TEXAS RE
Ensuring electric reliability for Texans

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

May 13, 2026, at 9:00 a.m. Central Time**
8000 Metropolis Drive, Building A, Suite 300, Austin, Texas 78744

WebEx Link:
https://texasre.webex.com/texasre/j.php?MTID=mce776d62a32ecee5bc4c0914d6e3e486
Call-In: +1-855-797-9485

Item	Member Representatives Committee Meeting
1.	**Call to Order** *Daniela Hammons, MRC Vice Chair*
2.	**Antitrust Admonition*** *Thad Crow, Communications and Training Coordinator*
3.	**Approval of February 25, 2026, and April 23, 2026, Meeting Minutes* (Vote)** *Curt Brockmann, MRC Chair*
4.	**NERC BOT Meeting Update** *Daniela Hammons, MRC Vice Chair*
5.	**SAR-013 Revision to BAL-001-TRE-2 Update* (Vote)** *Rachel Coyne, Executive Chief of Staff*
6.	**Special Topics:** a. Brazos Electric's AI Program* *Shari Heino, Chief Risk and Compliance Officer and Vice President, Regulatory Compliance, Brazos Electric Power Cooperative* b. AI – Exploration and Application* *Lance Spross, Director, NERC Compliance, Oncor Electric Delivery*
7.	**ERCOT Reliability Report – RTC+B Update*** *Gordon Drake*
8.	**NSRF Update* (Vote)** *Bradley Collard*
9.	**CIPWG Update*** *Thomas Standifur*
10.	**NERC Standing Committee Updates:** a. NERC Reliability and Security Technical Committee* *Venona Greaff* b. NERC Compliance and Certification Committee* *Daniela Hammons*

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

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

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
February 25, 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		
Imane Mrini	Austin Energy	Municipal	X	
Stacy Lee (Alternate)	City of College Station	Municipal		X
Rob Robertson	Leeward Renewable Energy	Generation		X
Truong Le	Acciona Energia	Generation	X	
Jeremy Carpenter	Tenaska Power Services, Inc.	Load Serving & Marketing		X
Venona Greaff	Occidental Power Services, Inc.	Load Serving & Marketing	X	
Jeffrey A. Corbett	Texas RE Board Chair		X	
Suzanne Spaulding	Texas RE Board Vice Chair			X
Crystal E. Ashby	Texas RE Independent Director		X	
Milton B. Lee	Texas RE Independent Director		X	
Thomas Gleeson	Public Utility Commission of Texas			
Benjamin Barkley	OPUC			
Jim Albright	Texas RE		X	
Joseph Younger	Texas RE		X	
Derrick Davis	Texas RE		X	
Donna Bjornson	Texas RE		X	
Bill Carroll	Texas RE		X	

Kenath Carver	Texas RE		X	
Mark Henry	Texas RE		X	
Kara Murray	Texas RE		X	
David Penney	Texas RE		X	
Kaitlin Van Zee	Texas RE		X	
Paul Curtis	Texas RE		X	
Matthew Barbour	Texas RE		X	
Rachel Coyne	Texas RE		X	
Erin Quigley	Texas RE		X	
Brad Collard	Pedernales Electric		X	
Thomas Standifur	Austin Energy		X	
Other Texas RE staff members and stakeholders attended in person and via conference call				

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

Discussions and Activities

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

Curt Brockmann called the MRC meeting to order at 9:00 a.m. Central Time. Shari Heino gave her proxy to Jonathan Lasley. Thad Crow reviewed the antitrust admonition.

3. **Approval of December 10, 2025, MRC Meeting Minutes**

Daniela Hammons made a motion to approve the December 10, 2025, MRC meeting minutes. Frank Owens seconded the motion. The Motion passed by unanimous voice vote.

4. **NERC BOT Meeting Update**

Curt Brockmann gave the NERC BOT update, noting that the Board discussed governance guidelines and GridEx VIII, and formally accepted the Standards Modernization process.

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

Rachel Coyne, Executive Chief of Staff, presented on SAR-013 Revisions to BAL-001-TRE-2. She said the Standard Drafting Team (SDT) met on December 16, 2025, and is scheduled to meet on March 10, 2026, to determine the path forward with the project.

6. **Special Topics**

Erin Quigley, Manager, Registration and Certification, presented on Registration of Large Loads.

David Penney, Director, Reliability Services, presented on the ERCOT Voltage-Sensitive Crypto Load Reduction report.

7. **ERCOT Reliability Report – NOGRR245**

Andrew Gallo, Assistant General Counsel – Regulatory, ERCOT, presented the ERCOT Reliability report on NOGRR245.

8. **NSRF Update**

Brad Collard, NSRF Chair, reported on the January NSRF meeting discussions and upcoming meeting topics. He said Requirement 1 of TPL-008-1, Transmission System Planning Performance Requirements for Extreme Temperature Events is becoming effective.

9. **CIPWG Update**

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

10. **NERC Standing Committee Updates**

Venona Greaff gave an update on the RSTC's recent meetings. She said the committee heard work group plans for 2026 and approved an RSTC work plan. She said the committee's Q2 meeting will be April 29-30, 2026, in Pensacola, Florida.

Daniela Hammons provided an update on the January CCC meeting, where the committee discussed consistency in ERO Enterprise internal controls assessments.

11. **Program Area Quarterly Reports**

Joseph Younger, Senior Vice President and Chief Operating Officer, noted that NERC revised the 2026 CMEP Implementation Plan to add a new risk element that will look at communications protocols and operating instructions.

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

12. Other Business & Future Agenda Items

None.

The meeting adjourned at 10:36 a.m. Central Time.

Member Representatives Committee Meeting
April 23, 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		
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		X
Stacy Lee (Alternate)	City of College Station	Municipal		
Rob Robertson	Leeward Renewable Energy	Generation		X
Truong Le	Acciona Energia	Generation		X
Jeremy Carpenter	Tenaska Power Services, Inc.	Load Serving & Marketing		X
Venona Greaff	Occidental Power Services, Inc.	Load Serving & Marketing		X
Jim Albright	Texas RE		X	
Joseph Younger	Texas RE		X	
Derrick Davis	Texas RE		X	
Donna Bjornson	Texas RE		X	
Other Texas RE staff members and stakeholders attended in person and via conference call				

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

Discussions and Activities

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

Curt Brockmann called the MRC meeting to order at 11:01 a.m. Central Time. Daniela Hammons gave her proxy to Lance Spross. Thad Crow reviewed the antitrust admonition.

2. **Review and Recommendation of the 2027 Business Plan and Budget**

Jim Albright, Joseph Younger, and Donna Bjornson presented on the proposed 2027 Business Plan and Budget. They said the proposed 2027 budget reflects an overall increase of 8.4% including technology investments, the addition of three FTEs, and increased staff costs and related benefits, for a total budget of $23,419,496. Mr. Younger discussed the need for the additional FTEs: a Reliability Services Assessments Manager, a Registration and Certification SME, and a Senior Accountant. Ms. Bjornson reviewed numbers from each category of the budget.

Lance Spross made a motion for the MRC to recommend that the Texas RE Board approve the proposed 2027 Business Plan and Budget. Shari Heino seconded the motion. The Motion passed by unanimous voice vote.

3. **Other Business & Future Agenda Items**

None.

The meeting adjourned at 11:40 a.m. Central Time.

MEMORANDUM

To:	Texas RE Member Representatives Committee
From:	Rachel Coyne, Executive Chief of Staff
Date:	May 13, 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 post proposed Regional Standard BAL-001-TRE-3 for an additional 45-day comment and ballot period.

During the December 10, 2025, MRC meeting, I reported that the recent ballot for draft Regional Standard BAL-001-TRE-3 and implementation plan passed the ballot and the Standard Drafting Team (SDT) met on December 3, 2025, to review comments.

The SDT met again on December 16, 2025, to continue its discussions from the previous meeting. Texas RE and leadership worked together to draft revised language to Regional Standard BAL-001-TRE-3 to ensure it meets the objectives of the SAR. The SDT met on March 10, 2026, to determine next steps of the project. During this meeting, the team finalized the revised language based on comments from stakeholders and SDT discussions. The quality review process took place from March 16 – April 3, 2026.

Based on its review, the SDT determined that certain revisions were substantive in nature. As such, Texas RE is requesting the MRC approve proposed Regional Standard BAL-001-TRE-3 for an additional 45-day comment period with a ballot period occurring during the last 15 days to ensure transparency and provide an opportunity for comment on the revised Regional Standard in light of these changes. I have included the following documents for the MRC's consideration:

- 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

Additionally, consistent with ensuring transparency and opportunity for comment and participation, Texas RE will solicit new members of the Registered Ballot Body and Registered Ballot Pool ahead of the ballot period, in accordance with the Regional Standards Processes Manual.

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

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

Member Representatives Committee Meeting

May 13, 2026

Public

SAR-013 Project Activity (June 2025 – April 2026)

September 22 – November 6, 2025:
Public posting period

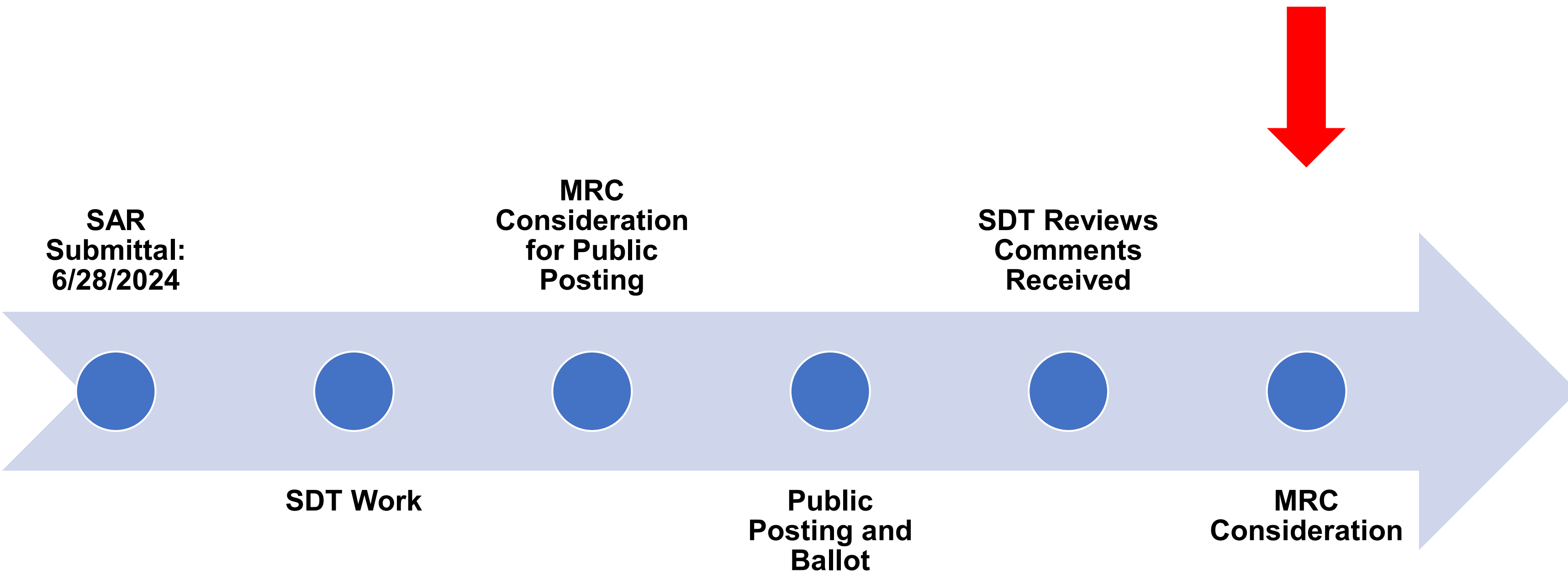
December 3, 2025:
SDT meeting to review comments

December 16, 2025:
SDT meeting to continue discussions

March 10, 2026:
SDT meeting to determine next steps

March 16 – April 3, 2026
Quality Review

SAR-013 Timeline



Standard Authorization Request

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

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

Define PFR performance requirements for battery energy storage systems (BESSs)

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

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

Milestone	Anticipated Date	Location	Comments
Standard Drafting Team Kick-off Meeting • The SDT shall elect the permanent chair and vice chair.	12/19/2024	Conference Call	
RSM and SDT develop a work plan.	1/21/2025	Conference Call	
SDT has first working meeting • SDT drafts the work product	2/7/2025	Conference Call	
Work plan delivered to the MRC.	2/19/2025	Hybrid MRC Meeting at Texas RE	
Subsequent SDT meeting(s) to draft the work product	Q2 2025	Conference Call/Possible Hybrid Meeting	
MRC approves the work product to be posted for a public comment and ballot period.	9/17/2025	Conference Call or Hybrid MRC Meeting at Texas RE	
The RSM shall post the work product for a 45-day public comment period with the ballot period occurring in the last 15 days.	9/22/2025 – 11/6/2025	N/A	
The RSM shall send a notice for registered entities to join the Registered Ballot Pool (RBP).	9/22/2025	N/A	
The SDT shall meet to discuss comments received within 30 days of the conclusion of the posting period. During the meeting, the SDT shall: • prepare responses to comments received; and • prepare a "modification report".	12/3/2025 12/12/2025 12/16/2025	Conference Call	

SDT Meeting to finalize revisions to proposed Regional Standard BAL-001-TRE-3	3/10/2026	Conference Call	
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.	Q2 2026	Via Email	
The RSM shall send a notice for registered entities to join the Registered Ballot Pool (RBP).	Q2 2026	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".	Q2-Q3 2026	Conference Call	
When the ballot passes in accordance with section 4.12 and 4.13, the RSM shall conduct a final ballot.	Q3 2026	N/A	
Once the final ballot final ballot, the MRC shall approve the final Work Product to be provided to the Texas RE Board for action.	Q3/Q4 2026	Conference Call or Hybrid MRC Meeting at Texas RE	
The Work Product shall be posted at least seven days prior to action by the Texas RE Board.	Q3/Q4 2026	N/A	
If deemed appropriate, the Texas RE Board will adopt the work product.	Q3/Q4 2026	Conference Call or Hybrid Board Meeting at Texas RE	
The RSM will submit the work product to NERC.	Q3/Q4 2026	N/A	
Once the Work Product is approved by FERC, the RSM shall send	TBD	N/A	

notification of the effective date to Texas RE stakeholders.			

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 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.

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

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.

Where

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

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

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

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

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

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]*

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

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.

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

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

D. Regional Variances

None

E. Associated Documents

Regional Standard BAL-001-TRE-3 Implementation Plan

Version History

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

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

Standard Attachments

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

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

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

Attachment 1

Primary Frequency Response Reference Document

Texas Reliability Entity, Inc.
BAL-001-TRE-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 available[1] for reference and use in understanding and performing these calculations.

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

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

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

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.

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.

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

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

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

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

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

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.

ramp to represent the ramp that should have been achieved during the post-perturbation measurement period.

Expected Primary Frequency Response (EPFR)

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

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

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

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

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

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

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

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

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

Where:

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

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

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

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

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

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

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

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

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

$EPFR_{final}$ for Steam Turbine

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

Where:

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

Where:

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

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

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

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

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

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

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

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.

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.

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

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.

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)

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

$P.U.SPFR_{Resource}$ 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.

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

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

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 (*$ASPFR_{Adj}$*)

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

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 = ($MW_{T-4} - MW_{T-60}$) x 0.821

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

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

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

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

This $ESPFR_{final}$ is the MW value a unit should have responded with if it is properly sustaining the output of its generating unit/generating facility in response to an FME. Determination of this value begins with establishing where it would be in an ideal situation; considers proper droop and dead-band values established in Requirement R6, 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.

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

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

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

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

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

Capacity 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

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

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

$ESPFR_{final}$ for Steam Turbine

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

Where:

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

Where:

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

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

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

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

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

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

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

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

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

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 ($Hz_{Post\text{-}perturbation}$ < 60 if:

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

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

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

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

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

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[4]; 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.

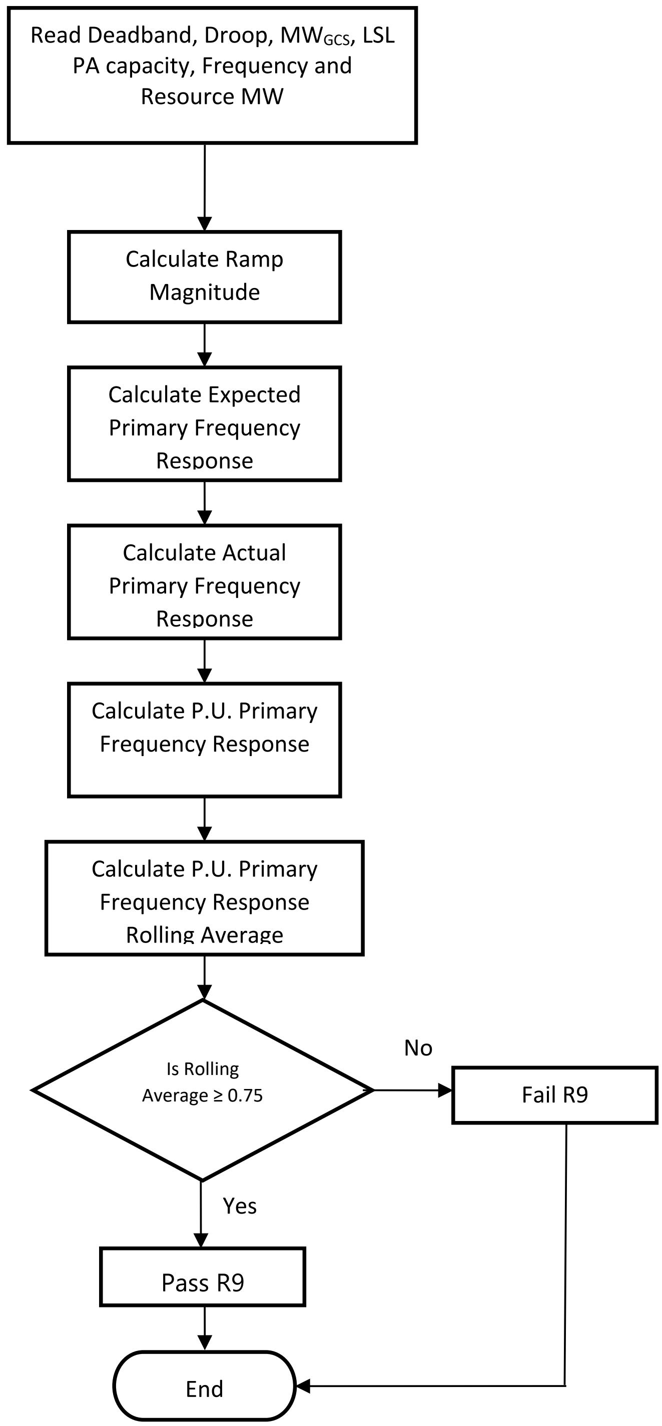
[4] In this circumstance, when frequency is below 60 Hz, the EPFR$_{final}$ is set to operating margin based on MW$_{GCS}$ (adjusted for any augmentation capacity) AND when frequency is above 60 Hz, the EPFR$_{final}$ is set to operating margin based on LSL for the purpose of calculating PUPFR$_{resource}$.

