Primary Frequency Response in the ERCOT Region

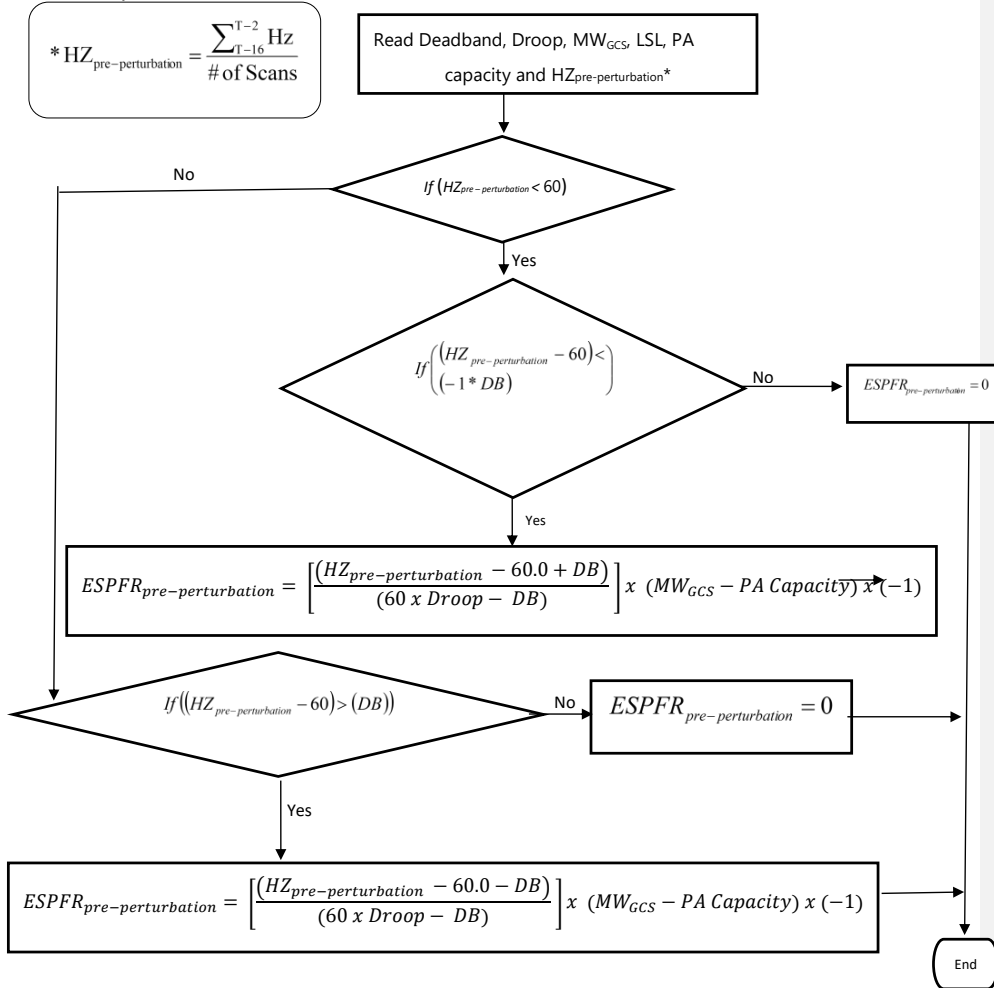
Expected Sustained Primary Frequency Response Calculation

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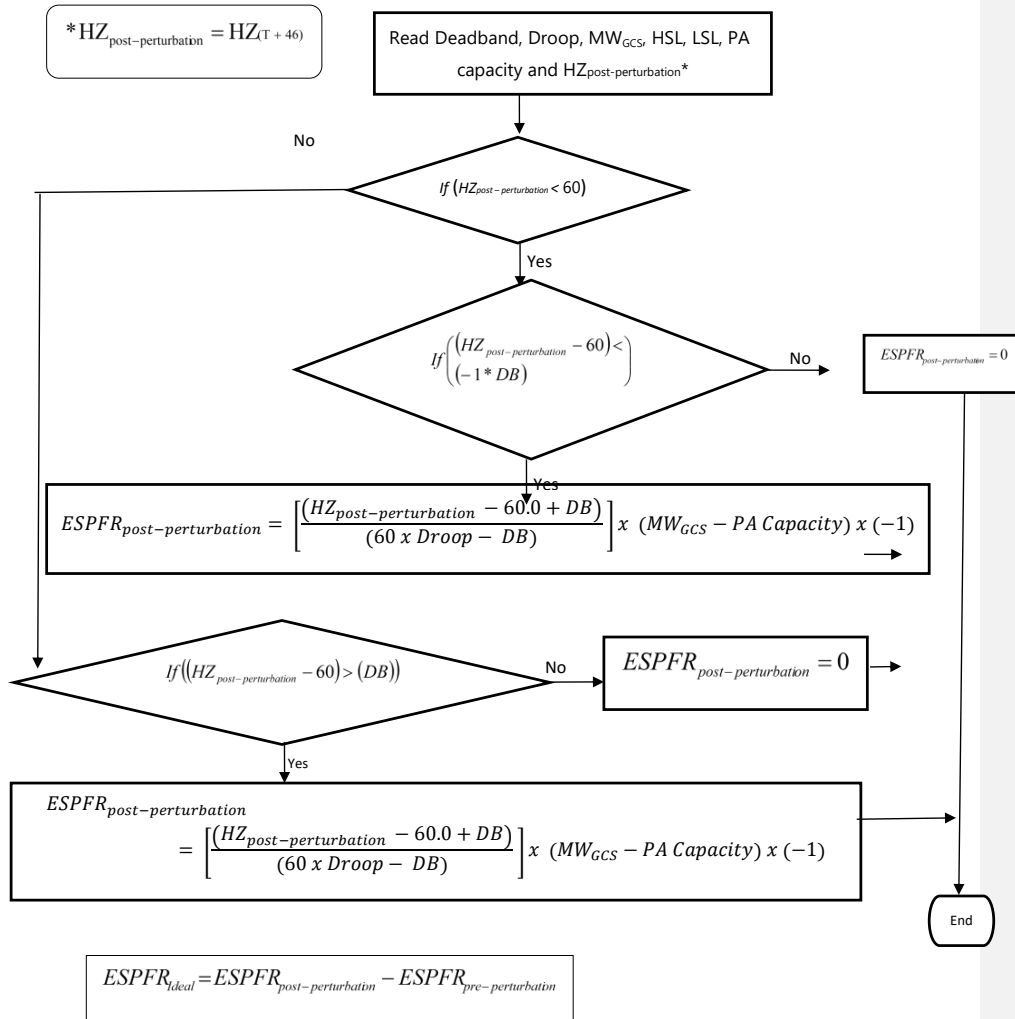
Use the droop and deadband as required by R6. For Combined Cycle Facility evaluation as a single resource (includes MW production of the steam turbine generator), the EPFR will use

BAL-001-TRE-32 — Primary Frequency Response in the ERCOT Region

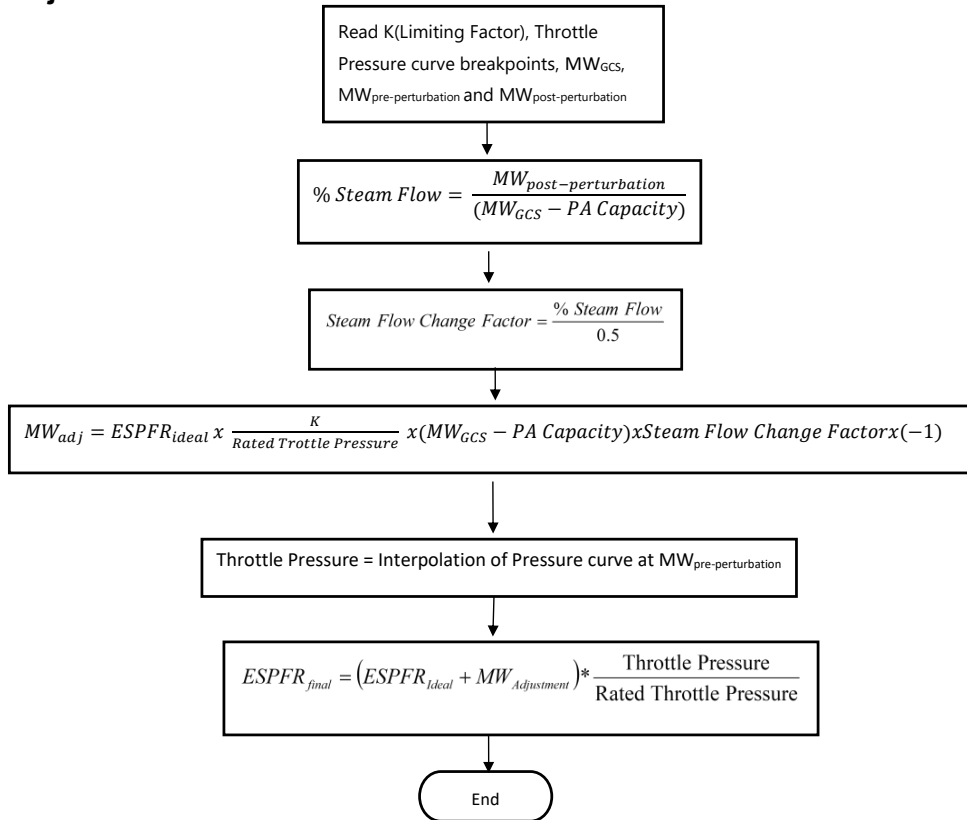
5.78% droop in all calculations.



BAL-001-TRE-32 — Primary Frequency Response in the ERCOT Region



Adjustment for Steam Turbine



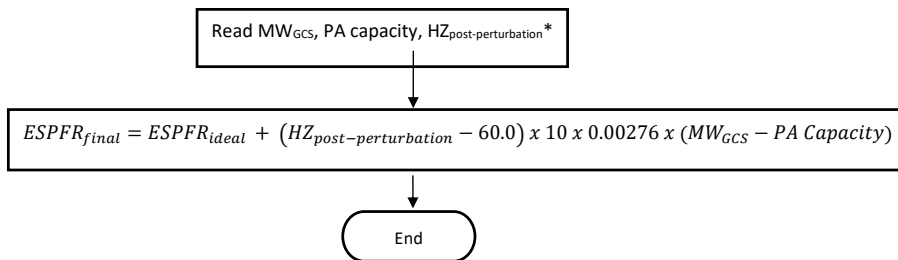
$MW_{post-perturbation} = \text{Maximum}(MW_{T+46} : MW_{T+60})$ for low frequency events.

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

BAL-001-TRE-32 — Primary Frequency Response in the ERCOT Region

Adjustment for Combustion Turbines and Combined Cycle Facilities

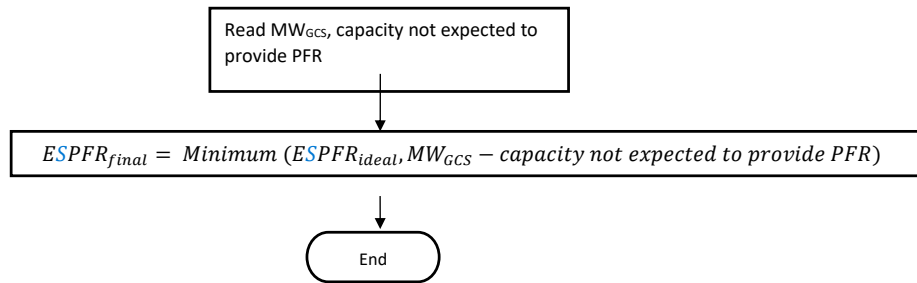
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0.00276 is the MW/0.1 Hz change per MW of capacity and represents the MW change in generator output due to the change in mass flow through the combustion turbine due to the speed change of the turbine during the post-perturbation measurement period.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

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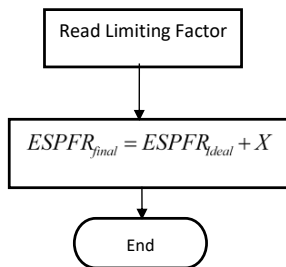
Adjustment for BESS with capacity that is not expected to provide PFR



[BESS may, in real time, be required to reserve capacity for providing non-proportional frequency response. When this occurs, the expected MW response from the BESS shall be limited to exclude this capacity. The BA will utilize system data to determine when capacity should be excluded from the calculations.](#)

BAL-001-TRE-32 — Primary Frequency Response in the ERCOT Region**Adjustment for Other Units**

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

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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.

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BAL-001-TRE-32 — Primary Frequency Response in the ERCOT Region

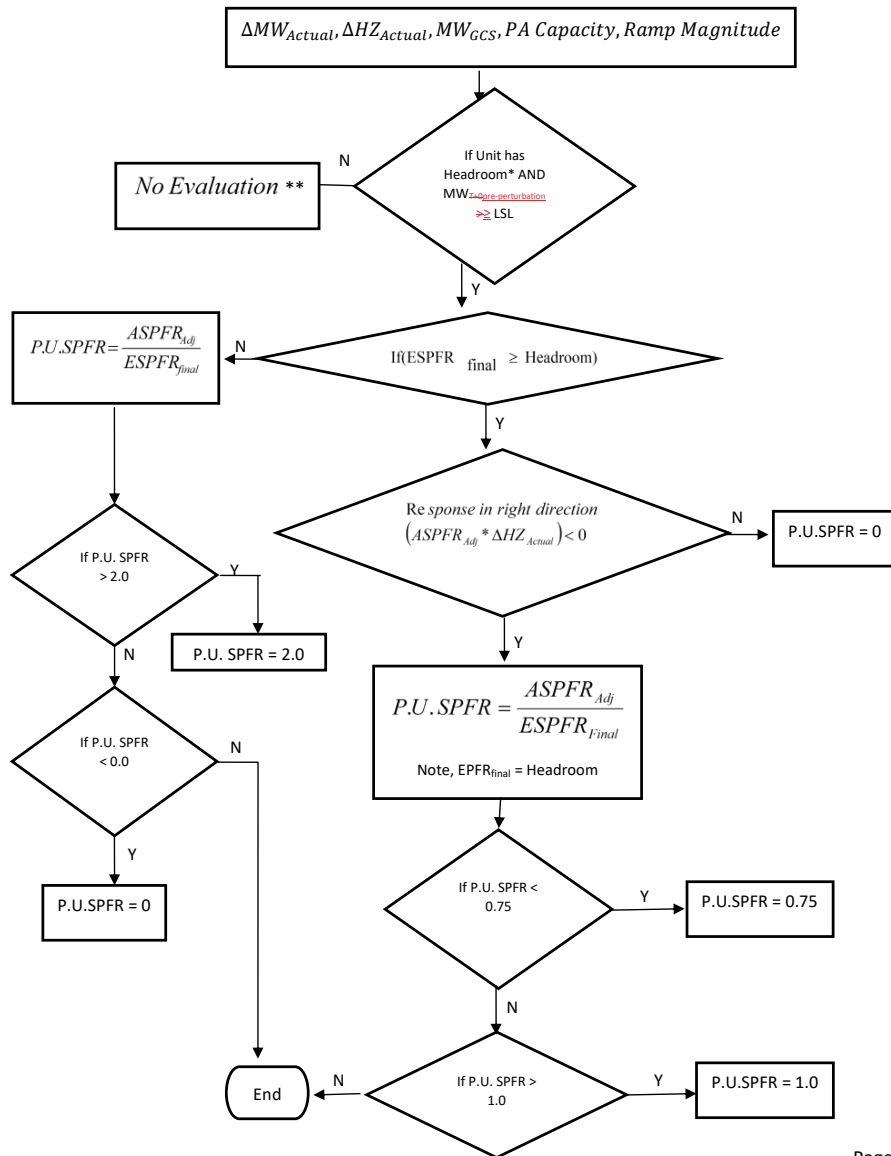
P.U. Sustained Primary Frequency Response Calculation

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

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BAL-001-TRE-32 — Primary Frequency Response in the ERCOT Region



BAL-001-TRE-32 — Primary Frequency Response in the ERCOT Region

*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.

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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.

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For low frequency events:

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

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For high frequency events:

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

**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.

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T = Time in Seconds

BAL-001-TRE-32 — Primary Frequency Response in the ERCOT Region

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

BAL-001-TRE-32 — Primary Frequency Response in the ERCOT Region

			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		<u>Attachment 1 was updated to align the MW_{GCS} definition and provide calculations for BESS. There is an additional calculation to provide a breakout for expected primary frequency response calculation for BESS and to account for any capacity that is not expected to provide PFR. Several sections were updated to align and</u>

BAL-001-TRE-32 — Primary Frequency Response in the ERCOT Region

			<u>account for capacity not expected to provide PFR for BESS as well. The flowcharts in Attachments A and B to the reference document were also updated to account for BESS expected primary frequency response calculations.</u> (Description of Changes to reference document)
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A. Introduction

1. **Title:** Primary Frequency Response in the ERCOT Region
2. **Number:** BAL-001-TRE-23
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-23.
 - 4.2.2 Generating units/generating facilities while operating in synchronous condenser mode are exempt from Standard BAL-001-TRE-23.
 - 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-23.
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~~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

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BAL-001-TRE-23 — Primary Frequency Response in the ERCOT Region

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~~terms “resource” ~~is synonymous with~~and “generating unit/generating facility” ~~refers to any resource capable of providing energy to the ERCOT region. Examples include, but are not limited to, the following:~~

- Hydro
- Combustion Turbine (Simple Cycle and Single-Shaft Combined Cycle)
- Steam Turbine
- Diesel
- Battery Energy Storage System (BESS)
- DC Tie Providing Ancillary Services

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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.

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R2. The Balancing Authority shall calculate the Primary Frequency Response of each generating unit/generating facility 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%.

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¹~~The 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. ~~This reference document is a Texas RE-controlled document that is subject to revision by the Texas RE Board of Directors.~~

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BAL-001-TRE-23 — Primary Frequency Response in the ERCOT Region

- 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 has not participated in a minimum of ~~(8)~~ eight (8) FMEs in a 12-month period, its performance shall be based on a rolling eight FME average response.
- 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 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~~ *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

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BAL-001-TRE-~~23~~ — Primary Frequency Response in the ERCOT Region

combined Frequency Response performance was less than the IMFR, per Requirement R5.

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- R6.** Each Generator Owner shall set its Governor parameters, as follows: set forth in Requirement R6, Parts 6.1, 6.2, and 6.3. Requirement R6, Parts 6.1, 6.2, and 6.3 are not applicable to steam turbine(s) of a combined cycle resource.

- 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
All Other Generating Units/Generating Facilities*Generating units/generating facilities that are not qualified ² to provide Operating Reserves and have obtained prior written approval from the Balancing Authority to widen their deadband settings.	+/- 0.017036 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%
Steam Turbine*All other generating units/generating facilities	5%
Diesel	5%
DC Tie Providing Ancillary Services	5%

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

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BAL-001-TRE-23 — Primary Frequency Response in the ERCOT Region

Variable Renewable (Non-Hydro)	5%
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*Requirements R6.1, R6.2, and R6.3 are not applicable to steam turbine(s) of a combined cycle resource.

6.2.6.3. 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.

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Where

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

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

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]

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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:

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- Governor test reports
- Governor setting sheets
- Performance monitoring reports
- [Written approval from the Balancing Authority to widen generating units'/generating facilities' deadband settings to +/- 0.036 Hz](#)

R7. Each Generator Owner shall operate each generating unit/generating facility that is connected to the interconnected transmission system with the Governor in service and responsive to frequency when the generating unit/generating facility is online and

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BAL-001-TRE-23 — Primary Frequency Response in the ERCOT Region

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 was online and released for dispatch. Evidence may include but not be limited to: operator logs, voice logs, or electronic communications.

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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]*

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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.

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~~R9.~~ 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, based on participation in at least eight FMEs. [See Attachment 1: Primary Frequency Response Reference Document for specific calculations.](#)

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~~9.1.~~ 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.

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~~9.2.~~ 9.2 If a generating unit/generating facility 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.~~ 9.3 A generating unit/generating facility's 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 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.

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~~R10.~~ 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, 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]

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~~10.1.~~ 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.

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~~10.2.~~ 10.2. If a generating unit/generating facility 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.~~ 10.3. A generating unit/generating facility's 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.

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M10. Each Generator Owner shall have evidence that each of its generating units/generating facilities 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.

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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/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 unit’s/generating facility’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). After CEA consultation with the BA, and 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 per under Requirements R9 and R10 of the Regional Standard.

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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 CEA 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 CEA 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 CEA 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

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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~~The CEA 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.

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	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 $\geq$ 0.65.	A Generator Owner's rolling average initial Primary Frequency Response performance per R9 was < 0.65 and $\geq$ 0.55.	A Generator Owner's rolling average initial Primary Frequency Response performance per R9 was < 0.55 and $\geq$ 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 $\geq$ 0.65.	A Generator Owner's rolling average sustained Primary Frequency Response performance per R10 was < 0.65 and $\geq$ 0.55.	A Generator Owner's rolling average sustained Primary Frequency Response performance per R10 was < 0.55 and $\geq$ 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-23 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.

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<u>3</u>			<u>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).</u> <u>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.</u> <u>Define PFR performance requirements for Battery Energy Storage Systems (BESS).</u>
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Standard Attachments

1. Attachment 1₁ – 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, R9₁ 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 meeting₂ and will accept and consider verbal and written comments pertaining to the request. The MRC will make a recommendation to the Texas

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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-23
Requirements R2, R9, and R10
Performance Metric Calculations

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I. Introduction

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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,

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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 available¹ for reference and use in understanding and performing these calculations.

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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.

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

High Sustained Limit (HSL) for a generating unit/generating facility: 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.

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

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In this regional **Maximum Megawatt Governor Control System (MW_{GCS})** for the purposes of this standard, the term maximum megawatt control range of the Governor control system MW_{GCS} is calculated from HSL to LSL for BESS and HSL to 0 for all other all generator types.

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Design Settings versus real-time Evaluation: Settings and verifications (Requirement 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.

In this Regional Standard the terms "resource" is synonymous with and "generating unit/generating facility" refers to any resource capable of providing energy to the ERCOT region. Examples include, but are not limited to, the following:

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

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- Hydro
- Combustion Turbine (Simple Cycle and Single-Shaft Combined Cycle)
- Steam Turbine
- Diesel
- Battery Energy Storage System (BESS)
- DC Tie Providing Ancillary Services

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, 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 has not participated in a minimum of eight FMEs in a 12-month period, performance shall be based on a rolling eight-FME average response.

9.3. A generating unit/generating facility's initial Primary Frequency Response performance during an FME may be excluded by the Balancing Authority 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 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 R9.

This process calculates the initial Per Unit per unit Primary Frequency Response of a resource [P.U.PFR_{Resource}] as a ratio between the Adjusted Actual Primary Frequency Response adjusted

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~~actual PFR~~ (APFR_{Adj}), adjusted for the pre-event ramping of the unit, and the ~~Final Expected~~~~final expected~~ Primary Frequency Response (EPFR_{final}) as calculated using the ~~Pre~~~~pre~~-perturbation and ~~Post~~~~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 Primary Frequency Response~~~~per unit PFR~~ [P.U.PFR_{Resource}] for any ~~Frequency Measurable Event (FME)~~.

Initial Primary Frequency Response performance requirement

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

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

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

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

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

~~The Adjusted Actual Primary Frequency Response~~~~adjusted actual PFR~~ (APFR_{Adj}) and the ~~Final Expected Primary Frequency Response~~~~final expected PFR~~ (EPFR_{final}) are calculated as described below.

EPFR ~~Calculations~~~~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 (APFR_{Adj})

The adjusted ~~Actual~~~~actual~~ Primary Frequency Response (APFR_{Adj}) 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.

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

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 Primary Frequency Response~~ **actual PFR** number that is used to calculate P.U.PFR is adjusted for the ramp magnitude of the generating unit/generating facility 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~~ **expected** Primary Frequency Response ($EPFR_{ideal}$) is calculated as the difference between the $EPFR_{post-perturbation}$ and the $EPFR_{pre-perturbation}$.

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

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

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$$EPFR_{pre-perturbation}$$

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

$$EPFR_{post-perturbation}$$

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

$$EPFR_{pre-perturbation}$$

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

$$EPFR_{post-perturbation}$$

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

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

$$EPFR_{pre-perturbation}$$

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

$$EPFR_{post-perturbation}$$

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

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

$$EPFR_{pre-perturbation}$$

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

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$$EPFR_{post-perturbation}$$

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

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 (Net Dependable Capacity))~~ are used interchangeably and the term ~~Capacity~~ **capacity** 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.~~

Power Augmentation: For ~~Combined Cycle~~ **combined cycle** facilities, ~~Capacity~~ **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

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

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

Note: The 0.00276 constant is the MW/0.1 Hz change per MW of ~~Capacity~~ **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

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measured on multiple combustion turbines in ERCOT.

EPFR_{final} for Steam Turbine

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

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Where:

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

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

Where:

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

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

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

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

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

The Rated Throttle Pressure rated throttle pressure and the Pressure 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 pressure and MW breakpoints where the Rated Throttle Pressure rated throttle pressure is achieved, is the first pair and the Minimum Throttle Pressure minimum throttle pressure and MW output, where the Minimum Throttle Pressure 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 aan FME. The GO can

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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~~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.

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EPFR_{final} for BESS with capacity that is not expected to provide PFR

$$EPFR_{final} = \text{Minimum} (EPFR_{ideal}, MW_{GCS} - \text{capacity not expected to provide PFR})$$

BESS may, in real time, be required to reserve capacity for providing non-proportional frequency response. When this occurs, the expected MW response from the BESS shall be limited to exclude this capacity. The BA will utilize system data to determine when capacity should be excluded from the calculations.

EPFR_{final} for Other Generating Units/Generating Facilities

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

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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.

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III. Sustained Primary Frequency Response Calculations**Requirement 10**

R10. ~~The 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, based on participation in at least eight FMEs. See Attachment 1: Primary Frequency Response Reference Document for specific calculations.

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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.

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10.2 If a generating unit/generating facility 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 sustained Primary Frequency Response performance during an FME may be excluded by the Balancing Authority 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 Primary Frequency Response 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 Primary Frequency Response 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 Primary Frequency Response per unit sustained 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

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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month period, the average of the unit's last 8 sustained ~~Primary Frequency Response~~_{PFR} performances when the unit provided frequency response during a ~~Frequency Measurable Event~~_{FME}.

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

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

$P.U.SPFR_{Resource}$ 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.

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Actual Sustained Primary Frequency Response (ASPFR) Calculations

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

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.

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Actual Sustained Primary Frequency Response, Adjusted ($ASPFR_{Adj}$)

$$ASPFR_{Adj} = ASPFR - RampMW_{Sustained}$$

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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$$\text{RampMW Sustained} = (MW_{T-4} - MW_{T-60}) \times 0.821$$

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 ($MW_{T-4} - MW_{T-60}$) 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

$$\frac{46 \text{ seconds}}{56 \text{ seconds}} \text{ or } 0.821.$$

FME. The modifier is

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Expected Sustained Primary Frequency Response (ESPFR) Calculations

The Expected Sustained Primary Frequency Response The expected sustained PFR ($ESPFR_{\text{final}}$) is calculated using the actual frequency at $T+46$, HZ_{T+46} .

This $ESPFR_{\text{final}}$ 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/limiting factors, each generating units / generating facilities may have and any Power Augmentation Capacity/power augmentation capacity (PA Capacity/capacity) that may be included in the HSL/LSL.

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Establishing the Ideal Expected Sustained Primary Frequency Response

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

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

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

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

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

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

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

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

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

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

Capacity and ~~Net Dependable Capability (NDC)~~ are used interchangeably and the term ~~Capacity~~ capacity 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 from Requirement R6.

For ~~Combined Cycle~~ combined cycle facilities, determination of ~~Capacity~~ capacity includes subtracting ~~Power Augmentation~~ power augmentation (PA) ~~Capacity~~ capacity, if any, from the original ~~HSL~~ MW_{GCS} . Other generator types may also have ~~Power Augmentation~~ 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

$$\cancel{ESPFR_{final}} = \cancel{ESPFR_{ideal}} + (HZ_{T+46} - 60) * 10 * 0.00276 * (HSL - PA Capacity)$$

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

Note: The 0.00276 constant is the MW/0.1 Hz change per MW of ~~Capacity~~ 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.)

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ESPFR_{final} for Steam Turbine

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

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Where:

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

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

Where:

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

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

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

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

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

The **Rated Throttle Pressure** rated throttle pressure, and the **Pressure** 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** pressure and MW breakpoints where the **Rated Throttle Pressure** rated throttle pressure and MW output where **Rated Throttle Pressure** rated throttle pressure is achieved is the first pair and the **Minimum Throttle Pressure** minimum throttle pressure and MW output where the **Minimum Throttle Pressure** 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 **ean** 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

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rated throttle pressure and resource capacity. An additional sensitivity factor, the Steam Flow Change Factor 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.

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ESPFR_{final} for BESS with capacity that is not expected to provide PFR

$$ESPFR_{final} = \text{Minimum}(ESPFR_{ideal}, MW_{GCS} - \text{capacity not expected to provide PFR})$$

BESS may, in real time, be required to reserve capacity for providing non-proportional frequency response. When this occurs, the expected MW response from the BESS shall be limited to exclude this capacity. The BA will utilize system data to determine when capacity should be excluded from the calculations.

ESPFR_{final} for Other Generating Units/Generating Facilities

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

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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.

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

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If ~~the~~ generating unit/generating facility is operating within 2% of its (~~HSL~~ MW_{GCS} – PA Capacity capacity and additional capacity not expected to provide PFR) or within 5 MW (whichever is greater), or a BESS is operating within 2% or 3 MW of its MW_{GCS} less capacity not expected to provide PFR 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.

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

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

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MW_{pre-perturbation}

$$\geq \min([MW_{GCS} - PA \text{ Capacity} - \text{capacity not expected to provide PFR}] \times .98), ([MW_{GCS} - PA \text{ Capacity} - \text{capacity not expected to provide PFR}] - Y \text{ MW})]$$

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

For frequency deviations above 60 Hz (HzPost-perturbation > 60, if:

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

$MW_{pre-perturbation}$

$$\leq \max[(LSL + ([MW_{GCS} - PA Capacity - \text{capacity not expected to provide PFR}] \times 0.02)), (LSL + Y MW)]$$

then ~~Primary Frequency Response~~PFR is not evaluated for this FME_Y, where Y 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 (~~HSL~~ MW_{GCS} less PA ~~Capacity~~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~~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 additional capacity not expected to provide PFR) and greater than 3 MW; and
- c. The Expected Primary Frequency Response_{final} is greater than the generating unit/generating facility's available frequency responsive ~~Capacity~~capacity⁴; and
- d. The generating unit/generating facility's APFR_{adj} response is in the correct direction.

2. When calculation of the P.U.PFR_{Resource} uses the resource's (~~HSL~~ less PA ~~Capacity~~ MW_{GCS} less PA capacity and additional capacity not expected to provide PFR) as the maximum expected output, the calculated P.U.PFR_{Resource} will not be greater than 1.0.

⁴ In this circumstance, when frequency is below 60 Hz, the EPFR_{final} is set to operating margin based on ~~HSL~~ 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}.

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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~~initial and ~~Sustained Primary Frequency Response~~sustained PFR measures.

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**Attachment A to
Primary Frequency Response Reference Document**

**Initial Primary Frequency Response Methodology for
BAL-001-TRE-~~23~~**

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BAL-001-TRE-23 — Primary Frequency Response in the ERCOT Region

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

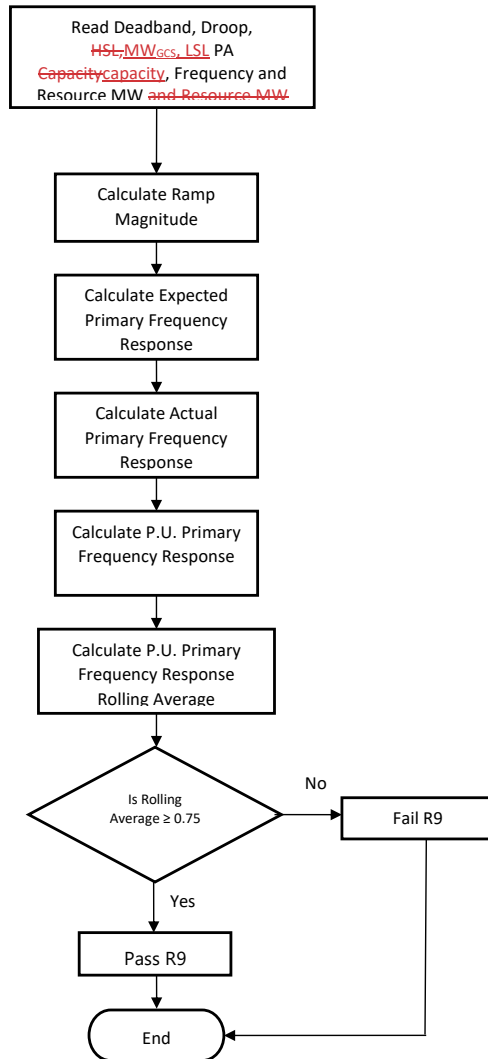
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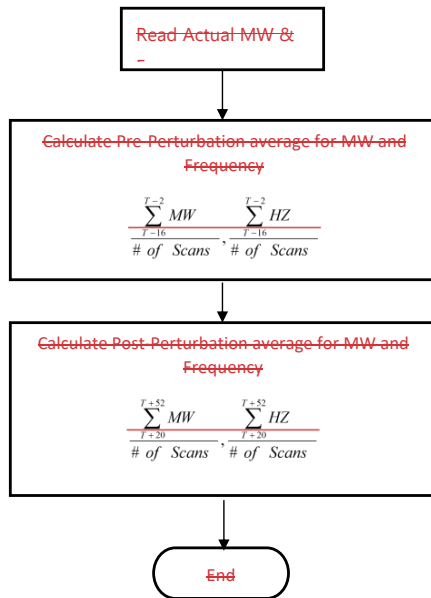
BAL-001-TRE-23 — Primary Frequency Response in the ERCOT Region



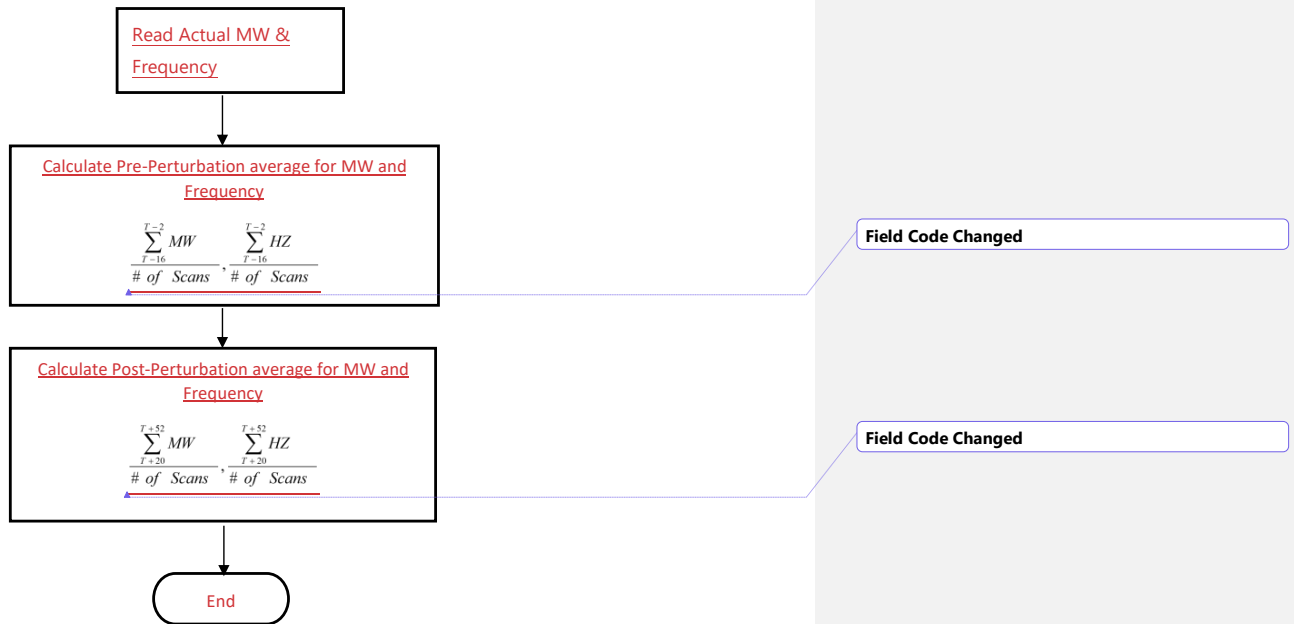
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Pre/Post-Perturbation Average MW and Average Frequency Calculations

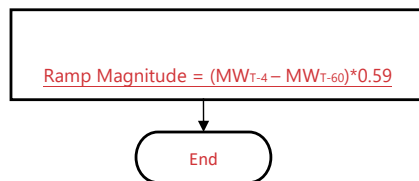
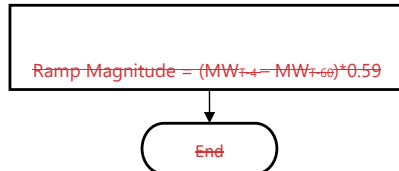
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BAL-001-TRE-23 — Primary Frequency Response in the ERCOT Region



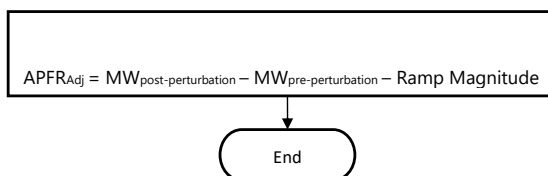
Ramp Magnitude Calculation



(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.

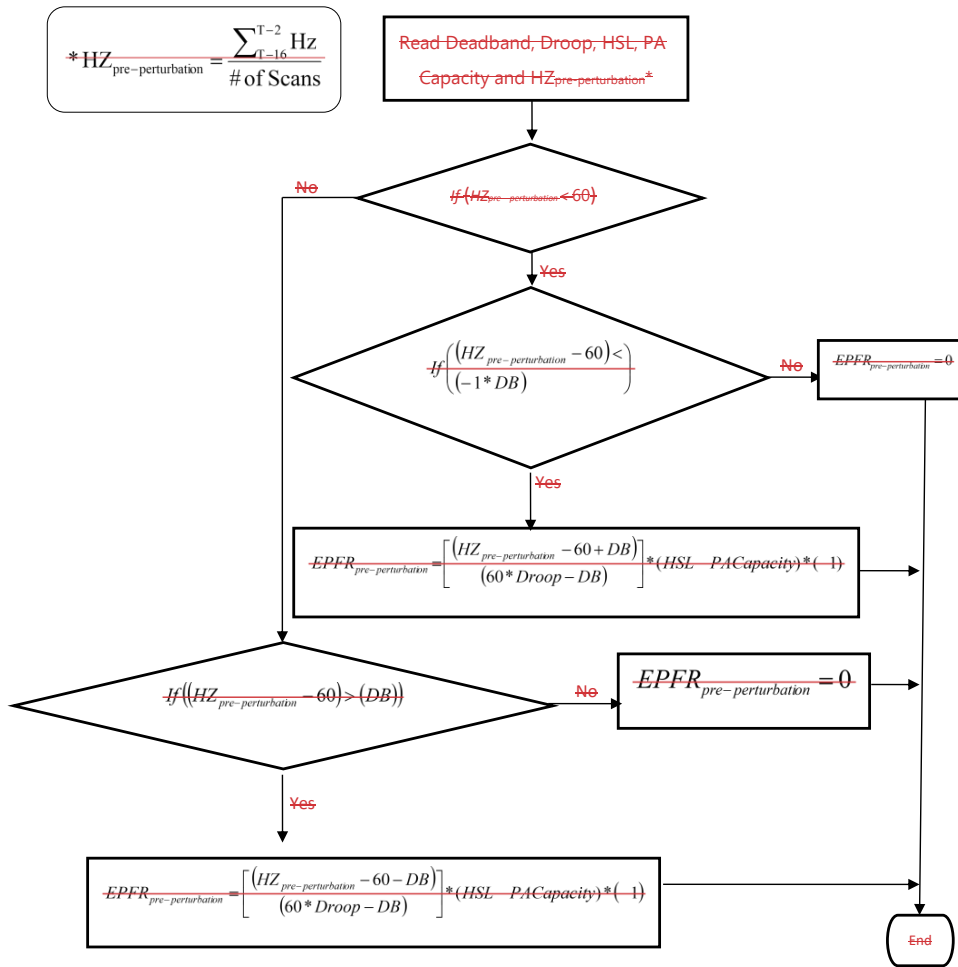
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Actual Primary Frequency Response (APFRA_{Adj})

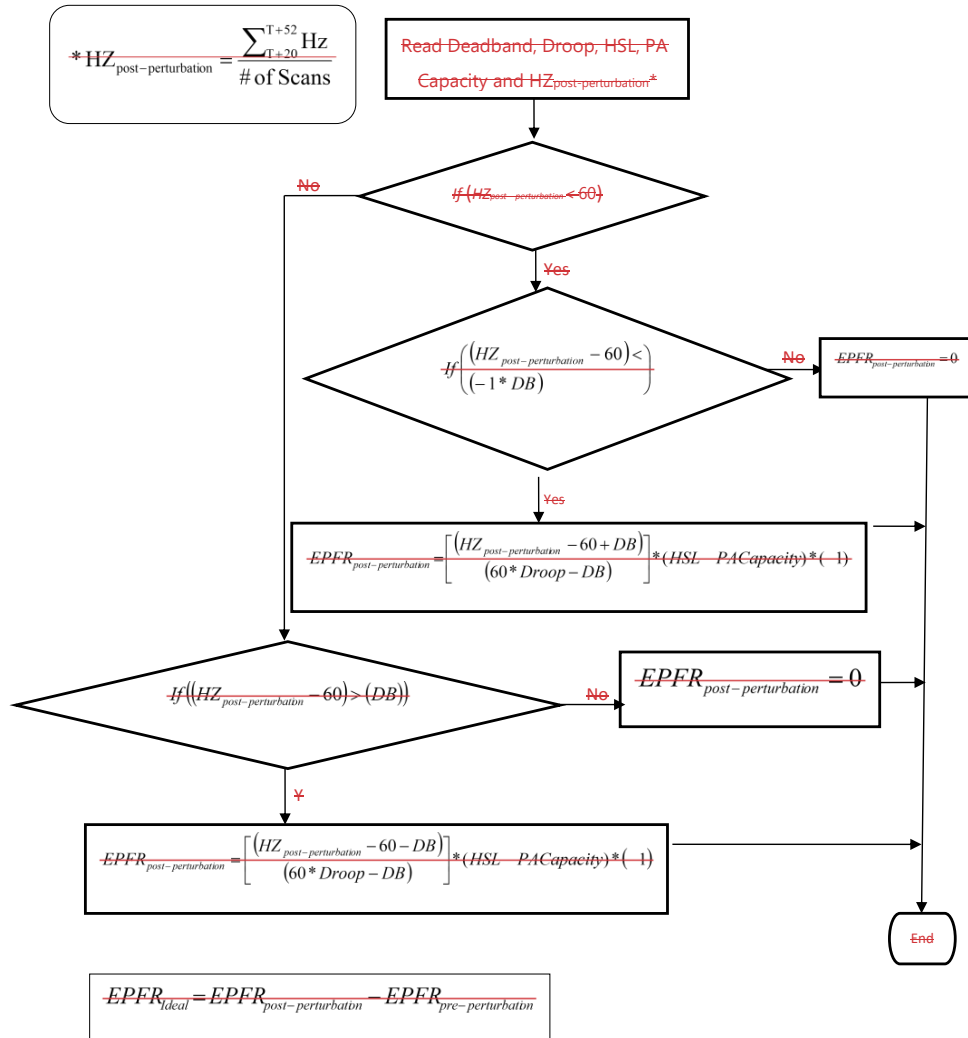


Expected Primary Frequency Response Calculation

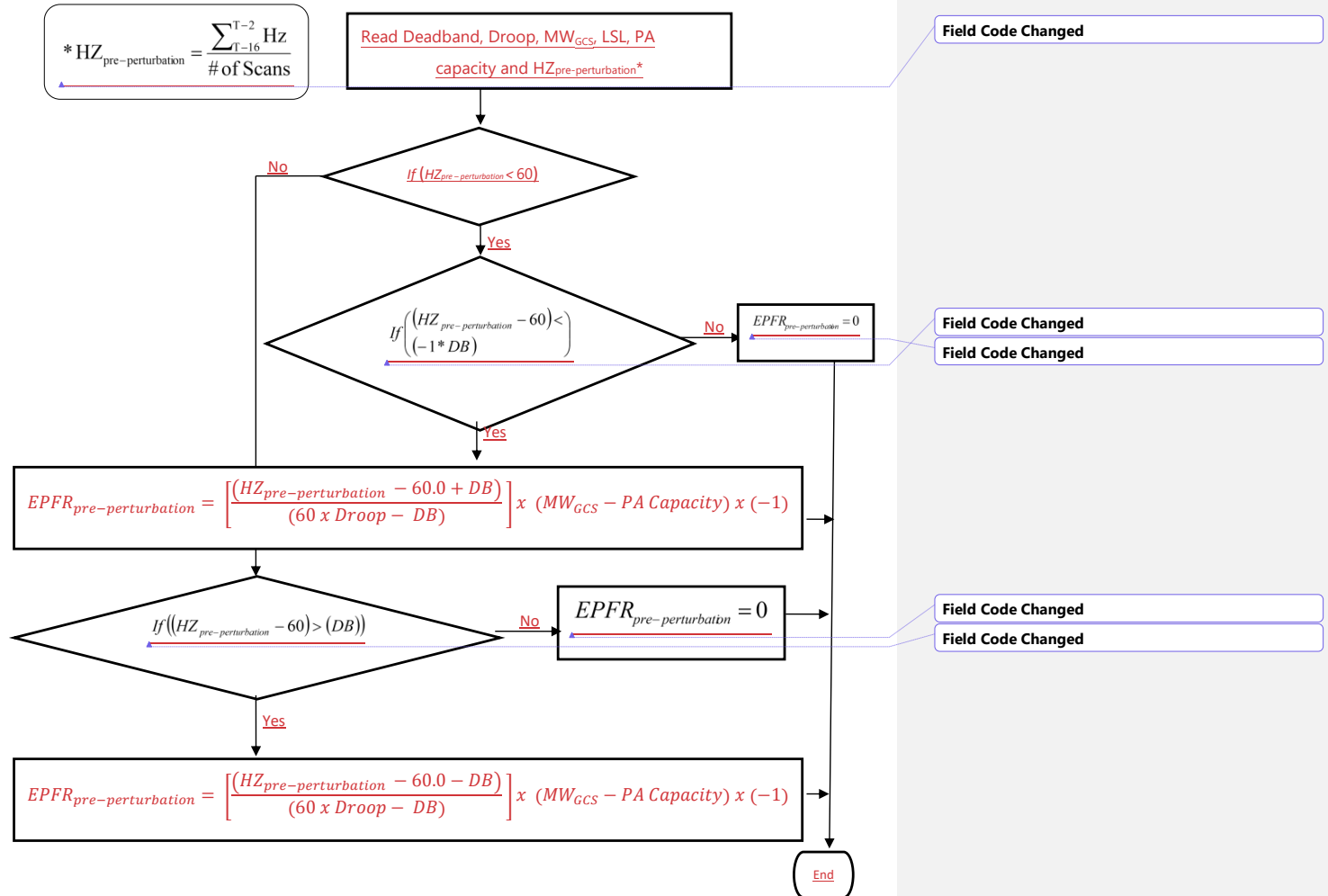
Use the maximum droop and maximum deadband as required by R6. For Combined Cycle Facility evaluation as a single resource (includes MW production of the steam turbine generator), the EPFR will use 5.78% droop in all calculations.



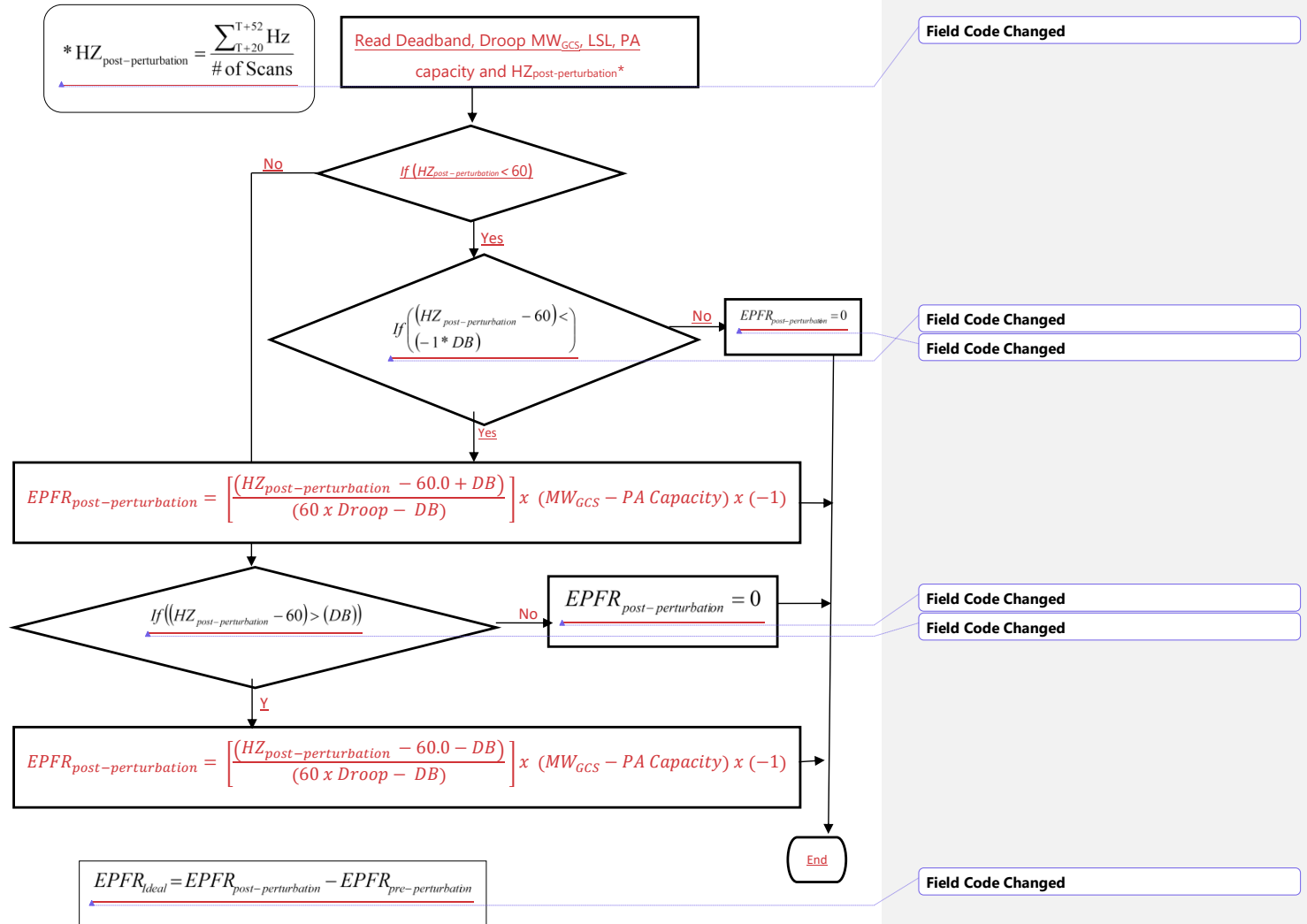
BAL-001-TRE-23 — Primary Frequency Response in the ERCOT Region



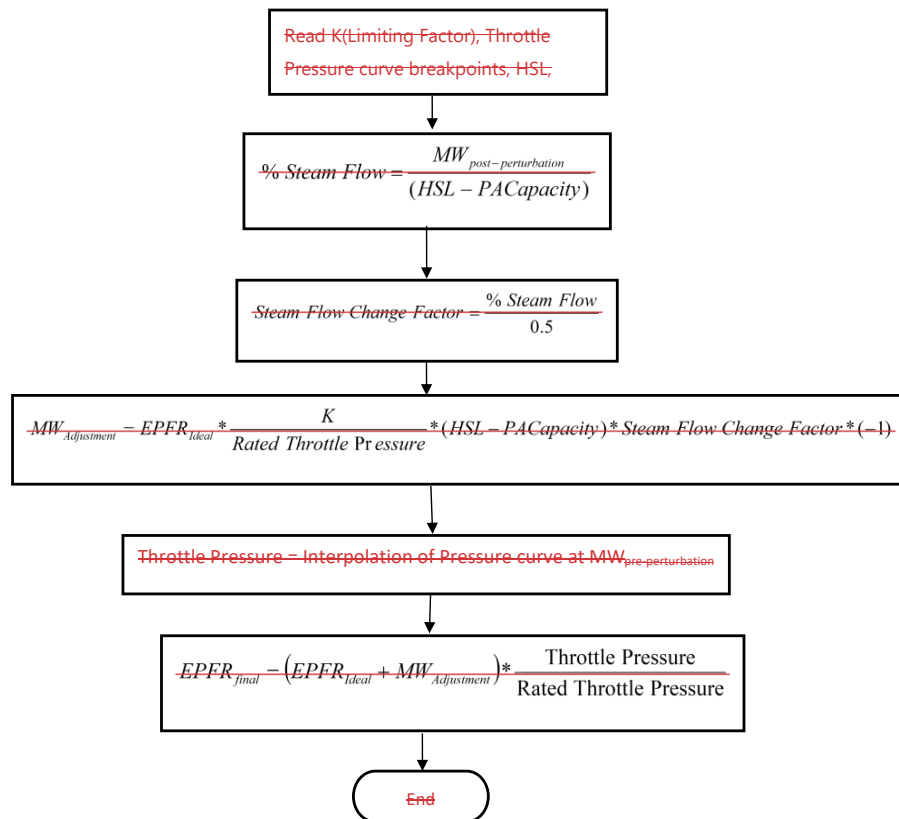
BAL-001-TRE-23 — Primary Frequency Response in the ERCOT Region



BAL-001-TRE-23 — Primary Frequency Response in the ERCOT Region



Adjustment for Steam Turbine

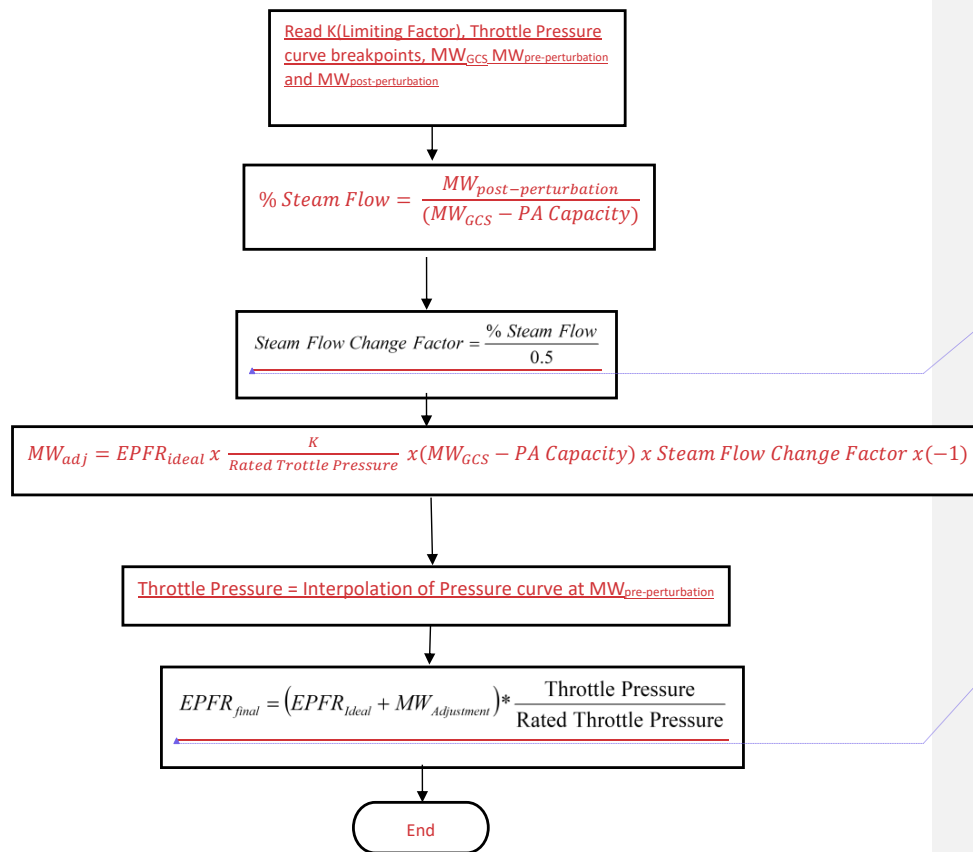


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BAL-001-TRE-23 — Primary Frequency Response in the ERCOT Region

Adjustment for Combustion Turbines and Combined Cycle Facilities



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BAL-001-TRE-23 — Primary Frequency Response in the ERCOT Region

Adjustment for Combustion Turbines and Combined Cycle FacilitiesRead HSL , $PA\ Capacity$, $HZ_{post-perturbation}$ *

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

End

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

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

End

0.00276 is the MW/0.1 Hz change per MW of ~~Capacity~~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.)

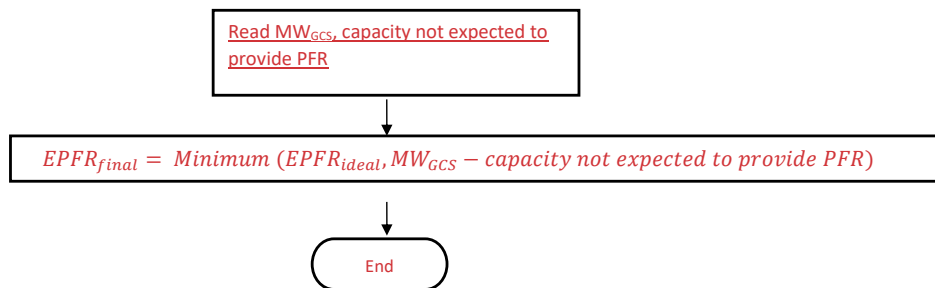
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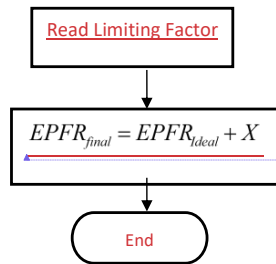
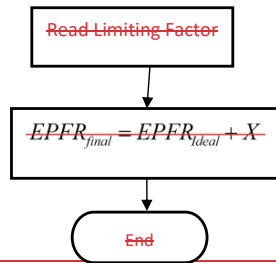
BAL-001-TRE-23 — Primary Frequency Response in the ERCOT Region**Adjustment for BESS with capacity that is not expected to provide PFR**

BESS may, in real time, be required to reserve capacity for providing non-proportional frequency response. When this occurs, the expected MW response from the BESS shall be limited to exclude this capacity. The BA will utilize system data to determine when capacity should be excluded from the calculations.

Adjustment for Other Units

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BAL-001-TRE-23 — Primary Frequency Response in the ERCOT Region



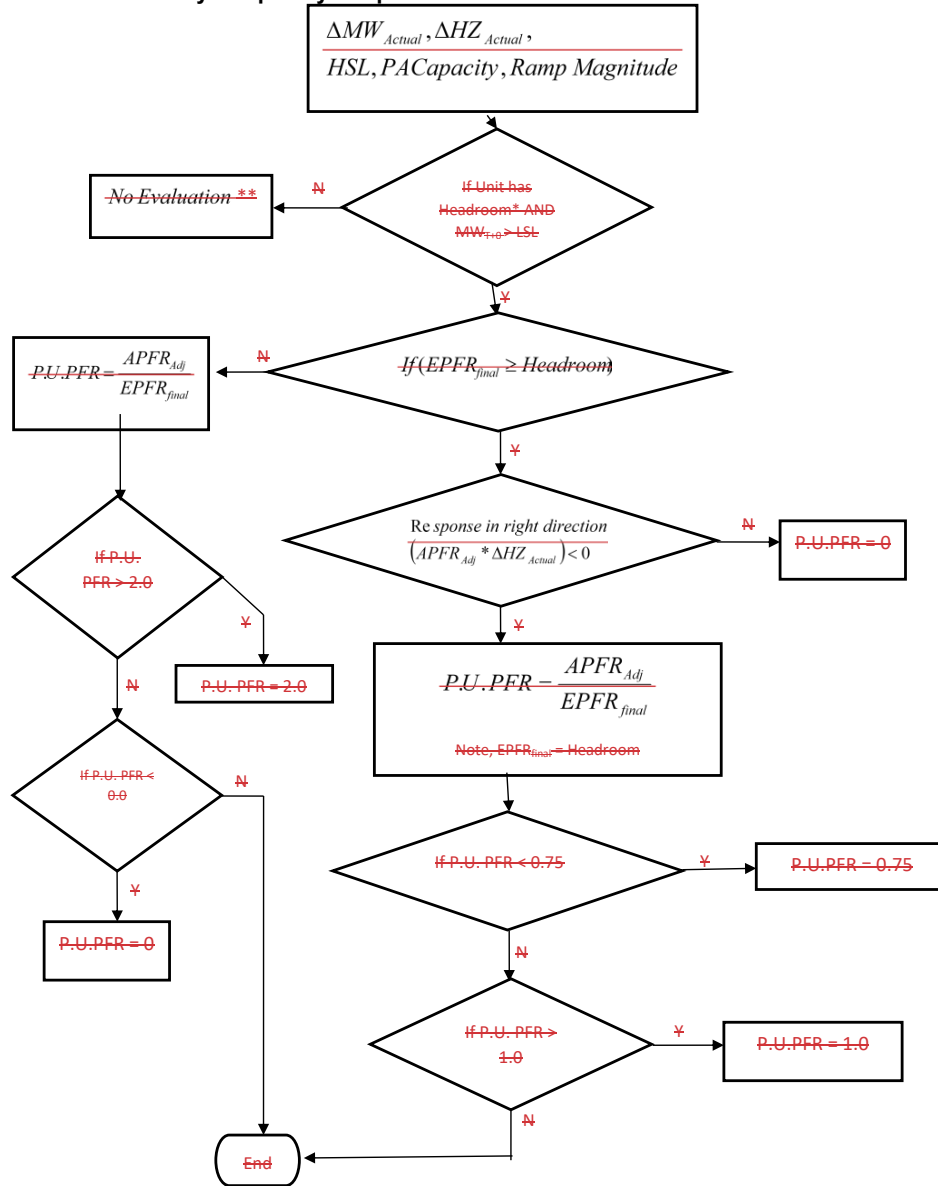
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$$* \text{HZ}_{\text{post-perturbation}} = \frac{\sum_{T+20}^{T+52} \text{HZ}_{\text{Actual}}}{\text{\# of Scans}}$$

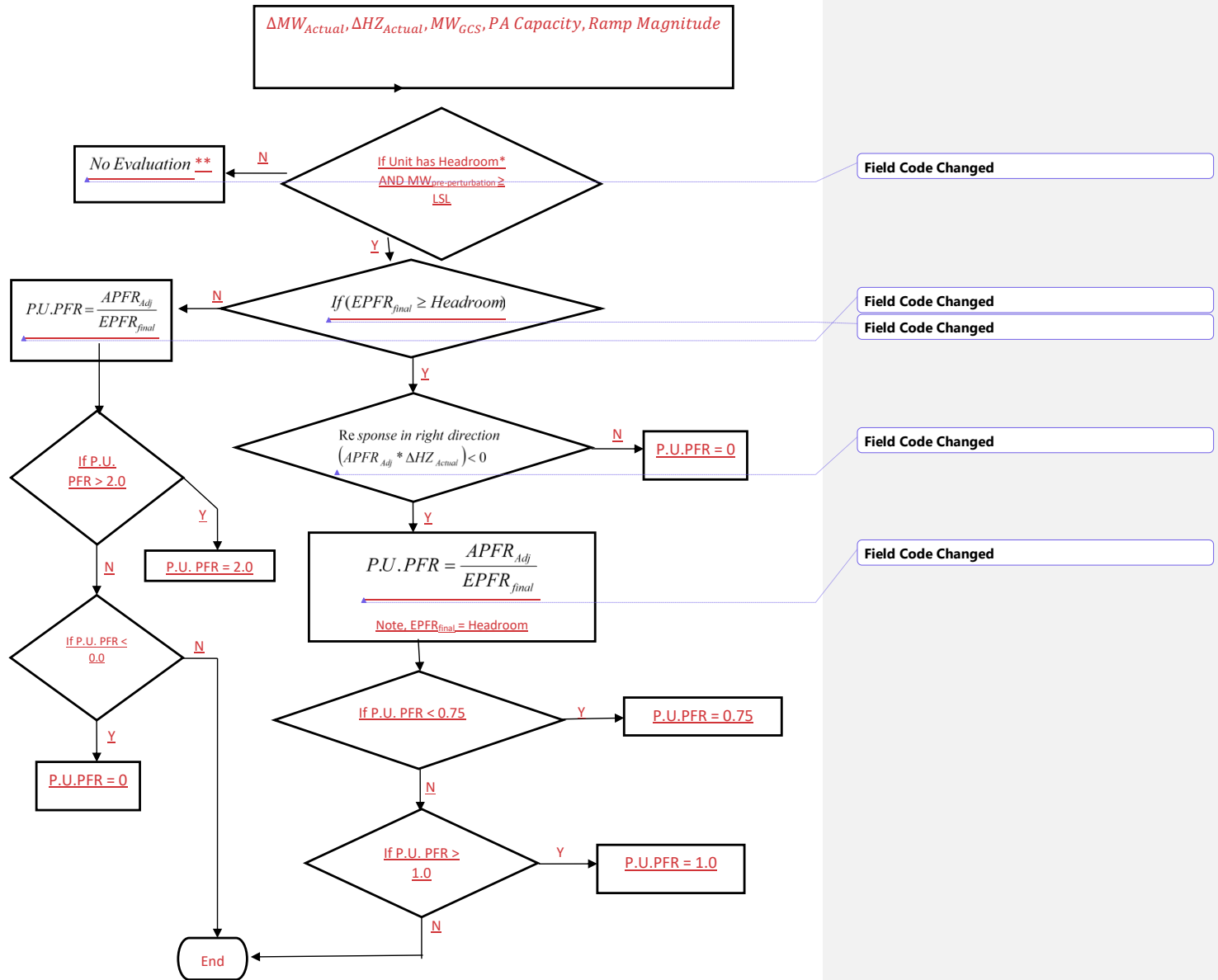
▲ This adjustment Factor X will be developed to properly model the delivery of PFR due to known and approved technical limitations of the resource. X may be adjusted by the BA and may be variable across the operating range of a resource.

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P.U. Initial Primary Frequency Response Calculation



BAL-001-TRE-23 — Primary Frequency Response in the ERCOT Region



BAL-001-TRE-23 — Primary Frequency Response in the ERCOT Region

*Check for adequate up headroom, low frequency events. Headroom must be greater than either ~~5MW~~~~XMW~~ or 2% of (~~HSL~~~~MW~~~~GCS~~ less PA ~~Capacity~~~~capacity and additional capacity not expected to provide PFR~~), 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 ~~5MW~~~~XMW~~ or 2% of (~~HSL~~~~MW~~~~GCS~~ less PA ~~Capacity~~~~capacity and additional capacity not expected to provide PFR~~), 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.

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For low frequency events:

$$\text{Headroom} = \text{HSL} - \text{PACapacity} - \text{MW}_{T-2}$$

$$\text{Headroom} = \text{HSL} - \text{PA Capacity} - \text{capacity not expected to respond with PFR} - \text{MW}_{T-2}$$

For high frequency events:

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$$\text{Headroom} = \text{MW}_{T-2} - \text{LSL}$$

$$\text{Headroom} = \text{MW}_{T-2} - \text{LSL}$$

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**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.