Attachment A to
Primary Frequency Response Reference Document

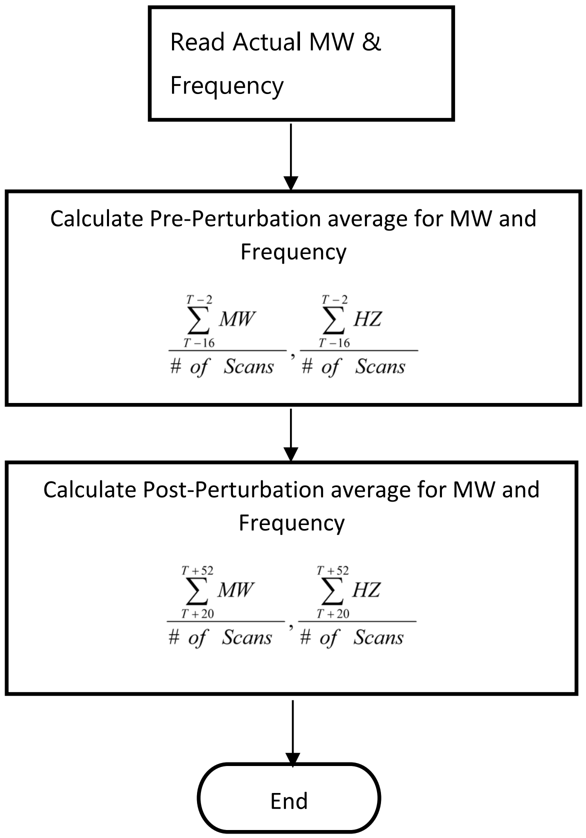
Initial Primary Frequency Response Methodology for
BAL-001-TRE-3

Primary Frequency Response Measurement and Rolling Average Calculation – Initial Response

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


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

Pre/Post-Perturbation Average MW and Average Frequency Calculations



Ramp Magnitude Calculation

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

End

(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.

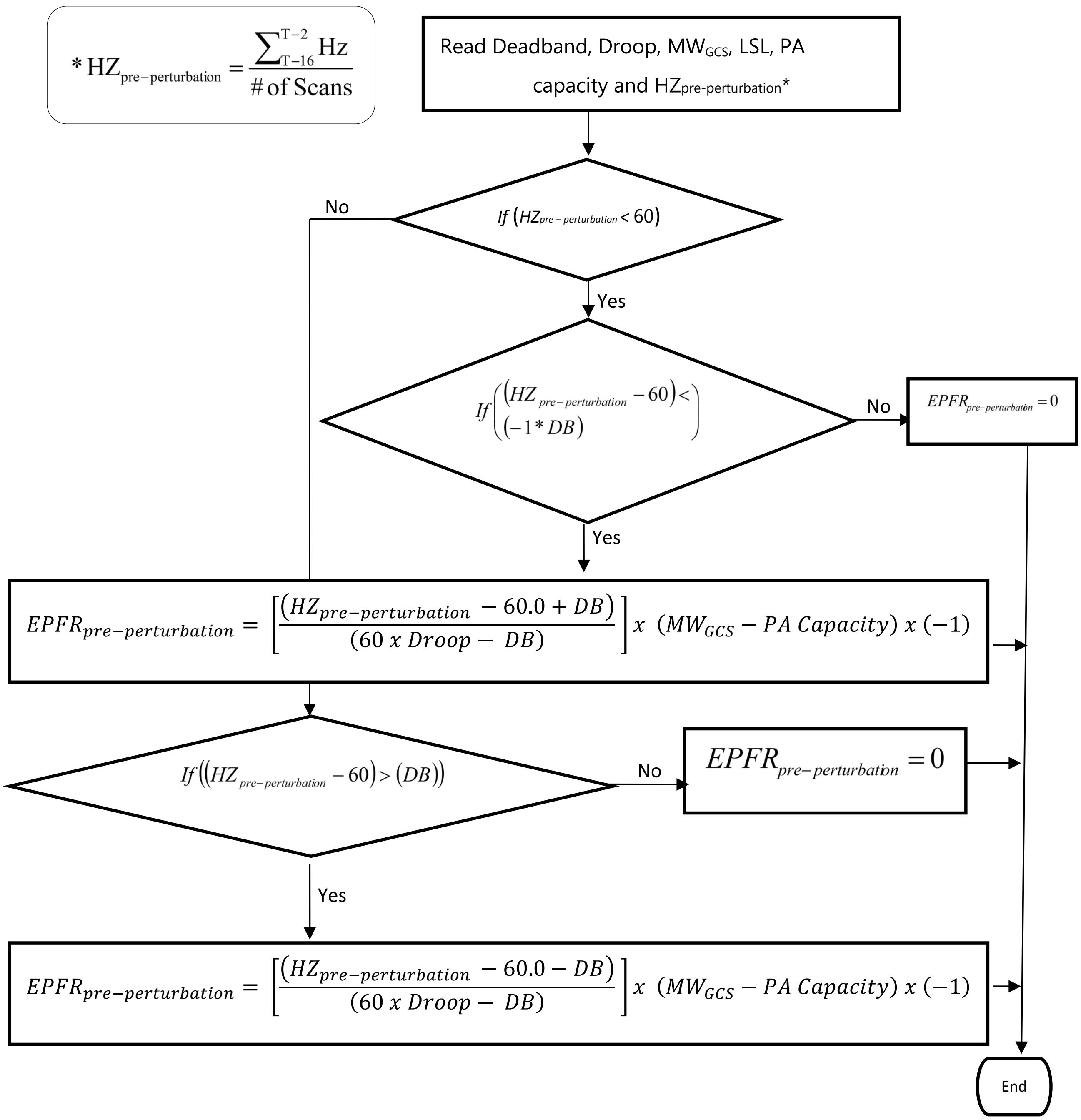
Actual Primary Frequency Response (APFRAdj)

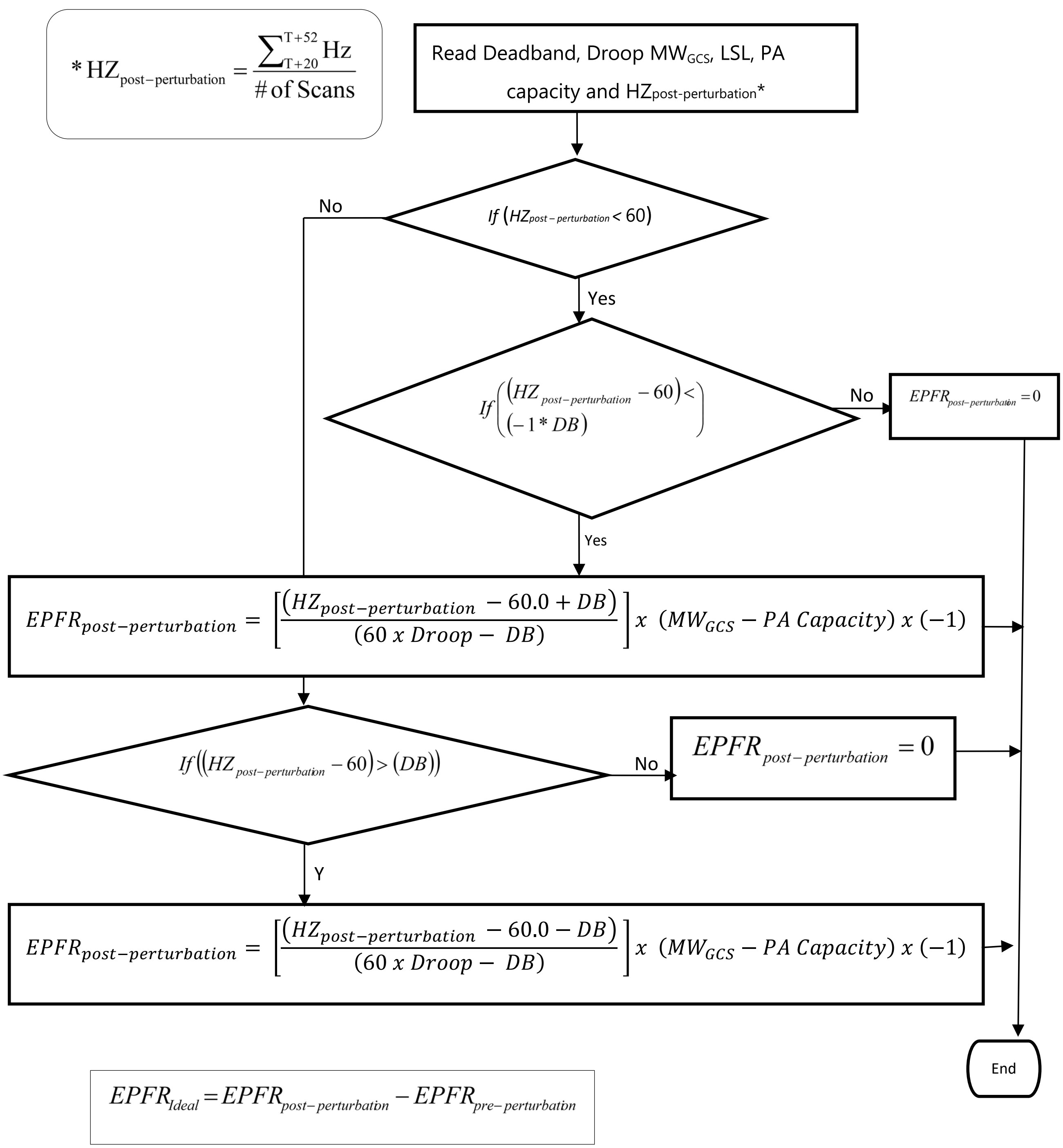
$$APFR_{Adj} = MW_{post\text{-}perturbation} - MW_{pre\text{-}perturbation} - \text{Ramp Magnitude}$$

End

Expected Primary Frequency Response Calculation

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




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

Adjustment for Steam Turbine

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

↓

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

↓

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

↓

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

↓

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

↓

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

↓

End

Adjustment for Combustion Turbines and Combined Cycle Facilities

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

↓

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

↓

End

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

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

Read MW_{GCS}, capacity not expected to provide PFR

↓

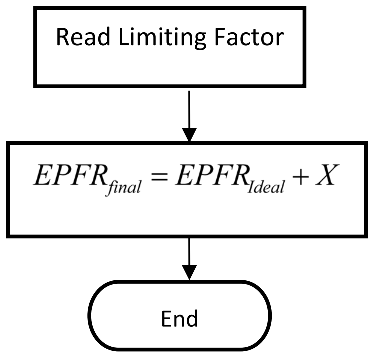
$$EPFR_{final} = Minimum\ (EPFR_{ideal}, MW_{GCS} - capacity\ not\ expected\ to\ provide\ PFR)$$

↓

End

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.

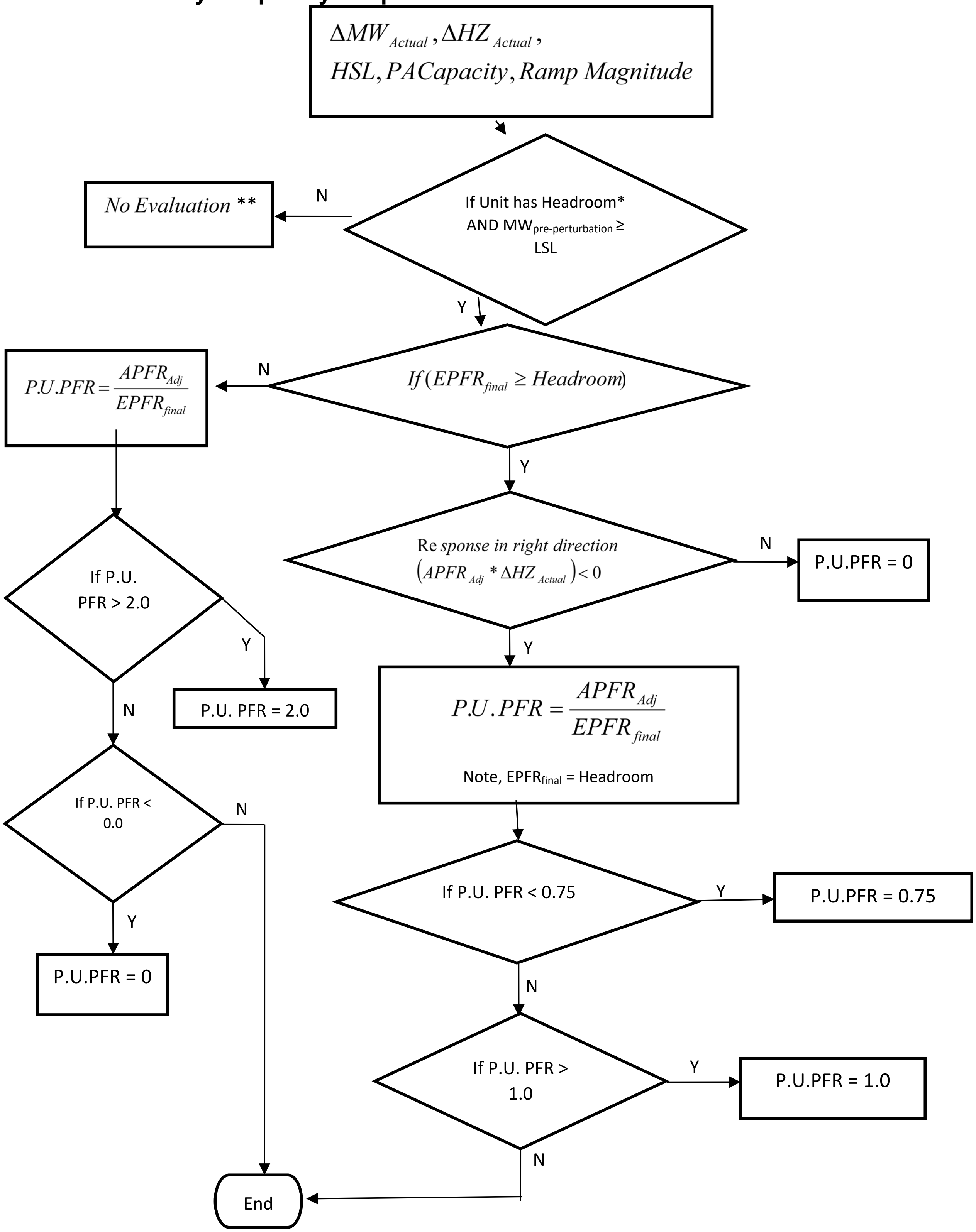
Adjustment for Other Units



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

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

P.U. Initial Primary Frequency Response Calculation



*Check for adequate up headroom, low frequency events. Headroom must be greater than either XMW or 2% of (MW_{GCS} less PA capacity 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:

$$\boxed{Headroom = HSL - PA\ Capacity - capcity\ not\ expeced\ to\ respond\ with\ PFR - MW_{T-2}}$$

For high frequency events:

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

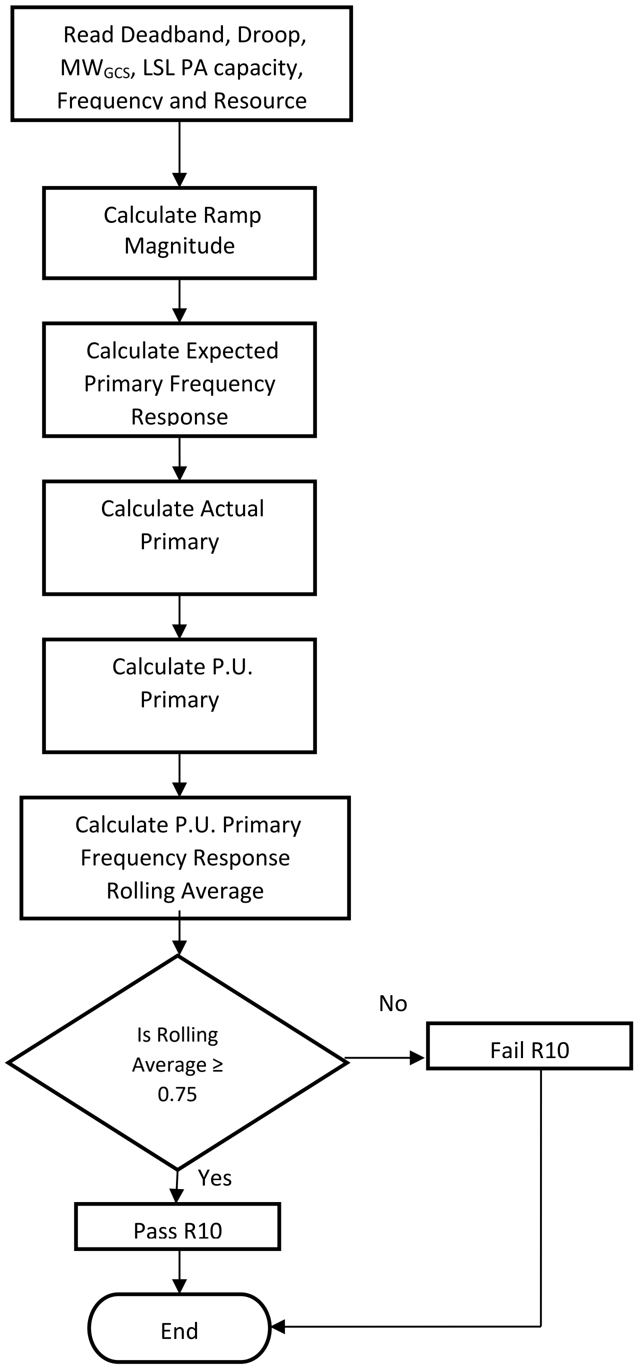
**No further evaluation is required for Sustained Primary Frequency Response. This event will not be included in the Rolling Average calculation of either Initial or Sustained Primary Frequency Response.