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Public

BAL-001-TRE-23 — Primary Frequency Response in the ERCOT Region

T = Time in Seconds

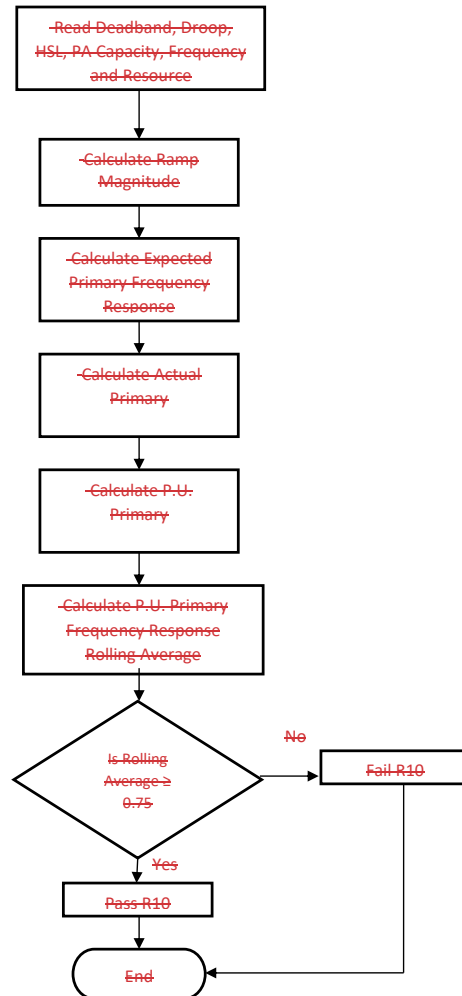
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**Attachment B to
Primary Frequency Response Reference Document**

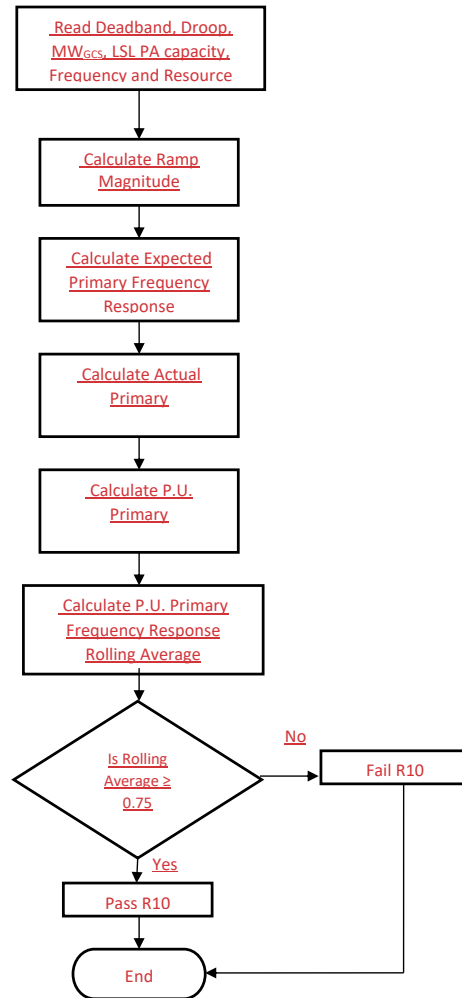
**Sustained Primary Frequency Response Methodology for
BAL-001-TRE-23**

Primary Frequency Response Measurement and Rolling Average Calculation—Sustained Response

BAL-001-TRE-23 — Primary Frequency Response in the ERCOT Region



BAL-001-TRE-23 — Primary Frequency Response in the ERCOT Region



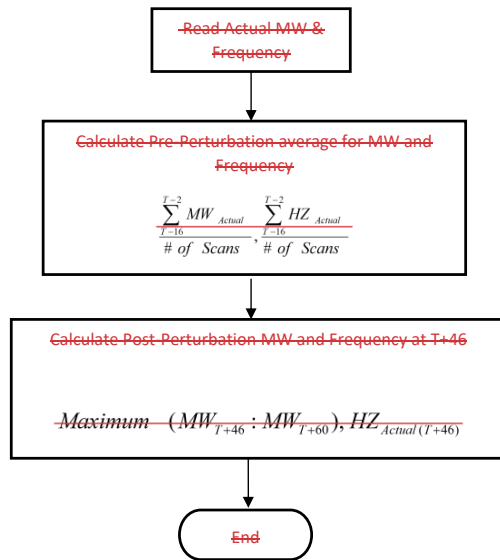
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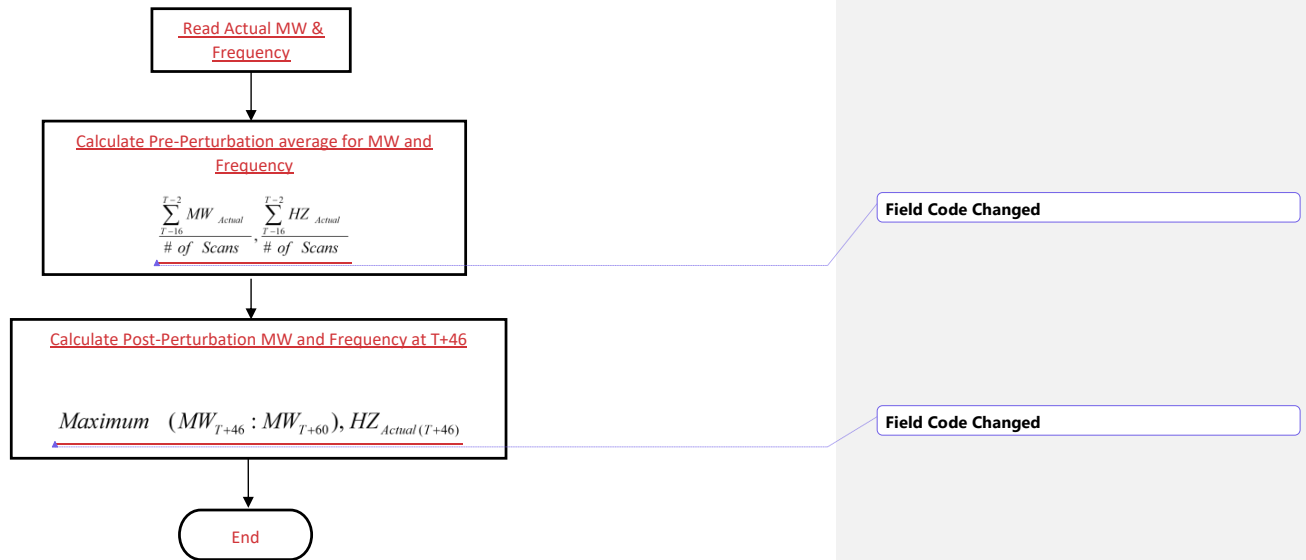
BAL-001-TRE-23 — Primary Frequency Response in the ERCOT Region

Pre/Post-Perturbation Average MW and Average Frequency Calculations

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BAL-001-TRE-23 — Primary Frequency Response in the ERCOT Region



BAL-001-TRE-23 — Primary Frequency Response in the ERCOT Region

BAL-001-TRE-23 — Primary Frequency Response in the ERCOT Region

Ramp Magnitude Calculation - Sustained

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

End

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

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End

(MWT-4 – MWT-60) represents the MW ramp of the generator resource/generator facility for a full minute prior to the event. The factor 0.821 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.

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Actual Sustained Primary Frequency Response (ASPFR_{Adj})

For low frequency events:

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

End

BAL-001-TRE-23 — Primary Frequency Response in the ERCOT Region

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

End

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For high frequency events:

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

End

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

End

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Expected Sustained Primary Frequency Response Calculation

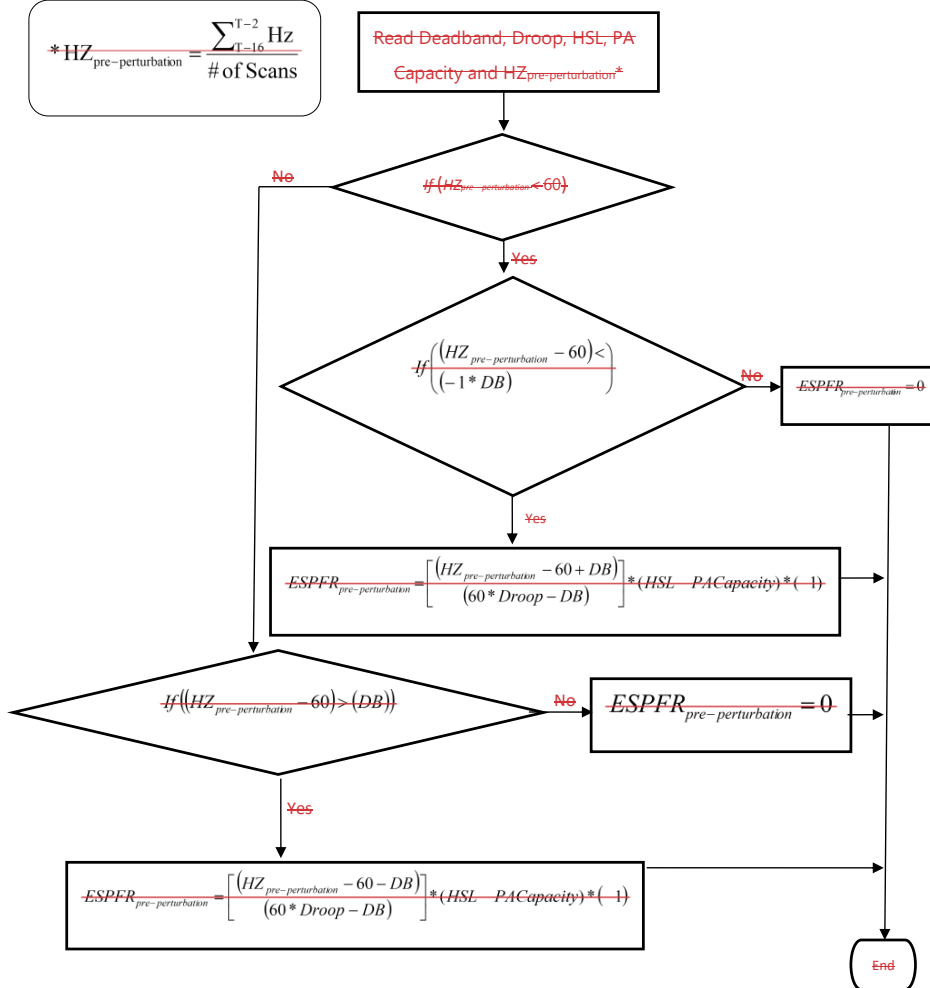
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Use the droop and deadband as required by R6. For Combined Cycle Facility evaluation as a single resource (includes MW production of the steam turbine generator), the EPFR will use

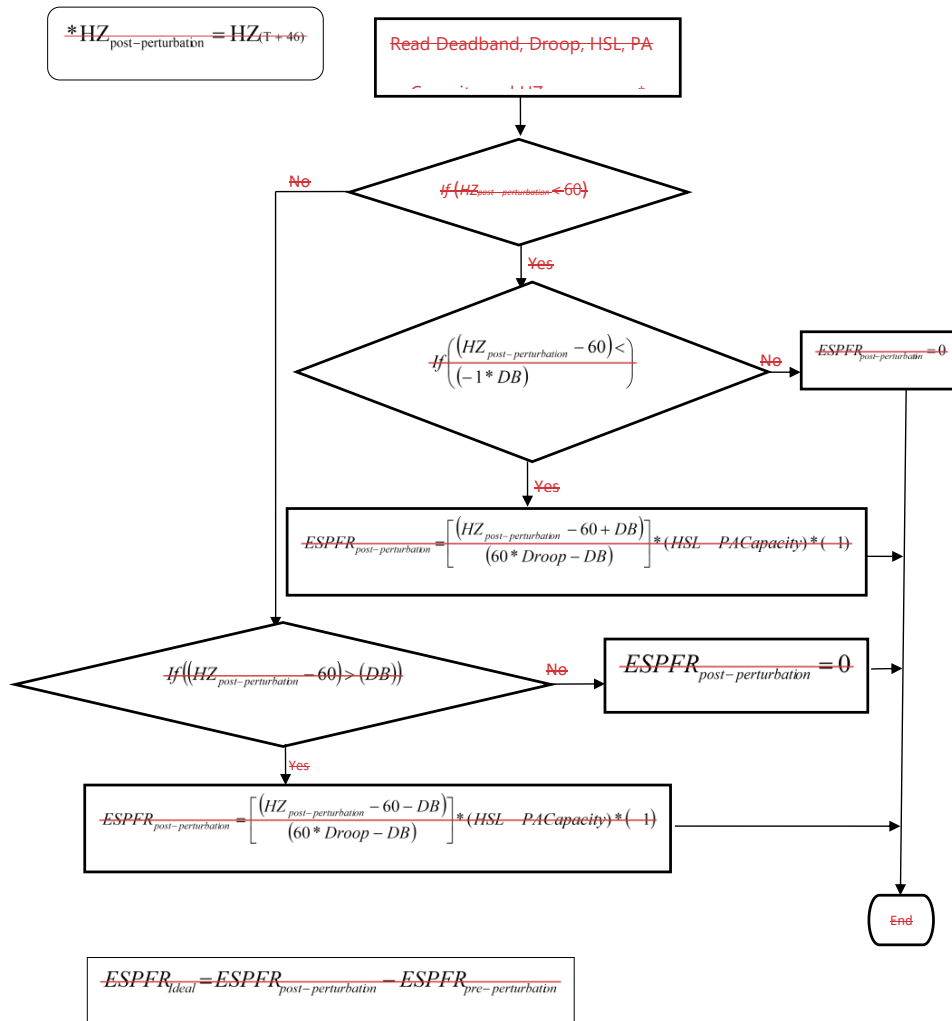
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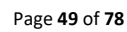
BAL-001-TRE-23 — Primary Frequency Response in the ERCOT Region

5.78% droop in all calculations.

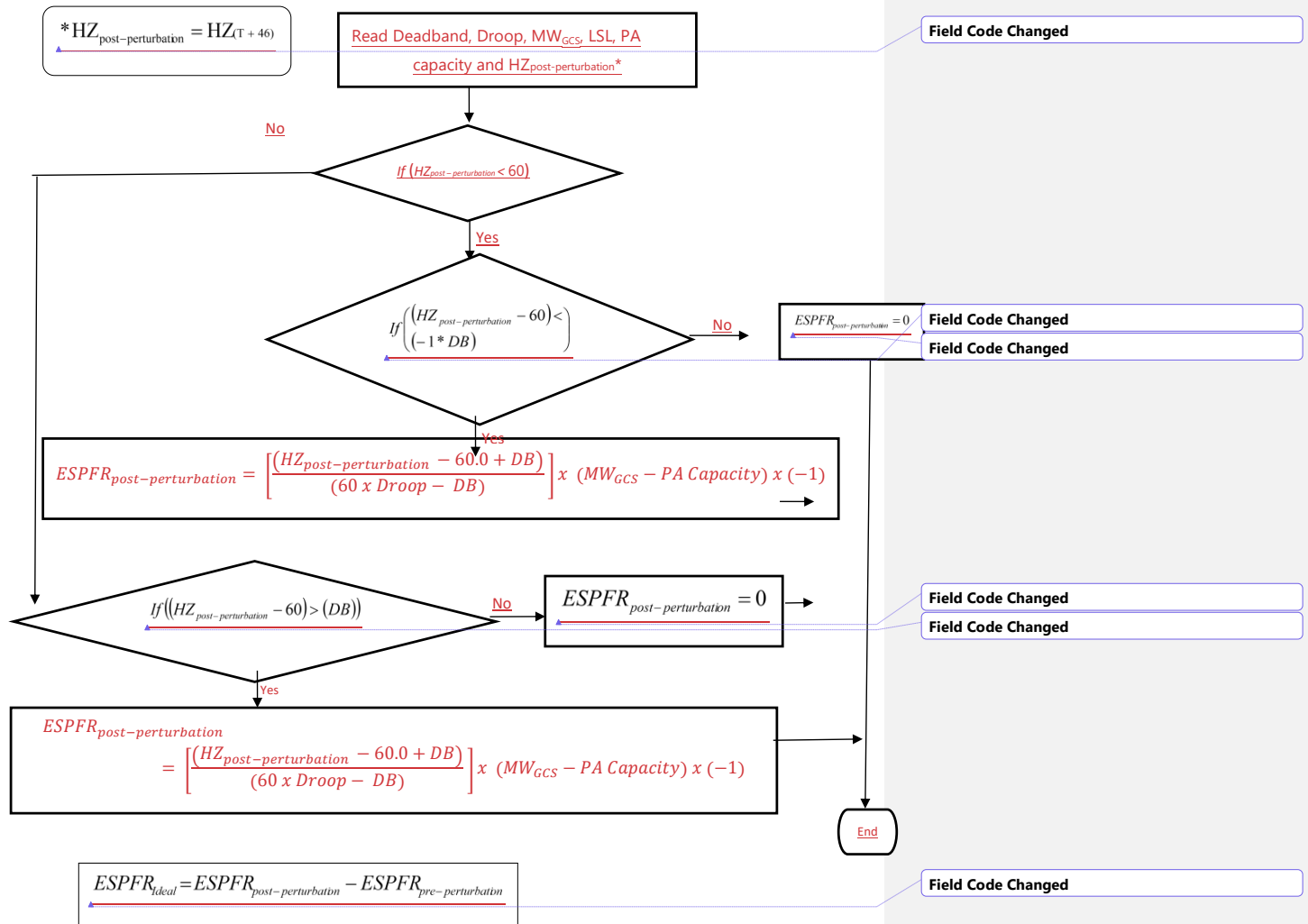


BAL-001-TRE-23 — Primary Frequency Response in the ERCOT Region



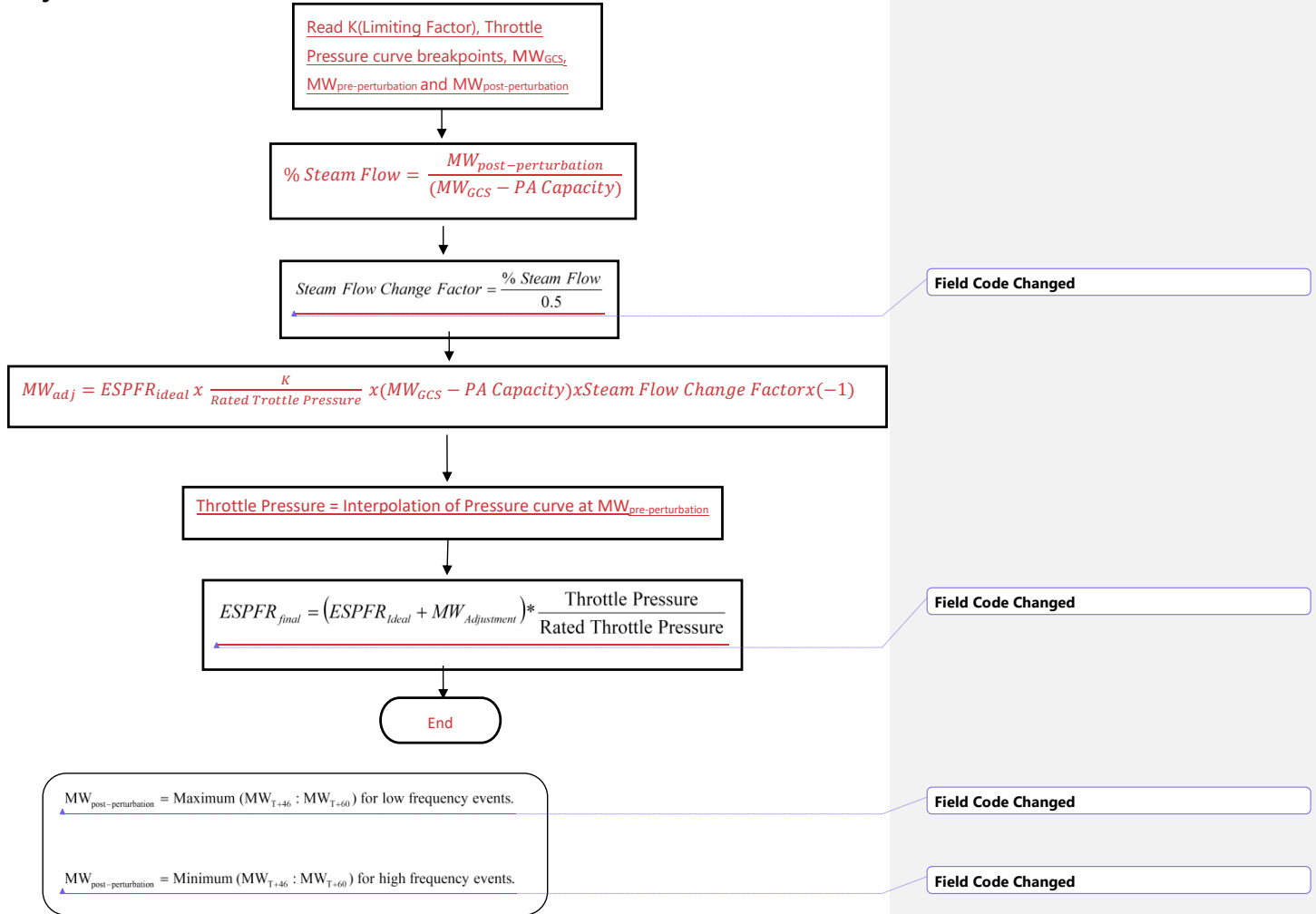


BAL-001-TRE-23 — Primary Frequency Response in the ERCOT Region



BAL-001-TRE-23 — Primary Frequency Response in the ERCOT Region

Adjustment for Steam Turbine



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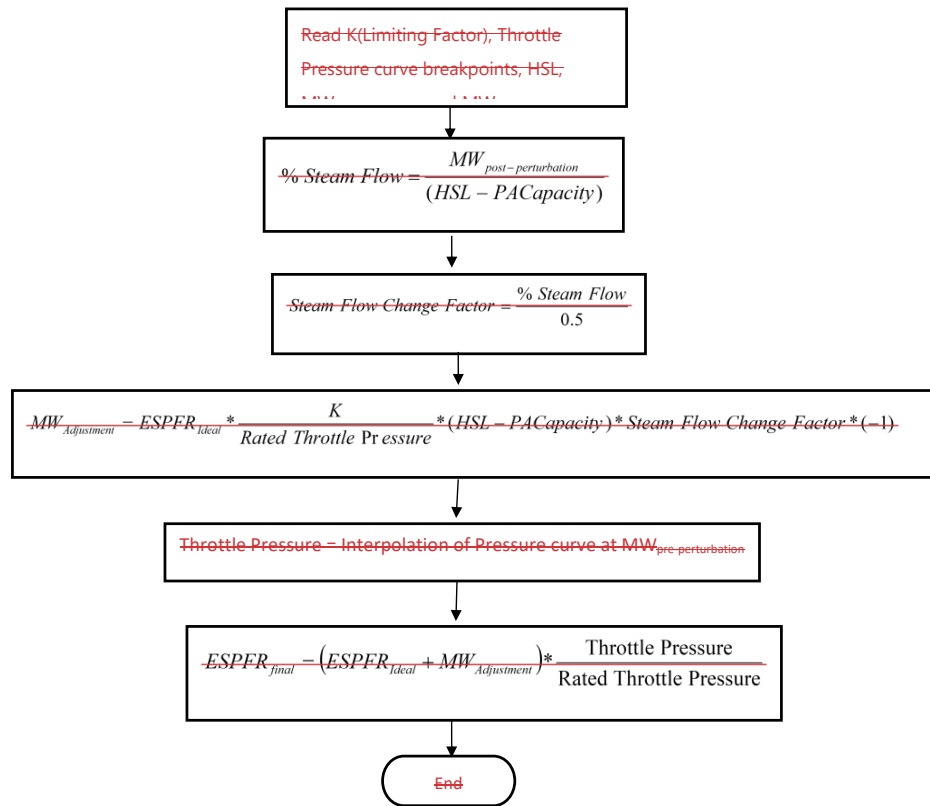
BAL-001-TRE-23 — Primary Frequency Response in the ERCOT Region

Adjustment for Combustion Turbines and Combined Cycle Facilities

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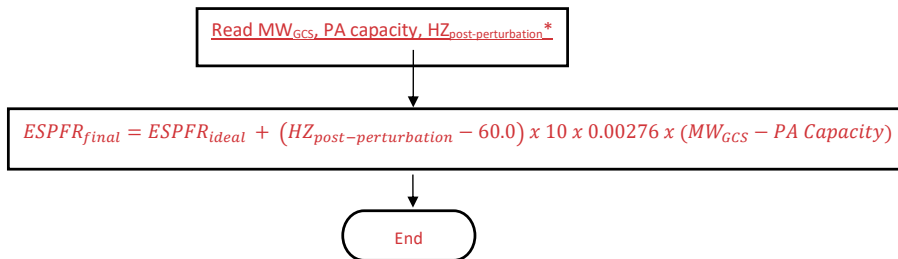
BAL-001-TRE-23 — Primary Frequency Response in the ERCOT Region



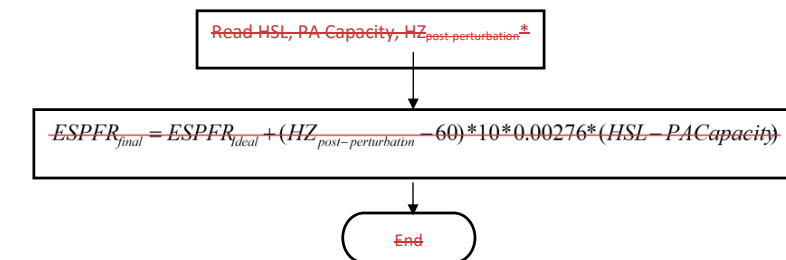
$MW_{\text{post-perturbation}} = \text{Maximum}(MW_{T+46} : MW_{T+60})$ for low-frequency events.

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

BAL-001-TRE-23 — Primary Frequency Response in the ERCOT Region



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 BESS with capacity that is not expected to provide PFR

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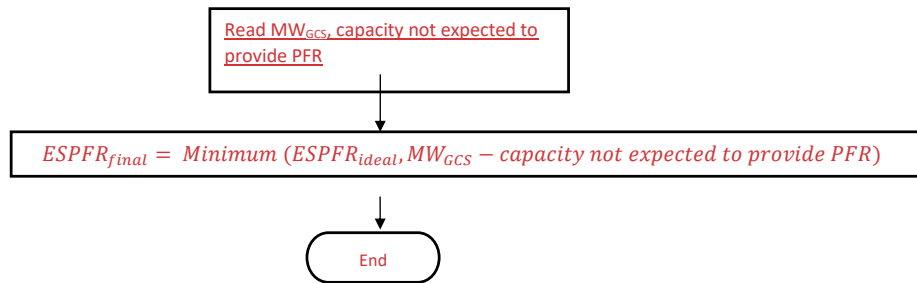
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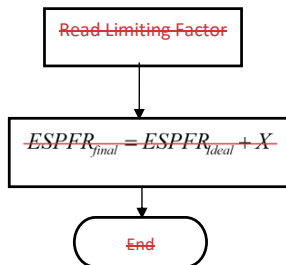
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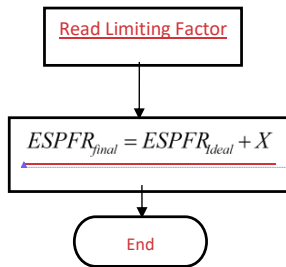
BAL-001-TRE-23 — Primary Frequency Response in the ERCOT Region

BESS may, in real time, be required to reserve capacity for providing non-proportional frequency response. When this occurs, the expected MW response from the BESS shall be limited to exclude this capacity. The BA will utilize system data to determine when capacity should be excluded from the calculations.

Adjustment for Other Units

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BAL-001-TRE-23 — Primary Frequency Response in the ERCOT Region

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

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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.

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BAL-001-TRE-23 — Primary Frequency Response in the ERCOT Region

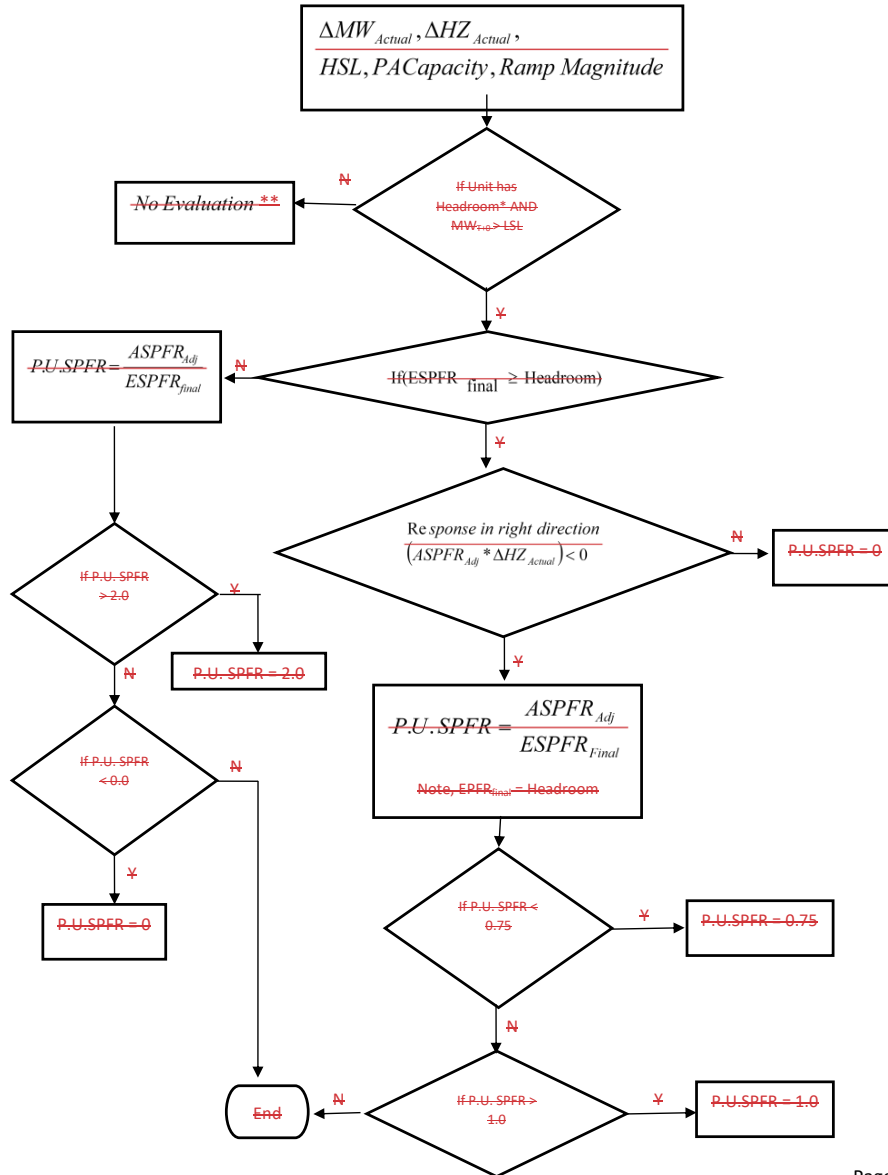
P.U. Sustained Primary Frequency Response Calculation

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

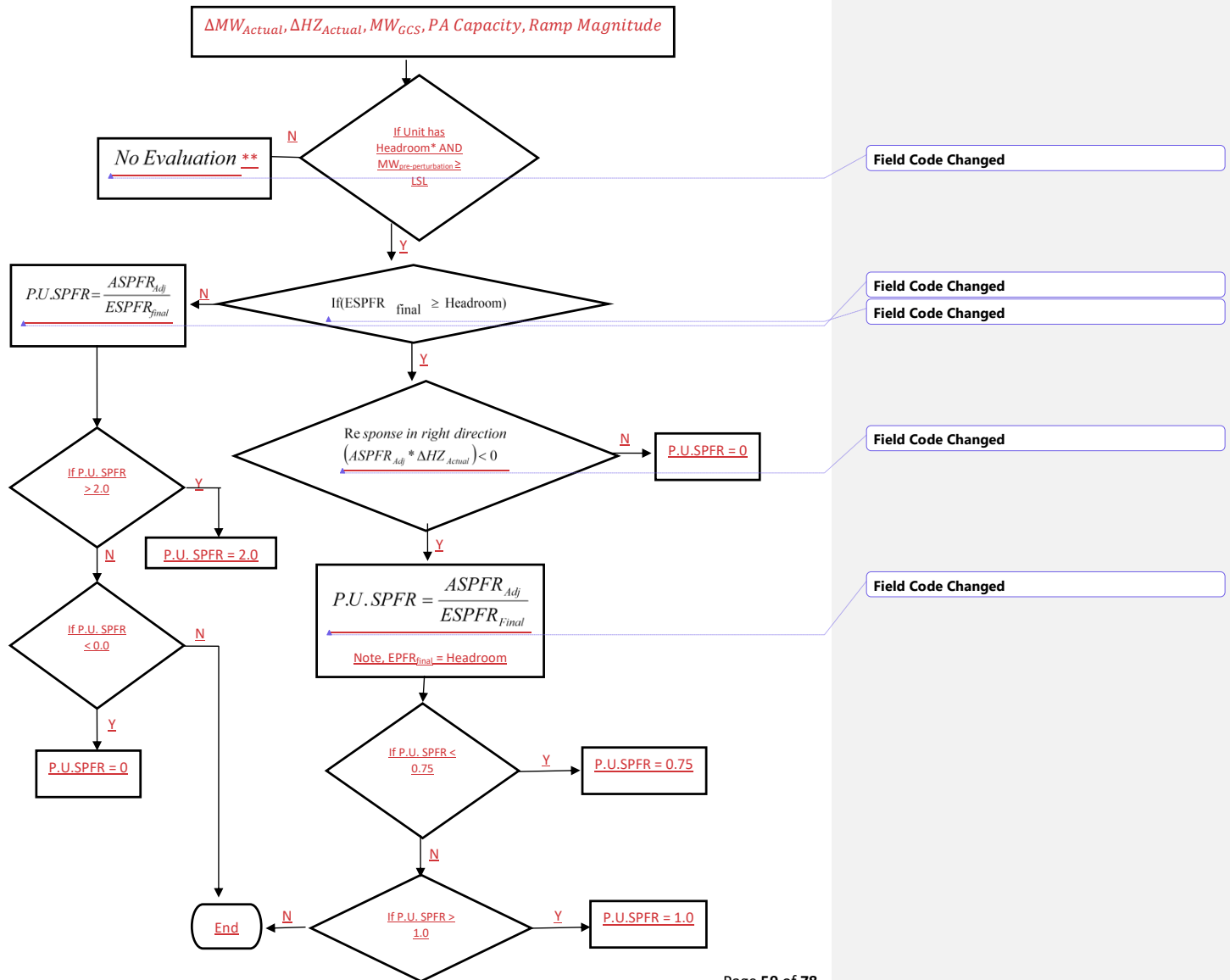
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BAL-001-TRE-23 — Primary Frequency Response in the ERCOT Region



BAL-001-TRE-23 — Primary Frequency Response in the ERCOT Region



BAL-001-TRE-23 — Primary Frequency Response in the ERCOT Region

*Check for adequate up headroom, low frequency events. Headroom must be greater than either ~~5MW~~ X or 2% of (~~HSL~~ MW_{GCS} less PA Capacity), ~~capacity and additional capacity not expected to provide PFR~~, 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 ~~5MW~~ X or 2% of (~~HSL~~ MW_{GCS} less PA Capacity), ~~capacity and additional capacity not expected to provide PFR~~, 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.~~

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For low frequency events:

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

$$\text{Headroom} = HSL - PA\text{ Capacity} - \text{capacity not expected to respond with PFR} - MW_{T-2}$$

For high frequency events:

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

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

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**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.

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T = Time in Seconds

BAL-001-TRE-23 — Primary Frequency Response in the ERCOT Region

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 Capacitycapacity. - 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

BAL-001-TRE-23 — Primary Frequency Response in the ERCOT Region

			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
<u>3.0</u>	<u>TBD</u>		<u>Attachment 1 was updated to align the MW_{GCS} definition and provide calculations for BESS. There is an additional calculation to provide a breakout for expected primary frequency response calculation for BESS and to account for any capacity that is not expected to provide PFR. Several sections were updated to align and</u>

BAL-001-TRE-23 — Primary Frequency Response in the ERCOT Region

			<u>account for capacity not expected to provide PFR for BESS as well. The flowcharts in Attachments A and B to the reference document were also updated to account for BESS expected primary frequency response calculations.</u>
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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-3.
 - Generating units/generating facilities while operating in synchronous condenser mode are exempt from Standard BAL-001-TRE-3.
 - 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.



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-~~23~~.
 - Generating units/generating facilities while operating in synchronous condenser mode are exempt from Standard BAL-001-TRE-~~23~~.
 - 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.



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 “measureable” to measurable”	Corrected a typo.
A 6 Background	Added a description of resource to the end of the description. Included the various types that were previously in Requirement Part 6.2. Added Battery Energy Storage System (BESS) to the list of examples.	This revision fulfills one of the objectives of the SAR.
M1	Added “that”	Corrected a typo.
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.
R2.3	Changed (8) eight to eight (8).	This is consistent with Requirement R4.
M3	Removed the “per” that should not have been there.	Corrected a typo
Requirement R4	Changed “occurs” to “occur”	Corrected a grammatical error.
Requirement R6	Revised the parent Requirement R6	Clarifies the language.
Requirement Part 6.1	Added “Generating units/generating facilities that are not qualified to provide Operating Reserves and have obtained prior written approval” to Table 6.1.	This revision fulfills one of the objectives of the SAR.
Requirement Part 6.1	Corrected capitalization of Generating unit/generating facility	Clarifies the language.
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.



BAL-001-TRE-3 Section	Description	Rationale
Requirement Part 6.2	Revised the table to only include Combustion Turbine (Combined Cycle) and All other generating units/generating facilities. The other Generator types were moved to Section A Background.	Clarifies the language.
Table 6.2 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. Moved this note from an asterisk to the body of Requirement R6.	This revision makes the language consistent.
Requirement Part 6,.3	Added Primary Frequency Response Reference Document to Attachment 1.	This aligns with footnote 1.
M6	Added "Written approval from the Balancing Authority to widen generating units'/generating facilities' deadband settings to +/- 0.036 Hz.	This clarifies how Requirement R6 can be measured.
Requirement R9	Added Primary Frequency Response Reference Document to Attachment 1.	This aligns with footnote 1.
Requirement R10	Added Primary Frequency Response Reference Document to Attachment 1.	This aligns with footnote 1.
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.
Section C 1.3	Abbreviated CEA	This is consistent with the change made in Section C 1.1.
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.



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	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.
	Added the same description of resource and list of examples from Section A Background.	This replaces the previous description of resource and is consistent with the language in the standard.
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	Added the revised description of the terms resource and generating unit/generating facility to be consistent with Section A 6 Background.	This revision fulfills one of the objectives of the SAR.
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	Corrected the language for Requirement R9.	This change is to be consistent with the Regional Standard language.
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 Adjusted 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.



Expected Primary Frequency Response (EPFR) - Pre-perturbation Average Hz	Removed capitalization of combined cycle.	This is not a NERC Glossary term.
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.
EPFR _{final} for BESS with capacity that is not expected to provide PFR	Added this new section to account for BESS.	This intended to be used for energy storage resources with Fast Frequency Response (FFR) capacity without having to define FFR capacity.



III. Sustained Primary Frequency Response Calculations	Corrected the language for Requirement R10 and Part 10.3.	To be consistent with the Regional Standard.
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.
Sustained Primary Frequency Response Performance Calculation Methodology	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.
Sustained Primary Frequency Response Calculation	Corrected the equation to reflect P.U.SPFR	Corrected a typo.
Sustained Primary Frequency Response Calculation	Changed Primary Frequency Response to the acronym (PFR).	The acronym is described previously.
Sustained Primary Frequency Response Calculation	Changed Frequency Measurable Event to acronym (FME).	The acronym is described previously.
Actual Sustained Primary Frequency Response, Adjusted	Changed Primary Frequency Response to the acronym (PFR).	The acronym is described previously.
Expected Sustained Primary Frequency Response (<i>ESPFR</i>) Calculations	Changed Expected Sustained to lower case (expected sustained)	This term is not defined in the NERC Glossary.



Expected Sustained Primary Frequency Response (<i>ESPFR</i>) Calculations	Changed Primary Frequency Response to the acronym (PFR).	The acronym is described in the Introduction paragraph.
Expected Sustained Primary Frequency Response (<i>ESPFR</i>) Calculations	Changed High Sustainable Limit to the acronym (HSL)	The acronym is described in the Introduction paragraph.
Expected Sustained Primary Frequency Response (<i>ESPFR</i>) Calculations	Changed Low Sustainable Limit (LSL) to the acronym.	The acronym is described in the Introduction paragraph.
Expected Sustained Primary Frequency Response (<i>ESPFR</i>) 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	Updated the $ESPRF_{ideal}$ equation to remove the vertical bar.	Corrected a typo.



Establishing the Ideal Expected Primary Frequency Response	Revised the equation to replace HSL with MW_{GCS} .	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	Removed capitalization from combined cycle.	This term is not defined in the NERC Glossary.
Establishing the Ideal Expected Primary Frequency Response	Removed capitalization from power augmentation capacity.	This term is not defined in the NERC Glossary.
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.
ESPFR _{final} for Steam Turbine	Changed steam flow change factor to lowercase.	This term is not defined in the NERC Glossary.
EPFR _{final} for BESS with capacity that is not expected to provide PFR	Added this new section to account for BESS.	Added this new section to account for BESS.
IV. Limits on Calculation of Primary Frequency Response Performance (Initial and Sustained):	Changed HSL to MW_{GCS} and added “capacity and additional capacity not expected to provide PFR. Added “or a BESS is operating within 2% or 3MW of its MW_{GCS}	Revised the equations 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):	Added the language “and additional capacity not expected to provide PFR” and “less capacity not expected to provide PFR”	This aligns the calculations to ensure that FFR capacity is excluded when identifying conditions where there is limited capacity available to provide PFR.



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 Y 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 “for generating units/generating facilities or 3 MW for BESS”	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 additional capacity not expected to provide PFR) 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:	To #2 – Added “ MW_{GCS} less PA capacity and additional capacity not expected to provide PFR”	This aligns the calculations to ensure that FFR capacity is excluded when identifying conditions where there is limited capacity available to provide PFR.



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.
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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.
- Added the flowchart for Adjustment for BESS with capacity that is not expected to provide PFR.
- Updated the verbiage under P.U. Initial Primary Frequency Response Calculation to include additional capacity that is not expected to provide PFR.
- Updated the formula for low frequency events.
- Added Adjustment for BESS with capacity that is not expected to provide PFR,

Attachment B

- Made conforming changes to align with Attachment 1
- Removed capitalization from “capacity” as it is not defined in the NERC Glossary.
- Added the flowchart for Adjustment for BESS with capacity that is not expected to provide PFR.



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.

<u>Milestone</u>	<u>Anticipated Date</u>	<u>Location</u>	<u>Comments</u>
Standard Drafting Team Kick-off Meeting The SDT shall elect the permanent chair and vice chair.	12/19/2024	Webinar	
RSM and SDT develop a work plan.	1/21/2025	Webinar	
SDT has first working meeting SDT drafts the work product	2/7/2025	Webinar	
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	Webinar /Possible Hybrid Meeting	
MRC approves the work product to be posted for a public comment and ballot period.	9/17/2025	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".	12/3/2025 12/12/2025 12/16/2025	Webinar	



SDT Meeting to finalize revisions to proposed Regional Standard BAL-001-TRE-3	3/10/2026	Webinar	
Quality Review	March 16 – April 3, 2026	Via Email, Texas RE's External Sharing Site	
MRC approves the work product to be posted for an additional public comment and ballot period.	May 13, 2026	Hybrid MRC Meeting at Texas RE	
Additional Ballot and Comment Period - The RSM shall post the work product for a 45-day public comment period with the ballot period occurring in the last 15 days.	May 14 - June 29, 2026	Via Email/Posted on Website	
The RSM shall send a notice for registered entities to join the Registered Ballot Pool (RBP).	May 14, 2025	Via Email	
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". • Approve the work product for final ballot	July 20, 2206	Webinar	
When the ballot passes in accordance with section 4.12 and 4.13, the RSM shall conduct a final ballot.	July 20 – August 4, 2026	Via Email/Posted on Website	
Once the final ballot final ballot, the MRC shall approve the final Work Product to be provided to the Texas RE Board for action.	September 16, 2026	Virtual MRC and Board Meeting	
The Work Product shall be posted at least seven days prior to action by the Texas RE Board.	September 9, 2026	N/A	
If deemed appropriate, the Texas RE Board will adopt the work product.	September 16, 2026	Virtual MRC and Board Meeting	
The RSM will submit the work product to NERC.	Subsequent to Texas RE MRC and Board Approval	Via Email	
Once the Work Product is approved by FERC, the RSM shall send	TBD	N/A	



notification of the effective date to Texas RE stakeholders.			
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Regional Standard BAL-001-TRE-3 Additional Ballot Results					
Ballot Period Ended June 29, 2026					
	No. in ballot pool	Affirmative	Negative	Abstain	No Ballot
System Coordination and Planning	1	1	0	0	0
Transmission and Distribution	4	3	0	0	1
Cooperative Utility	1		0	0	1
Municipal Utility	1	1	0	0	
Generation	6	5	0	0	1
Load-serving and Marketing	1		0	0	1
Totals	14	10	0	0	4



Standard Drafting Team's Responses to Comments
Additional Comment Period: May 14 – June 29, 2026
Project SAR-013: Revisions to Regional Standard BAL-001-TRE-2

Question 1	Regional Standard BAL-001-TRE-3: In Section A. 6. Background, the SDT revised the description of the terms “resource” and generating unit/generating facility for clarity. In addition, it moved examples from Requirement R6 to this section. Do you agree with the change?
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Commenter	Answer	Comment	SDT Response
Shane Herrera, ERCOT	Yes		
Marie Potter, Constellation Energy Generation, LLC	Yes	Constellation agrees with defining the term “resource” in the background instead of Requirement 6. Please note ERCOT IBRWG posting from January 17th, 2025, a curtailment to low output including down to 0 MW prevents a generator of certain technology types from being able to respond to a frequency event. Please consider adding an exclusion and expectations, that includes timeline for submitting exclusion paperwork requests, due to operational limitations for the technology types that cannot respond to a frequency event when concurrently being curtailed.	Thank you for your comment. The drafting team has determined that this is out of scope for this project. There are ongoing discussions during ERCOT's Performance Disturbance Compliance Working Group (PDCWG) and Inverter-Based Resource Working Group (IBRWG) on this topic.

Question 2	Regional Standard BAL-001-TRE-3: The SDT made revisions to Requirement R6: it moved the asterisk language to the requirement language, revised the table in Requirement R6.2 since it moved the examples of resources to the background section, and added some information to Measure M6. The SDT had previously revised the language to account for including a provision for a resource that is not qualified to provide operating reserves and accounting for BESS. Do you agree with these changes?
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Commenter	Answer	Comment	SDT Response
Shane Herrera, ERCOT	Yes		
Marie Potter, Constellation Energy Generation, LLC	Yes	There is relief available for wider deadband settings for certain units. An example of where this may be used is when you have a Mechanical Hydraulic Control (MHC) unit that cannot meet the 17 mHz criteria and is not economically justified to upgrading to Electro-Hydraulic Control (EHC) unit.	Thank you for your comment.

Question 3	Attachment 1: Primary Frequency Response Reference Document: The SDT updated the attachment to include language for capacity not expected to provide PFR in order to accurately account for expected frequency response. The SDT also included an equation for $EPFR_{final}$ and $ESPFR_{final}$ for BESS with capacity not expected to provide PFR and associated flowcharts to attachment A and B to the Primary Frequency Response Reference Document. Do you agree with the changes to Attachment 1?		
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Commenter	Answer	Comment	SDT Response
Shane Herrera, ERCOT	Yes		
Marie Potter, Constellation Energy Generation, LLC	Yes		

Question 4	Do you have any additional comments for the standard drafting team?		
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Commenter	Answer	Comment	SDT Response
Shane Herrera, ERCOT	No		



Marie Potter, Constellation Energy Generation, LLC	Yes	Continued conversation and consideration are needed on how to better align the ERCOT protocols with how renewable resources naturally perform. It seems there is an opportunity to add additional market changes to better convey expected WGR PFR and scoring criteria during events surrounding ERCOT curtailment events especially with respect to renewable resources. For example, if a site was curtailed or had the curtailment lifted immediately prior to a frequency event. This creates a scenario in which the wind turbines need to go through a “startup” phase to return to normal operations. The WGR to ERCOT has an LSL of 0 MW and RST of ‘ON’, while the HSL is the forecast. In the event of the curtailment to 0 MW, the WGR must shut down the facility but cannot telemeter shut down as a normal resource would because there would not be an outage ticket, and ERCOT would not have a way to communicate when the curtailment may be lifted. When ERCOT lifts a curtailment and issues a new base point above 0 MW, the WGR will then re-enable the turbines to re-engage and return to normal operations. At that point it would be practical to expect PFR. Potentially there is an opportunity to leverage the “Non-Frequency Response Capability” that combined cycles use for the periods in which the WGR is going through a startup, returning from an ERCOT curtailment. Further collaboration with	Thank you for your comment. The drafting team has determined that this is out of scope for this project. There are ongoing discussions during ERCOT’s Performance Disturbance Compliance Working Group (PDCWG) and Inverter-Based Resource Working Group (IBRWG) on this topic.
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		ERCOT and affected stakeholders would be beneficial. To reiterate, per ERCOT IBRWG posting from January 17th, 2025, a curtailment to low output including down to 0 MW prevents a generator of certain technology types from being able to respond to a frequency event. ERCOT has confirmed that “wind resources cannot respond to frequency requirements while curtailed to zero output”. ERCOT has added the scenario of curtailment as “an additional exclusion to the BAL-001-TRE-2 PFR exclusion process.” With this additional exclusion ERCOT requires formal exclusion paperwork to be submitted for each PFR event within 30 days of the event.	
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Regional Standard BAL-001-TRE-3 Final Ballot Results					
Ballot Period Ended August 4, 2026					
	No. in ballot pool	Affirmative	Negative	Abstain	No Ballot
System Coordination and Planning	1	1	0	0	0
Transmission and Distribution	4	3	0	0	1
Cooperative Utility	1		0	0	1
Municipal Utility	1	1	0	0	
Generation	6	5	0	0	1
Load-serving and Marketing	1		0	0	1
Totals	14	10	0	0	4



NERC Standards Review Forum Update

Texas RE MRC Meeting
September 16, 2026

Thomas Brinckman, Chair - NSRF



AGENDA

NSRF LEADERSHIP UPDATE

NOTABLE STANDARD/PROJECT/FILING CHANGES

KEY NSRF DISCUSSION TOPICS

LOOKING AHEAD



NSRF Leadership Grown to Include GO/GOP Representative

Thomas Brinckman
Chair



TO

TOP

TP

DP

Manivone Vorabouth
Co-Vice Chair



TO

TOP

TP

DP

Jose (Joe) Trevino
Co-Vice Chair



TO

TOP

TP

DP

GO

GOP

AGENDA

NSRF LEADERSHIP UPDATE

NOTABLE STANDARD/PROJECT/FILING CHANGES

KEY NSRF DISCUSSION TOPICS

LOOKING AHEAD



Notable NERC Standard Updates, Project Changes, and Filings

FERC Filings

FERC Letter order approving
EOP-004-5 (RD26-8)

FERC Letter order approving
CIP-015-2 (RD26-6)

NERC Filings

NERC Petition for approval of
CIP-014-4 (RD26-9-000)

Petition for Approval of
PRC-029-2 (RD26-10-000)

NERC Wildfire Report
publication (RD25-9-000)

Major Project Updates

Publication of 2026-02 (Computational
Loads) drafts for public comment/balloting

Project 2025-03 (Order 901 Operational
Studies) passed ballot and will be
considered by NERC Board

Project 2025-04 (Order 901 Planning
Studies) passed ballot and will be
considered by NERC Board

Project 2025-05 (Ride-Through
Revisions) passed ballot & NERC Board;
filed with FERC (PRC-029-2)

*Note, only notable and Texas RE/ERCOT-applicable NERC/FERC filings are listed.

AGENDA

NSRF LEADERSHIP UPDATE

NOTABLE STANDARD/PROJECT/FILING CHANGES

KEY NSRF DISCUSSION TOPICS

LOOKING AHEAD



CLO Registration Criteria Crosswalk

Computational
Load Owner

Computational
Load Operator

Criteria (cumulative)	April NERC Proposal ¹	August Revised NERC Proposal ²	ERCOT (effective) ³
Demand Threshold	≥ 20 MW	≥ 50 MW	≥ 75 MW
Voltage Threshold	≥ 60 kV	≥ 100 kV	None
Facility Type	Computational Large Loads only with at least 1 MW of computational load	Computational Large Loads only; narrative definition ⁴	No distinction made between industrial or computational Large Loads

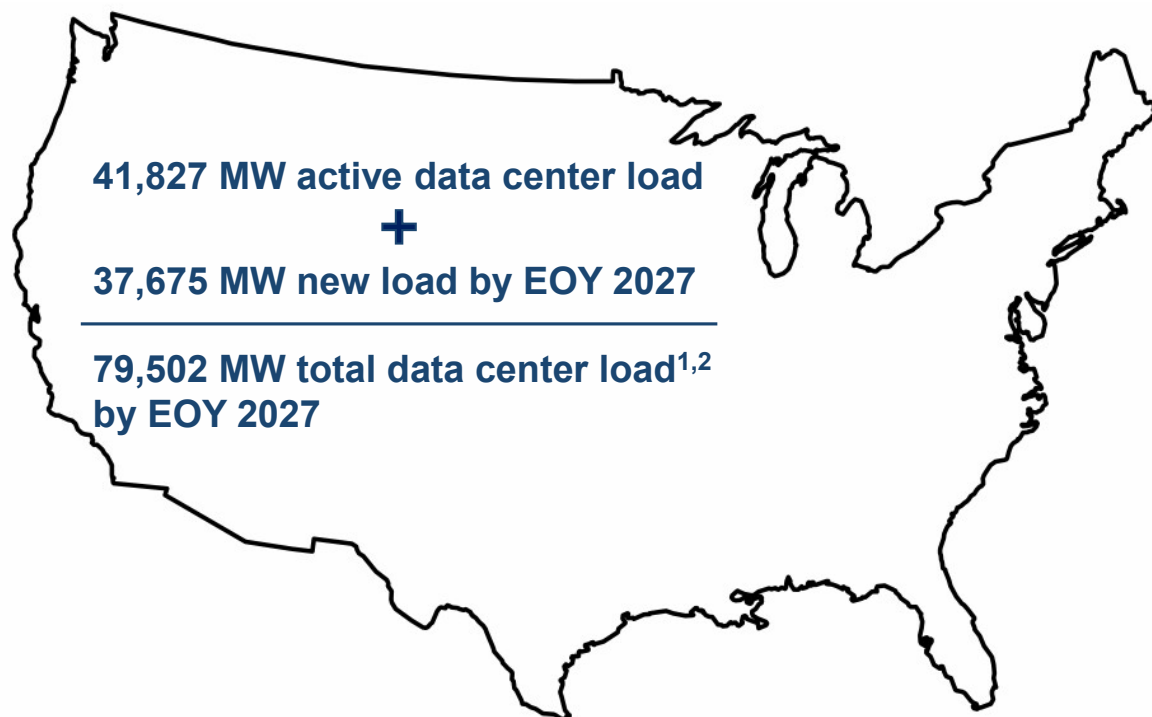
¹Proposed by NERC on April 1, 2026.

²Proposed by NERC on August 19, 2026.

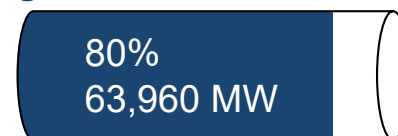
³The 75 MW threshold established in ERCOT through ERCOT Nodal Protocol Revision Request (NPRR) 1234, approved by the Texas Public Utilities Commission (PUC) on May 15, 2025. Additionally, Texas Senate Bill 6 codified the 75 MW threshold in statute, effective June 20, 2025 (in Section 37.0561 of the Texas Utilities Code).

⁴The site "[p]rimarily contains information technology infrastructure used for: (a) creating, executing, and delivering software applications and services; (b) artificial intelligence training, deployment, and delivery; (c) cryptocurrency mining; or (d) other computational activities at a data center.

Why Did NERC Set the Threshold at ≥ 50 MW and ≥ 100 kV?

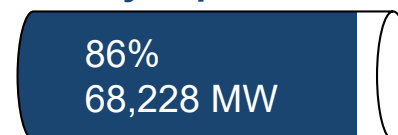


Using a 75 MW, 100 kV threshold

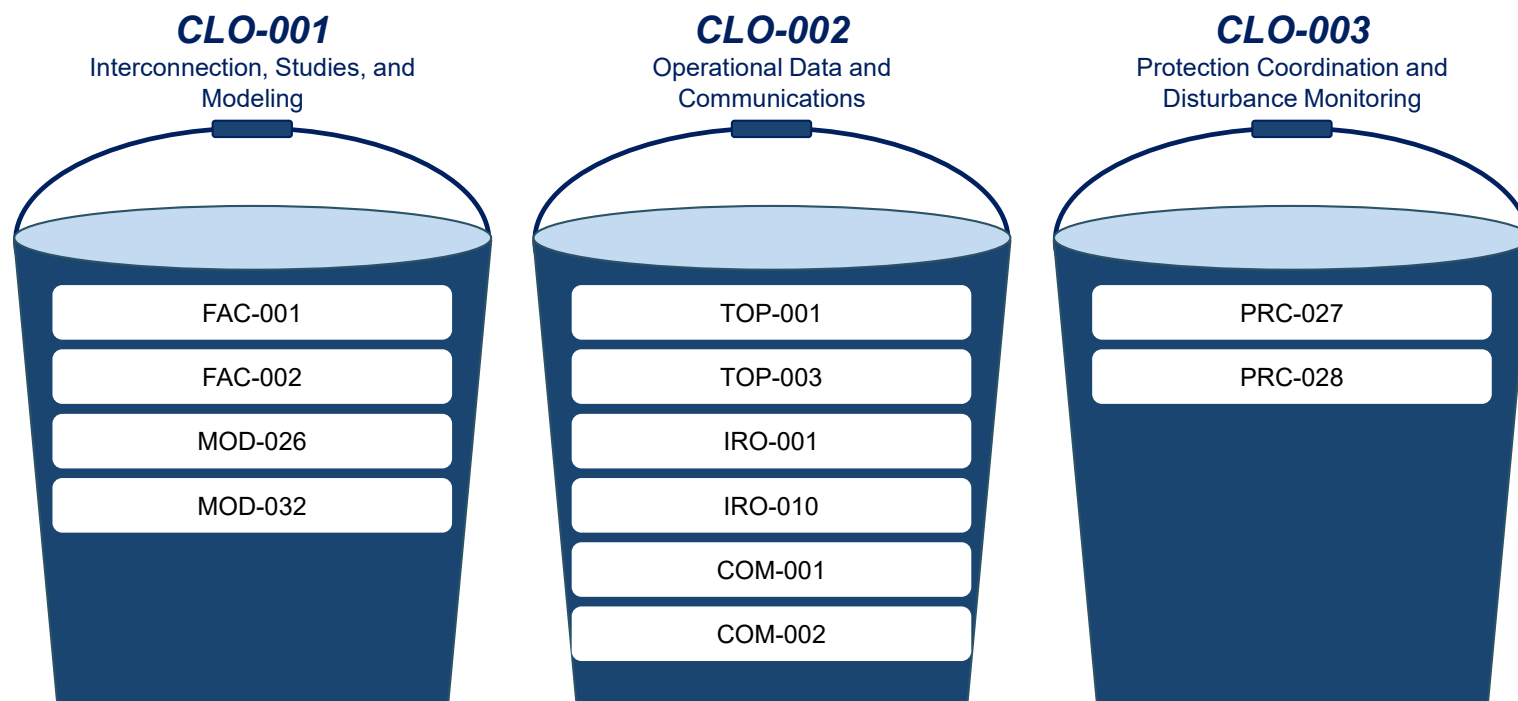


...is captured

But decreasing the threshold to 50 MW only captures 4 GW more



NERC is Proposing Three New Standards | CLO Series



Broad support for NERC's approach of recycling existing Standards/Requirements

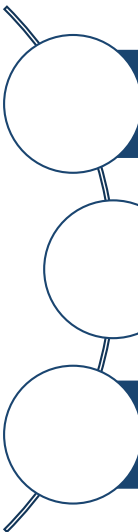
MOD-026-2 Implementation Review

What is it?

Consolidates MOD-026-1 and MOD-027-1

Strengthens modeling requirements for IBRs

Improves modeling of conventional generation and Transmission System equipment



Broad industry concerns about the implementation plan and overlapping timelines

Clarification provided by Texas RE during in-depth compliance overview

ERCOT review of changes to model review process

AGENDA

NSRF LEADERSHIP UPDATE

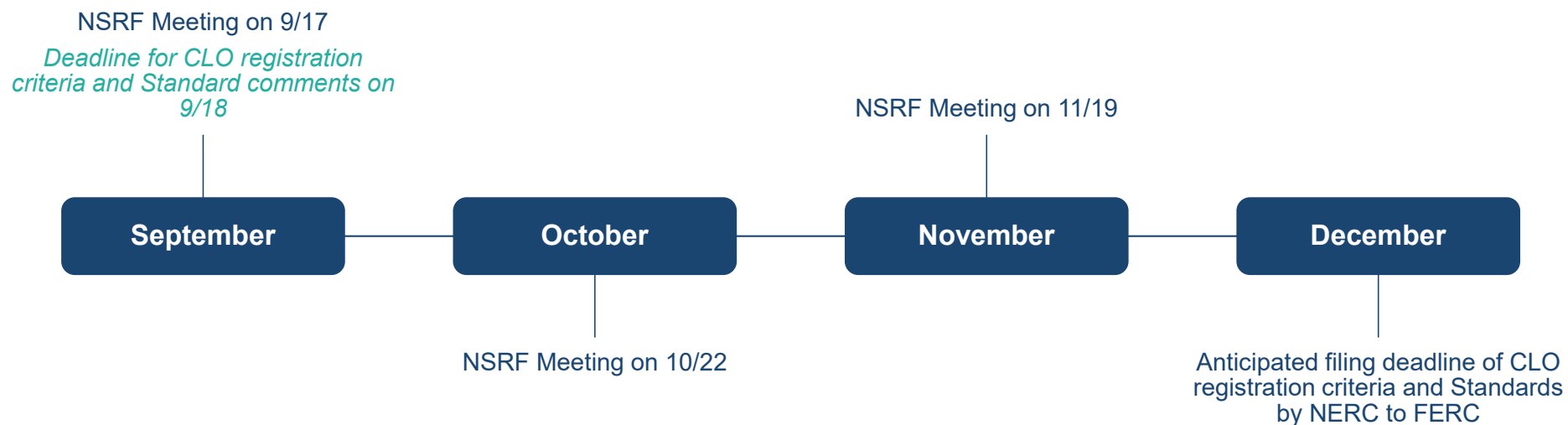
NOTABLE STANDARD/PROJECT/FILING CHANGES

KEY NSRF DISCUSSION TOPICS

LOOKING AHEAD



Looking Ahead – Continued Collaboration in NSRF Meetings



Appendix

Registration Criteria for Computational Loads

New Definitions Used in the NERC Rules of Procedure

“Computational Load Operator” [CLOP] means the entity that operates a Computational Load Site.

“Computational Load Owner” [CLO] means the entity that owns and maintains a Computational Load Site.

“Computational Load Site” means one or more buildings, structures, or installations at a single location that

1) Primarily contains information technology infrastructure used for:

- creating, executing, and delivering software applications and services;
- artificial intelligence training, deployment, and delivery;
- cryptocurrency mining; or
- other computational activities at a data center; and

2) is supplied through electrical equipment that is connected to the BPS.

Rules of Procedure Appendix 2
Emphasis Added

ERCOT CIP WORKING GROUP UPDATE

For the Texas RE – Member Representatives Committee (MRC)
September 16, 2026

Thomas Standifur, Austin Energy
CIPWG Chair

Danté Jackson, CenterPoint
CIPWG Vice Chair

- ▶ June 5, 2026 – Virtual Only
- ▶ July 10, 2026 – Virtual Only
- ▶ August 7, 2026 – Virtual (Open), In-Person (Closed)

RECENT MEETINGS

- ▶ E-ISAC briefings
- ▶ E-ISAC review & debrief on regional VISA Workshop (August 4-6, 2026)
 - ▶ Austin Energy/Texas RE hosted
 - ▶ 1st regional (pilot), Keynote from Michael Ball (E-ISAC CEO)
 - ▶ 65+ participants: utilities, local law enforcement, and state and federal partners
- ▶ PUCT – Review of upcoming Cyber Security Conference in Sept/Oct 2026
- ▶ ERCOT
 - ▶ Cyber Threat Training pre-announcement
 - ▶ Project 2023-09 Risk Management for Third-Party Cloud Services: outreach presentation
 - ▶ ERCOT NPRR1334 review and discussion
- ▶ Presentation: BCSI in the Cloud (Alrich, Standifur)
- ▶ Presentation: AI Critical Infrastructure impacts – trends & price management

OPEN SESSION TOPICS SUMMARY

- ▶ Ask TRE
 - ▶ CIP-004-7 R6 (Physical Security)
 - ▶ Physical security risks (2026 CMEP IP Risk Element)
 - ▶ CIP-015-1 (Internal Network Security Monitoring)
 - ▶ General considerations & Standard review (Future Enforceable Standard)
 - ▶ CIP-010-4 R1 (Config. Change Management & Vuln. Assessments)
 - ▶ Supply chain considerations (2026 CMEP IP Risk Element)
 - ▶ General Questions

OPEN SESSION TOPICS SUMMARY

► Standards typically tracked during the open sessions

HIGH PRIORITY

- 2025-02 Internal Network Security Monitoring Standard Revision (CIP-015-2)
 - Final ballots for Project 2025-02 INSM Standard Revision concluded Thursday, March 5, 2026 – Passed
- 2023-06 CIP-014 Risk Assessment Refinement
 - Additional ballots for the Standard and implementation plan was conducted May 5 – 14, 2026
- 2023-09 Risk Management for Third-Party Cloud Services
 - Project moved to High
 - Open for comments: 7/28/2026 – 8/21/2026
- 2025-06 Supply Chain Risk Management
 - Project moved to High
 - 52-day formal comment period for Project 2025-06 SCRM, concluded Friday, July 17, 2026

MEDIUM PRIORITY

- 2021-03 CIP-002 Transmission Owner Control Centers
 - Project is currently in Phase Two of Standards Development

LOW PRIORITY

- 2022-05 Modifications to CIP-008 Reporting Threshold
 - Initial ballots & non-binding poll: 9/4/2026 – 9/14/2026

WITH FERC

- 2021-03 CIP-002 Transmission Owner Control Centers under docket number RM25-7-000
- Petition of the NERC for Approval of Proposed Reliability Standard CIP-014-4 docket number RD26-9 : Filed 7/16/2026

OPEN SESSION CIP STANDARDS TRACKED

► Subject To Future Enforcement

CIP-002 – CIP-013 (All Standards being up-versioned)

- July 1, 2028
- Biggest “update” since CIP v3 -> v5: specifically addresses virtualization and other cyber security topics as well as numerous new and updated defined terms; new asset classes
- Standards Affected: CIP-002, CIP-003, CIP-004, CIP-005, CIP-006, CIP-007, CIP-008, CIP-009, CIP-010, CIP-011, CIP-012-1, CIP-013

CIP-015-1 (Internal Network Security Monitoring)

- Phase1 – October 1, 2028 (High & Medium BCS at Control Centers)
- Phase 1a – October 1, 2029 (High & Medium EACMS, PACS, and SCI at Control Centers)
- Phase 2 – October 1, 2030 (Medium BCS and PCA)
- Phase 2a – October 1, 2031 (Medium EACMS, PACS, and SCI)

CIP-003-11 (Security Management Controls)

- July 1, 2029

OPEN SESSION CIP STANDARDS TRACKED

▶ Security Topics

- ▶ E-ISAC VISA regional pilot recap
- ▶ PUCT - LSIPA updates and potential impacts
- ▶ ERCOT
 - ▶ Discussed direct Internet Access (DIA) circuits into each TDSP and QSE for them to transmit ICCP data to the cloud hosted solution Cloud/AI Security Questionnaire share and discussion
 - ▶ NPPR 1334 - expands the scope of Cybersecurity Incidents and requires a Market Participant to notify ERCOT upon determination of a Cybersecurity Incident
 - ▶ Cloud EMS discussion

▶ Compliance Topics

- ▶ Audit experience share
- ▶ Peer share
- ▶ Peer check

▶ Administrative

- ▶ Discussion & vote to reinstitute physical security break-out group (in-person meetings)
- ▶ Upcoming in-person meeting planning and presentation solicitation

CLOSED SESSION TOPICS SUMMARY

- ▶ Greater involvement of Cybersecurity and Infrastructure Security Agency (CISA)
- ▶ Quarterly In-Person Meetings
 - ▶ Dallas (Sharyland Utilities) – Q1
 - ▶ Houston (CenterPoint) – Q2
 - ▶ Austin (Austin Energy) – Q3
 - ▶ San Antonio (UTSA) – Q4
- ▶ ERCOT CIPWG Chair & Vice Chair election in November/December

LOOK AHEAD IN 2026

ANY QUESTIONS?