T = Time in Seconds

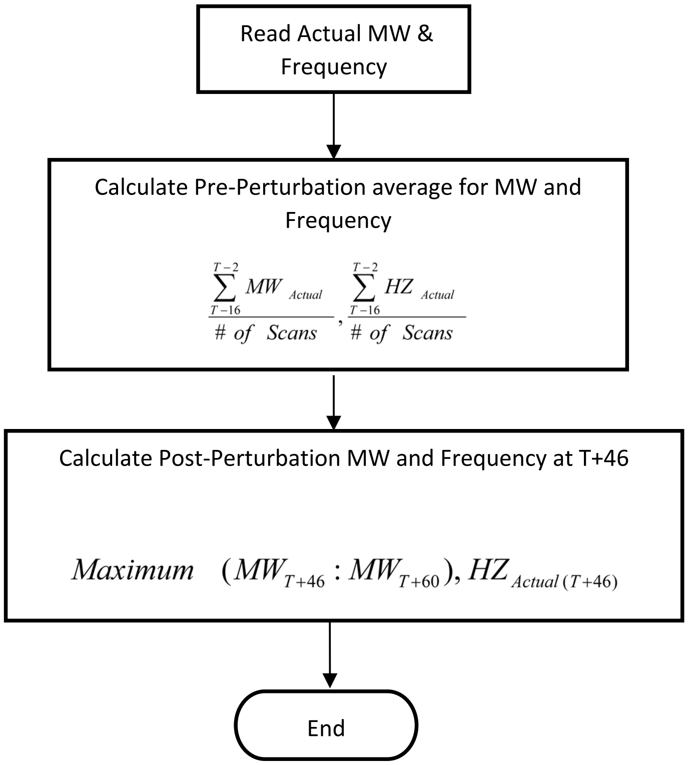
Attachment B to
Primary Frequency Response Reference Document

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

Primary Frequency Response Measurement and Rolling Average Calculation–Sustained Response



Pre/Post-Perturbation Average MW and Average Frequency Calculations



Ramp Magnitude Calculation - Sustained

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

$$\downarrow$$

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.

Actual Sustained Primary Frequency Response (ASPFRadj)

For low frequency events:

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

$$\downarrow$$

End

For high frequency events:

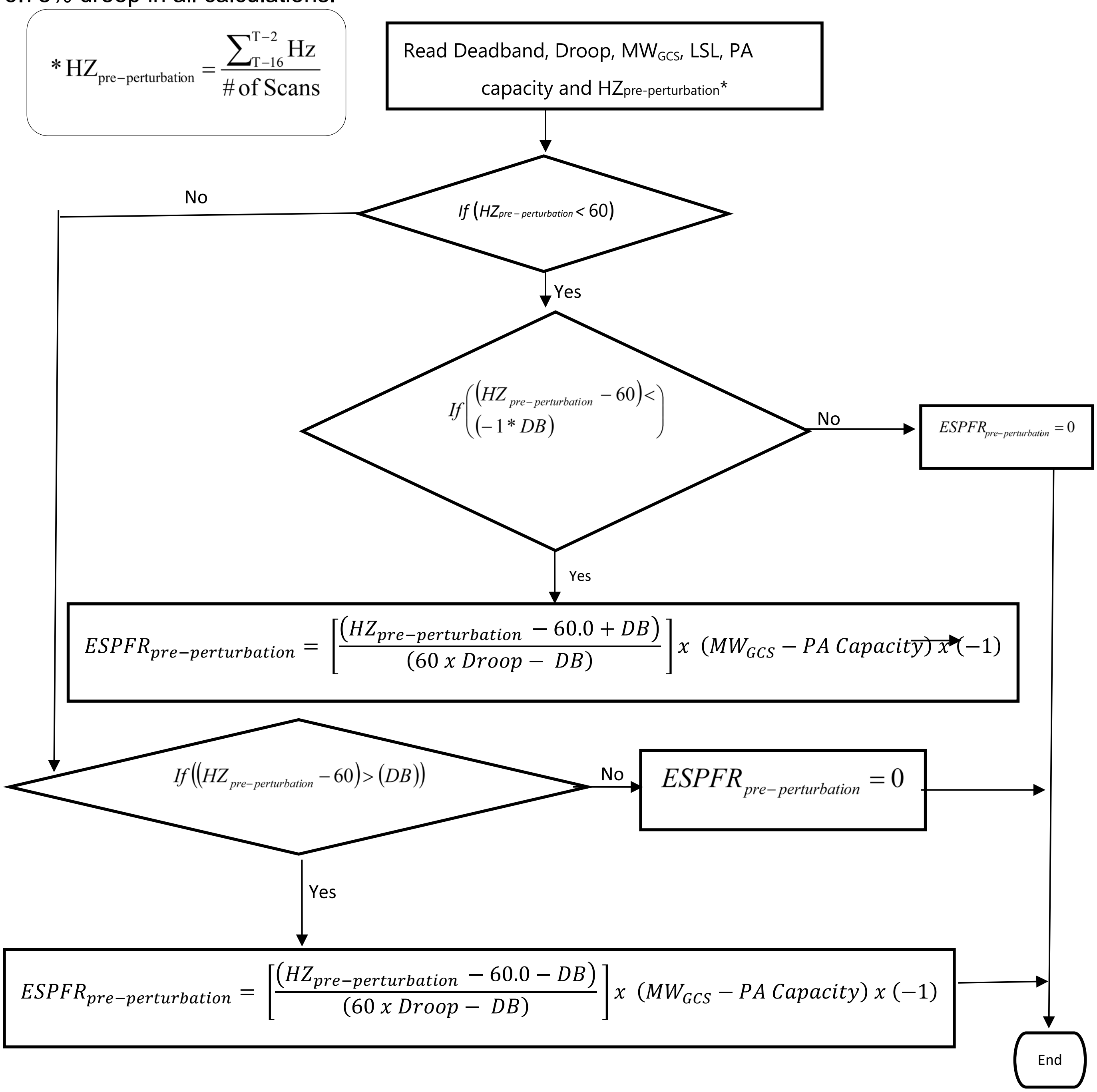
$$\boxed{ASPFR_{Adj} = Minimum(MW_{T+46} : MW_{T+60}) - MW_{pre\text{-perturbation}} - Ramp\ Magnitude_{Sustained}}$$

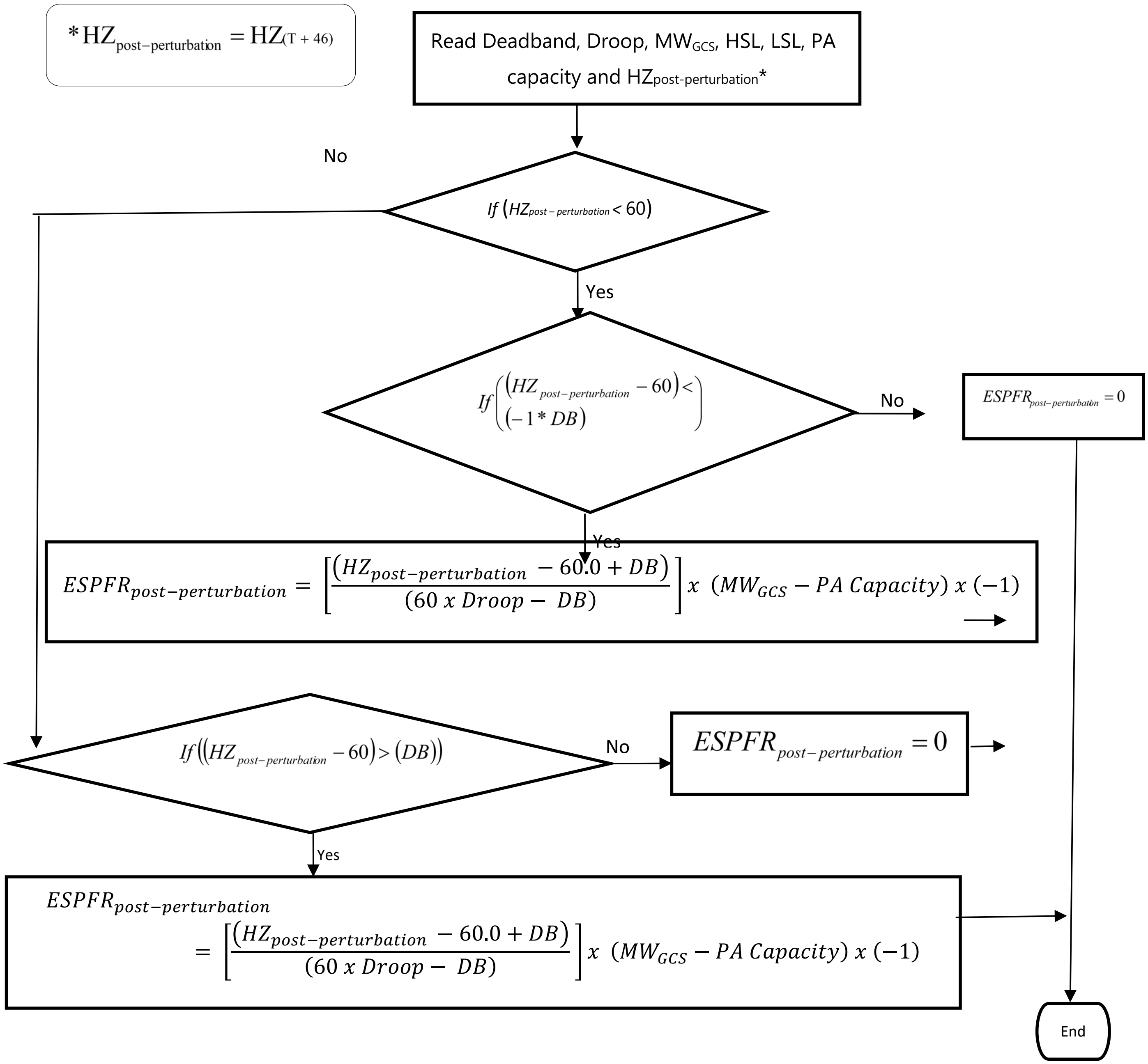
$$\downarrow$$

End

Expected Sustained Primary Frequency Response Calculation

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





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

Adjustment for Steam Turbine

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

↓

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

↓

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

↓

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

↓

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

↓

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

↓

End

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

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

Adjustment for Combustion Turbines and Combined Cycle Facilities

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

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

End

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

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

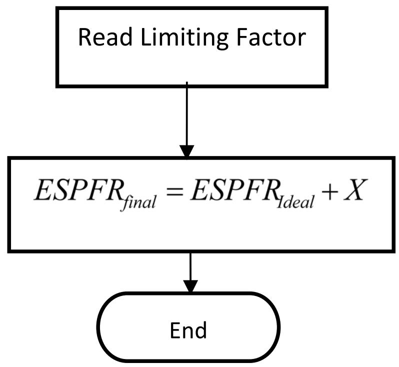
Read MW_{GCS}, capacity not expected to provide PFR

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

End

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

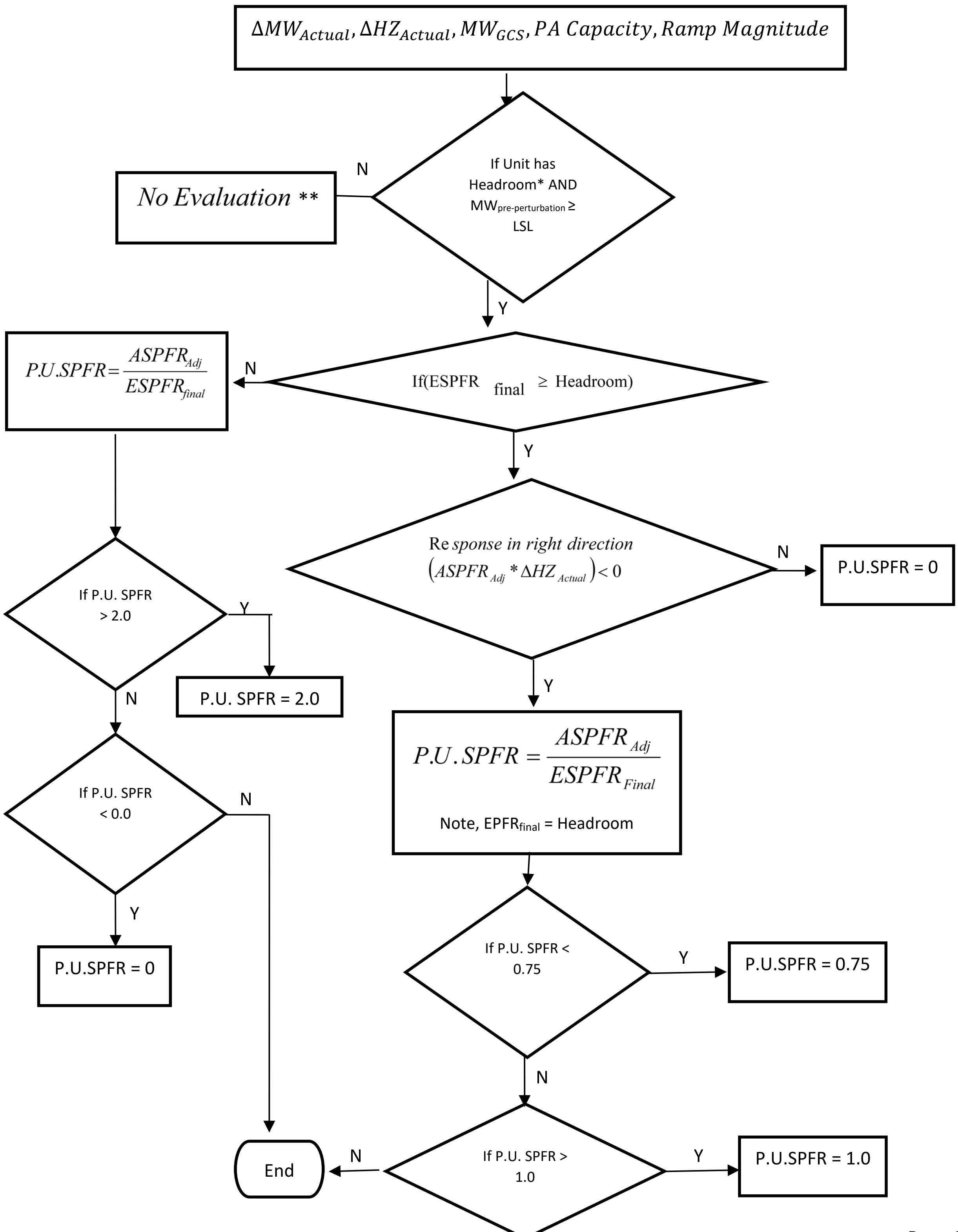


$* HZ_{Actual} = HZ_{(T + 46)}$

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

P.U. Sustained Primary Frequency Response Calculation

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


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

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

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

For low frequency events:

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

For high frequency events:

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

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

T = Time in Seconds

Revision History

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

			Frequency Response Calculations: o Unit needs to have Headroom and be above LSL to be scored. o 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

			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.

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 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.

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

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

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.

Where

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

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

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

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

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

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]*

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

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.

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

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

D. Regional Variances

None

E. Associated Documents

Regional Standard BAL-001-TRE-3 Implementation Plan

Version History

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

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

Standard Attachments

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

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

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

Attachment 1

Primary Frequency Response Reference Document

Texas Reliability Entity, Inc.
BAL-001-TRE-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 available[1] for reference and use in understanding and performing these calculations.

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

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

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

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.

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.

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

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

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

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

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

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.

ramp to represent the ramp that should have been achieved during the post-perturbation measurement period.

Expected Primary Frequency Response (EPFR)

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

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

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

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

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

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

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

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

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

Where:

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

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

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

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

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

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

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

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

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

$EPFR_{final}$ for Steam Turbine

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

Where:

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

Where:

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

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

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

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

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

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

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

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.

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.

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

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.

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)

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

$P.U.SPFR_{Resource}$ 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.

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

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

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 (*$ASPFR_{Adj}$*)

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

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 = ($MW_{T\text{-}4} - MW_{T\text{-}60}$) x 0.821

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

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

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

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

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

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

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

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

Capacity 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

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

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

$ESPFR_{final}$ for Steam Turbine

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

Where:

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

Where:

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

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

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

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

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

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

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

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

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

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 ($Hz_{Post\text{-}perturbation}$ < 60 if:

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

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

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

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

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

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[4]; 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.

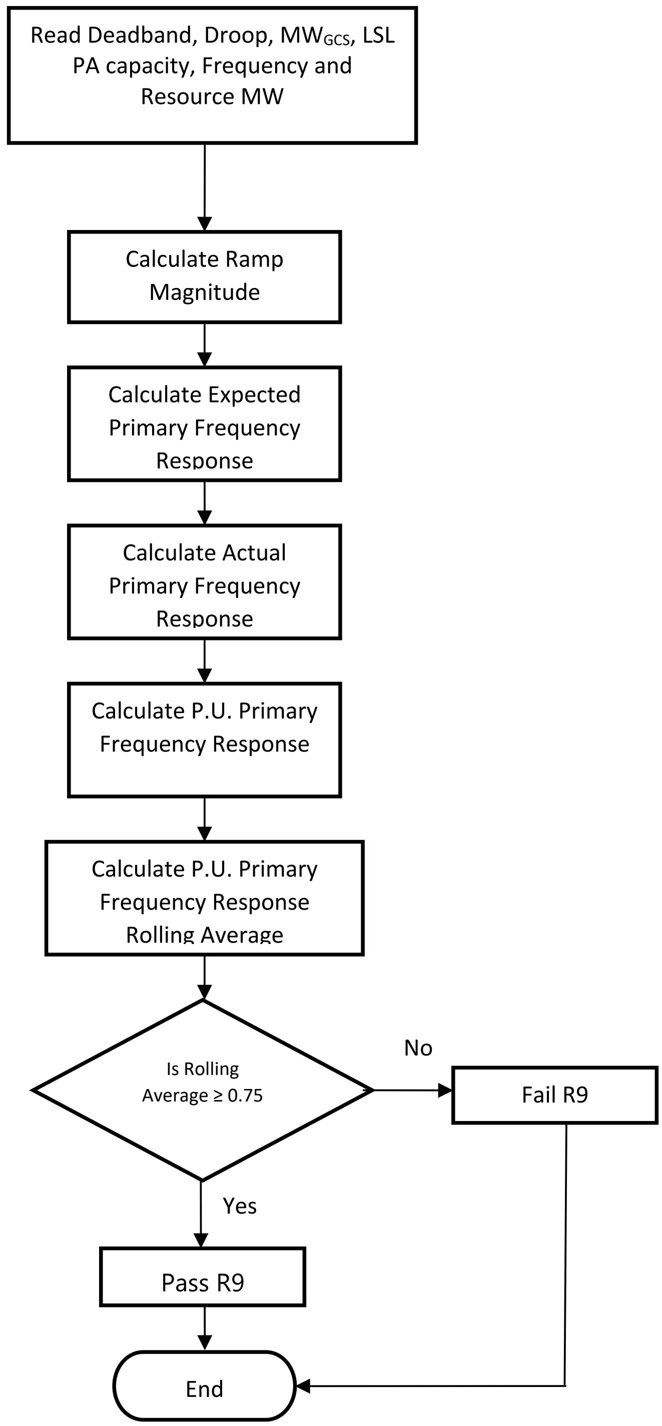
[4] In this circumstance, when frequency is below 60 Hz, the EPFR$_{final}$ is set to operating margin based on MW$_{GCS}$ (adjusted for any augmentation capacity) AND when frequency is above 60 Hz, the EPFR$_{final}$ is set to operating margin based on LSL for the purpose of calculating PUPFR$_{resource}$.