COMPLIANCE AND CERTIFICATION COMMITTEE

*Update to Texas RE Member Representatives Committee
September 2026*

- **CCC Meeting ([CCC Agenda Package](#))** – July 23, 2026 (virtual)
 - Q3 Focus Discussion – Inverter-Based Resources Category 2 GO/GOP Registration
 - 2025 Stakeholders' Perception Report – Endorsed
 - Standing Committee Governance Initiative – CCC Sample Charter
 - CCC Membership and Officer Nominations – Approved
 - Program Alignment Consistency Tool
 - Align Users Group / Secure Evidence Locker Update
 - Executive Session
 - NERC will release a Guidance Document in August regarding PRC-029-1
 - Q4 Meeting – October 27-29, 2026 (Chicago, IL)



TEXAS RE

CIP and O&P Compliance Monitoring and Risk Assessment Report

**Member Representatives Committee
Meeting
September 16, 2026**

Critical Infrastructure Protection Compliance Monitoring





Q2 2026: Workshop, Webinar, Training, and Conference Highlights

Public

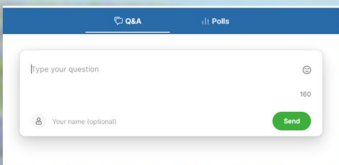


Texas RE Spring Standards, Security, & Reliability Workshop

April 1, 2026



To submit questions during the workshop, please visit slido.com and enter today's participant code: **TXRE**



AGENDA

- [Aggregation of Control](#)
- [CIP-003-9 Low Impact BES Remote Connectivity](#)
- [Frequency and Voltage Protection Settings for Generation Resources](#)
- [Common Root Cause Codes](#)
- [FERC Update](#)
- [Large Loads Interconnection in ERCOT](#)
- [NERC CIP Drip](#)
- [Supply Chain Resilience in a World of Geopolitical Cyber Risk](#)
- [AI-Augmented Embedded Security Assessment for BES Resilience](#)



TEXASRE

Ensuring electric reliability for Texans



New Entity/PCC Expectations

Brook Rodaway
Registration and Certification Program Coordinator

Jeff Hargis
Risk Assessment Engineer, Sr.

Rebekah Barber
Compliance Team Lead

Alexandra Huey
O&P Compliance Engineer III



TEXASRE

talk
TEXASRE



Supply Chain

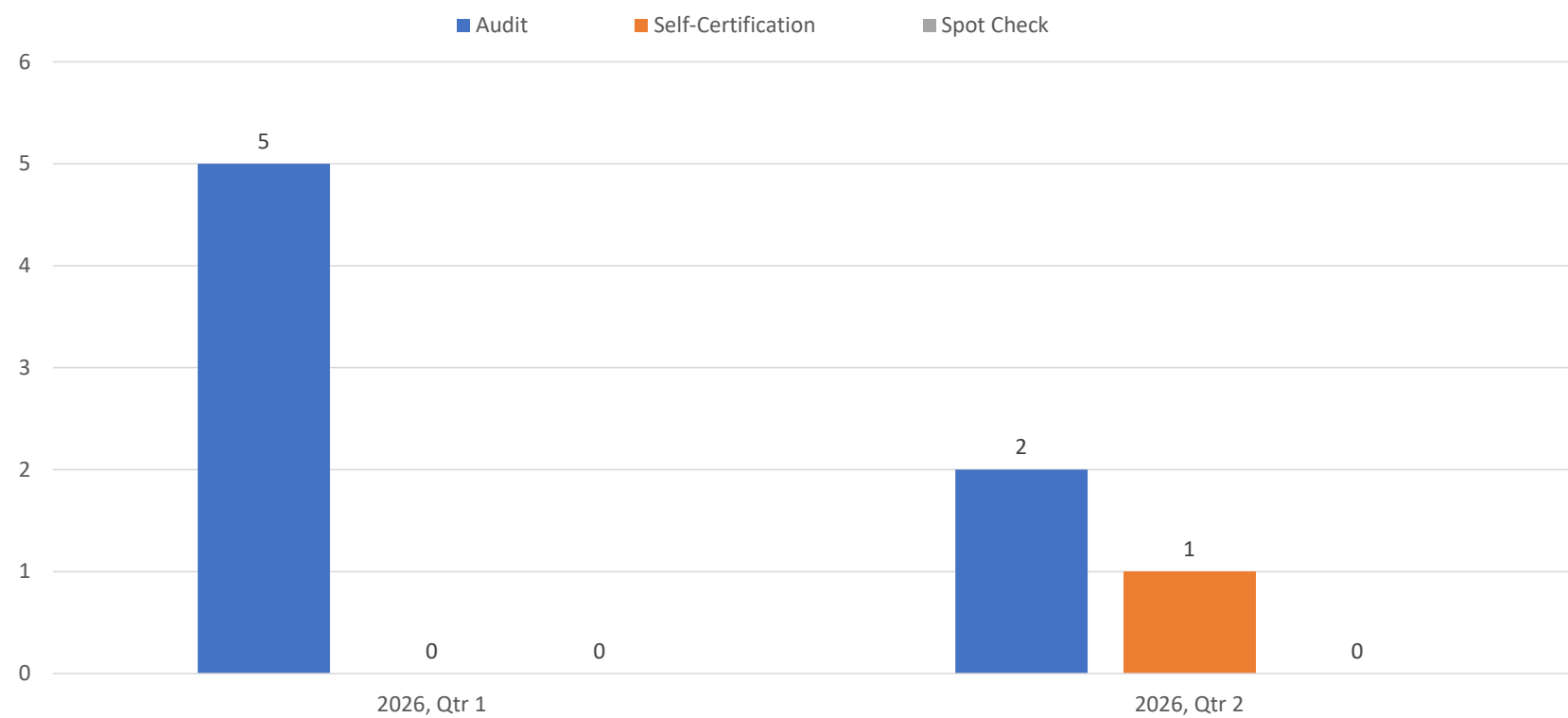
Rebekah Barber
CIP Compliance Team Lead

June 30, 2026



Total CIP Engagements

Public



Operations and Planning Compliance Monitoring





Q2 2026: Workshop, Webinar, Training, and Conference Highlights

Public

STANDARDS, SECURITY & RELIABILITY
WORKSHOP

Texas RE Spring Standards, Security, & Reliability Workshop

April 1, 2026

To submit questions during the workshop, please visit slido.com and enter today's participant code: **TXRE**

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- Common Root Cause Codes
- FERC Update
- Large Loads Interconnection in ERCOT
- NERC CIP Drip
- Supply Chain Resilience in a World of Geopolitical Cyber Risk
- AI-Augmented Embedded Security Assessment for BES Resilience

QR code for registration

TEXASRE

Facility Ratings Internal Controls

William Braun
Risk Assessment Analyst, Sr.

Allie Huey
O&P Compliance Engineer

April 22, 2026

talk TEXASRE

TEXASRE
Ensuring electric reliability for Texans

New Entity/PCC Expectations

Brook Rodaway
Registration and Certification Program Coordinator

Jeff Hargis
Risk Assessment Engineer, Sr.

Rebekah Barber
Compliance Team Lead

Alexandra Huey
O&P Compliance Engineer III

Announcement Cold Weather Preparedness Small Group Advisory Sessions (SGAS)

Planned activities will begin March 26, 2026.

Note: All meetings will be virtual through WebEx

Event Information – NERC, in collaboration with the Regional Entities, will host a SGAS for those entities that have been identified and notified during the Inverter-Based Resources Registration Initiative for registration with NERC as a Category 2 Generator Owner (referred to as GO-2) and/or Category 2 Generator Operator (referred to as GOP-2).

- The target audience for this SGAS will be GO-2s and GOP-2s with no previous NERC Regulatory experience.

This SGAS will help GO-2s and GOP-2s understand their compliance obligations and prepare for implementation. Specifically, the SGAS will cover the set of Reliability Standards that GO-2s and GOP-2s must comply with in 2026.

Please note that GO-2s and GOP-2s are required to comply with an initial set of eight Reliability Standards on their registration effective date of **May 15, 2026**.

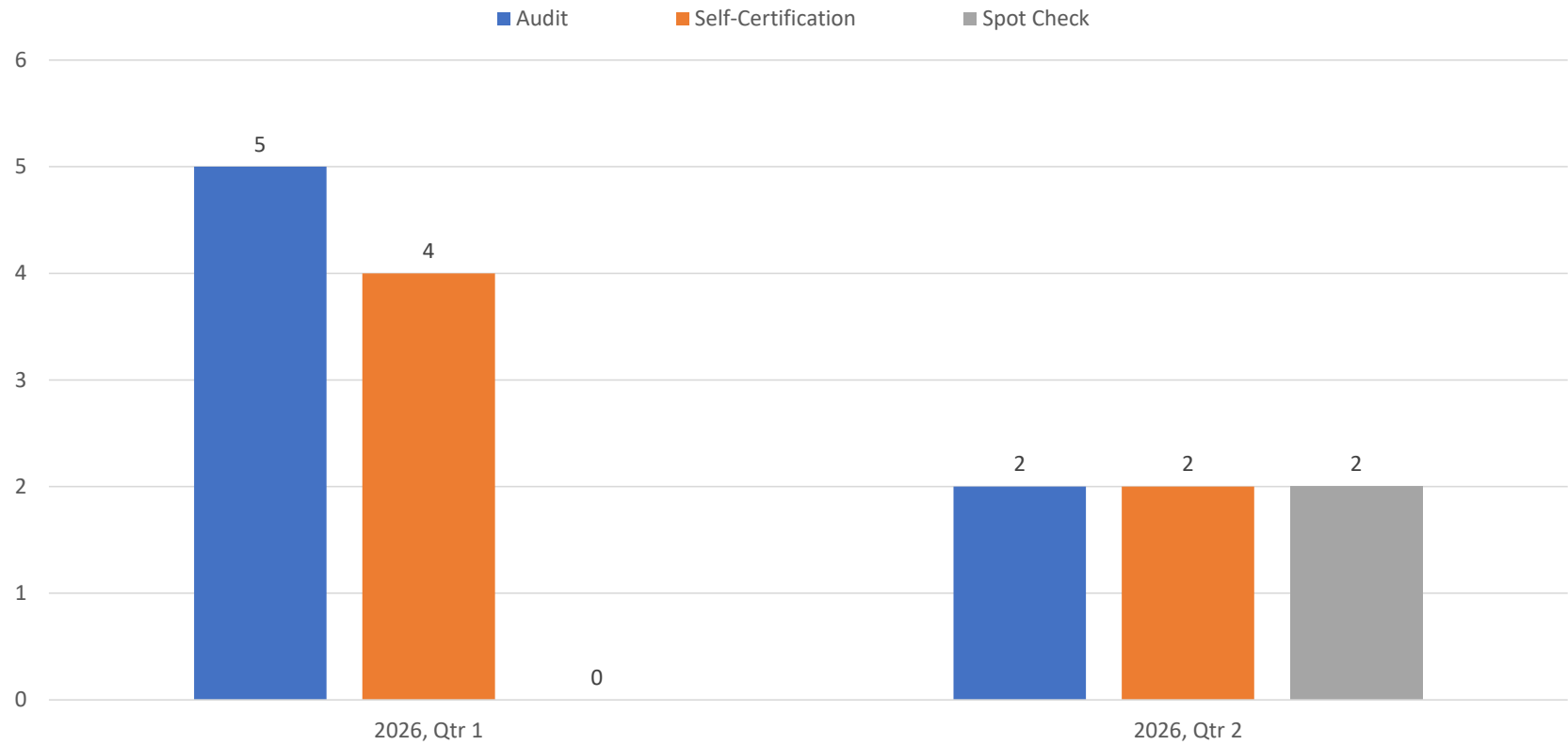
The SGAS will consist of two parts:

1. **General Session Live Webinar:** A general session will be held to help GO-2s and GOP-2s understand their compliance obligations with the initial set of Reliability Standards on Thursday, March 26, 2026, 2:00-4:00 p.m. Eastern. This session will:
 - a. Introduce NERC, Regional Entities, and the Compliance Monitoring and Enforcement Program.
 - b. Review the NERC Reliability Standards that GO-2s and GOP-2s must comply with day one of their registration effective date.
 - c. Registration for a one-on-one session (detailed below) is not necessary to attend the General Session Live Webinar.
2. **SGAS One-on-One Sessions:** Closed, one-on-one discussions between a registered entity's Subject Matter Experts (SMEs) and ERO Enterprise (collectively NERC and Regional Entities) staff about issues pertinent to their implementation of NERC compliance obligations. These sessions will occur between Monday, March 30 – Friday, April 10, 2026. **NERC will schedule the one-on-one sessions after registration is received and is coordinated with Regional Entity staff.**

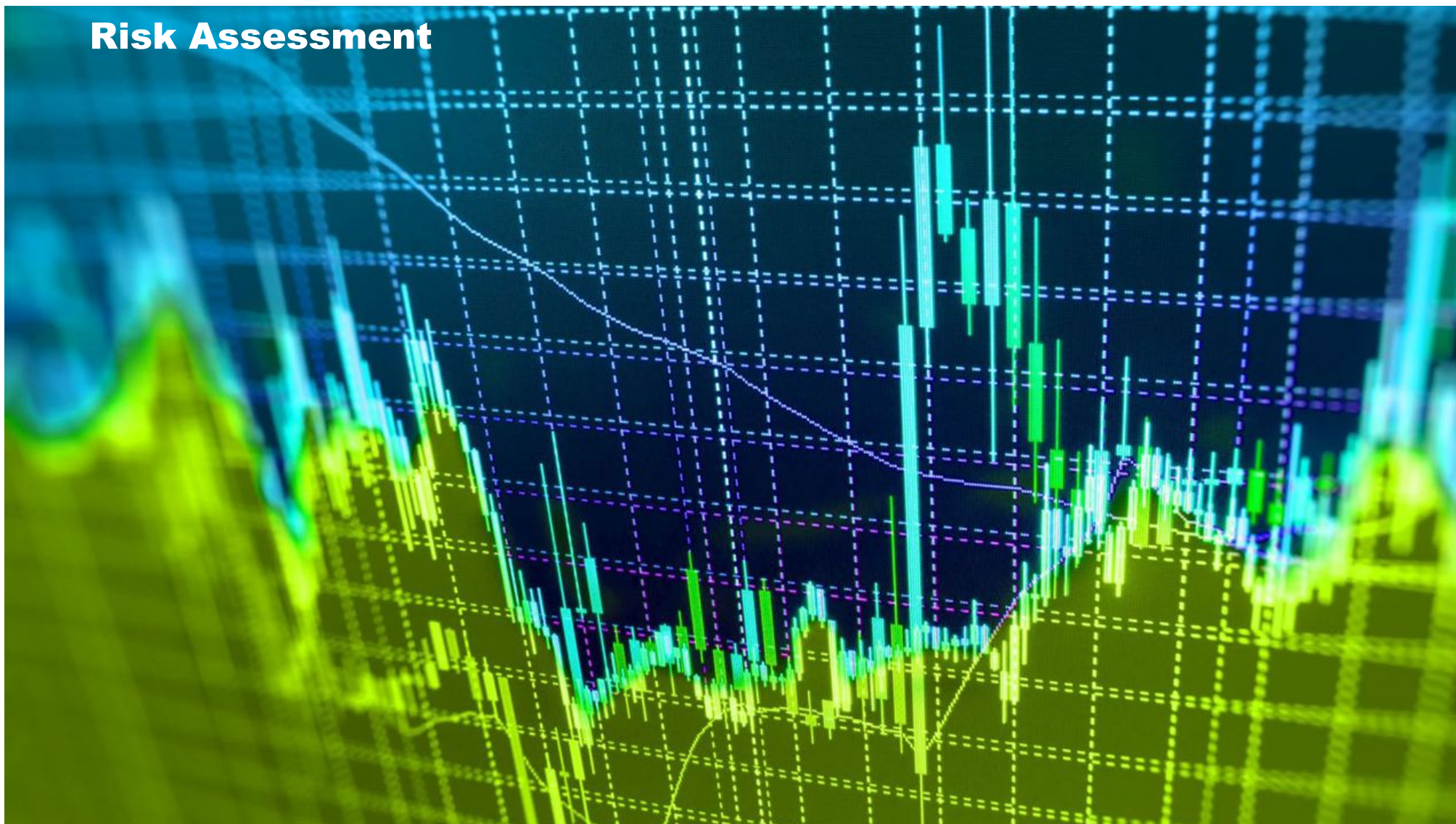


Total O&P Engagements

Public



Risk Assessment





Q2 2026: Workshop, Webinar, Training, and Conference Highlights

Public



Cold Weather Risk

Diego Bailey
Risk Assessment Analyst II

April 8, 2026

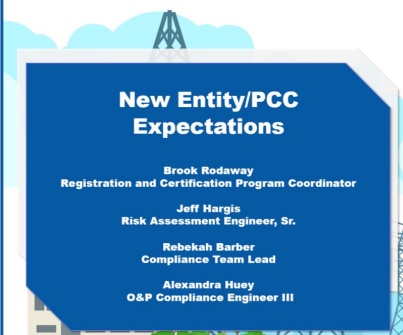


**Facility Ratings
Internal Controls**

William Braun
Risk Assessment Analyst, Sr.

Allie Huey
O&P Compliance Engineer

April 22, 2026



**New Entity/PCC
Expectations**

Brook Rodaway
Registration and Certification Program Coordinator

Jeff Hargis
Risk Assessment Engineer, Sr.

Rebekah Barber
Compliance Team Lead

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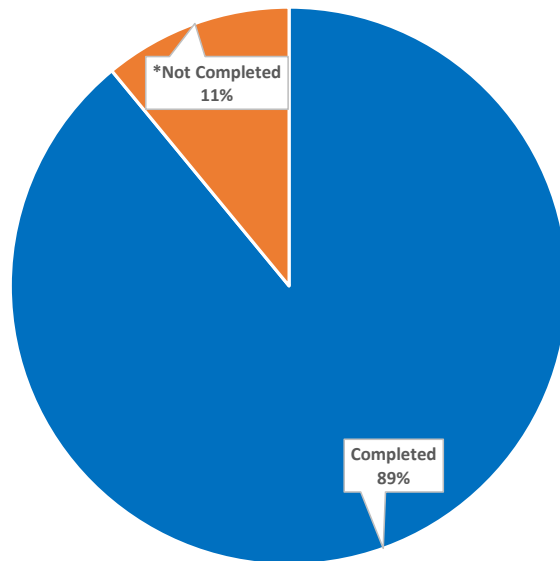
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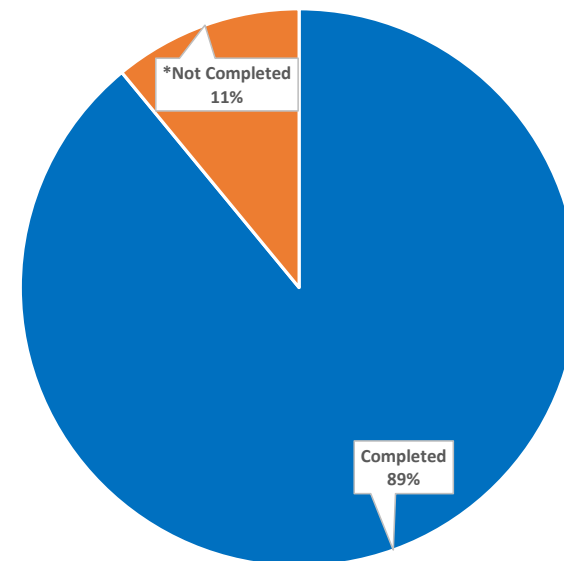
Q2 2026: Texas RE IRA and COP Completion

Public

2026 YTD:
Percentage of Entities with an IRA



2026 YTD:
Percentage of Entities with a COP



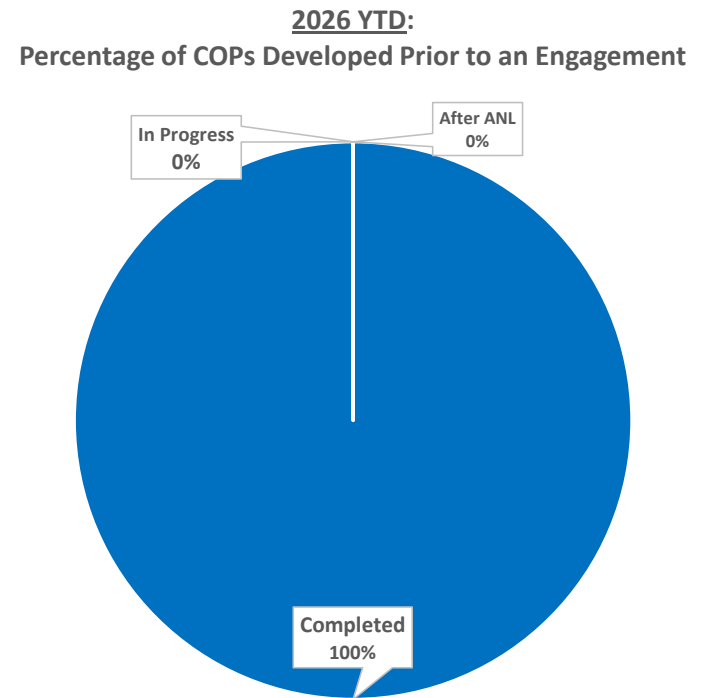
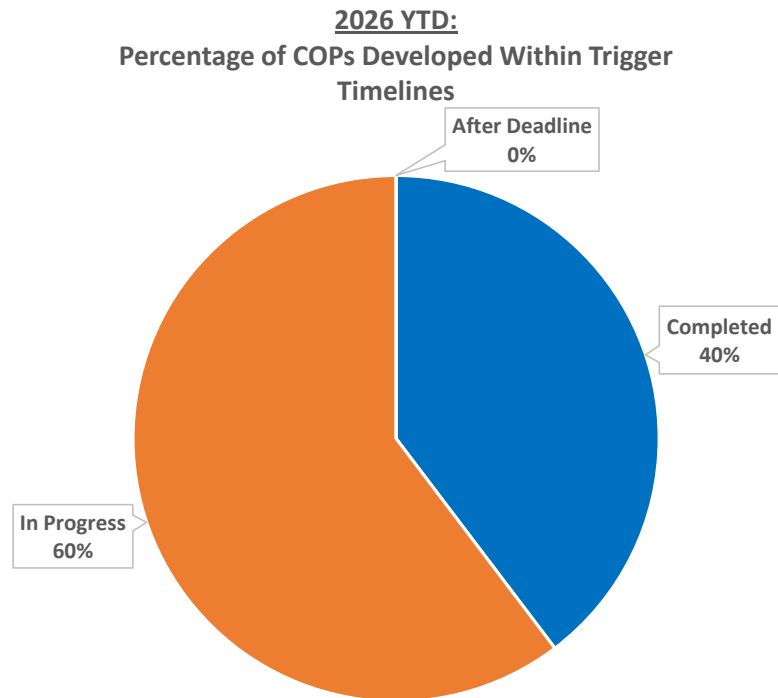
As of June 30, 2026

*The 11% Not Completed is due to the Category 2 GO/GOP registrations that took place in Q2



Q2 2026: COP Completion Within Trigger(s) and Prior to an Engagement

Public



As of June 30, 2026



TEXAS RE

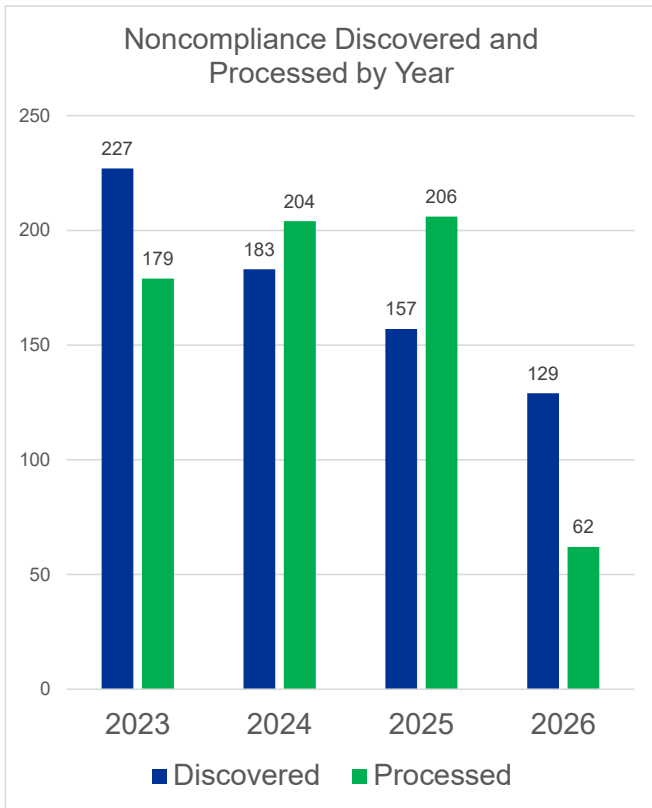
Enforcement Report

**Member Representatives Committee
Meeting
September 16, 2026**

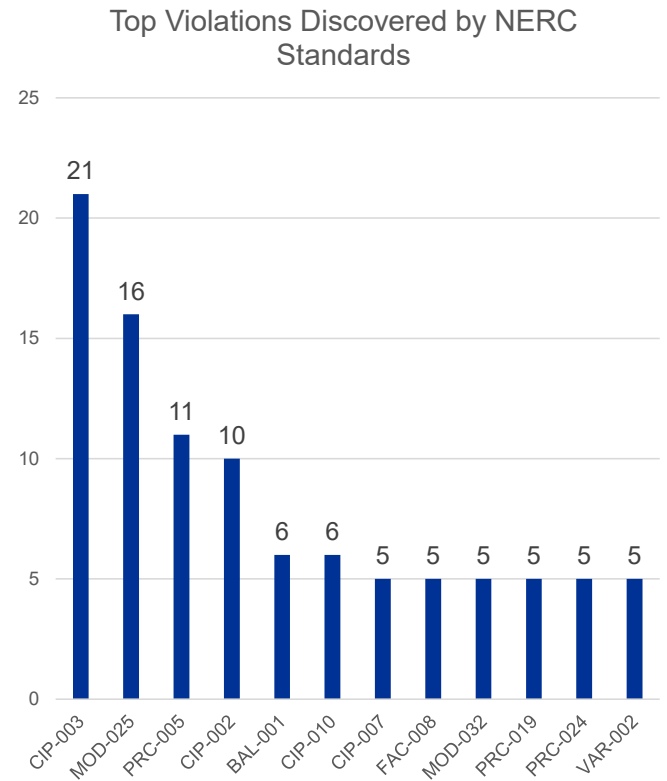
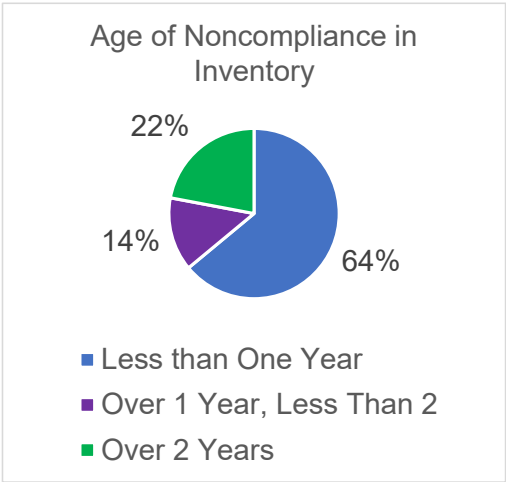


Enforcement Inventory Dashboard

Public



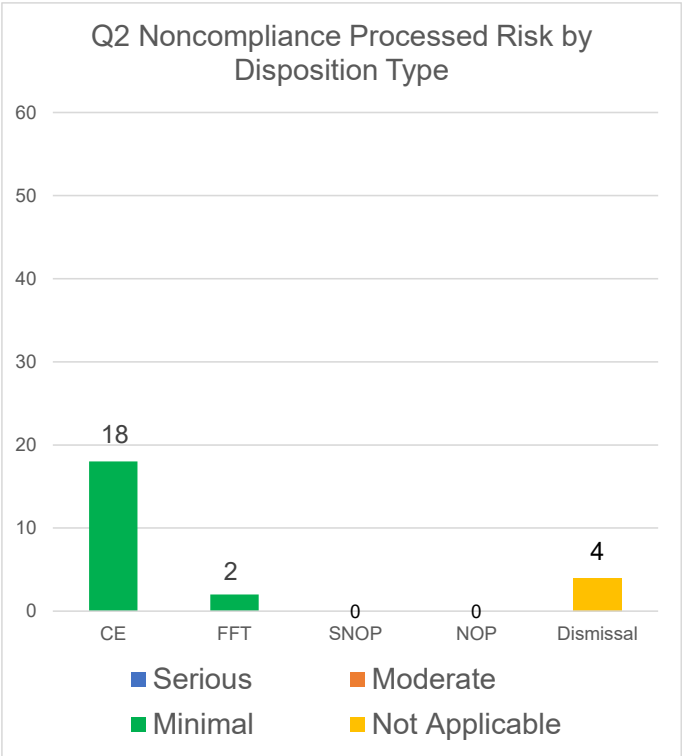
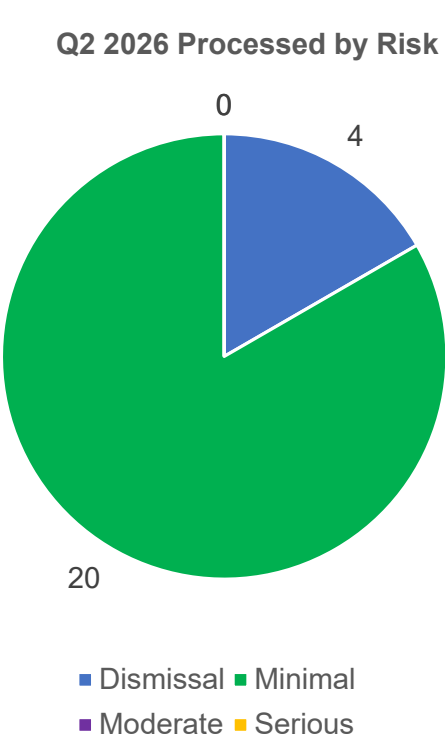
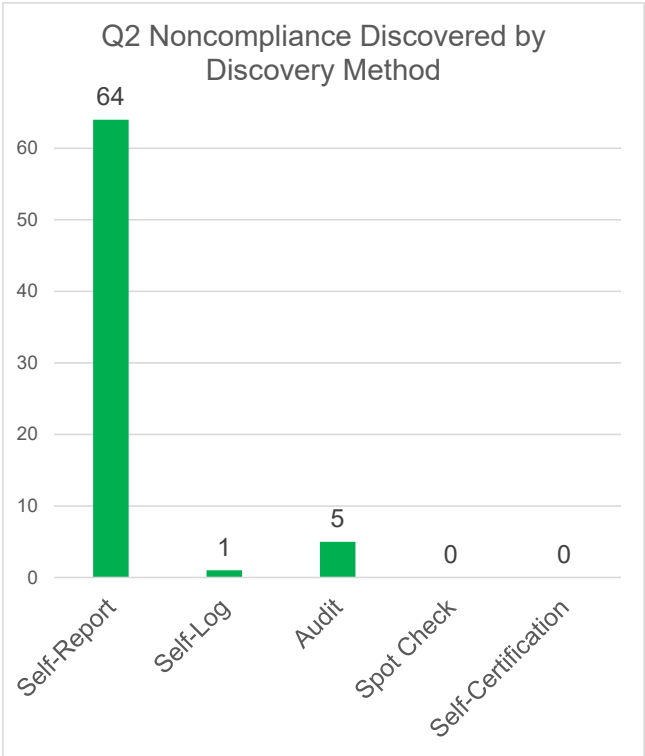
Inventory as of
7/1/2026:
236





Enforcement Processing Quarterly Dashboard

Public





TEXAS RE

Registration Report

**Member Representatives Committee
Meeting
September 16, 2026**



Registration Initiatives

Public



Inverter-Based Resource Registration Initiative

- Texas RE registered 30 Category 2 Generator Owners and 21 Category 2 Generator Operators on May 15, 2026
- Texas RE completed all required registration analysis ahead of schedule



Large Computational Loads

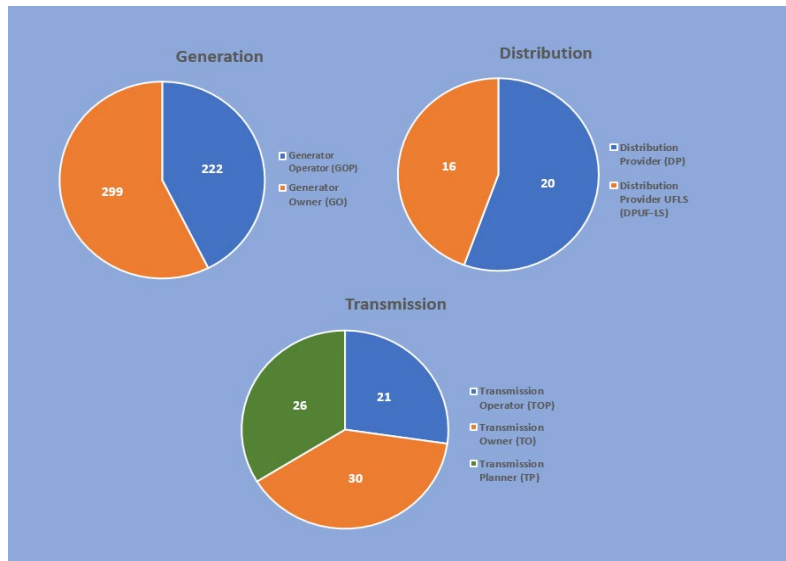
- Proposed changes to registry criteria are open for comment until September 18, 2026
- More information to come!



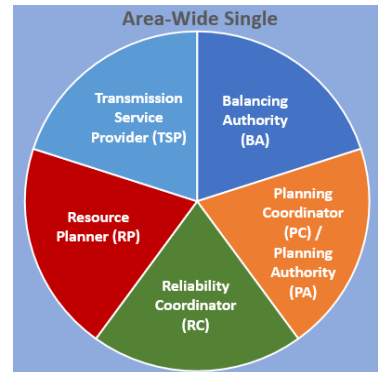
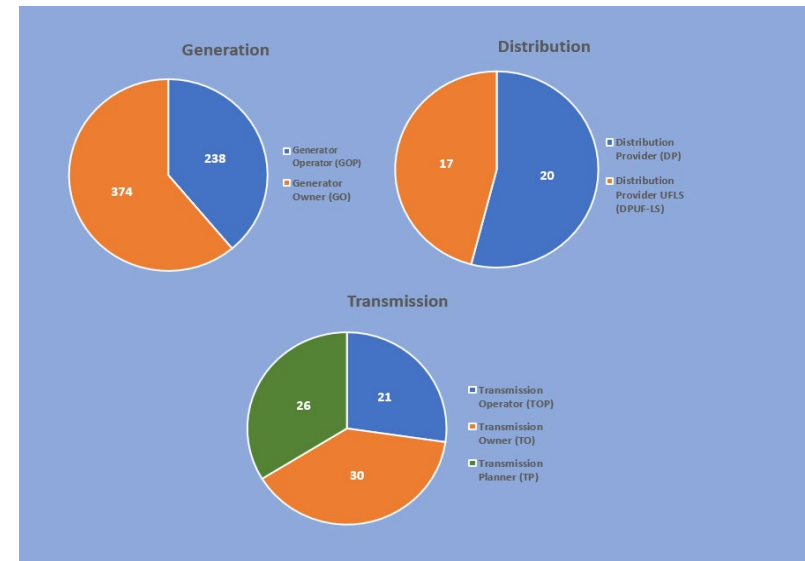
Number of Registered Entities by Function – Texas RE Region

Public

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



**463 Registered Entities | 726 Functions*
As of August 1, 2026**



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

***This includes 30 Category 2 GOs and 21 Category 2 GOPs that were registered as a result of the Inverter-Based Resources Registration Initiative**



Other Registration Activities – CFR and JRO Agreements

Public

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 five active CFRs
 - 1 GO CFR (MRO is the lead region)
 - 2 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 six active JROs:
 - 1 DP JRO
 - 1 DP UFLS JRO
 - 2 GO JROs
 - 1 GOP JRO
 - 1 TP JRO



TEXAS RE

Reliability Services Report

**Member Representatives Committee
Meeting
September 16, 2026**



Key Activities in Q2 2026

Public

A vertical timeline graphic consisting of five white circles connected by a thin grey line, positioned to the left of the activity bars.

Scope completed for 2026 Energy Assessment

LTRA data submission and data quality review

MAST frequency study scope development

2026 Regional Risk Assessment underway

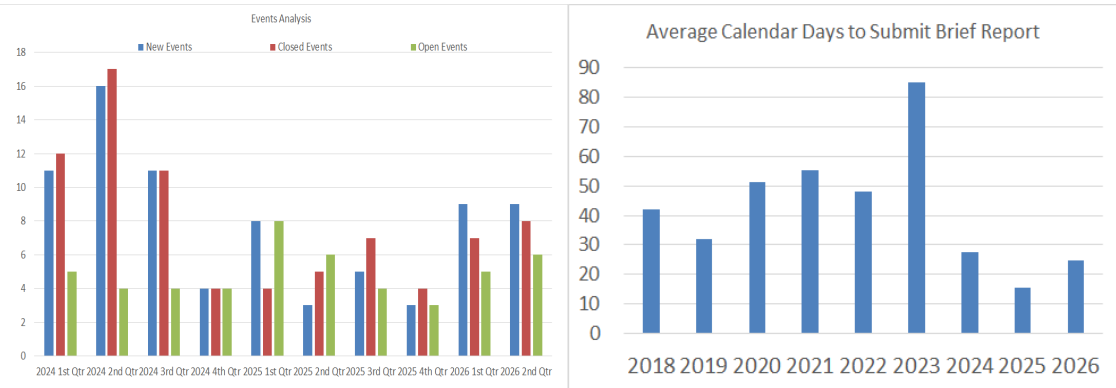
RAPA oversight and ERM updates



Reliability Services Functional Dashboard as of August 1, 2026

Public

EVENTS ANALYSIS



SITUATIONAL AWARENESS

Through 8/1/2026

Category	OE-417 Submission	EOP-004 Submission
Physical/cyber Threat	3	
System Separation or Islanding		
Loss of Firm Load		
Public Appeals		
Loss of Monitoring	6	1
Control Center Evacuation		
Loss of > 50k Customers		
Fuel Supply Emergency		
Damage/Destruction of Facility	5	2
Generation Loss		
Transmission Loss	2	

PERFORMANCE ANALYSIS

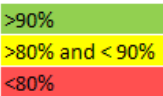
On-Time Section 1600 Reporting Status as of 8/15/2026

	2025 Q3	2025 Q4	2026 Q1	2026 Q2
TADS	100%	100%		
GADS	100%	100%	100%	97%
MIDAS	99%	97%	97%	
Wind GADS	96%	92%	76%	76%
Solar GADS	92%	94%	75%	70%

*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 Quality	LTRA Timeliness	WRA Quality	WRA Timeliness	SRA Quality	SRA Timeliness
MRO						
NPCC						
RF						
SERC						
TEXAS-RE						
WECC						



Grid Reliability Dashboard as of August 1, 2026

Public





APPENDIX:

Reliability and Performance

Indicators Update

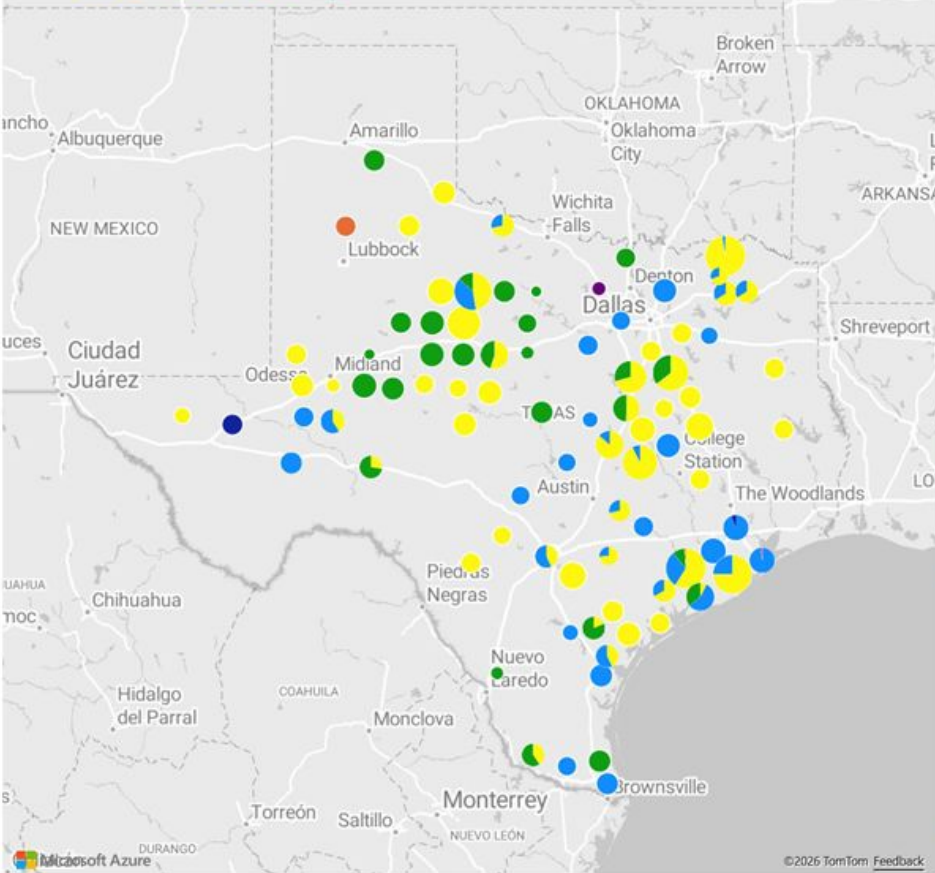


New Generation Interconnections as of August 1, 2026

Public

New Generation Interconnections

Technology PV BA WT IC GT CC ST



Technology	Year	Count of Capacity (MW)	Sum of Capacity (MW)
BA	2025	1	154.20
BA	2026	32	4,742.86
BA	2027	15	2,201.68
BA	2028	3	961.30
BA	2030	1	148.61
CC	2026	1	21.00
GT	2025	1	16.10
GT	2027	1	210.00
IC	2026	1	30.00
IC	2027	1	224.50
PV	2025	8	1,328.27
PV	2026	54	12,139.94
PV	2027	25	6,647.11
PV	2028	1	171.00
ST	2025	1	14.00
WT	2023	1	7.20
WT	2024	1	7.30
WT	2025	2	258.60
WT	2026	27	4,113.07
WT	2027	12	2,237.67
Total		189	35,634.41

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	6	649.70
2021	10	1,693.83
2022	8	1,756.75
2023	7	1,682.44
2024	15	3,250.90
2025	24	4,289.81
2026	31	5,873.80
Total	110	19,847.93

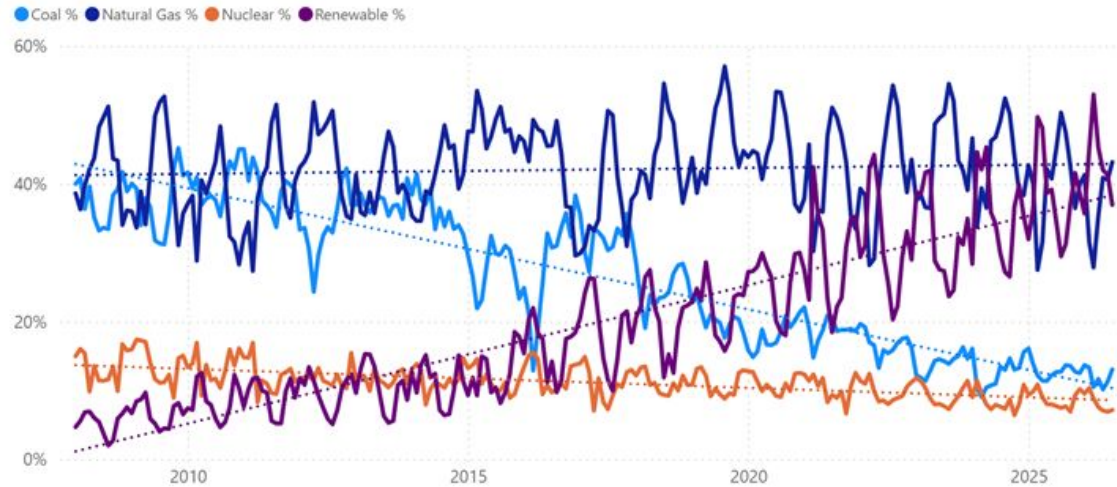
New Generation interconnections with a signed interconnection agreement and meeting all Planning Guide requirements



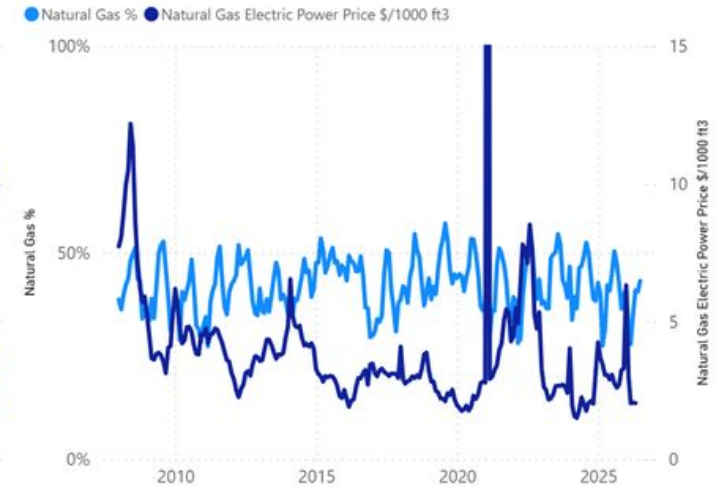
Generation Mix Trends

Public

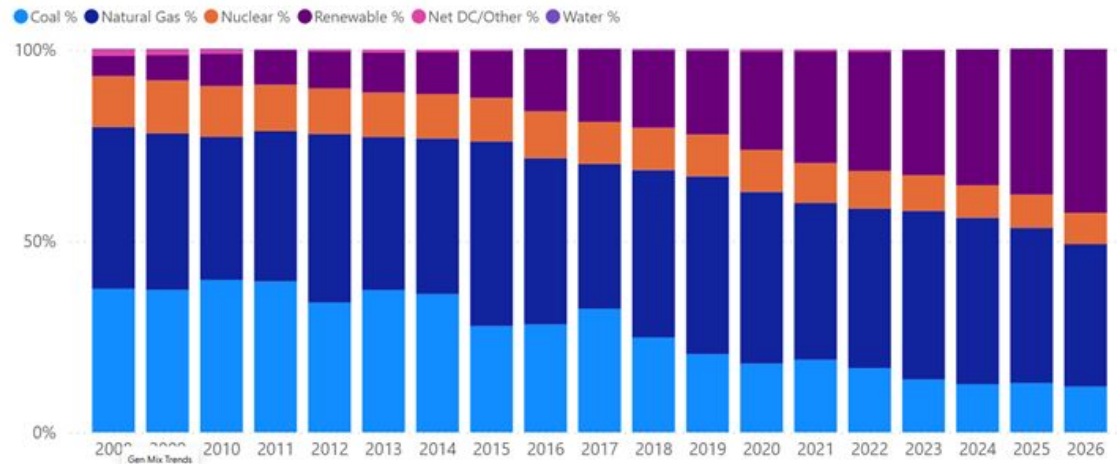
Coal %, Natural Gas %, Nuclear % and Renewable % by Year and Month



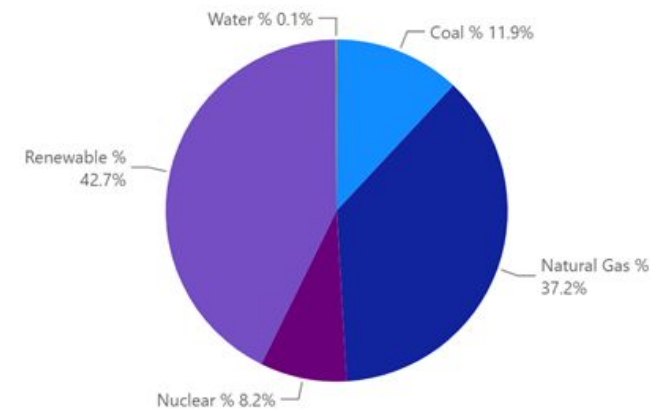
Natural Gas % and Natural Gas Electric Power Price \$/1000 ft3



Coal %, Natural Gas %, Nuclear %, Renewable %, Net DC/Other % and Water % by Year



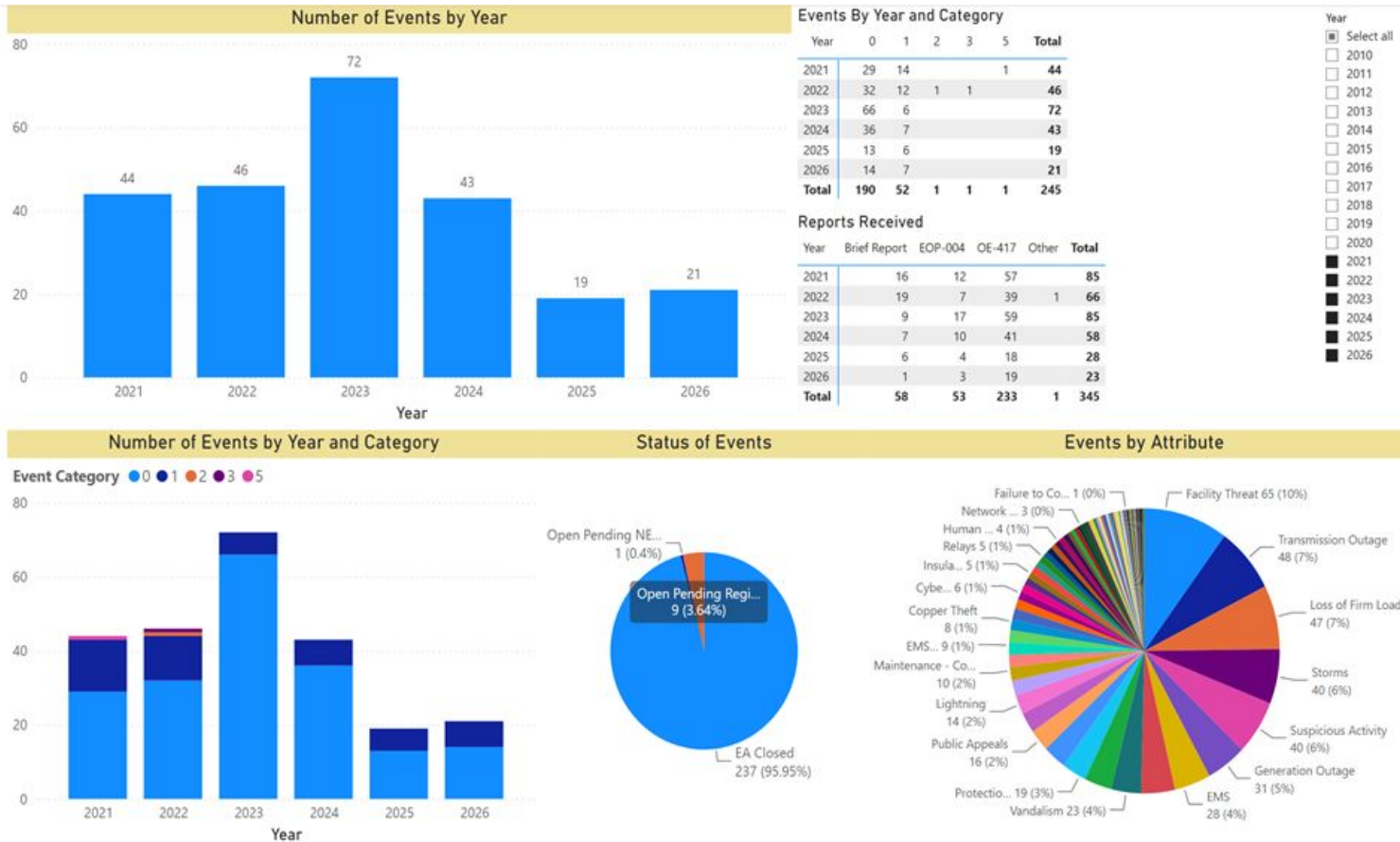
2026 Generation Mix by Fuel Type





System Events Dashboard as of August 1, 2026

Public



Key 2026 System Events

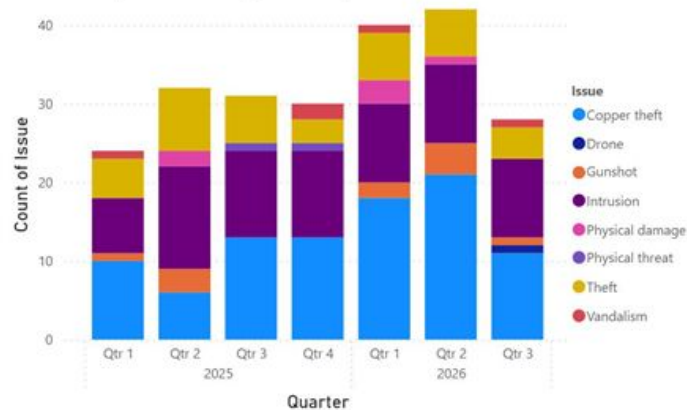
- Six reported loss of monitoring and control events
- Multiple reported physical security events
- Three cyber events
- One loss of multiple elements event



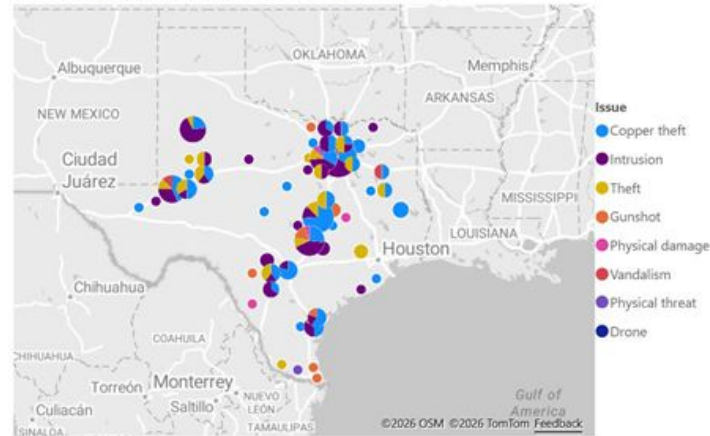
Infrastructure Protection – 2025-2026

Public

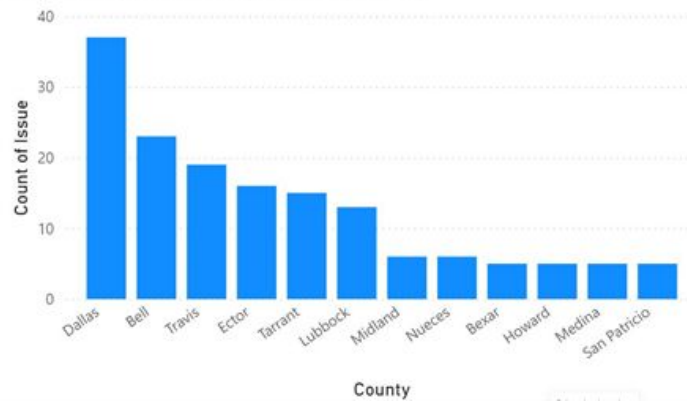
Count of Physical Security Events by Year, Quarter



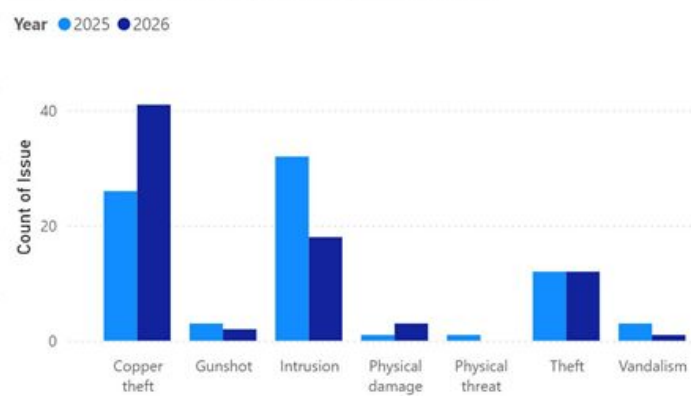
Count of Physical Security Events by Location



Count of Physical Security Events by County



Count of Physical Security Events by Issue and Year



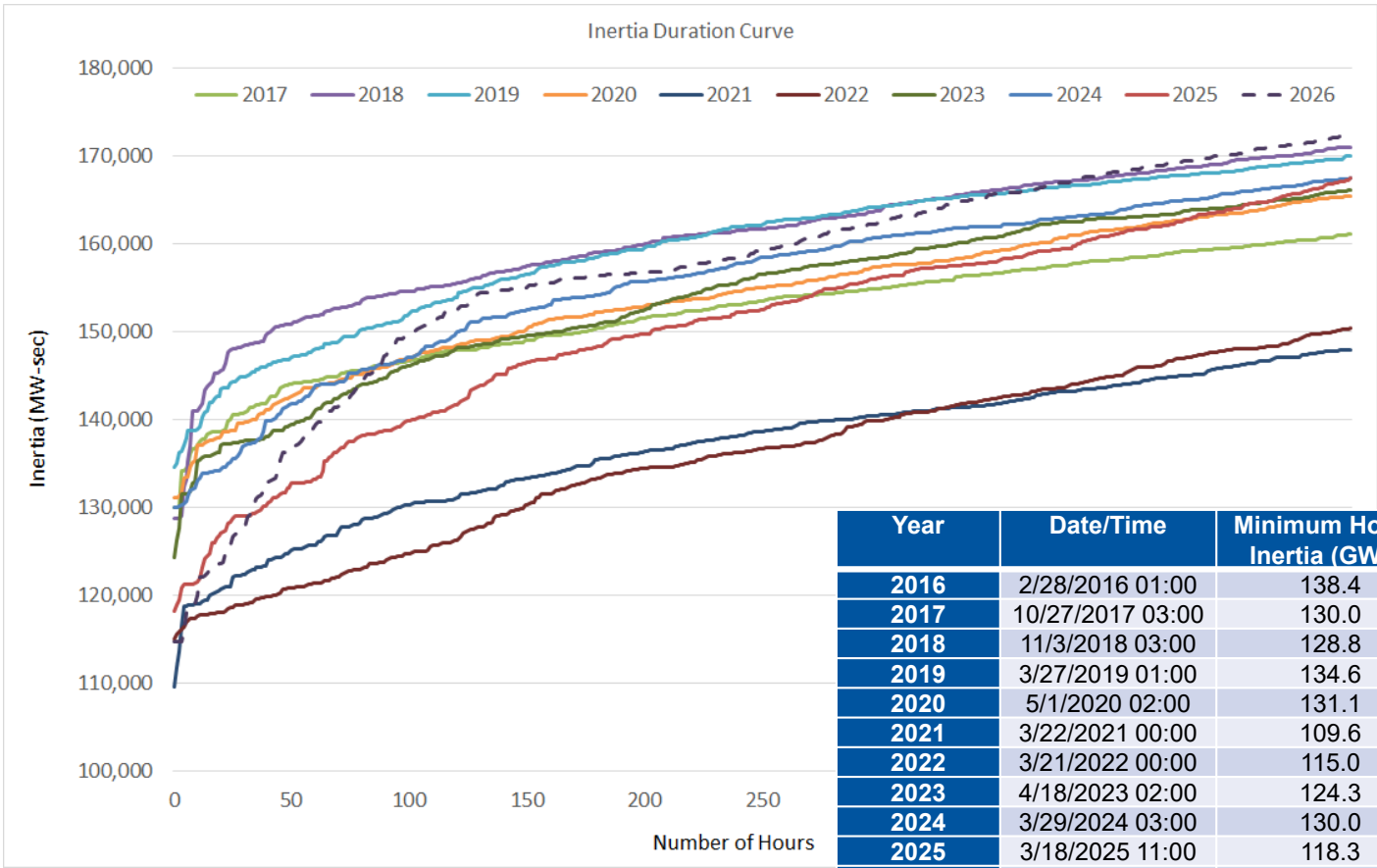
Incidents reported to System Security Response Group (SSRG)

2026 physical security event count has almost surpassed the 2025 total



System Inertia as of August 1, 2026

Public



2026 Inertia Duration Curve

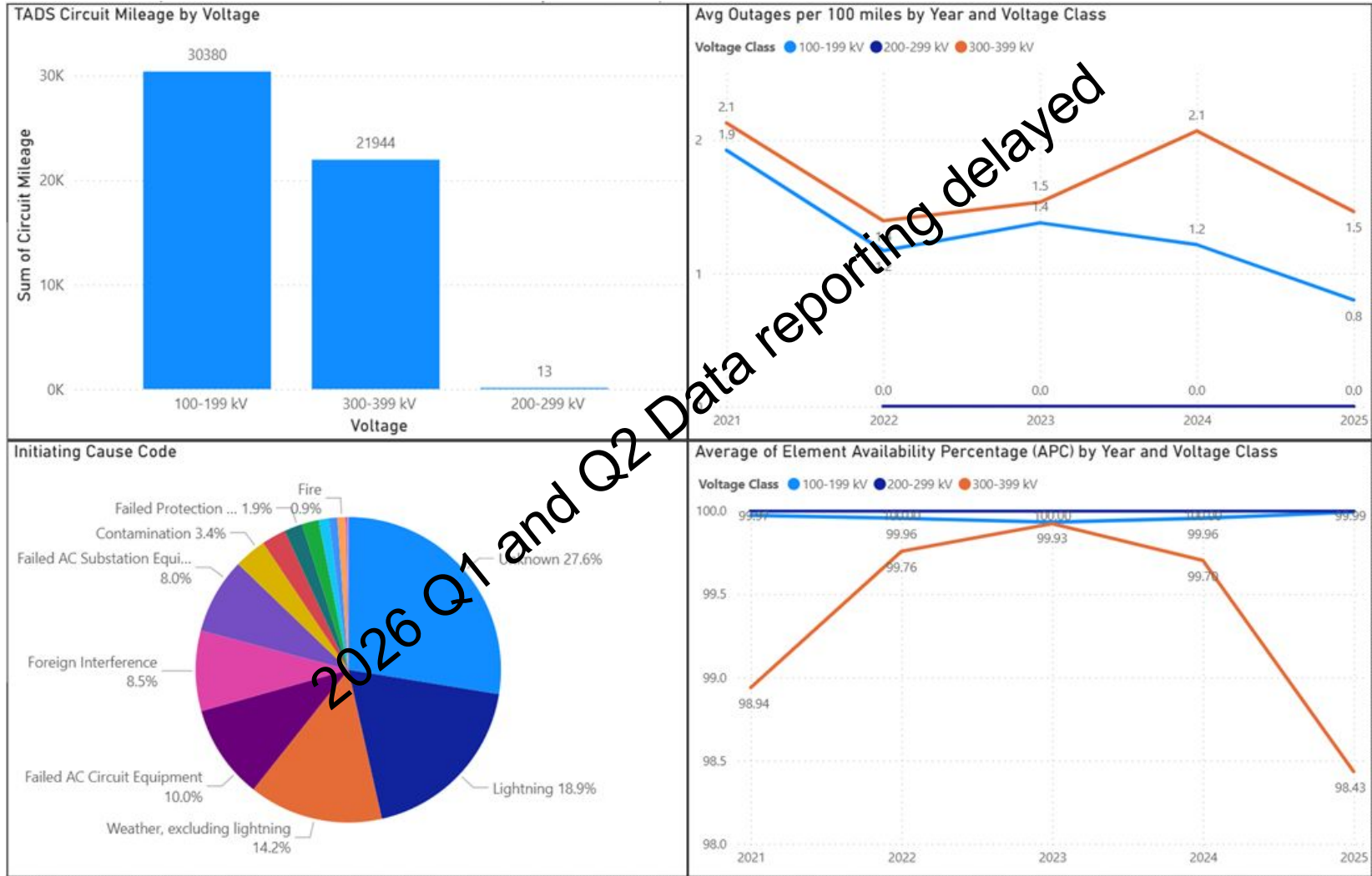
Year	# Hours > 70% Renewables	Maximum Hourly IRR%
2021	0	65.8%
2022	1	70.5%
2023	0	68.1%
2024	39	75.0%
2025	163	75.6%
2026 YTD	315	85.1%

Year	Date/Time	Minimum Hourly Inertia (GW-s)	Load (MW)	Net Load (MW)	IRR %
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	3/18/2025 11:00	118.3	48,973	12,290	74.9%
2026 YTD	3/14/2026 11:00	114.7	47,573	8,518	82.1%