Attachment A to
Primary Frequency Response Reference Document

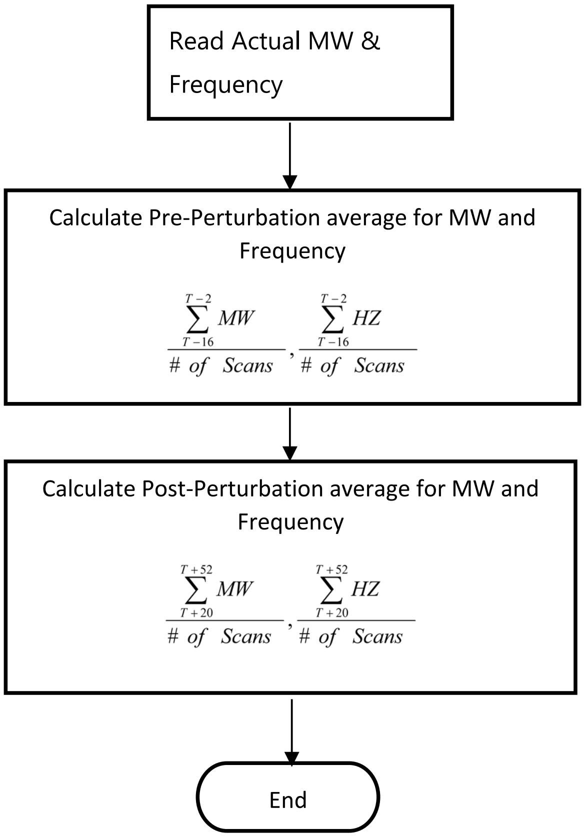
Initial Primary Frequency Response Methodology for
BAL-001-TRE-3

Primary Frequency Response Measurement and Rolling Average Calculation – Initial Response

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


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

Pre/Post-Perturbation Average MW and Average Frequency Calculations



Ramp Magnitude Calculation

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

↓

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 0.59 adjusts this full minute ramp to represent the ramp that should have been achieved during the post-perturbation measurement period.

Actual Primary Frequency Response (APFRAdj)

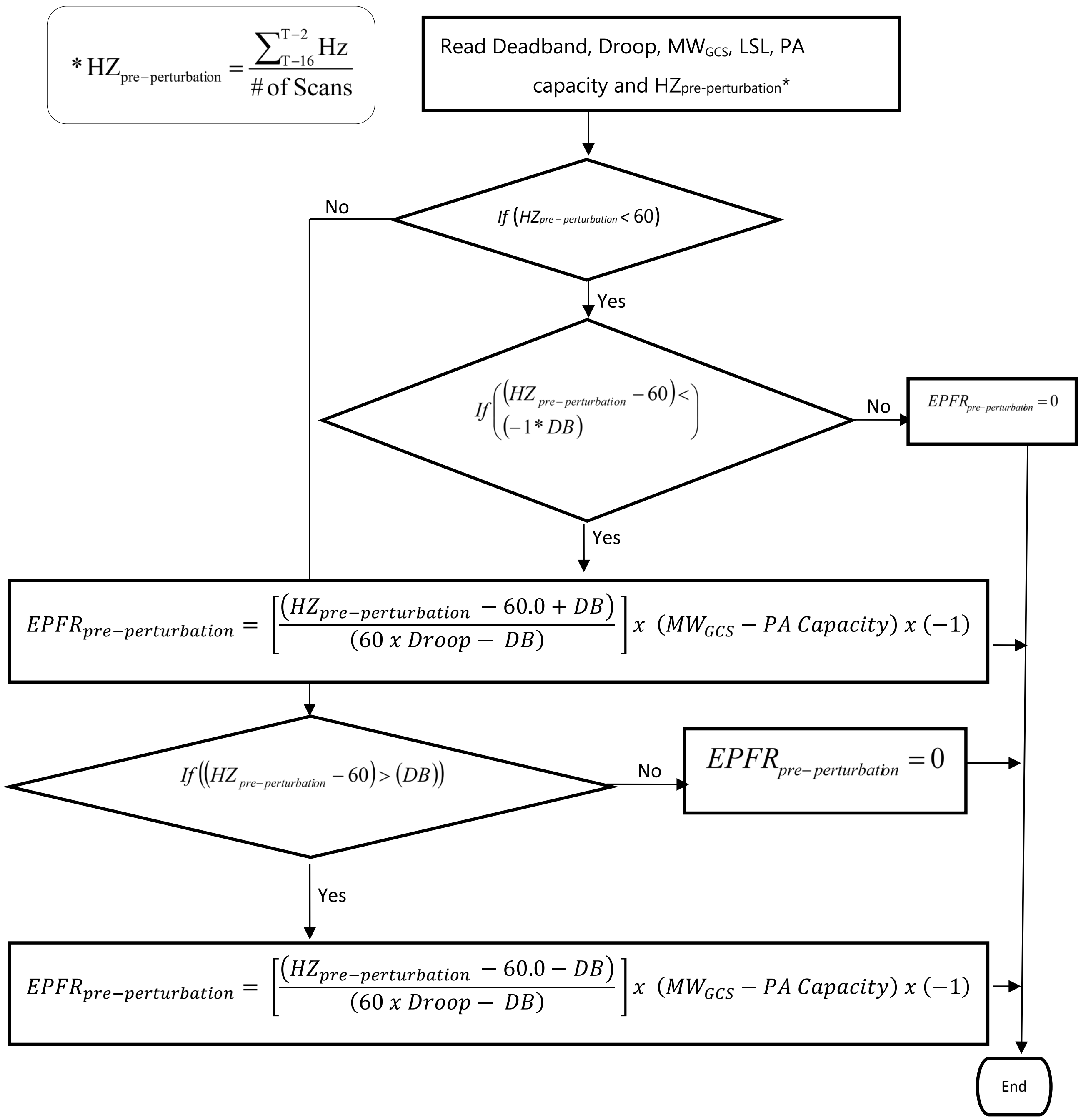
$APFR_{Adj} = MW_{post\text{-}perturbation} – MW_{pre\text{-}perturbation}$ – Ramp Magnitude

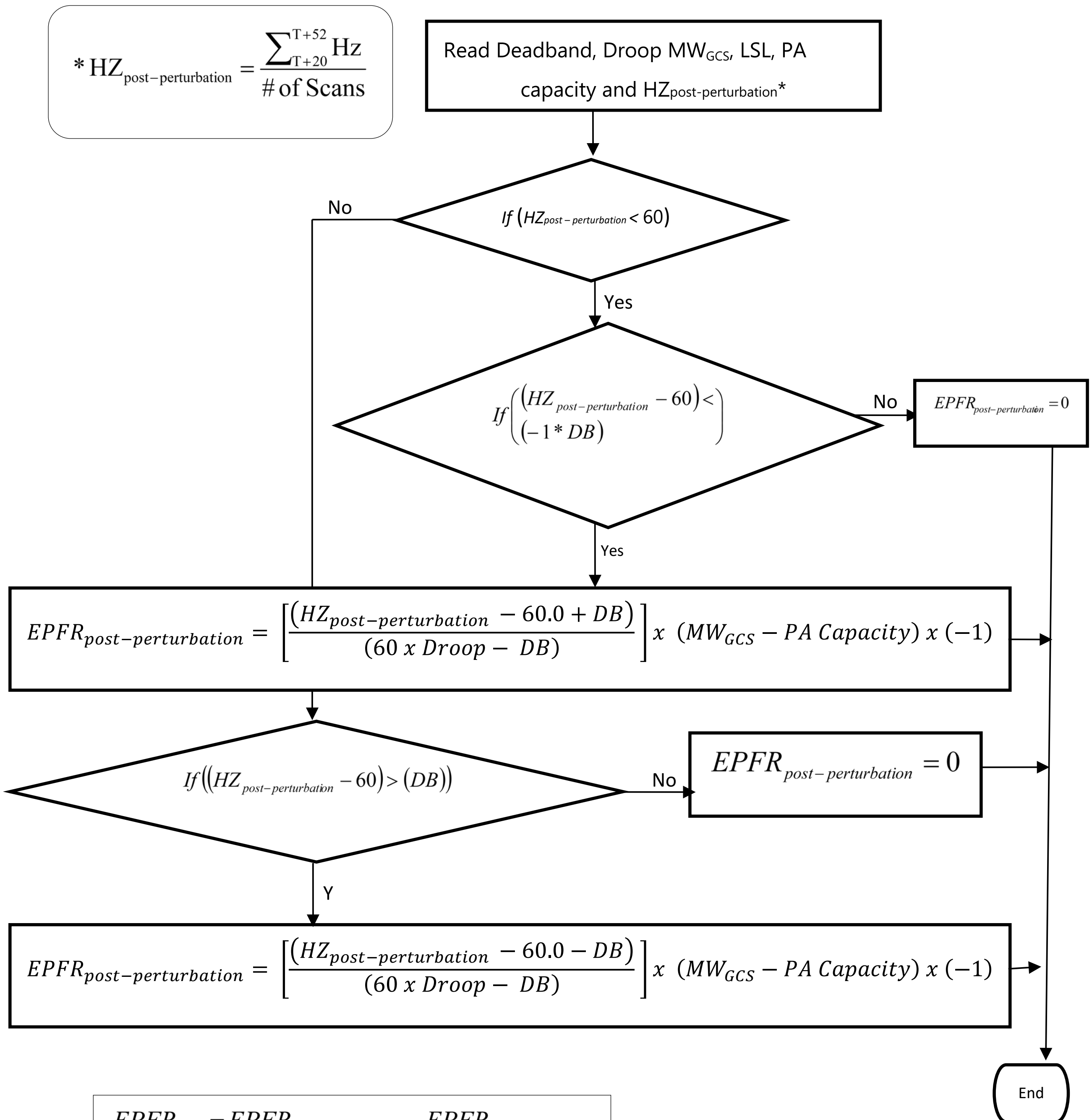
↓

End

Expected Primary Frequency Response Calculation

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





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

Adjustment for Steam Turbine

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

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

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

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

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

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

End

Adjustment for Combustion Turbines and Combined Cycle Facilities

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

↓

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

↓

End

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

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

Read MW_{GCS}, capacity not expected to provide PFR

↓

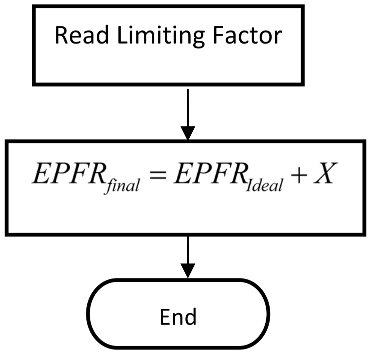
$$EPFR_{final} = Minimum\ (EPFR_{ideal}, MW_{GCS} - capacity\ not\ expected\ to\ provide\ PFR)$$

↓

End

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.

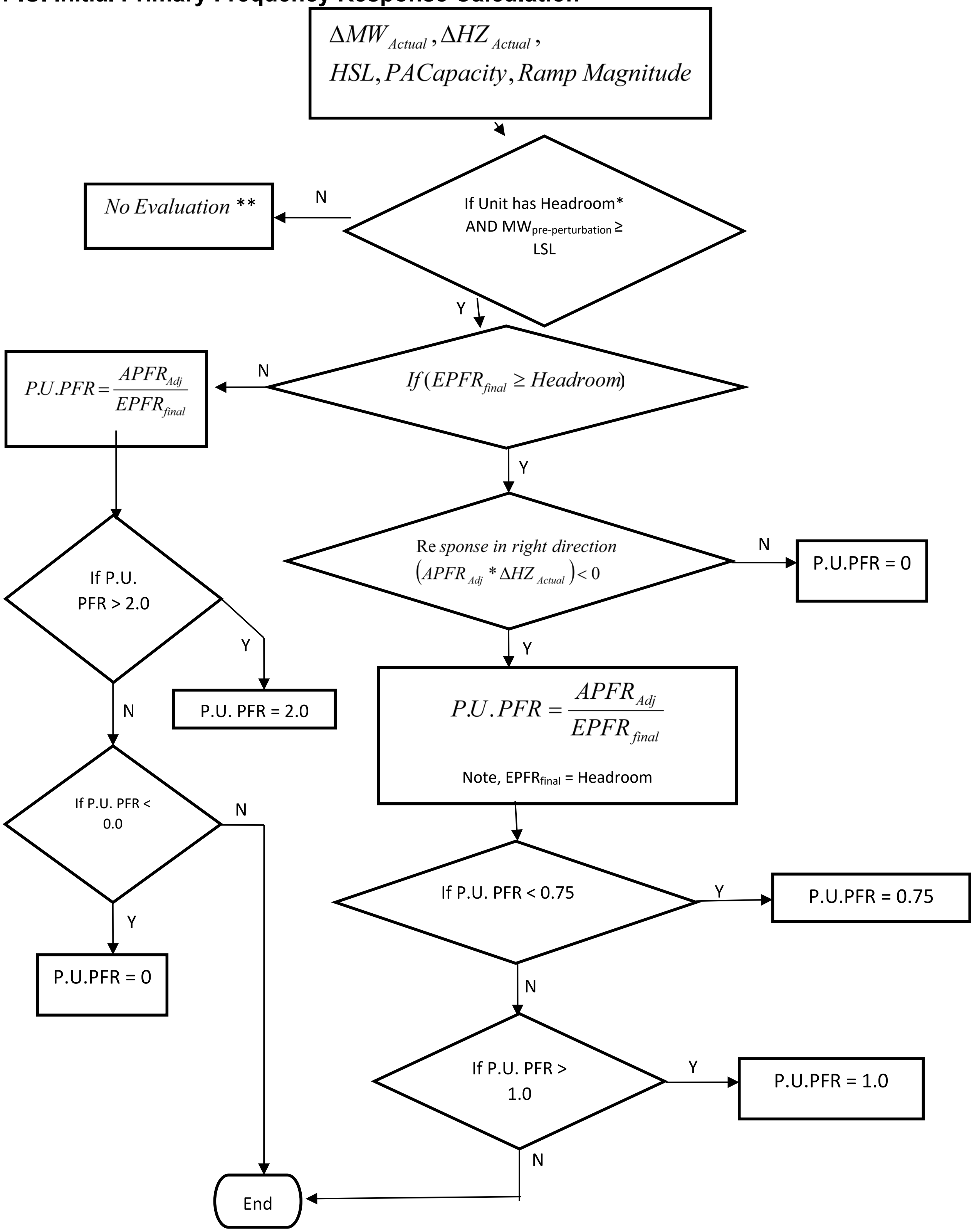
Adjustment for Other Units



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

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

P.U. Initial Primary Frequency Response Calculation



*Check for adequate up headroom, low frequency events. Headroom must be greater than either XMW or 2% of (MW_{GCS} less PA capacity 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:

$$\boxed{Headroom = \ HSL - PA\ Capacity - capcity\ not\ expeced\ to\ respond\ with\ PFR - \ MW_{T-2}}$$

For high frequency events:

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

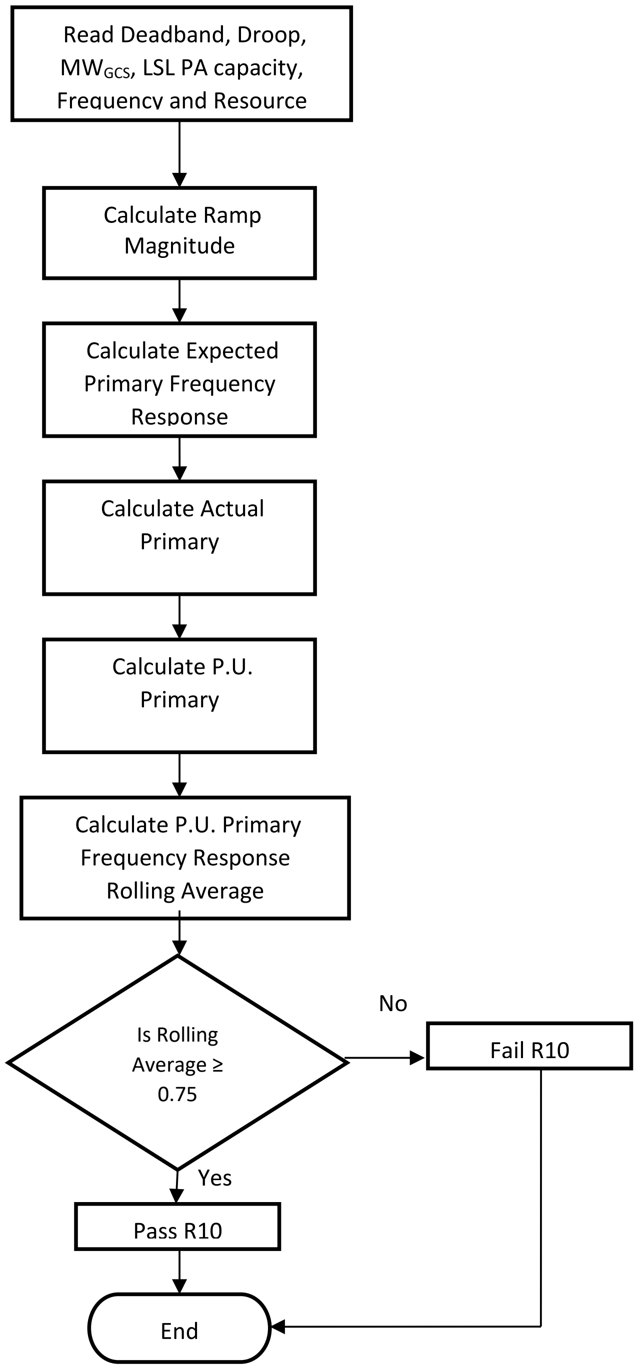
**No further evaluation is required for Sustained Primary Frequency Response. This event will not be included in the Rolling Average calculation of either Initial or Sustained Primary Frequency Response.

T = Time in Seconds

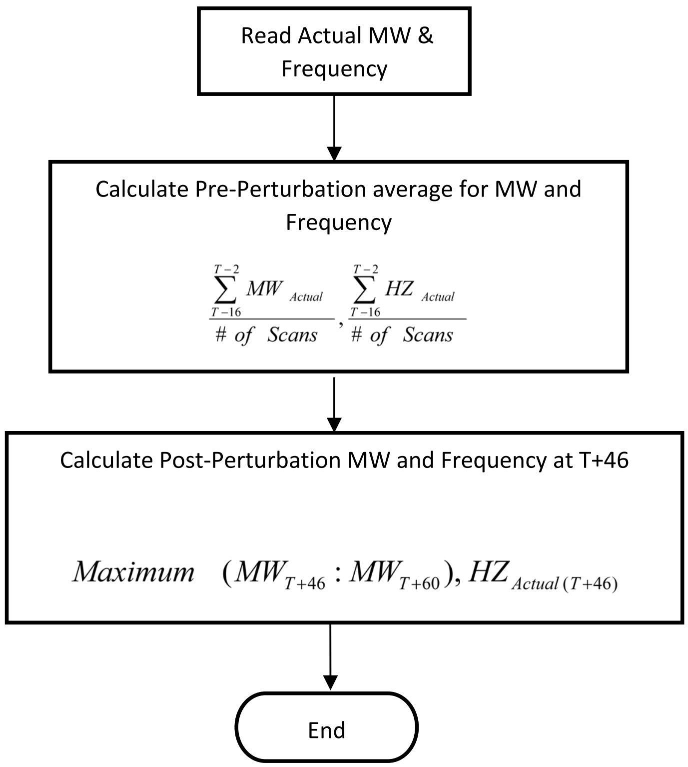
Attachment B to
Primary Frequency Response Reference Document

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

Primary Frequency Response Measurement and Rolling Average Calculation–Sustained Response



Pre/Post-Perturbation Average MW and Average Frequency Calculations



Ramp Magnitude Calculation - Sustained

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

$\downarrow$

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.

Actual Sustained Primary Frequency Response (ASPFRadj)

For low frequency events:

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

$\downarrow$

End

For high frequency events:

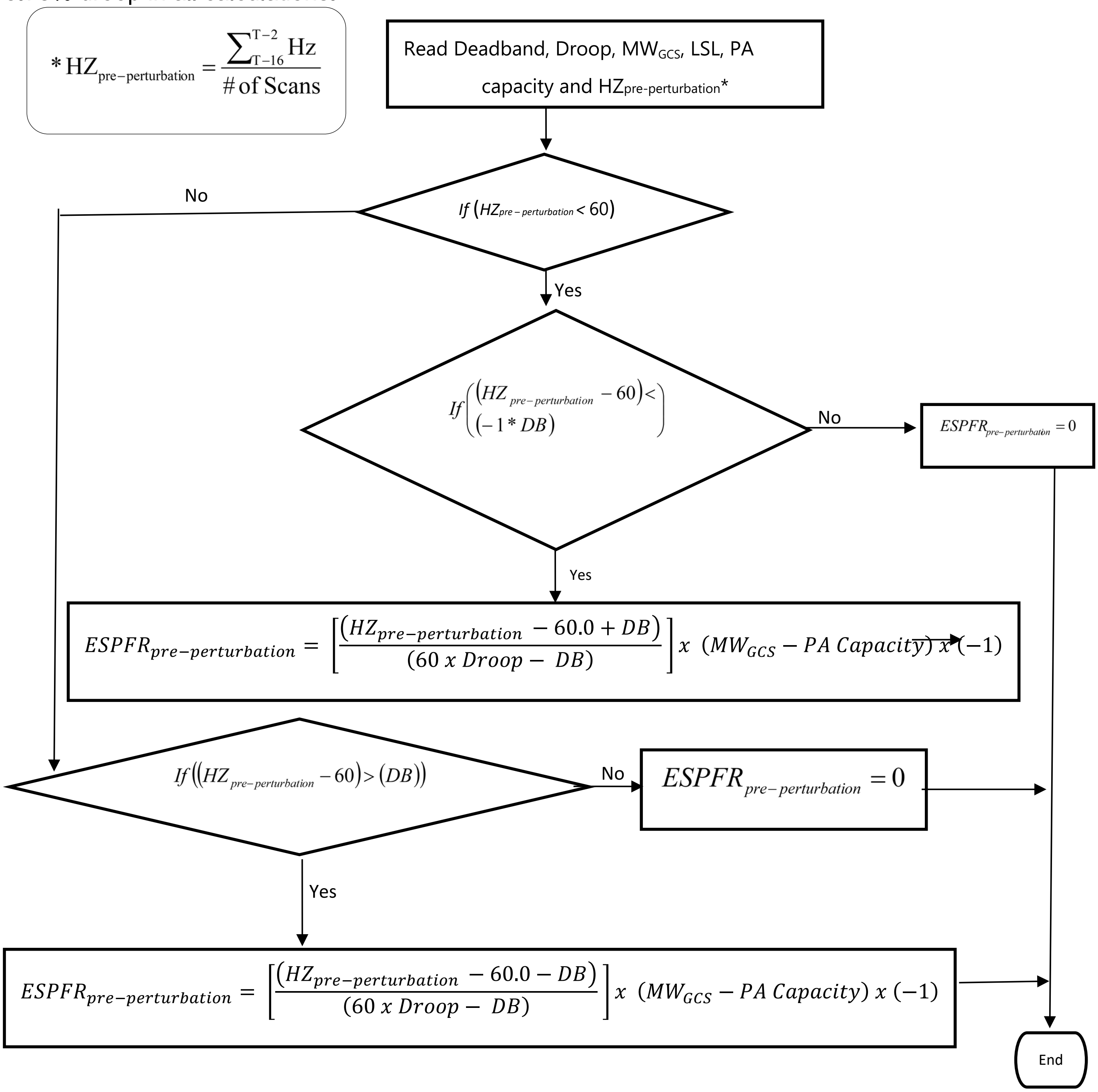
$$ASPFR_{Adj} = Minimum(MW_{T+46} : MW_{T+60}) - MW_{pre\text{-}\mathrm{perturbation}} - Ramp\ Magnitude_{Sustained}$$

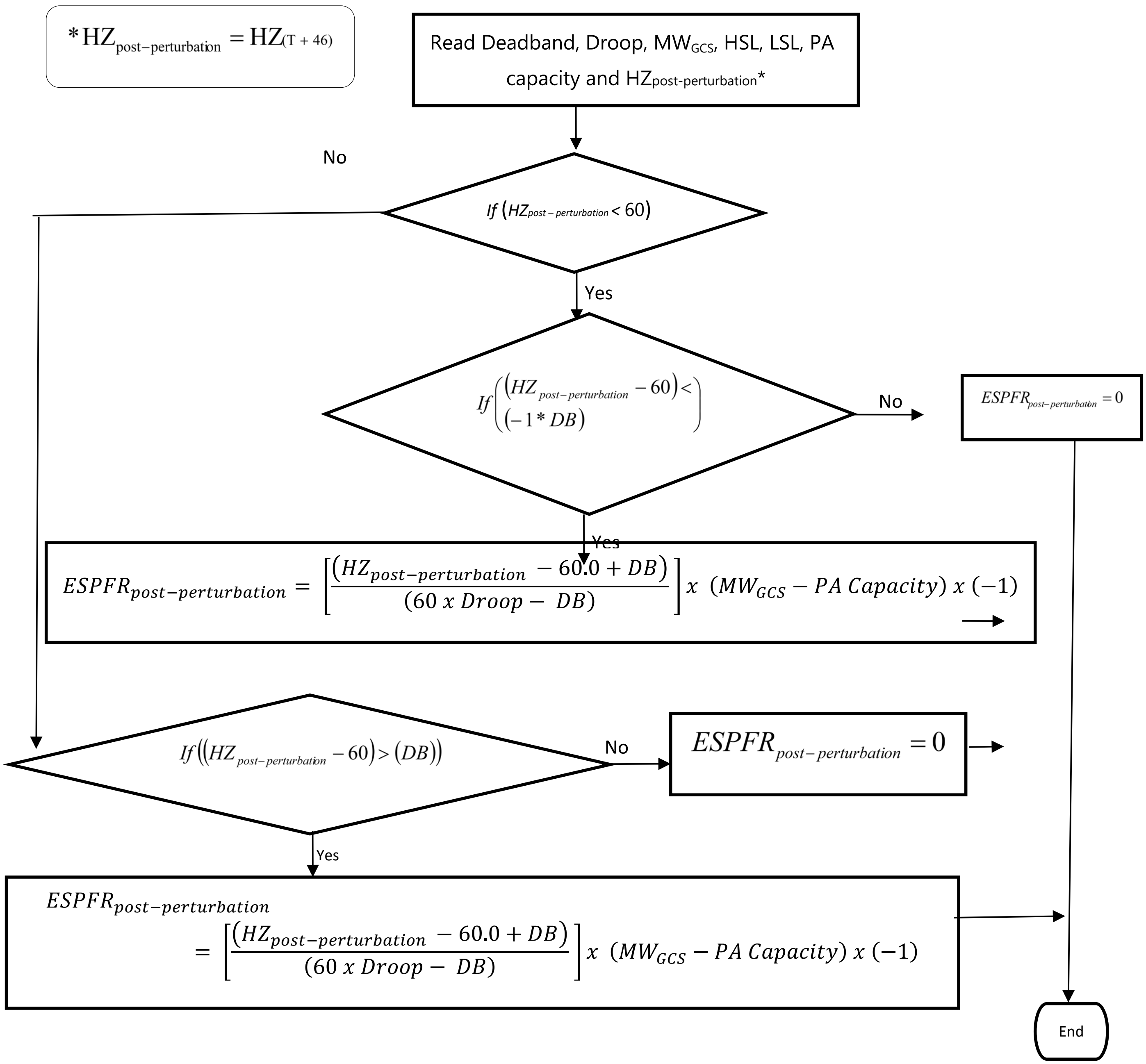
$\downarrow$

End

Expected Sustained Primary Frequency Response Calculation

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





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

Adjustment for Steam Turbine

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

↓

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

↓

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

↓

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

↓

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

↓

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

↓

End

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

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

Adjustment for Combustion Turbines and Combined Cycle Facilities

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

↓

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

↓

End

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

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

Read MW_{GCS}, capacity not expected to provide PFR

↓

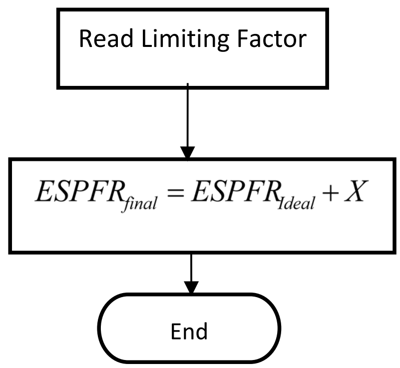
$$ESPFR_{final} = Minimum\ (ESPFR_{ideal}, MW_{GCS} - capacity\ not\ expected\ to\ provide\ PFR)$$

↓

End

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

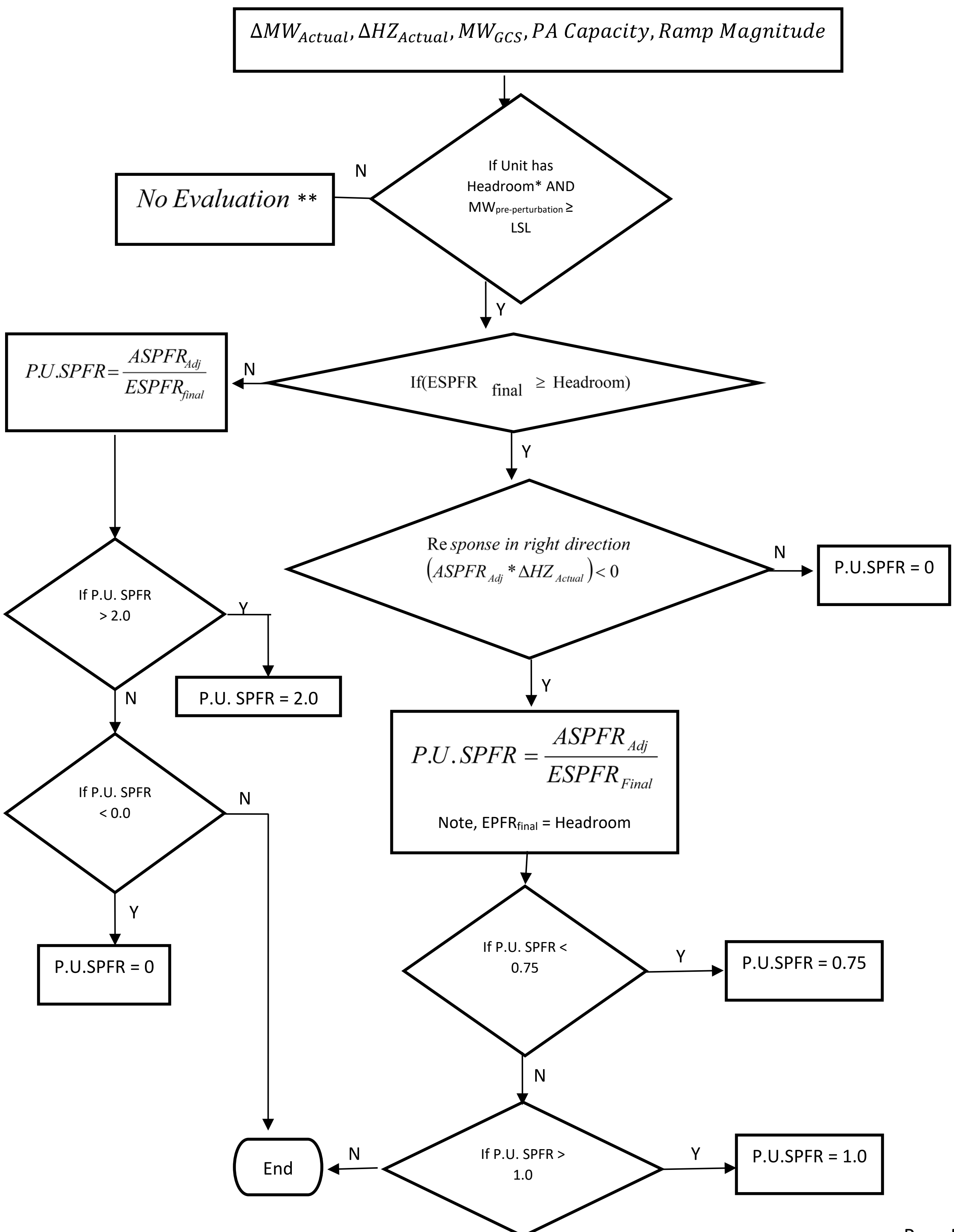


$*HZ_{Actual} = HZ_{(T + 46)}$

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

P.U. Sustained Primary Frequency Response Calculation

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


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

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

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

For low frequency events:

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

For high frequency events:

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

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

T = Time in Seconds

Revision History

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

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

			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.

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 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.

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

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.

Where

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

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

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

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

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

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]*

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

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.

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

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

D. Regional Variances

None

E. Associated Documents

Regional Standard BAL-001-TRE-3 Implementation Plan

Version History

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

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

Standard Attachments

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

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

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

Attachment 1

Primary Frequency Response Reference Document

Texas Reliability Entity, Inc.
BAL-001-TRE-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 available[1] for reference and use in understanding and performing these calculations.

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

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

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

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.

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.

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

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

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

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

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

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.

ramp to represent the ramp that should have been achieved during the post-perturbation measurement period.

Expected Primary Frequency Response (EPFR)

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

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

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

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

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

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

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

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

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

Where:

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

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

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

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

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

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

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

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

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

EPFR$_{final}$ for Steam Turbine

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

Where:

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

Where:

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

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

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

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

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

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

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

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.

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.

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

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.

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)

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

$P.U.SPFR_{Resource}$ 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*$_{Adj}$)

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

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 = ($MW_{T-4} - MW_{T-60}$) x 0.821

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

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

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

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

This $ESPFR_{final}$ is the MW value a unit should have responded with if it is properly sustaining the output of its generating unit/generating facility in response to an FME. Determination of this value begins with establishing where it would be in an ideal situation; considers proper droop and dead-band values established in Requirement R6, 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.

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

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

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

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

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

Capacity 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

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

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

$ESPFR_{final}$ for Steam Turbine

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

Where:

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

Where:

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

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

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

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

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

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

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

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

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

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:

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

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

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

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

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

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[4]; 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.