Transmission Performance Dashboard

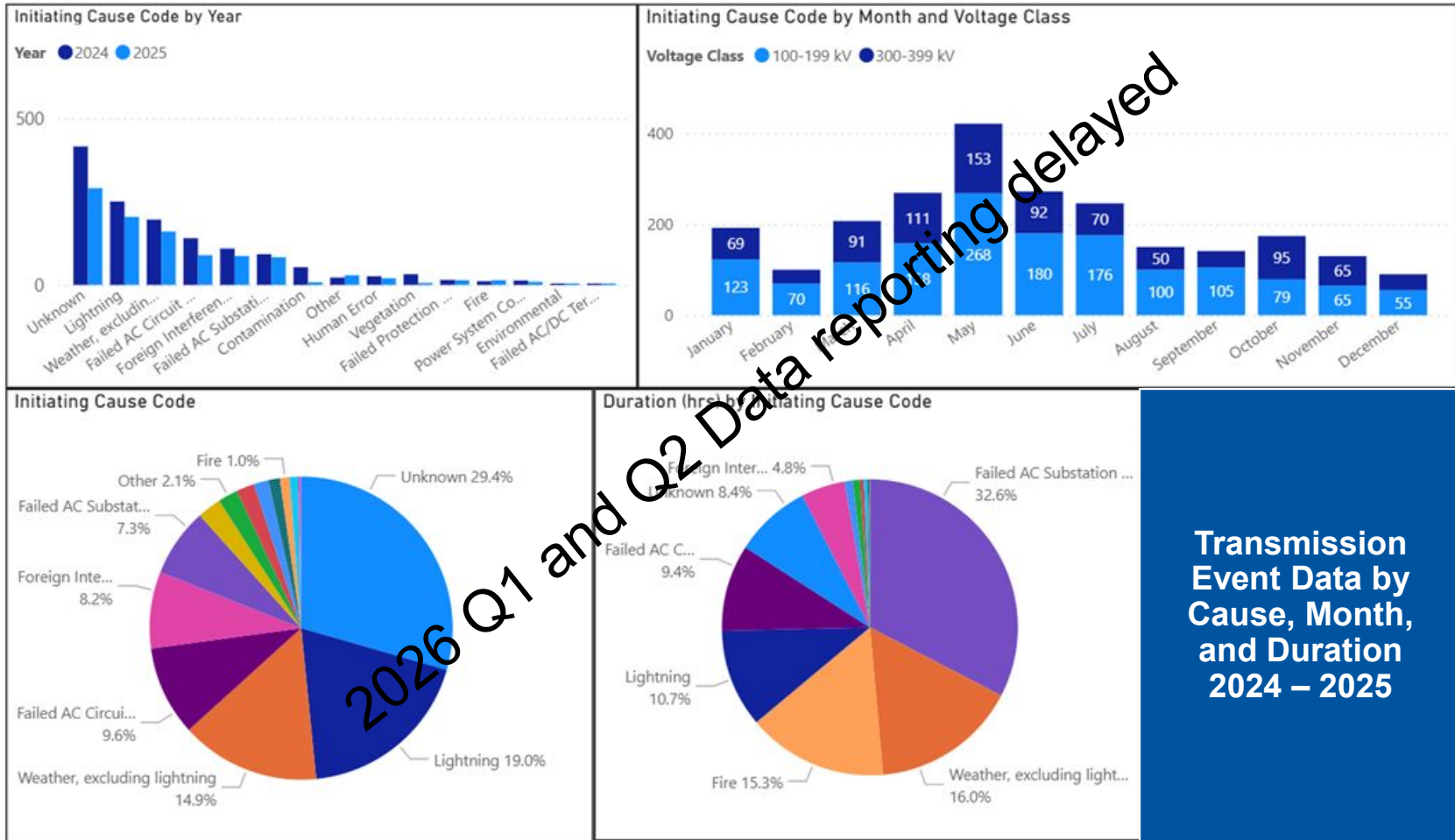
Public





Transmission Performance Dashboard

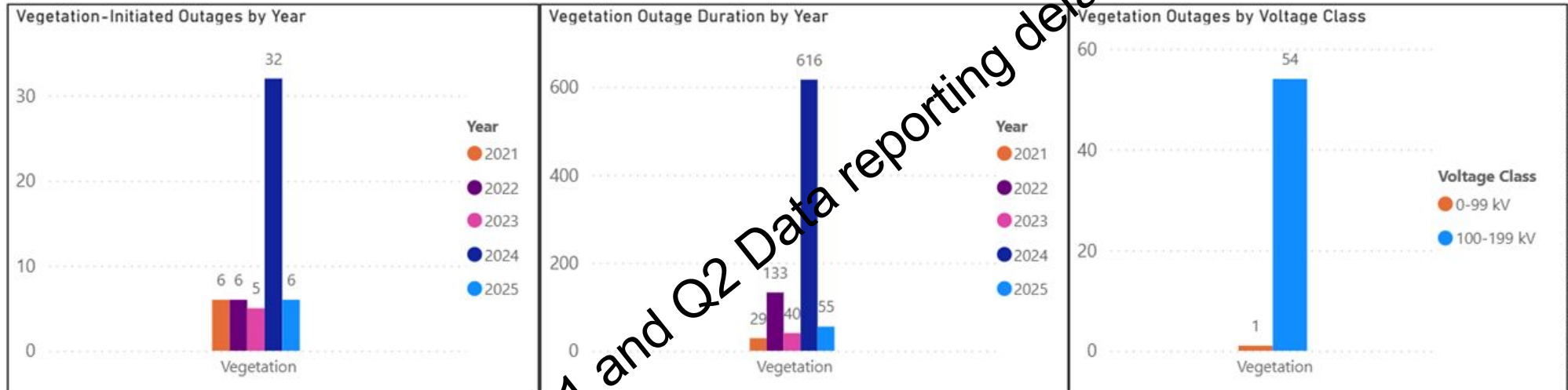
Public





Vegetation Outage Trends – Available Data

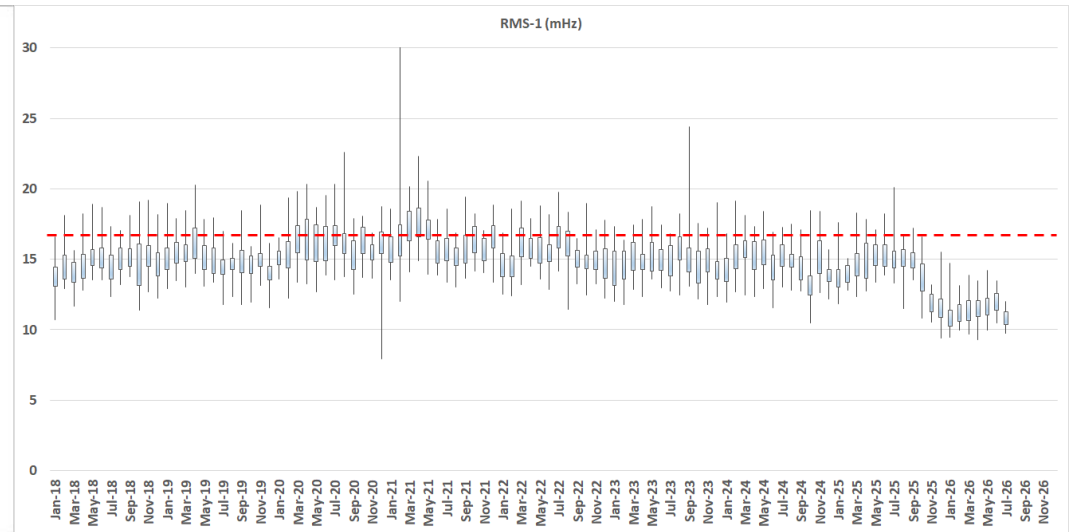
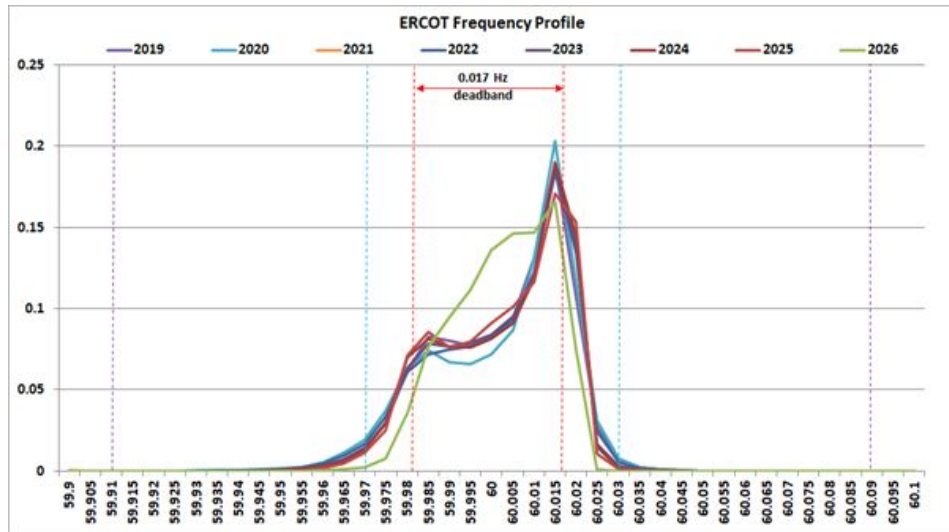
Public





Frequency Control as of August 1, 2026

Public



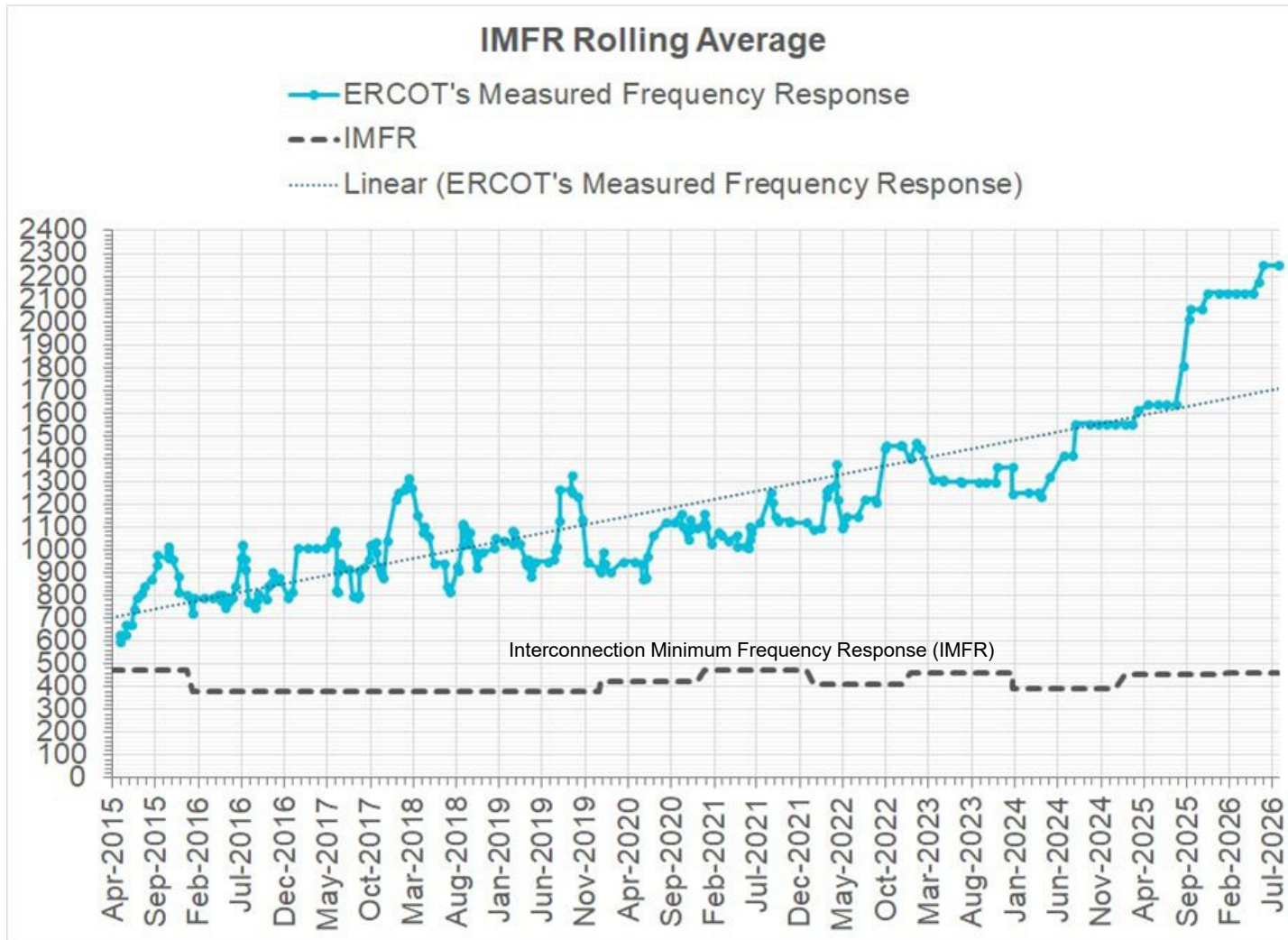
Balancing Authority ACE Limit (BAAL) Exceedances

- 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
- 0 clock-minutes of BAAL Exceedances in 2026



Primary Frequency Response – BAL-001-TRE

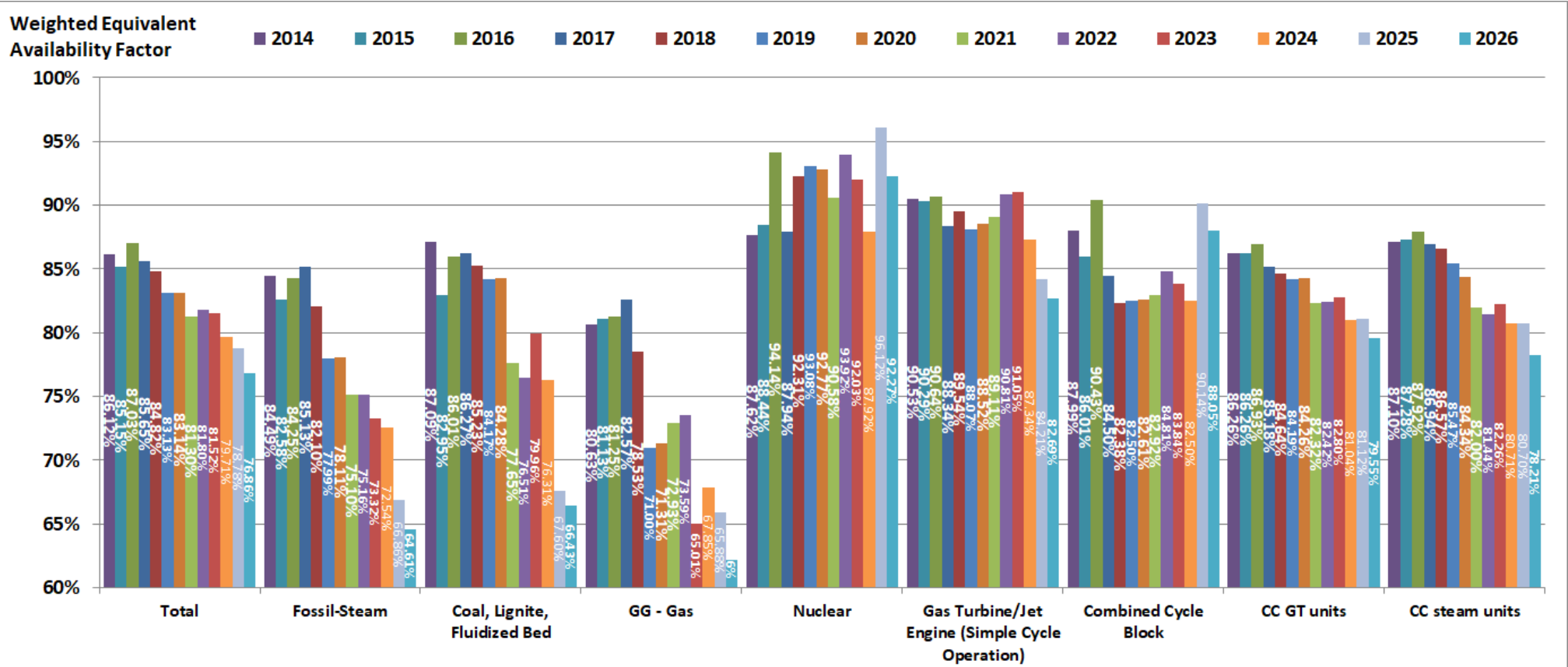
Public





Generation Availability (Conventional)

Public



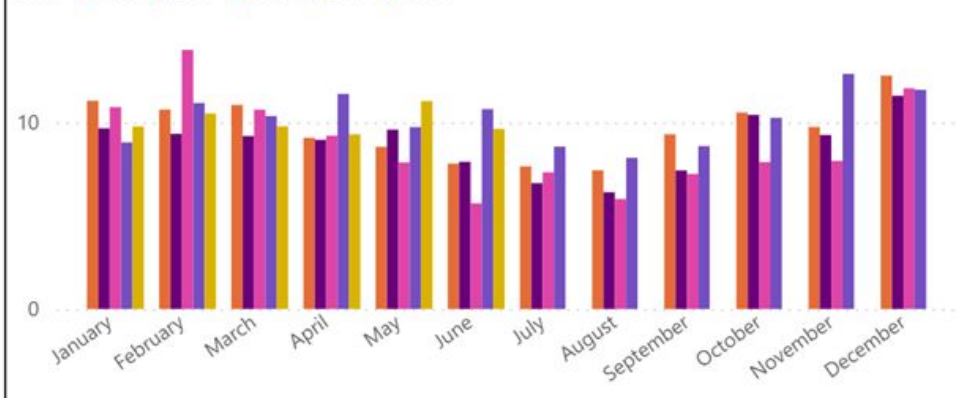


Generation Equivalent Forced Outage Rates (Conventional)

Public

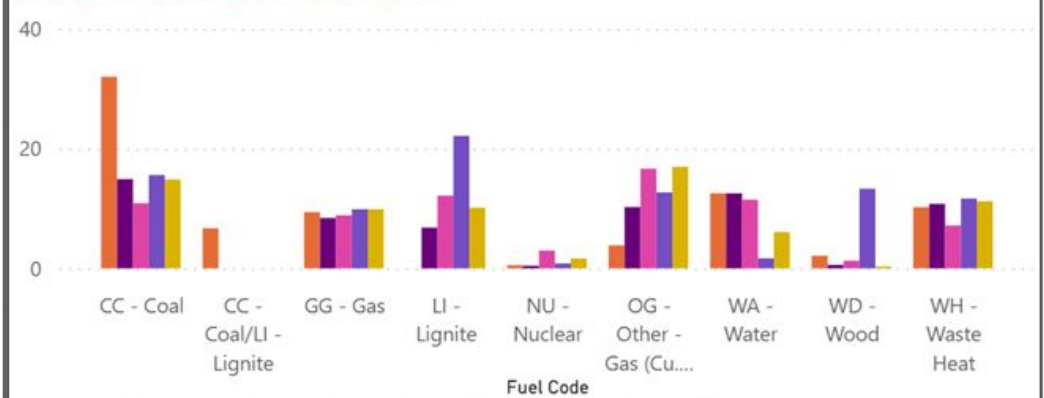
Average of Equivalent Forced Outage Rate (EFOR) by Month and Year

Year ● 2022 ● 2023 ● 2024 ● 2025 ● 2026



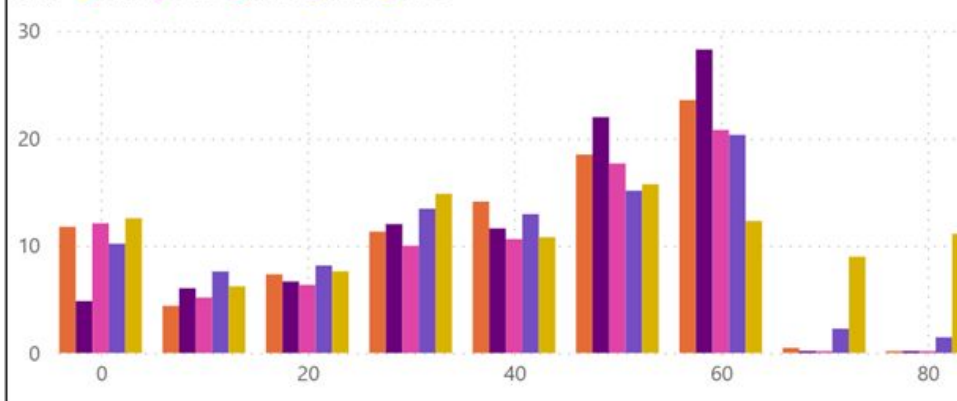
Average of Equivalent Forced Outage Rate (EFOR) by Fuel Code and Year

Year ● 2022 ● 2023 ● 2024 ● 2025 ● 2026



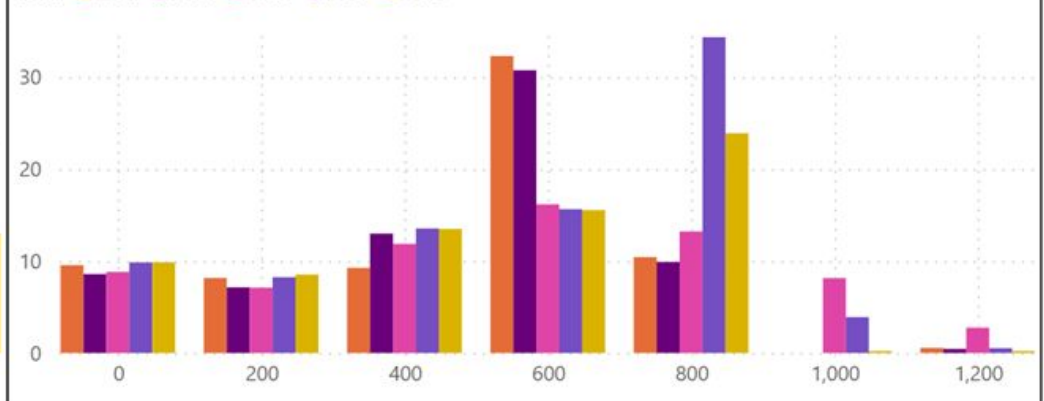
Average of Equivalent Forced Outage Rate (EFOR) by Age (bins) and Year

Year ● 2022 ● 2023 ● 2024 ● 2025 ● 2026



Average of Equivalent Forced Outage Rate (EFOR) by Unit Size and Year

Year ● 2022 ● 2023 ● 2024 ● 2025 ● 2026



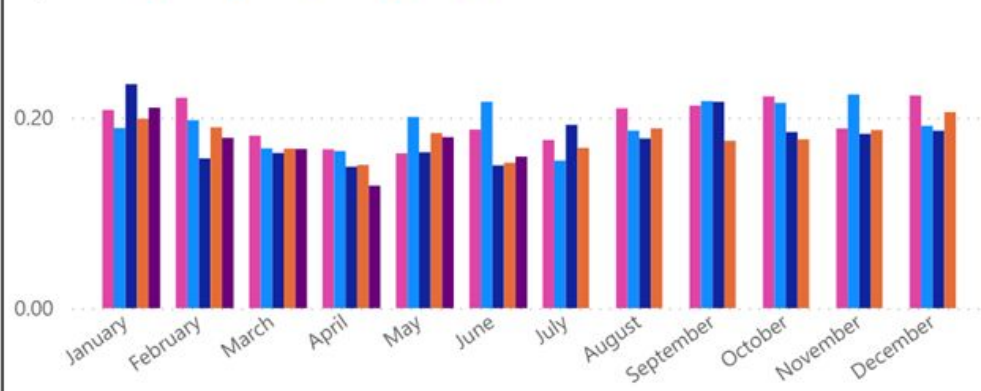


Wind GADS Metrics

Public

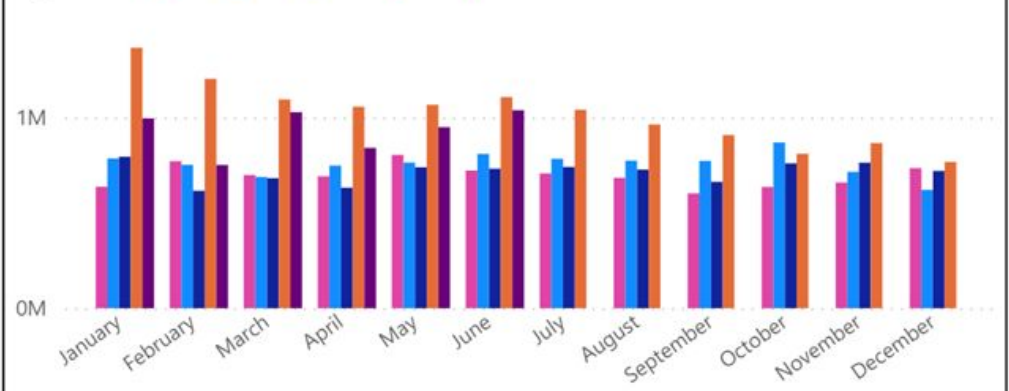
Average of (REFOR) Resource Equivalent Forced Outage Rate by Month

Report Year 2022 2023 2024 2025 2026



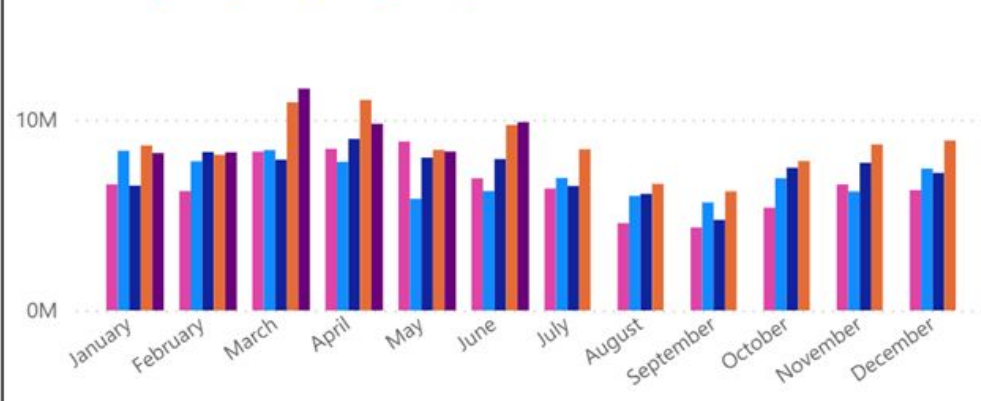
Sum of (FTH) Forced Turbine-Hours by Month and Report Year

Report Year 2022 2023 2024 2025 2026



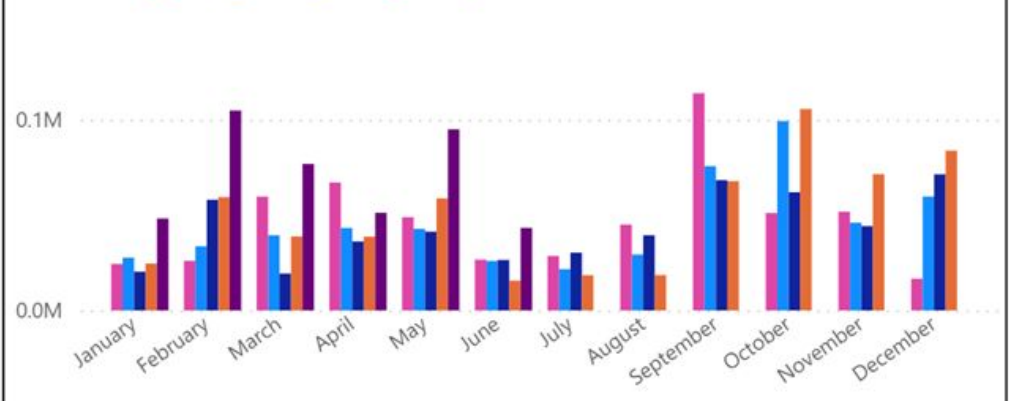
Sum of (NAG) Net Actual Generation by Month and Report Year

Report Year 2022 2023 2024 2025 2026



Sum of (PTH) Planned Turbine-Hours by Month and Report Year

Report Year 2022 2023 2024 2025 2026

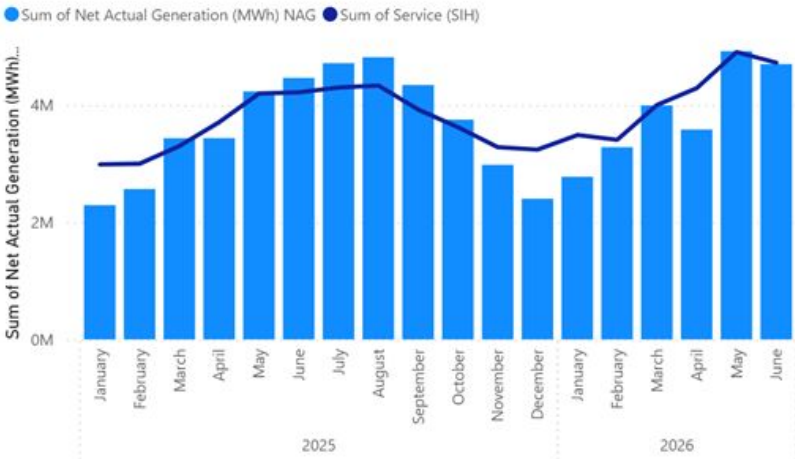




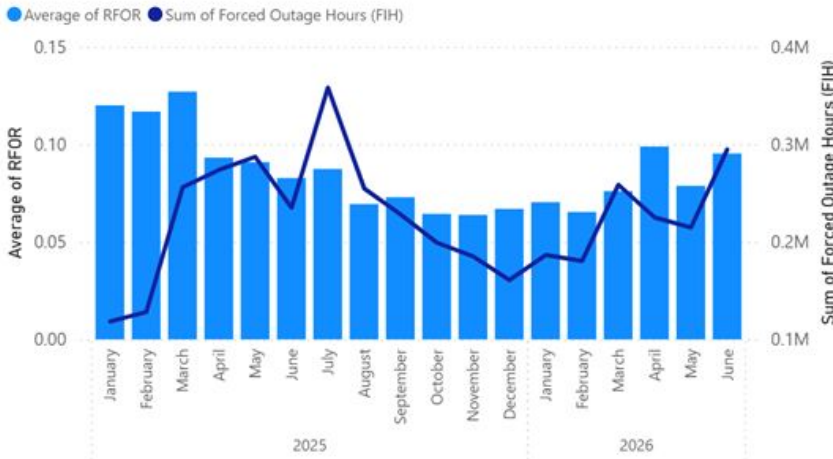
Solar GADS Metrics

Public

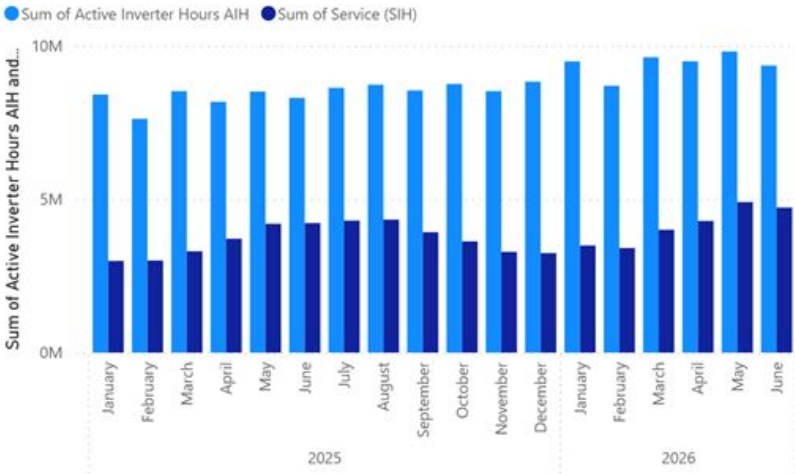
Net Actual Generation (MWh) NAG and Service Hours (SIH) by Month



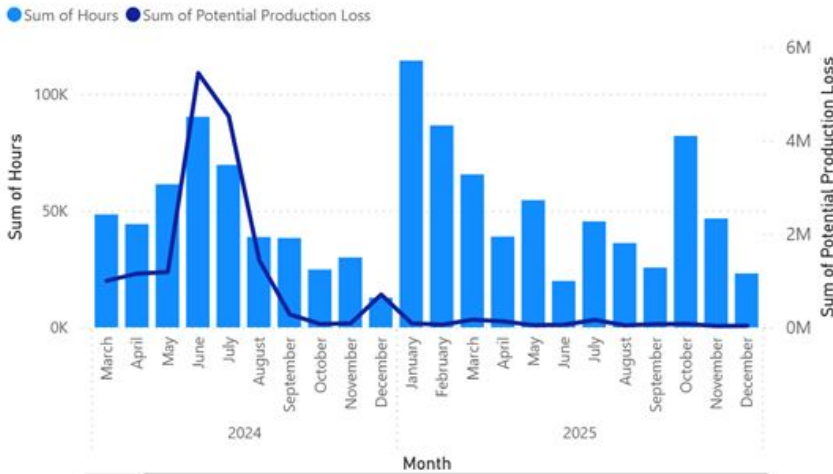
Average Forced Outage Rate and Forced Outage Hours (FIH) by Month



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



Outage Hours and Potential Production Loss by Month

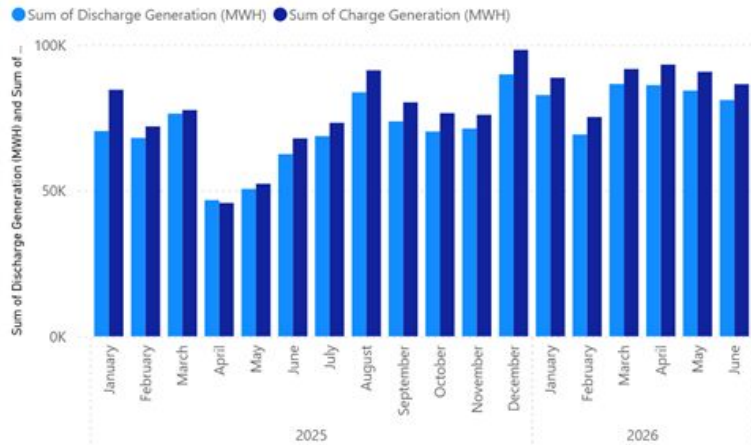




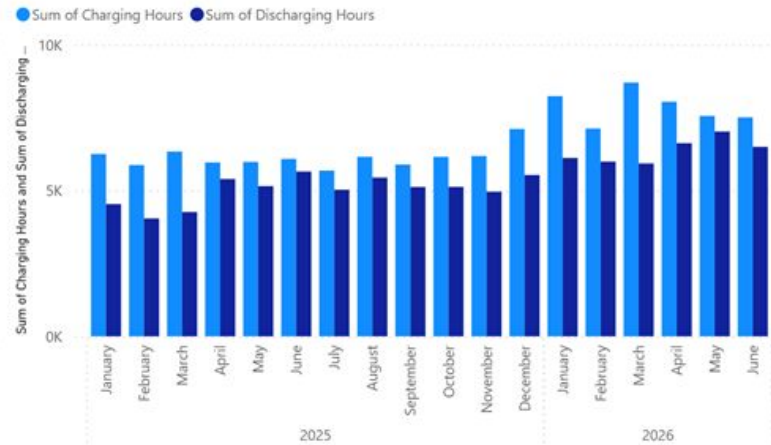
BESS GADS Metrics

Public

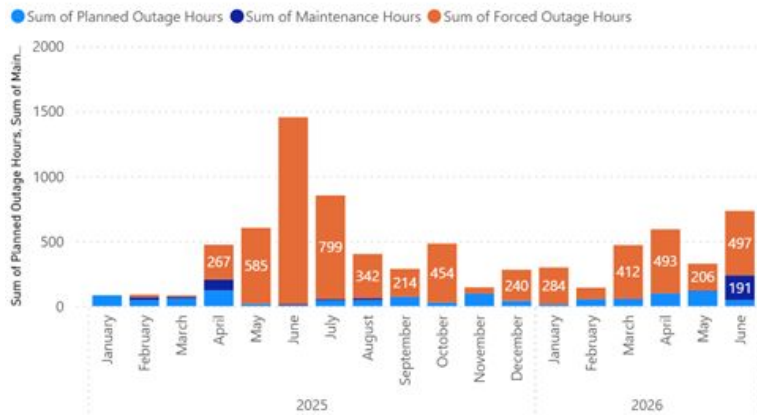
Sum of Discharge Generation (MWH) and Sum of Charge Generation (MWH) by Year and Month



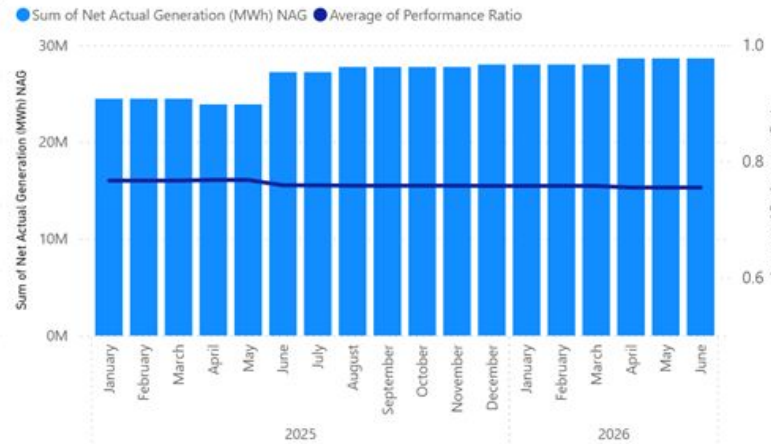
Sum of Charging Hours and Sum of Discharging Hours by Year and Month



Sum of Planned Outage Hours, Sum of Maintenance Hours and Sum of Forced Outage Hours by Year and Month



Sum of Net Actual Generation (MWh) NAG and Average of Performance Ratio by Year and Month