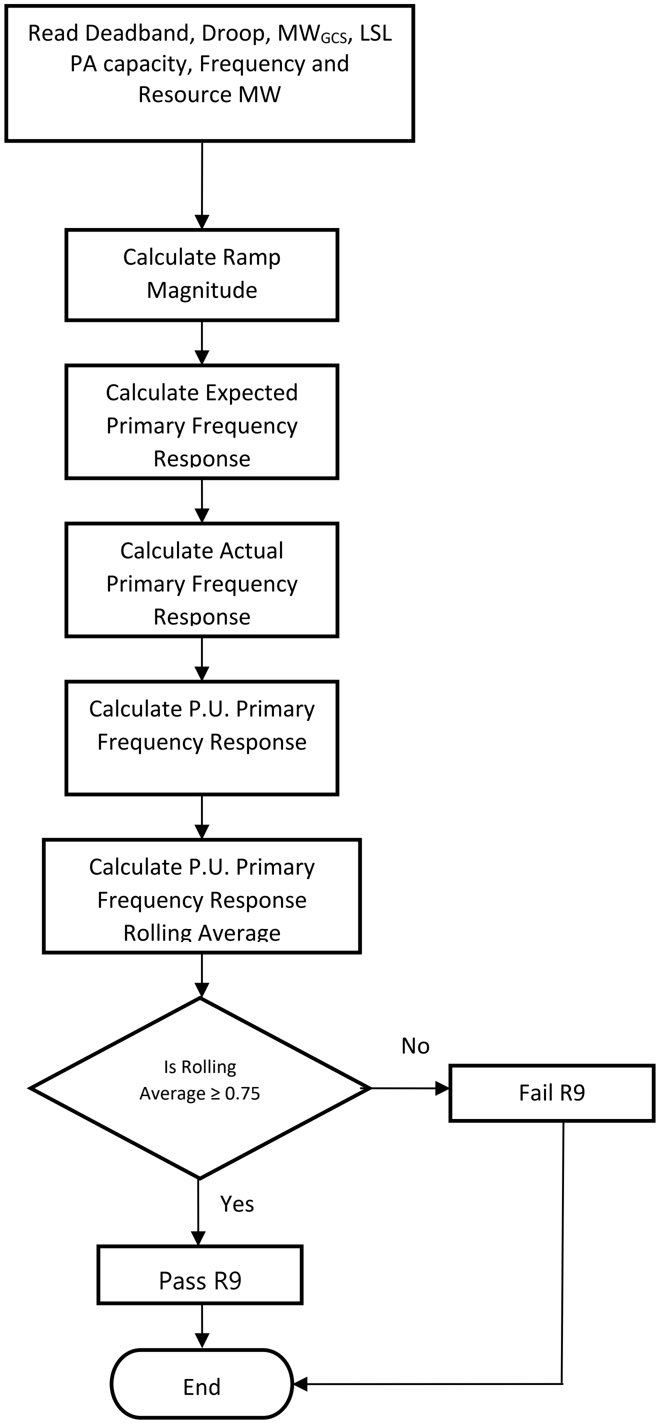
[4] In this circumstance, when frequency is below 60 Hz, the EPFR$_{final}$ is set to operating margin based on MW$_{GCS}$ (adjusted for any augmentation capacity) AND when frequency is above 60 Hz, the EPFR$_{final}$ is set to operating margin based on LSL for the purpose of calculating PUPFR$_{resource}$.

Attachment A to
Primary Frequency Response Reference Document

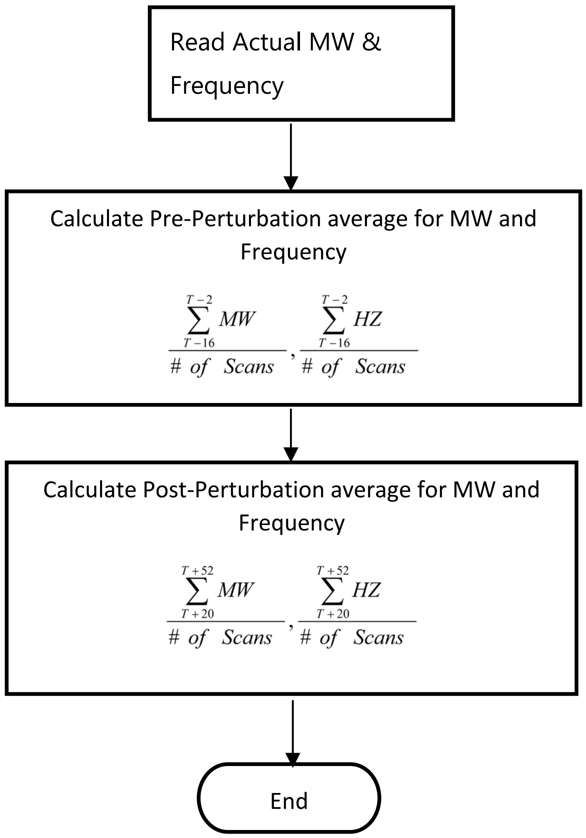
Initial Primary Frequency Response Methodology for
BAL-001-TRE-3

Primary Frequency Response Measurement and Rolling Average Calculation – Initial Response

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


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

Pre/Post-Perturbation Average MW and Average Frequency Calculations



Ramp Magnitude Calculation

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

↓

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 0.59 adjusts this full minute ramp to represent the ramp that should have been achieved during the post-perturbation measurement period.

Actual Primary Frequency Response (APFRAdj)

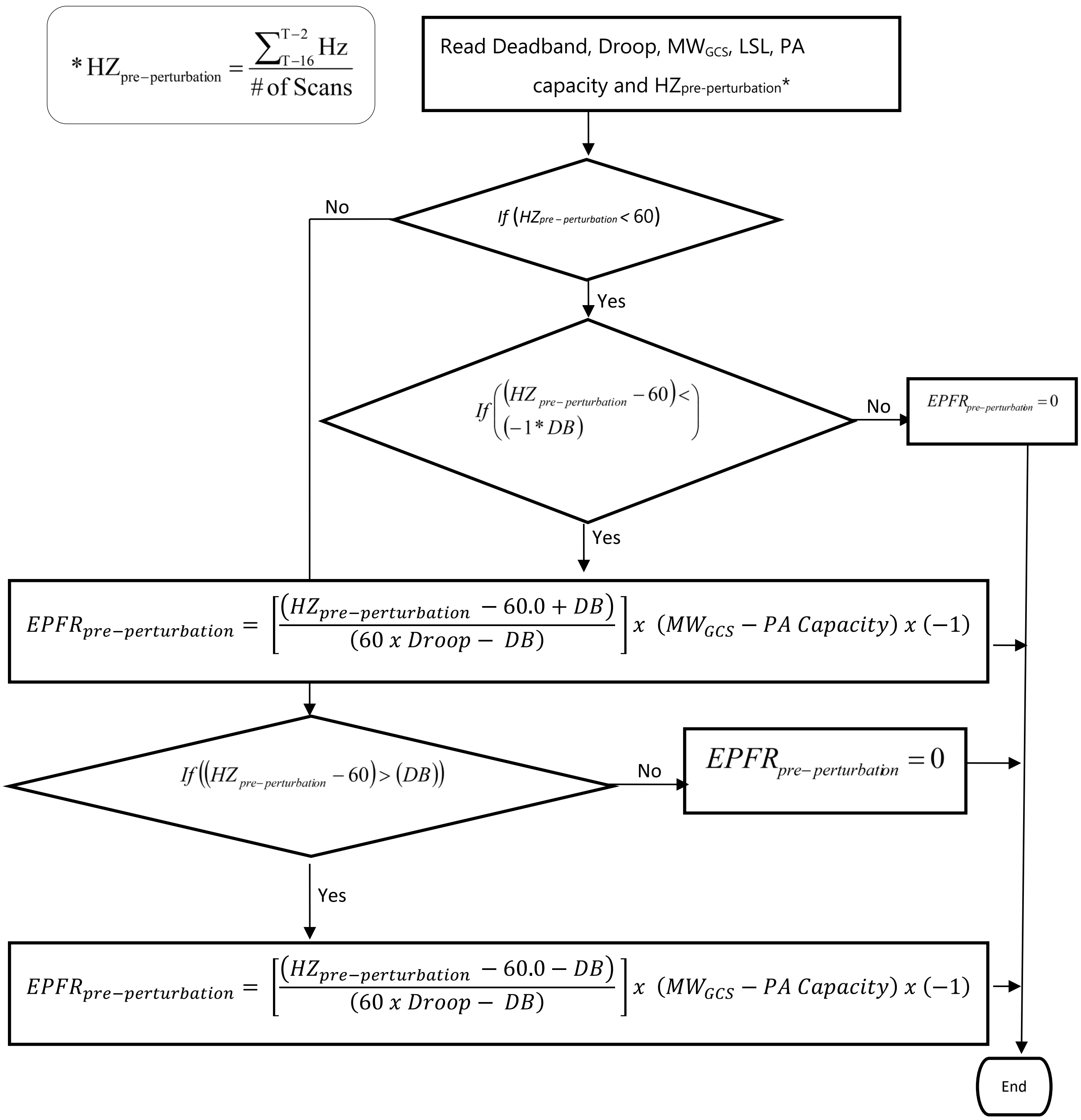
$APFR_{Adj} = MW_{post\text{-}perturbation} – MW_{pre\text{-}perturbation}$ – Ramp Magnitude

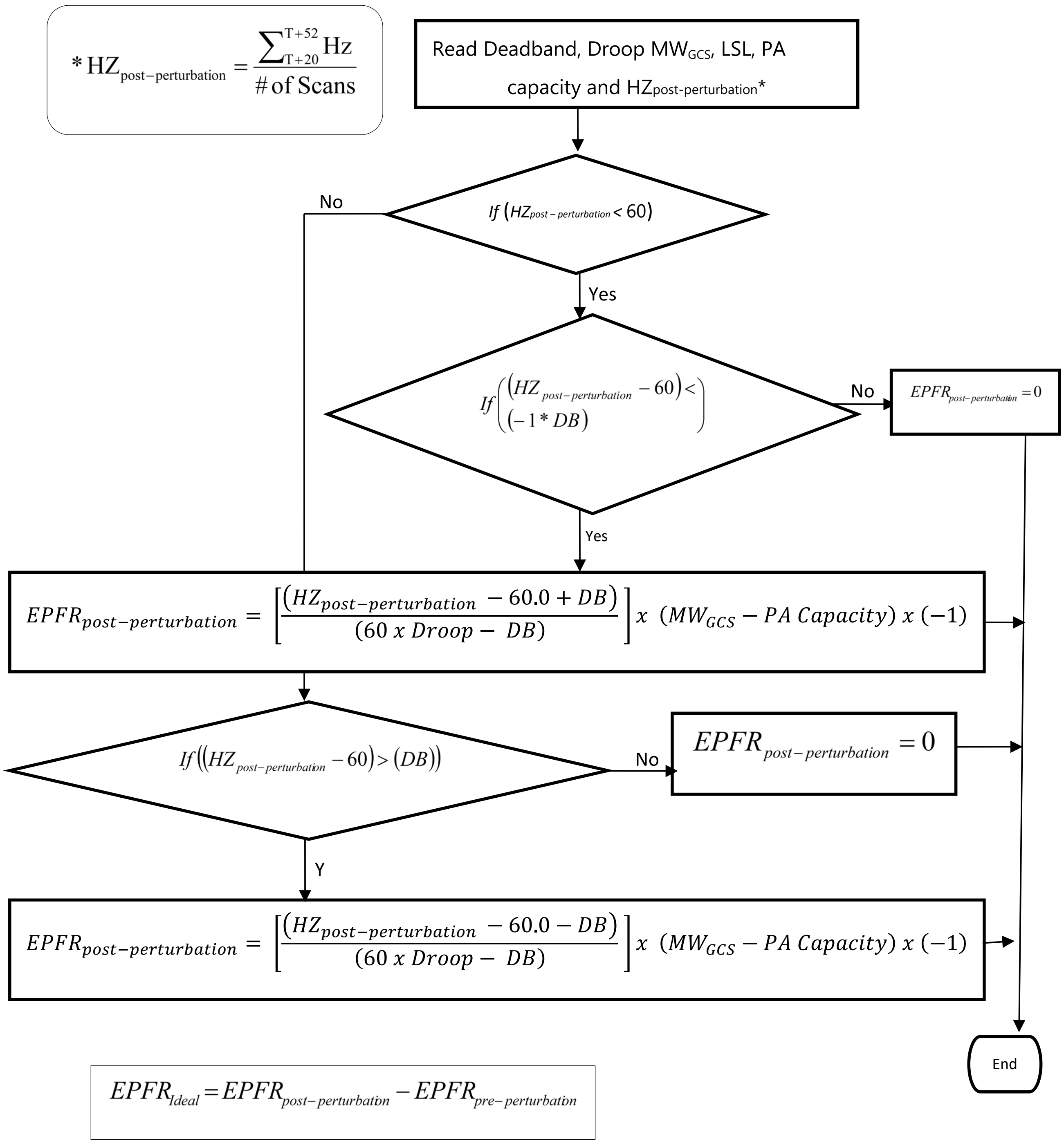
↓

End

Expected Primary Frequency Response Calculation

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




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

Adjustment for Steam Turbine

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

↓

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

↓

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

↓

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

↓

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

↓

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

↓

End

Adjustment for Combustion Turbines and Combined Cycle Facilities

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

↓

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

↓

End

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

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

Read MW_{GCS}, capacity not expected to provide PFR

↓

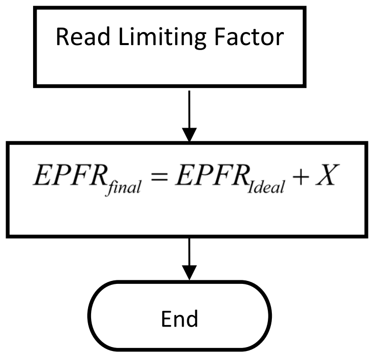
$$EPFR_{final} = Minimum\ (EPFR_{ideal}, MW_{GCS} - capacity\ not\ expected\ to\ provide\ PFR)$$

↓

End

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.

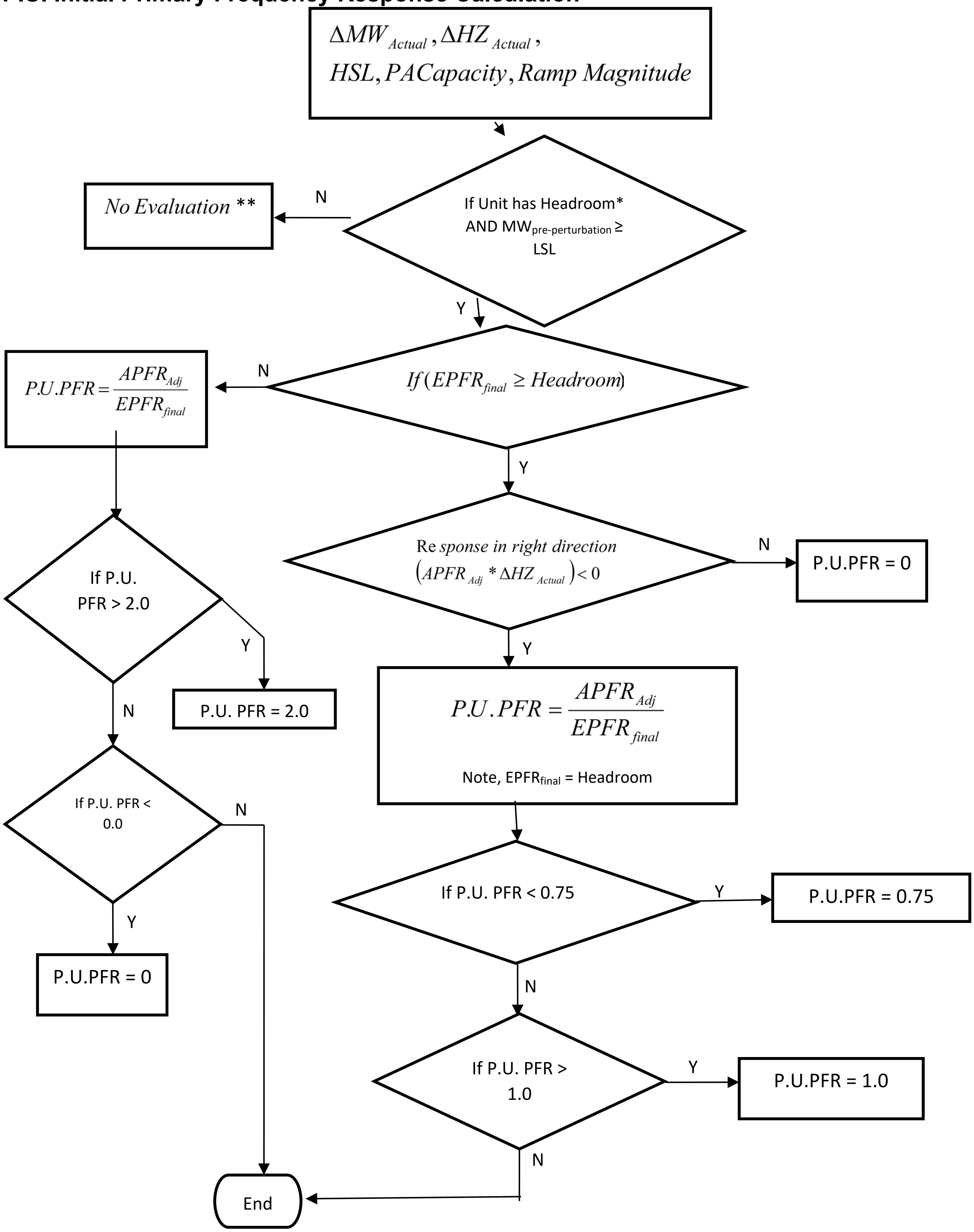
Adjustment for Other Units



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

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

P.U. Initial Primary Frequency Response Calculation



*Check for adequate up headroom, low frequency events. Headroom must be greater than either 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:

$$\boxed{Headroom = HSL - PA\ Capacity - capcity\ not\ expeced\ to\ respond\ with\ PFR - MW_{T-2}}$$

For high frequency events:

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

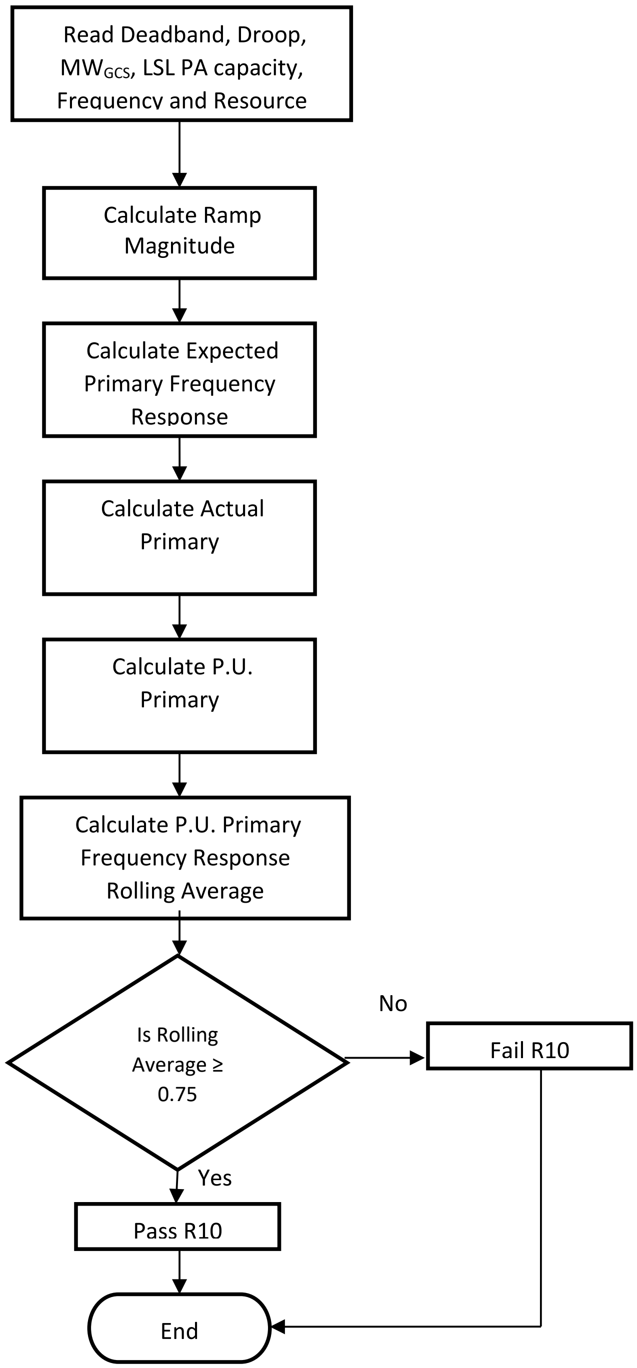
**No further evaluation is required for Sustained Primary Frequency Response. This event will not be included in the Rolling Average calculation of either Initial or Sustained Primary Frequency Response.

T = Time in Seconds

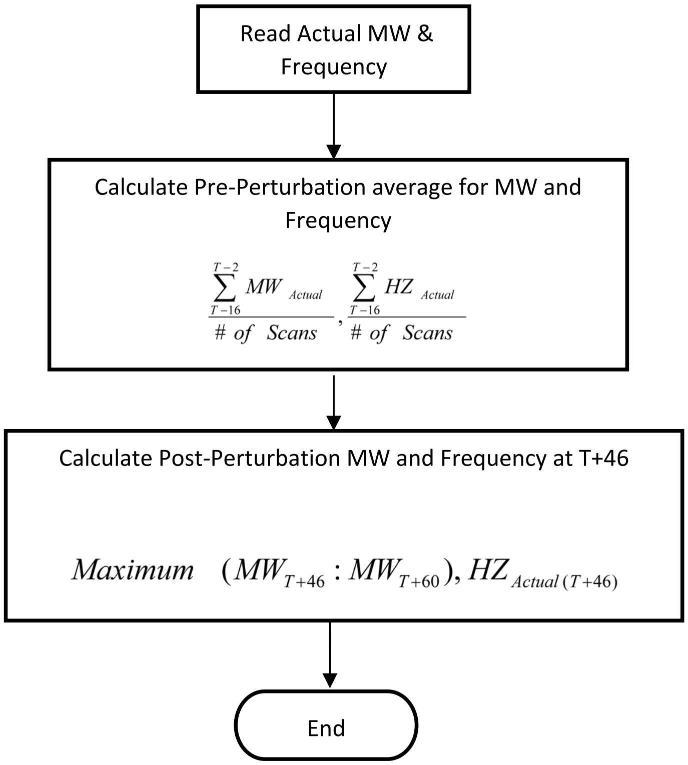
Attachment B to
Primary Frequency Response Reference Document

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

Primary Frequency Response Measurement and Rolling Average Calculation–Sustained Response



Pre/Post-Perturbation Average MW and Average Frequency Calculations



Ramp Magnitude Calculation - Sustained

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

$$\downarrow$$

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.

Actual Sustained Primary Frequency Response (ASPFRadj)

For low frequency events:

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

$$\downarrow$$

End

For high frequency events:

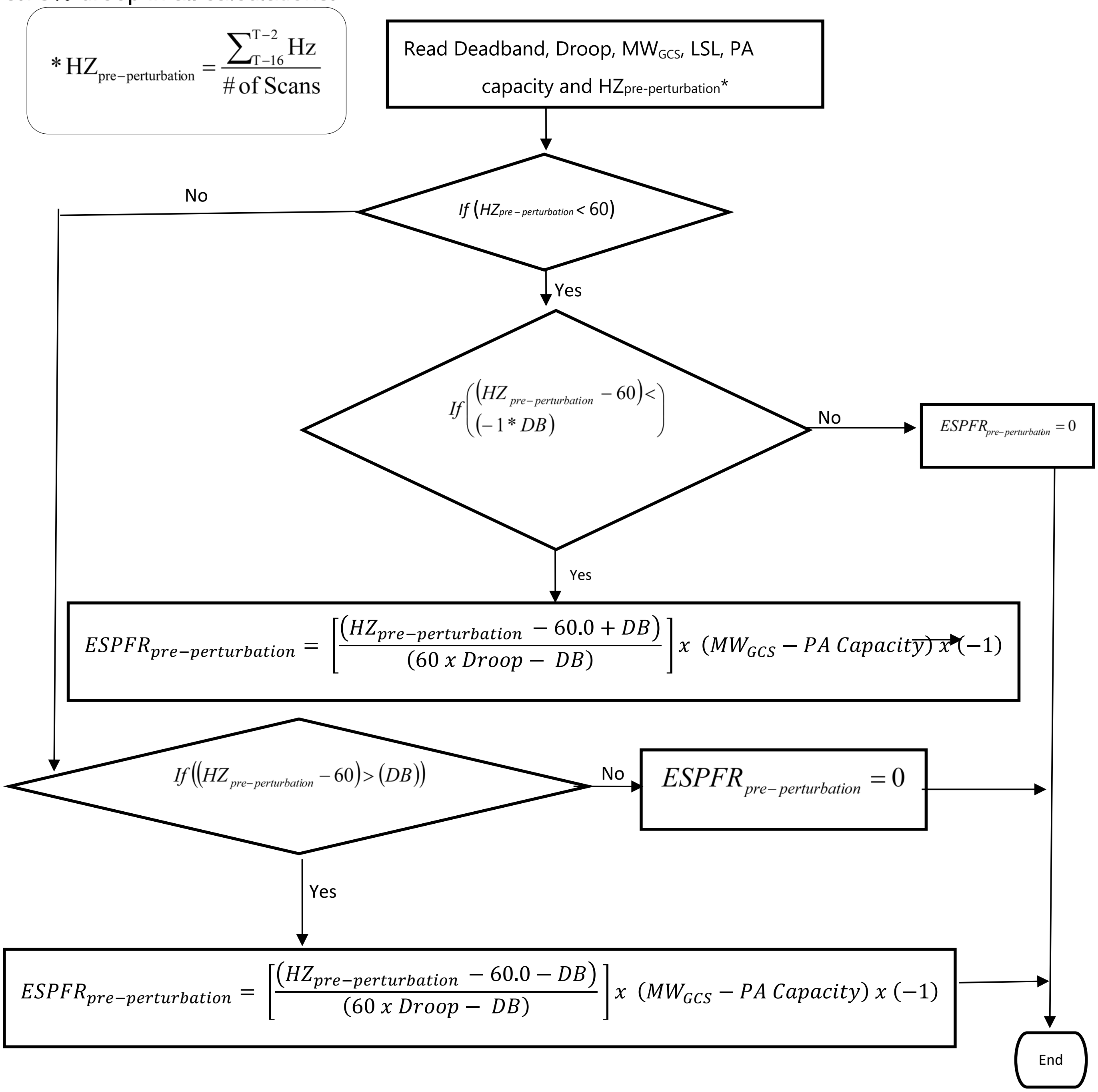
$$\boxed{ASPFR_{Adj} = Minimum(MW_{T+46} : MW_{T+60}) - MW_{pre\text{-perturbation}} - Ramp\ Magnitude_{Sustained}}$$

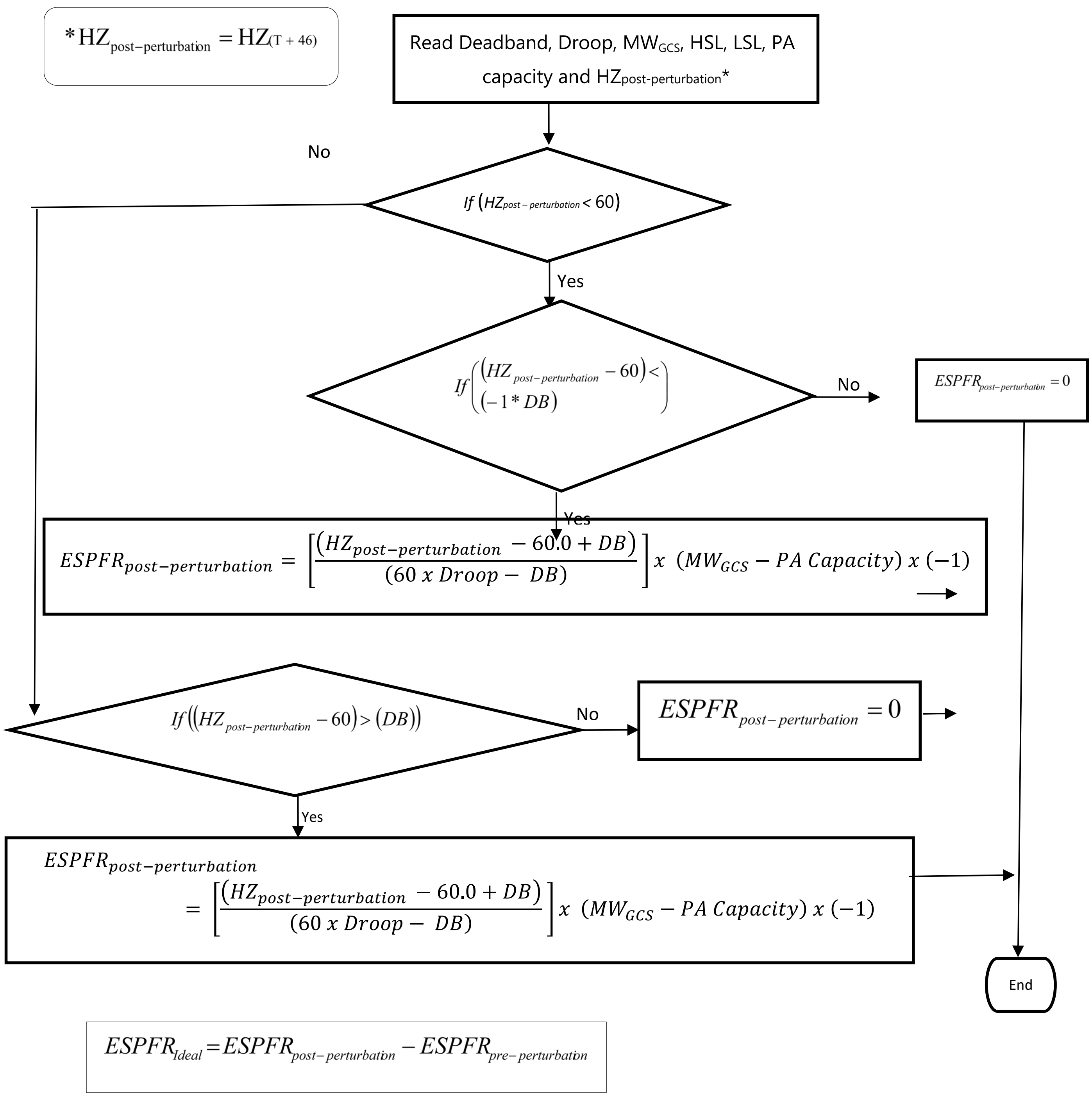
$$\downarrow$$

End

Expected Sustained Primary Frequency Response Calculation

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




$* HZ_{post-perturbation} = HZ_{(T + 46)}$
Read Deadband, Droop, MW_{GCS}, HSL, LSL, PA capacity and $HZ_{post-perturbation}$*
No
$If\left(HZ_{post-perturbation} < 60\right)$
Yes
$If\left(\begin{matrix}\left(HZ_{post-perturbation} - 60\right) < \\ \left(-1 * DB\right)\end{matrix}\right)$
No
$ESPFR_{post-perturbation} = 0$
Yes
$ESPFR_{post-perturbation} = \left[\frac{\left(HZ_{post-perturbation} - 60.0 + DB\right)}{\left(60 \ x \ Droop - DB\right)}\right] x \ \left(MW_{GCS} - PA \ Capacity\right) x \ (-1)$
$If\left(\left(HZ_{post-perturbation} - 60\right) > \left(DB\right)\right)$
No
$ESPFR_{post-perturbation} = 0$
Yes
$ESPFR_{post-perturbation} = \left[\frac{\left(HZ_{post-perturbation} - 60.0 + DB\right)}{\left(60 \ x \ Droop - DB\right)}\right] x \ \left(MW_{GCS} - PA \ Capacity\right) x \ (-1)$
End
$ESPFR_{Ideal} = ESPFR_{post-perturbation} - ESPFR_{pre-perturbation}$

Adjustment for Steam Turbine

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

↓

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

↓

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

↓

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

↓

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

↓

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

↓

End

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

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

Adjustment for Combustion Turbines and Combined Cycle Facilities

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

↓

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

↓

End

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

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

Read MW_{GCS}, capacity not expected to provide PFR

↓

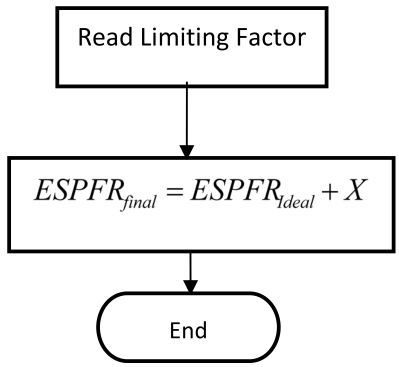
$$ESPFR_{final} = Minimum\ (ESPFR_{ideal}, MW_{GCS} - capacity\ not\ expected\ to\ provide\ PFR)$$

↓

End

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

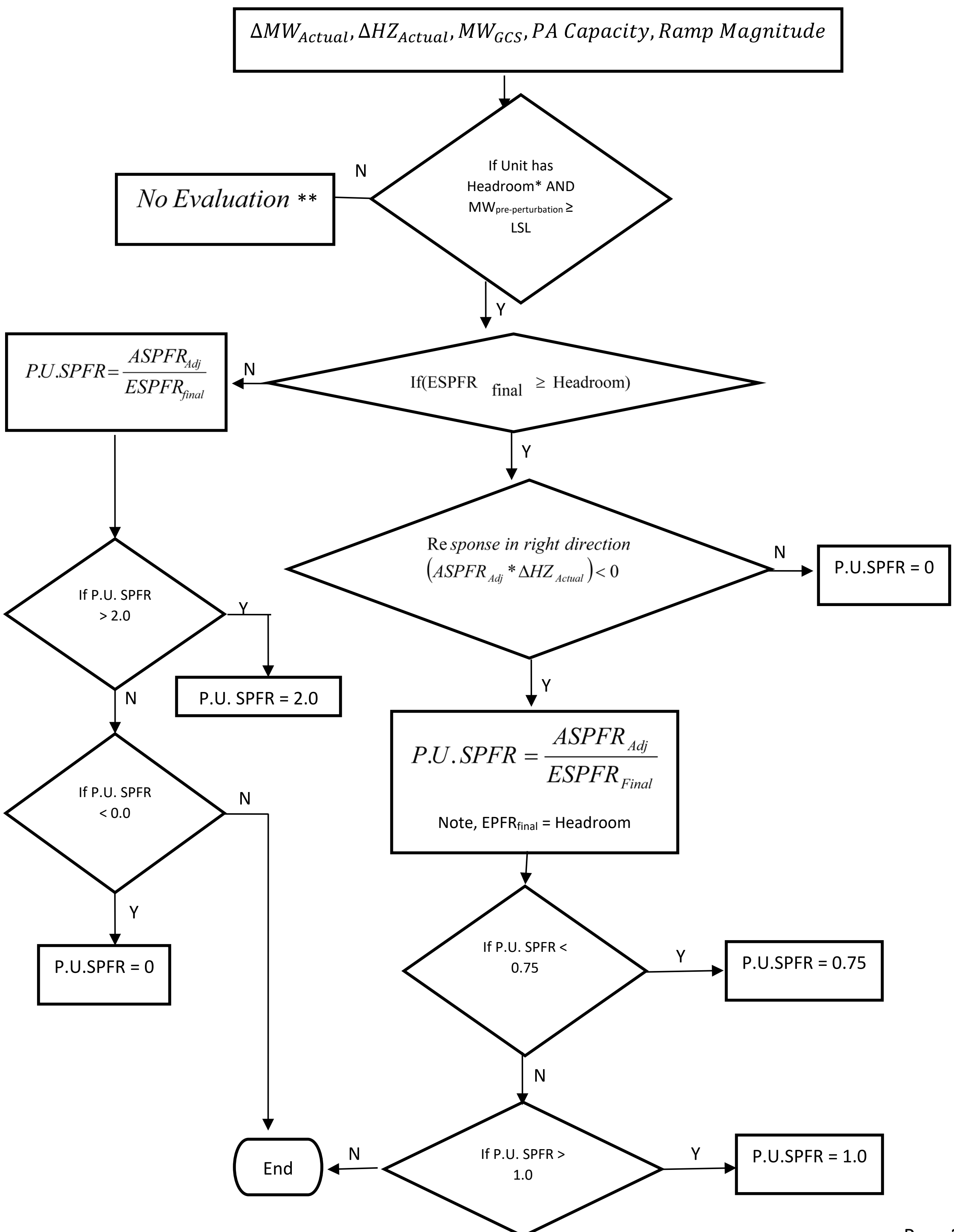


$* HZ_{Actual} = HZ_{(T + 46)}$

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

P.U. Sustained Primary Frequency Response Calculation

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


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

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

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

For low frequency events:

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

For high frequency events:

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

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

T = Time in Seconds

Revision History

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

			Frequency Response Calculations: o Unit needs to have Headroom and be above LSL to be scored. o 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

			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.