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

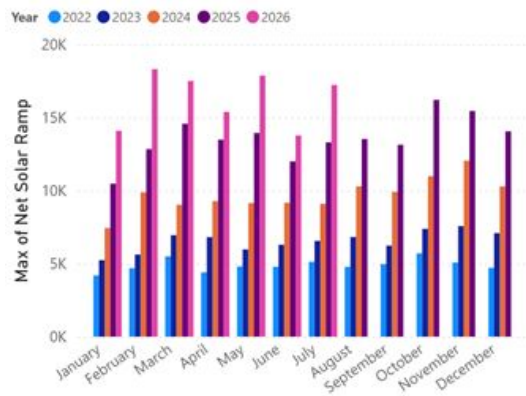


Ramping as of August 1, 2026

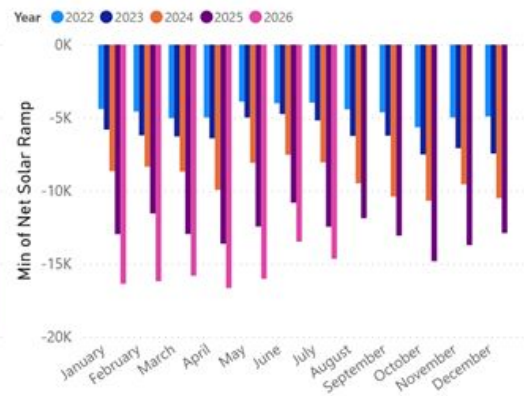
Public

2026 maximum solar up and down ramps exceeding 16,000 MW per hour

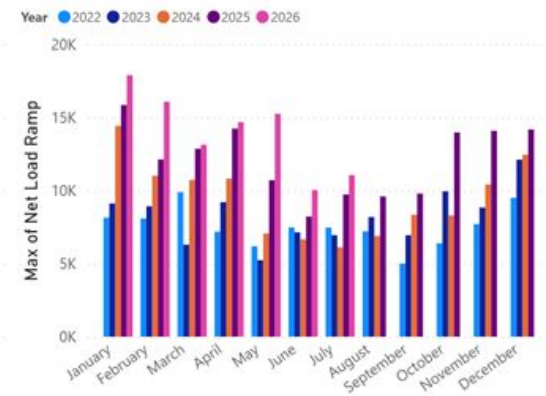
Max of Hourly Solar Up-Ramp by Month and Year



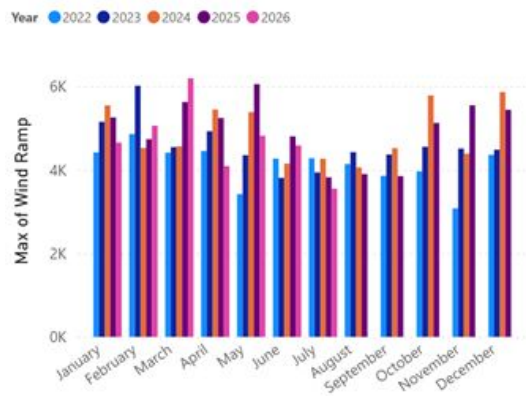
Max of Hourly Solar Down Ramp by Month and Year



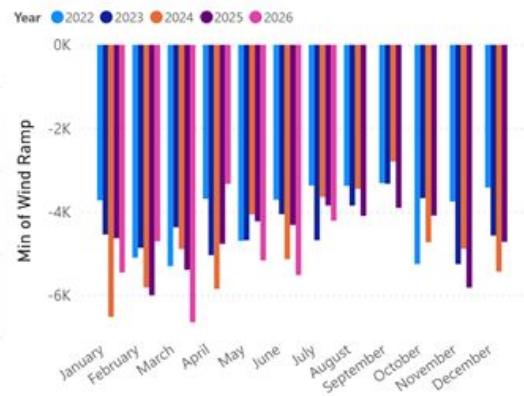
Max of Net Load Ramp by Month and Year



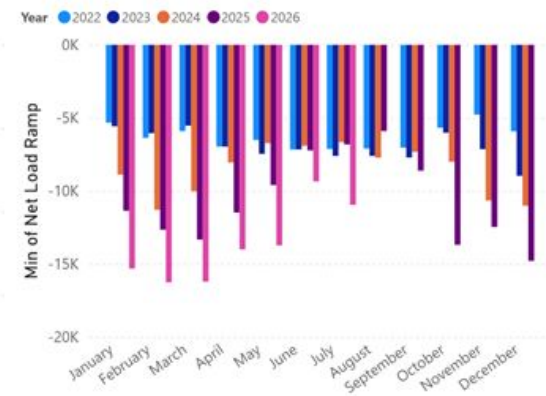
Max of Hourly Wind Up-Ramp by Month and Year



Max of Hourly Wind Down Ramp by Month and Year



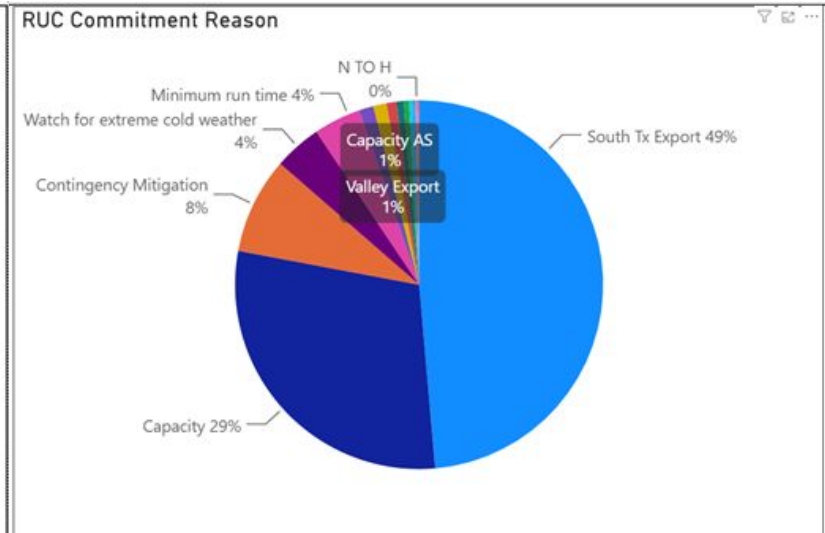
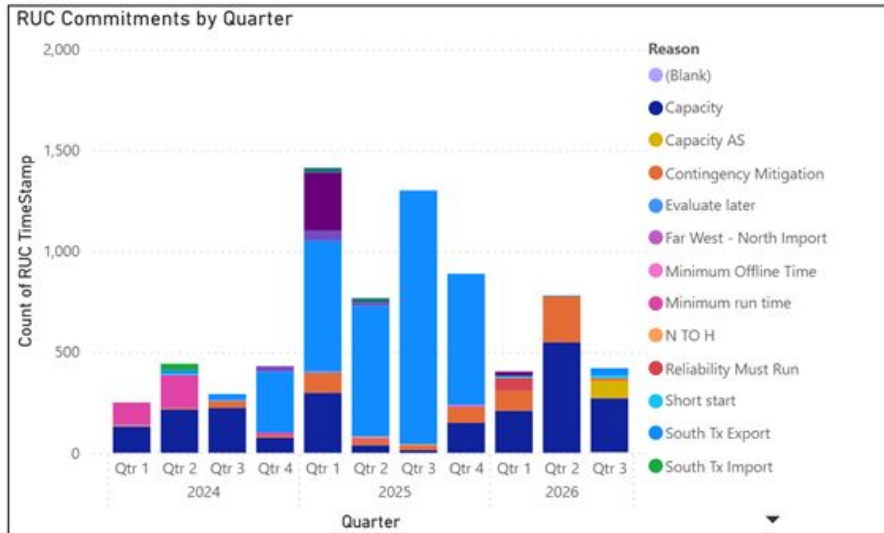
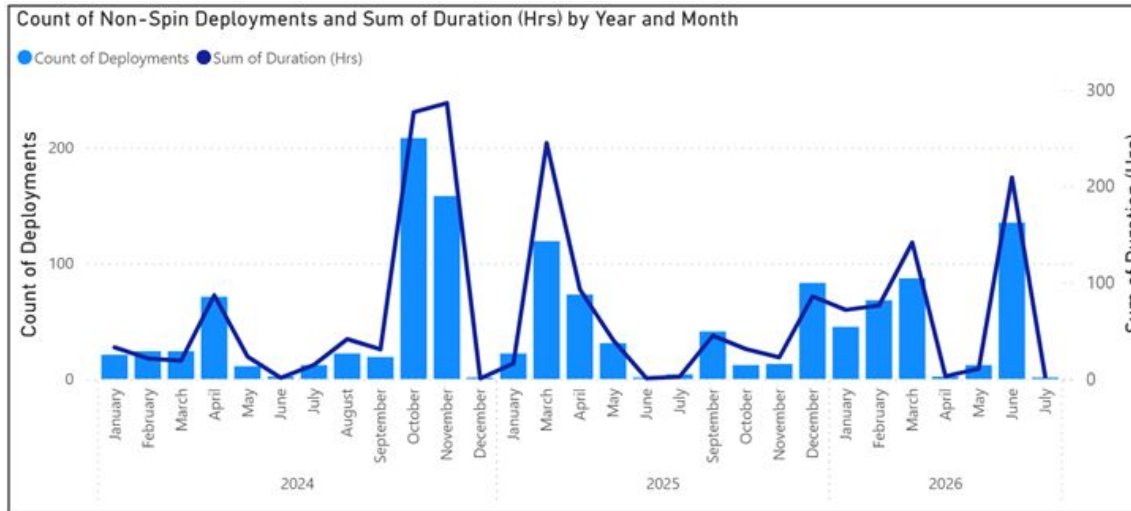
Min of Net Load Ramp by Month and Year





Non-Spin and RUC Deployments as of August 1, 2026

Public





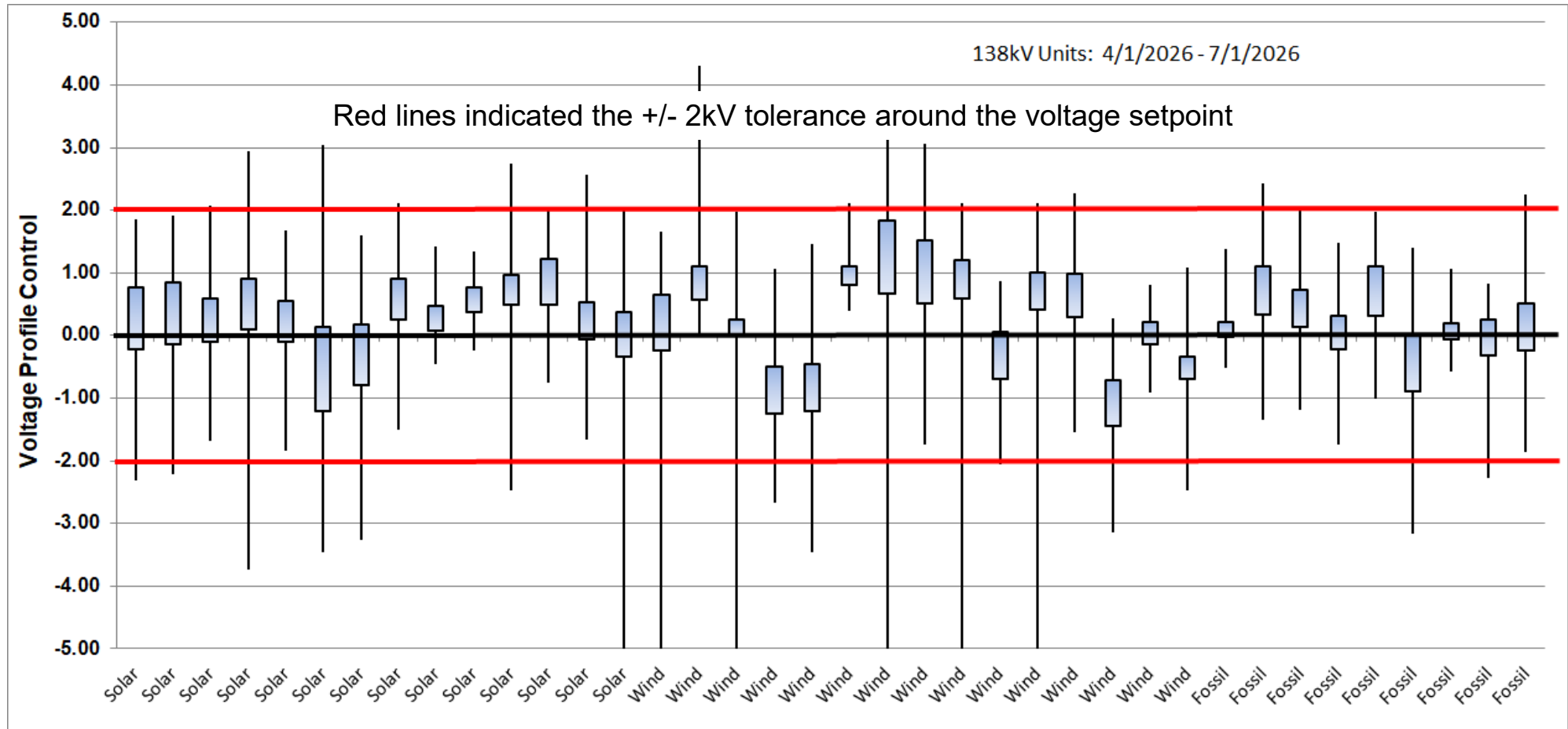
Red lines indicated the ± 4 kV tolerance around the voltage setpoint

The chart displays the distribution of Voltage Profile Control (VPC) for 30 power plants, categorized by fuel type: Solar (15) and Fossil (15). The y-axis represents VPC values from -10.00 to 10.00. Two horizontal red lines at ± 4 kV define the tolerance around the voltage setpoint. Solar power plants show a wider distribution of VPC values, with many exceeding the tolerance limits, while Fossil power plants show a narrower distribution, mostly within the tolerance limits.



Voltage Control Metrics – 138kV Units for Apr-Jun 2026

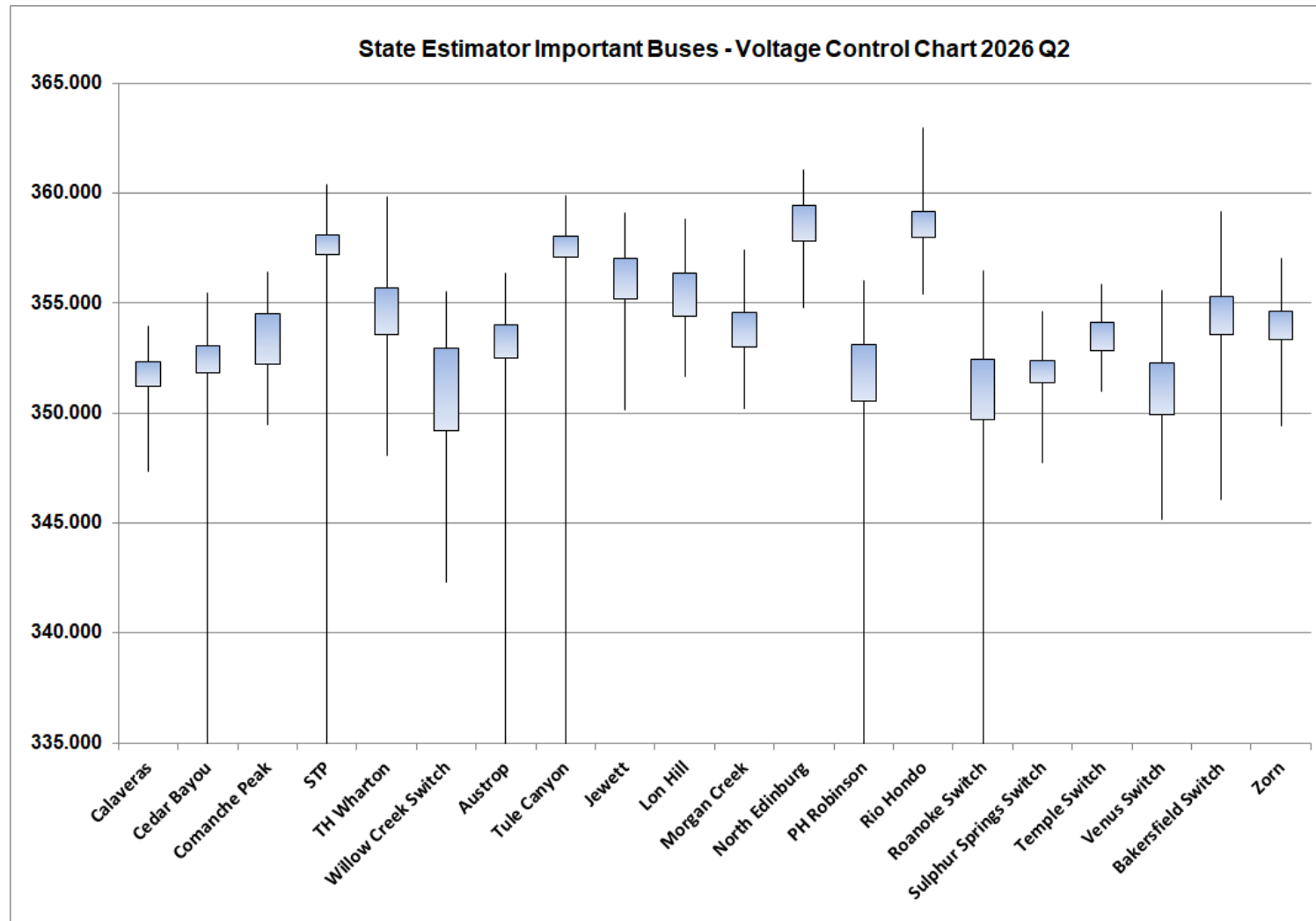
Public





Voltage Control Metrics – State Estimator Important Buses

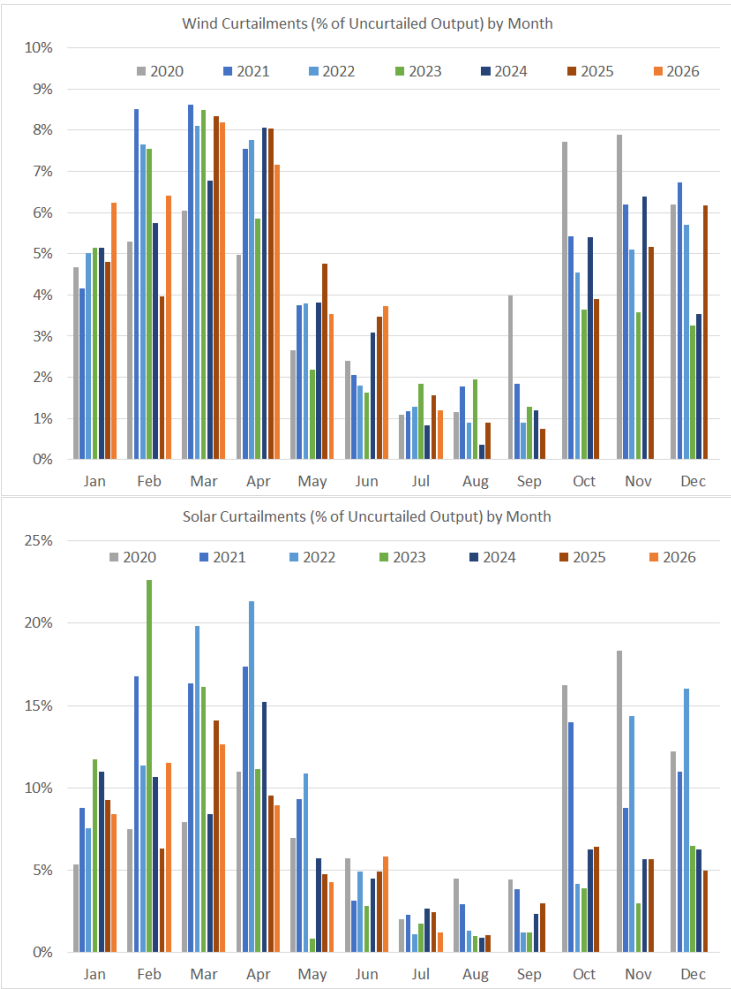
Public



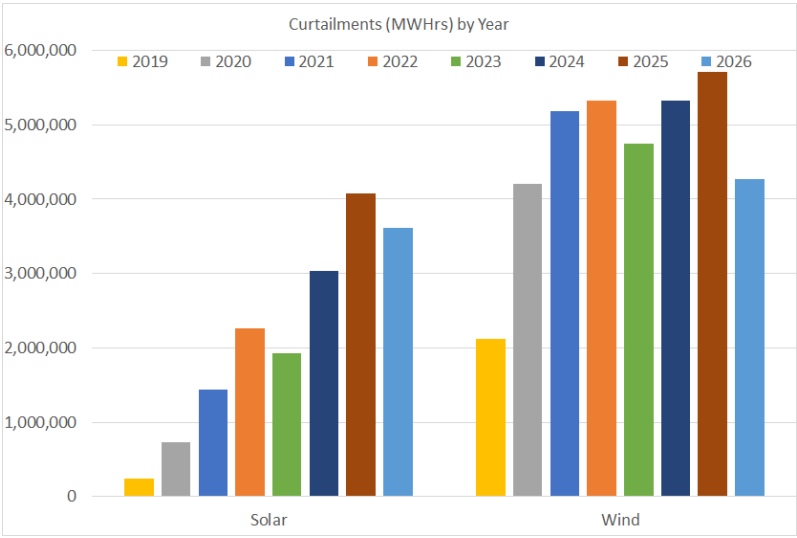


Curtailments as of August 1, 2026

Public



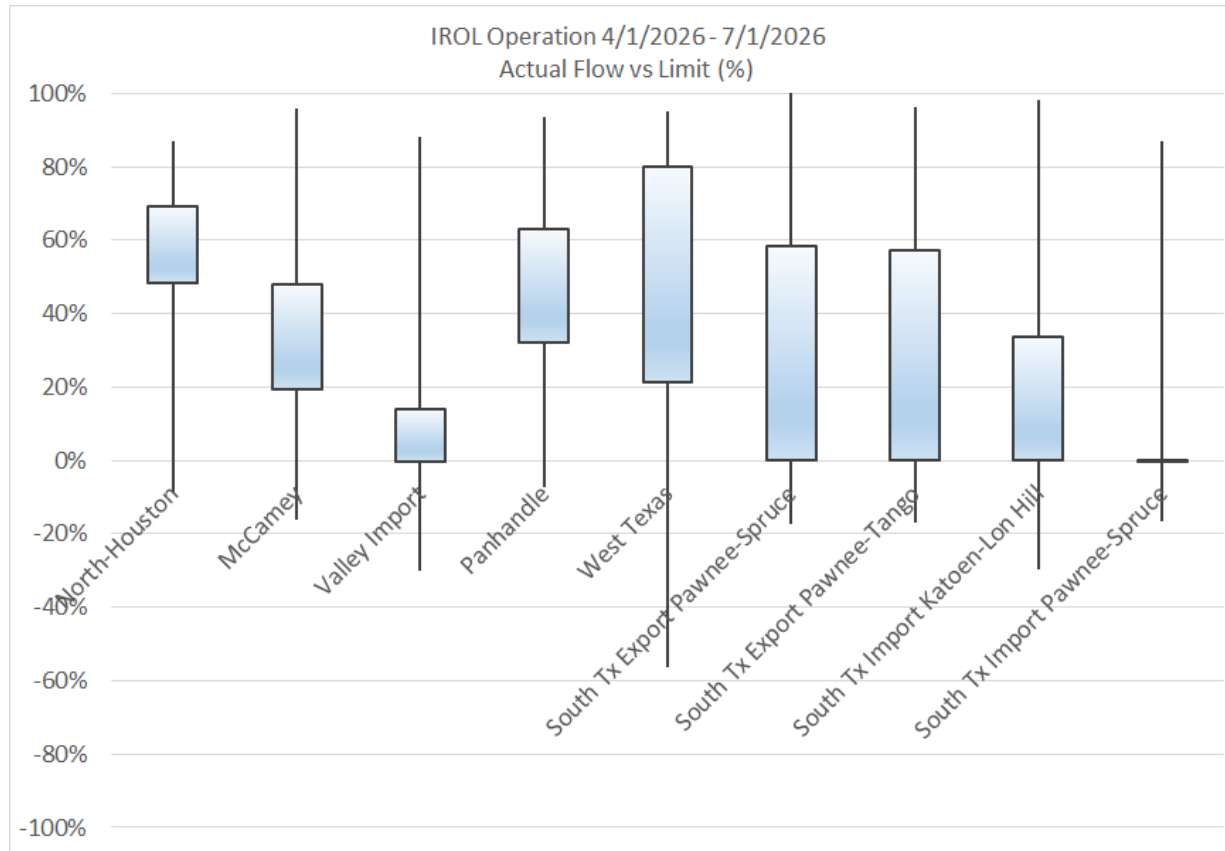
2026 YTD	Wind	Solar
GWHrs	4,272.8	3,611.5
Max Hourly MW Curtailment	8,813	15,593
Avg % of Uncurtailed Output	5.4%	7.0%





Generic Transmission Constraints

Public

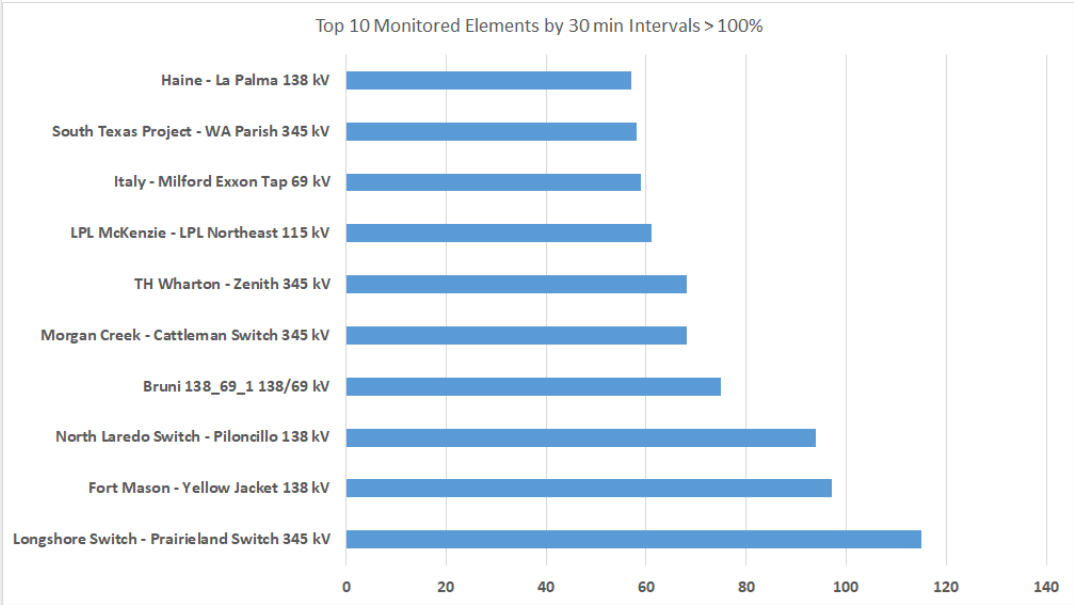
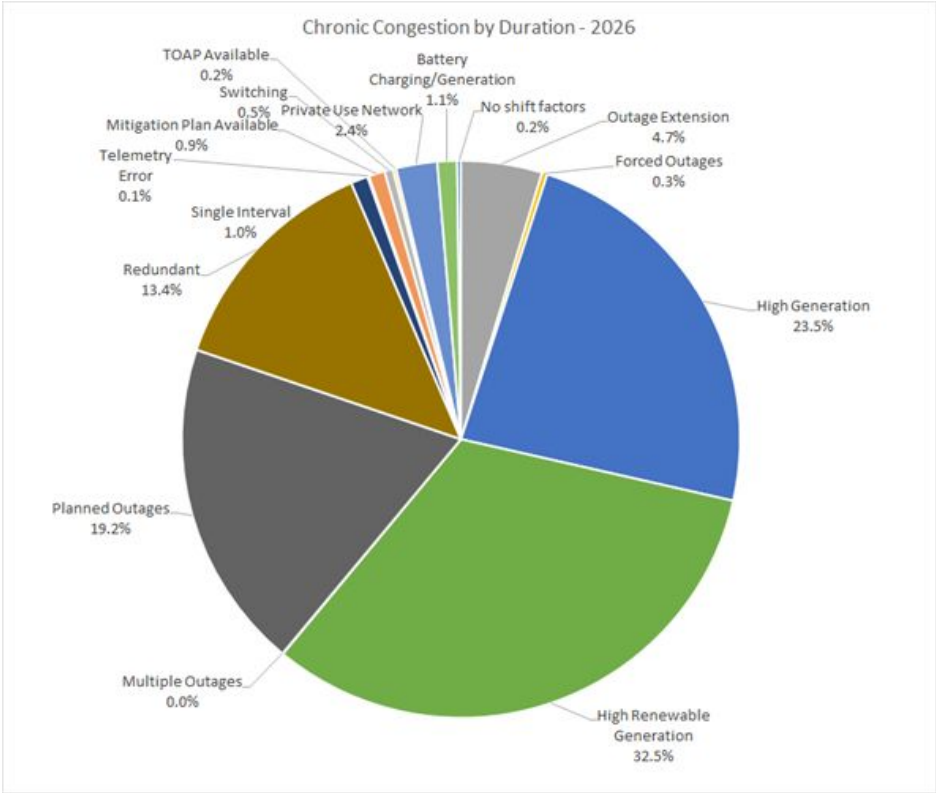


	North-Houston	McCamey	Valley Import	Panhandle	West Texas	South Tx Export Pawnee-Spruce	South Tx Import Pawnee-Spruce	South Tx Export Pawnee-Tango	South Tx Export Katoen-Lon Hill
# Minutes > 90%	0	25	0	45	4066	103	7	111	0
# Minutes > 100%	0	0	0	0	0	5	0	0	0



Transmission Congestion as of August 1, 2026

Public





Protection System Misoperations Dashboard as of July 1, 2026

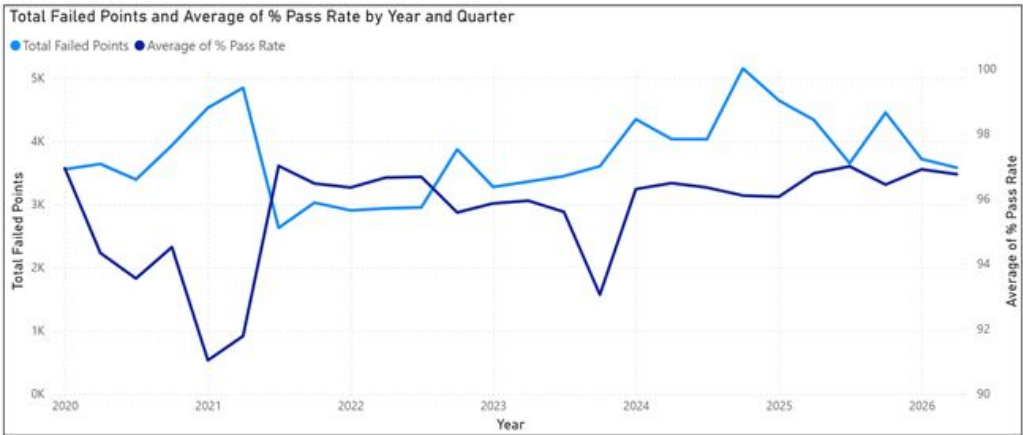
Public





Telemetry Availability and Accuracy as of August 1, 2026

Public





TEXAS RE

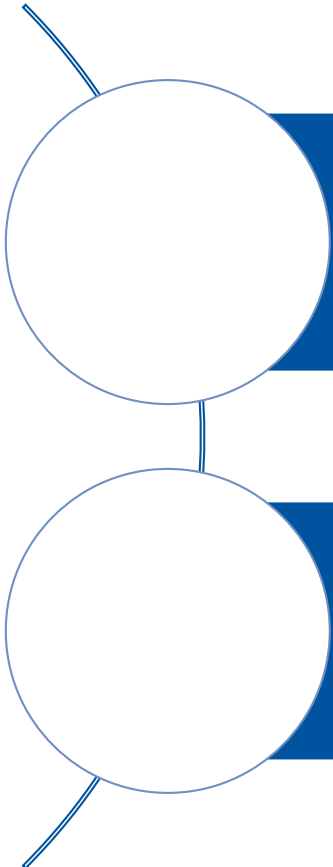
Standards Report

**Member Representatives Committee
Meeting
September 16, 2026**



Executive Summary

Public

A diagram consisting of two white circles with blue outlines, connected by a vertical blue line. Each circle has a short blue line extending from its top and bottom, giving it a speech bubble-like appearance.

**Texas RE acted on six NERC
Reliability Standard Project Phases**

**Seven High-Priority Projects in
Active Standards Development**



Texas RE Comments Submitted

Public

<u>Project Number</u>	<u>Project Name</u>	<u>Action</u>
2023-06	CIP-014 Risk Assessment Refinement	Additional Ballot and Comment Period
2023-09	Risk Management for Third Party Cloud Services	Comment Period
2025-03	Order No. 901 Operational Studies	Initial and Additional Ballots and Comment Period
2025-05	Ride-through Revisions	Initial and Additional Ballots and Comment Periods
2025-06	Supply Chain Risk Management	Initial Ballot and Comment Period



Q2 2026 NERC Filings to FERC

Public

FERC Docket Number	Filing	FERC Submittal Date
RD22-4-001	IBR Workplan Filing, April 2026 Update	4/29/2026
RD25-9-000	Wildfire Report Filing	5/1/2026
FA11-21-000	Compliance Filing in Response to January 2013 Order	5/15/2026
RR26-2-000	NERC 2025 True-up Filing	6/1/2026
RD26-6-000	Petition for Approval of CIP-015-2	6/18/2026
RD26-8-000	Petition for Approval of EOP-004-5	6/26/2026



High-Priority Active Projects

Public

2023-09 Risk
Management for
Third-Party
Cloud Services

2024-02
Planning Energy
Assurance

2025-03 Order
No. 901
Operational
Studies

2025-04 Order
No. 901
Planning Studies

2025-05 Ride-
through
Revisions

2025-06 Supply
Chain Risk
Management

2026-02
Computational
Loads



MSPP Implementation

Public

Informal Comment Period May 18 - June 17, 2026

- Rules of Procedure – Section 300
- Appendix 2 – Definitions Used in the Rules of Procedure
- Appendix 3A – Standard Processes Manual
- Appendix 3B – Election Procedure for Members of NERC Standards Committee
- Appendix 3D – Development of the Registered Ballot Body
- Reliability and Security Technical Committee Charter
- Reliability Issues Steering Committee Charter
- RISC Reliability Standard Development Subcommittee Scope Document

60-Day Formal Comment Period

- Approved by Standards Committee during its August 19, 2026 Meeting

[MSPP Webpage](#)