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-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.

TEXAS RE
Ensuring electric reliability for Texans

Standard Drafting Team's Responses to Comments
Comment Period: October 22 – November 6, 2025
Project SAR-013: Revisions to Regional Standard BAL-001-TRE-2

Question 1	**Regional Standard BAL-001-TRE-3: Do you agree with the revisions to Requirement R6, to 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)?**

Commenter	Answer	Comment	SDT Response
Shane Herrera, ERCOT	No	ERCOT suggests using the language "prior **written** approval from the Balancing Authority" in that same part of Table 6.1. Additionally, ERCOT suggests reviewing the use of generating unit/generating facility throughout the standard.	Thank you for your comment. The SDT revised Requirement R6 to add "written".
Michael Cruz-Montes, Brazoria County Solar Project	Yes	We support adding the optional deadband-widening provision for resources not qualified to provide Operating Reserves, provided it is implemented only with explicit prior Balancing Authority (BA) approval. This change adds needed flexibility for smaller or non-AS units while preserving fleet-level frequency performance. We recommend that ERCOT/TRE publish minimum approval criteria and duration/renewal expectations to ensure the provision does not become a de facto default setting.	Thank you for your comment. The SDT determined this information does not need to be included as part of the standard, but could be included as part of outreach during implementation of the standard.

Question 2	**Regional Standard BAL-001-TRE-3: In Regional Standard BAL-001-TRE-3 Requirement R6, what evidence should be provided for generating units to show they have obtained prior approval from the BA?**

TEXAS RE
Ensuring electric reliability for Texans

Commenter	Answer	Comment	SDT Response
Shane Herrera, ERCOT		In the near future, ERCOT intends to have a process in place that would require those resources that intend to operate at a 0.036 Hz deadband to submit registration data indicating this field setting and a valid governor response test with the same setting. This would limit resources from qualifying for Ancillary Services or trigger disqualification for those who may have previously been qualified for ancillary services prior to the setting change. A letter from ERCOT stating that the unit is approved to operate at 0.036 Hz would be provided to the resource.	Thank you for your comment. The SDT added "Written approval from the Balancing Authority to widen generating units'/generating facilities' deadband settings to +/- 0.036 Hz" to Measure M6.
Michael Cruz-Montes, Brazoria County Solar Project		Acceptable evidence should include written or electronic confirmation from the BA (e-mail, ticket, or formal dispatch system acknowledgment) specifying: • The resource ID, requested deadband, and approval date/time; • Effective period and any expiration/renewal date; and • Authorized BA representative. Supporting plant documentation, such as governor-setting screenshots or OEM setting sheets, should reference the approved values and be retained with compliance evidence.	Thank you for your comment. The SDT notes that these items are covered by the items in Measure M6. The SDT added "Written approval from the Balancing Authority to widen Generating Unit(s) generating units'/generating facilities' deadband settings to +/- 0.036 Hz" to Measure M6.

Question 3	Regional Standard BAL-001-TRE-3: Do you agree with the revised and/or added footnotes 2, 3, and 4?

Commenter	Answer	Comment	SDT Response
Shane Herrera, ERCOT	No	To ensure stylistic consistency with other NERC Reliability Standards, ERCOT recommends that the language “R6.1, R6.2, and R6.3” in footnotes 3 and 4 be replaced with “Requirement R6, Parts 6.1, 6.2, and 6.3.”	Thank you for your comment. In the course of the project, the SDT revised Requirement R6 to state “Requirement R6, Parts 6.1, 6.2, and 6.3 are not applicable to steam turbine(s) of a combined cycle resource.” This is no longer in the footnote.
Michael Cruz-Montes, Brazoria County Solar Project	Yes	The revised footnotes clarify exceptions, implementation details, and BA coordination, improving interpretability for both GOs and GOPs. We suggest Texas RE include these notes in associated Guidance material to ensure uniform understanding during audits and performance reviews.	Thank you for your comment. The SDT determined not to draft guidance at this time. This information could be included as part of outreach during implementation of the standard.

Question 4	**Regional Standard BAL-001-TRE-3: Do you agree with adding battery energy storage system (BESS) to section A. 6 and throughout BAL-001-TRE-3 and the attachments?**

Commenter	Answer	Comment	SDT Response
Shane Herrera, ERCOT	No	ERCOT understands the concept of generating unit/generating facilities to already include BESS and does not agree that callouts for the inclusion of BESS throughout the standard are necessary. Adding these references could create confusion since BESSs are not specifically identified in other NERC standards that address generating units. We do agree	Thank you for your comment. The SDT revised the language in the background section to describe what is meant by generating units/generating facilities, including examples. The SDT revised the table in Requirement Part 6.2 to complement the language in the background section.

		there is valid reason to include BESS callouts in specific calculations related to BESS in the attachment and when necessary to discuss specific generation type settings, such as in Table 6.2 of the standard.	
Michael Cruz-Montes, Brazoria County Solar Project	Yes	Explicitly incorporating Battery Energy Storage Systems (BESS) modernizes the standard and aligns it with ERCOT's rapidly expanding inverter-based fleet. The scoring windows (Initial 20–52 s, Sustained 46–60 s) and exclusion logic for resources within 2 % or 3 MW of MWGCS are appropriate. We request brief guidance on applying this exclusion to small or hybrid BESS configurations to prevent inconsistent scoring.	Thank you for your comment. The SDT determined not to draft guidance at this time. This information could be included as part of outreach during implementation of the standard.

Question 5	**Regional Standard BAL-001-TRE-3 Section C. 1.2: The drafting team revised the Compliance Monitoring Period and Reset Time Frame to clarify the roles and timing of when the GO should initiate the process to reset its rolling average. Do you agree with the change?**

Commenter	Answer	Comment	SDT Response
Shane Herrera, ERCOT	No	The edits in the SAR provide better clarification of the expected score reset process, but they excluded the potential need for the BA to participate in reviewing corrective actions plans and resets. We believe there should be language similar to that found in the original standard acknowledging the BA's input may be needed prior to CEA approval. We suggest the following edit: Option 1:	Thank you for your comment. The SDT added "After CEA consultation with the BA, and" to Section C. 1. 1.2.

		If a generating unit/generating facility's rolling average from Requirements R9 or R10 falls below the required minimum rolling average(s) performance level, and the CEA, **<u>in conjunction with the BA as necessary</u>**, has approved the GO's mitigation activities, the GO may initiate a request to the CEA to reset the rolling average(s). Option 2: If the CEA, **<u>in conjunction with the BA as necessary</u>**, 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).	
Michael Cruz-Montes, Brazoria County Solar Project	Yes	The clarification of GO, BA, and CEA roles provides transparency and a clear path to reset the rolling average once mitigation is verified. To ensure timely reinstatement, we recommend adding a target processing interval (e.g., within 30 days of CEA notice) for BA implementation of the reset.	The SDT agreed not to put a timing requirement on the BA. The current language is sufficient to ensure the reset occurs as soon as possible.

Question 6	**Attachment 1: Primary Frequency Response Reference Document: Do you agree with the revised descriptions of Maximum Megawatt Governor Control System (MW_{GCS}) and Design Settings versus real-time Evaluation?**

Commenter	Answer	Comment	SDT Response
Shane Herrera, ERCOT	No	1. MW_{GCS} should exclude capacity not reserved for primary frequency response. a. As an example, ERCOT has an ancillary service product called Fast Frequency Response (FFR), which is capacity held to provide an instantaneous response, which can be "blocky" when frequency hits 59.85 Hz. This FFR capacity is not used to provide PFR. Ensuring MW_{GCS} does not	The SDT revised the description of MW_{GCS} in attachment 1. The SDT added verbiage throughout the attachment to account for capacity that is not expected to provide PFR.

		include this capacity provides a more accurate picture of the expected response from a resource. 2. ERCOT does not believe there is a need to specifically include a discussion or definition about design settings versus real-time evaluation in the attachment. Potentially it could be included in a rationale document separate from the attachment	
Michael Cruz-Montes, Brazoria County Solar Project	Yes	The revised language properly distinguishes design-set control parameters from real-time measured response. We recommend specifying that MWGCS (for BESS, HSL→LSL range) be telemetered or reconstructable via EMS/historian data to maintain auditable performance calculations.	Thank you for your comment. The BA has the information it needs.

Question 7	Attachment 1: Primary Frequency Response Reference Document: The drafting team changed HSL to MW_{GCs} throughout the Primary Frequency Response Reference Document. Do you agree with this change?

Commenter	Answer	Comment	SDT Response
Shane Herrera, ERCOT	Yes		
Michael Cruz-Montes, Brazoria County Solar Project	Yes	Replacing HSL with MWGCS ties expected response to actual controllable capacity, improving accuracy for both conventional and inverter-based resources. This update harmonizes scoring across technologies and eliminates long-standing ambiguity for charge/discharge-limited assets.	Thank you for your comment.

TEXAS RE
Ensuring electric reliability for Texans

Question 8	Implementation Plan - Do you agree Regional Standard BAL-001-TRE-3 should 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?

Commenter	Answer	Comment	SDT Response
Shane Herrera, ERCOT	Yes		
Michael Cruz-Montes, Brazoria County Solar Project	Yes	We agree the standard should become effective on the first day of the first calendar quarter after regulatory approval. However, we recommend the drafting team explicitly recognize a 90- to 180-day transition period after the effective date for entities to: (a) verify and, if needed, adjust governor or inverter droop/deadband settings, (b) implement MWGCS-based reporting, and (c) validate historical PFR calculations. This avoids inadvertent non-compliance due to OEM or scheduling lead times rather than performance issues.	The SDT considered the comment and determined the current implementation plan provides adequate notice.

Question 9	Do you have any additional comments for the standard drafting team?

Commenter	Answer	Comment	SDT Response
Shane Herrera, ERCOT	Yes	1. Attachment A and B workflow updates for PU Initial and Sustained Frequency Response Calculations a. The flow charts indicate that a unit must have Headroom and be operating with MW_{t+0} > LSL to be evaluated. i. ERCOT suggests the MW_{t+0} should be updated to utilize the MW_{Pre} value already used in other formulas within the standard. The MW_{Pre} value is an average of actual MW from t-16 and t-2, which better represents the resource's operating	Thank you for your comment. The SDT made revisions to the flowcharts.

		condition prior to an event rather than an instantaneous reading of MW at the time of the event ii. ERCOT additionally suggests the formula be updated to ensure evaluations of resources that are operating at LSL are included. There are many resources that may sit at their LSL and are dispatchable. ERCOT's expectation is these resources must provide governor response. Additionally, LSL for a BESS could mean the unit is fully charging at LSL and must also provide governor response. This would ensure all resources are evaluated on the same basis.	
Michael Cruz-Montes, Brazoria County Solar Project	Yes	We support BAL-001-TRE-3 as a balanced update that enhances reliability and brings BESS into the ERCOT frequency-control framework. • We recommend TRE/ERCOT monitor system frequency characteristics and FME selection post-implementation to assess aggregate BESS droop behavior and ensure the 0.75 rolling-average threshold continues to incentivize sustained, real PFR. • Overall, we vote Affirmative – with comments, emphasizing implementation clarity, MWGCS auditability, and consistent governance for BA-approved deadband widening.	Thank you for your comment. The normal process monitors system frequency characteristics post-implementation.

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 (*ESPFR*) Calculations	Changed Expected Sustained to lower case (expected sustained)	This term is not defined in the NERC Glossary.

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

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 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.

Brazos Electric's AI Program

History

- 2025: Pilot Program
  - Started with roughly 20 users
  - AI Policy adopted prior to implementation
  - Training required for all pilot users
  - Significant time savings reported and many use cases identified and logged
  - Saving an hour or more per month of an employee’s time makes AI use cost-effective for us.
- 2026: AI Program Full Launch
  - Highlighted at quarterly employee communication meeting in March 2026

Program Parameters

Approved Environment

- Contracted & managed by Brazos Electric
- Security & data protection controls
- Prevents public model training
- Restricted to authorized users
- Does not eliminate confidentiality obligations
- Not considered secure enough for highly sensitive information
- Developing prompt library

Public AI and personal AI accounts

- Not approved for company work

Responsible Use & Guardrails

- Policy in place
- Training
- AI supports work — it does not replace decision-making
- Human review required
- Not used for protected NERC CIP information, privileged, or highly sensitive data.

- **Stop before you upload.**
- Slow down.
- Think.
- Check.
- Re-Check.
- Approve.

AI in Action – Employee Use Cases

- Grammar, spelling and consistency checks
- Custom GPTs used to review Brazos policies, summarize reliability requirements, and implement specialized document review
- Custom instructions to review easements
- Email and meeting note summaries
- Code creation and review
- Email draft review
- Policy review
- Web design
- Image and video creation

AI in Action - Benefits

Planning & Project Support

- Project outlines and work plans
- Step-by-step procedures
- Checklists and task breakdown

Knowledge & Learning

- Simplify complex topics
- Quick-reference guides

Decision Support

- Brainstorming alternatives
- Risks Identification
- Pros/cons comparisons

Making the Most of AI Assistance

- AI tools can rapidly identify typos, grammar, and consistency issues that are difficult to detect manually.
- AIs perform best when tasks are broken down into subtasks.
  - Example: Document review is best split into separate activities such as mechanical, consistency and clarity.
- Always ask the AI to check its work after it gives you a response.
- Have the AI suggest changes for you to make to your documents, but make the changes yourself.
  - This will help ensure that the changes suggested make sense.
- Ask the AI to provide links and references to verify its sources.
  - All AIs hallucinate – you must check to be sure the sources provided are real.

Closing Thoughts

- AI is a very useful tool, but use of AI is not without risk.
- We continue to monitor our use cases for potential improvement / expansion and risk management.

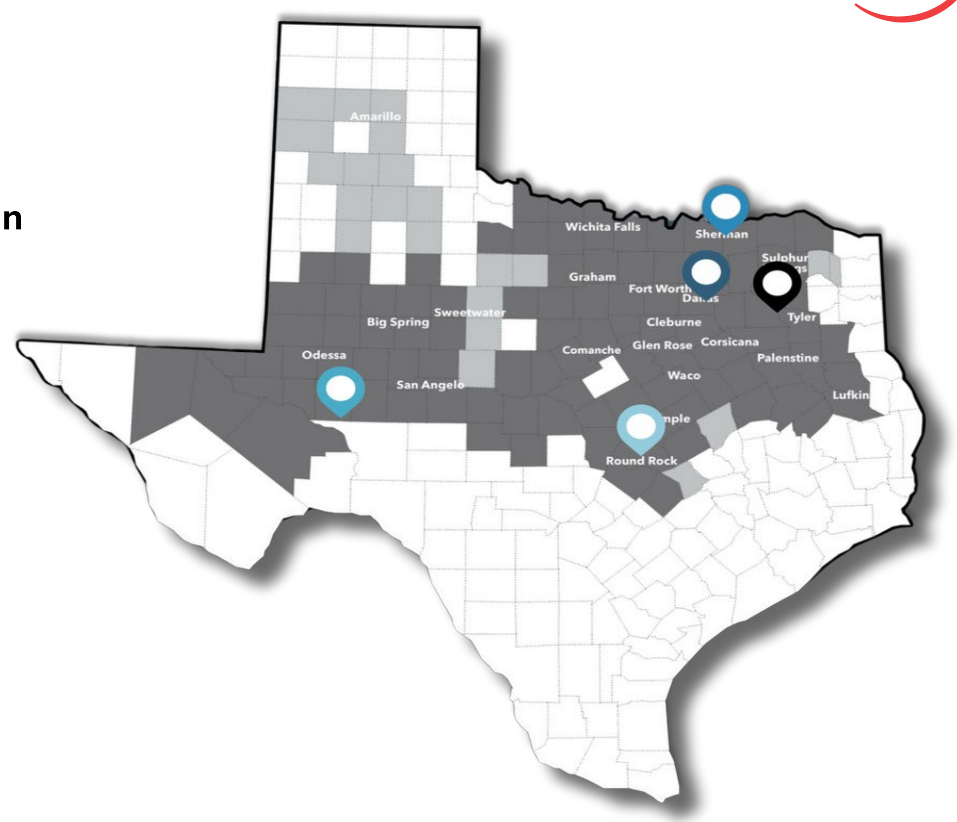
AI - Exploration and Application

Texas RE MRC Meeting
May 13, 2026

Lance K. Spross, P.E.
Director, NERC Compliance
Oncor Electric Delivery, LLC

About Oncor

- Largest TDSP in Texas
- 4+ Million Advanced Meters, 13+ Million Texans
- 3.2% Annual Load Growth
- 144,000+ Miles
- 5,500+ Employees
- 98 Communities



Our AI Journey

2019-2022

- Advanced Analytics & AI group stood-up at Oncor
- Significant data classification and clean up
- Application of advanced analytics across Oncor
- **SARA** the Chatbot introduced

2023-2024

- Began testing opensource LLMs on premise in 2024
- Built out our beta GenAI Chatbot and platform Lumen

2025

- Release of Lumen v2 to the workforce
- Build and Release of WatsonX for Customer FAQs
- Wildfire platform introduced

2026

- Implementation of Microsoft CoPilot for employee workforce
- AI Policy and training
- Customer engagement channels powered by AWS Connect

Balancing AI for Our Employees and Our Customers

People First:

AI will augment and enable our employees, not replace them.

Our focus is on freeing people from repetitive tasks, enabling sharper decisions, and giving every employee access to the tools they need to thrive in the future of work.

Customer Focused:

Every AI investment should improve customer safety, reliability, or affordability.

AI has real value only when it helps us serve Texans better, whether by anticipating outages faster, improving communication, or reducing costs.

ASASP — As Soon As Securely Possible:

We'll move with speed, but only as fast as we can keep our data, systems, field employees, and customers safe.

Security isn't a brake. It's a condition for progress. We will innovate boldly with generative AI and agentic AI while maintaining the trust that safety and compliance demand.

AI at the Table:

We default to considering AI but avoid performing "AI theater."

At every level of the organization, we'll explore how AI can meaningfully contribute to our work. We experiment openly and share what we learn. We don't bolt AI on just for headlines, only where it adds real value.

ONCOR®

Lumen: Oncor's On-Prem AI

What is Lumen?

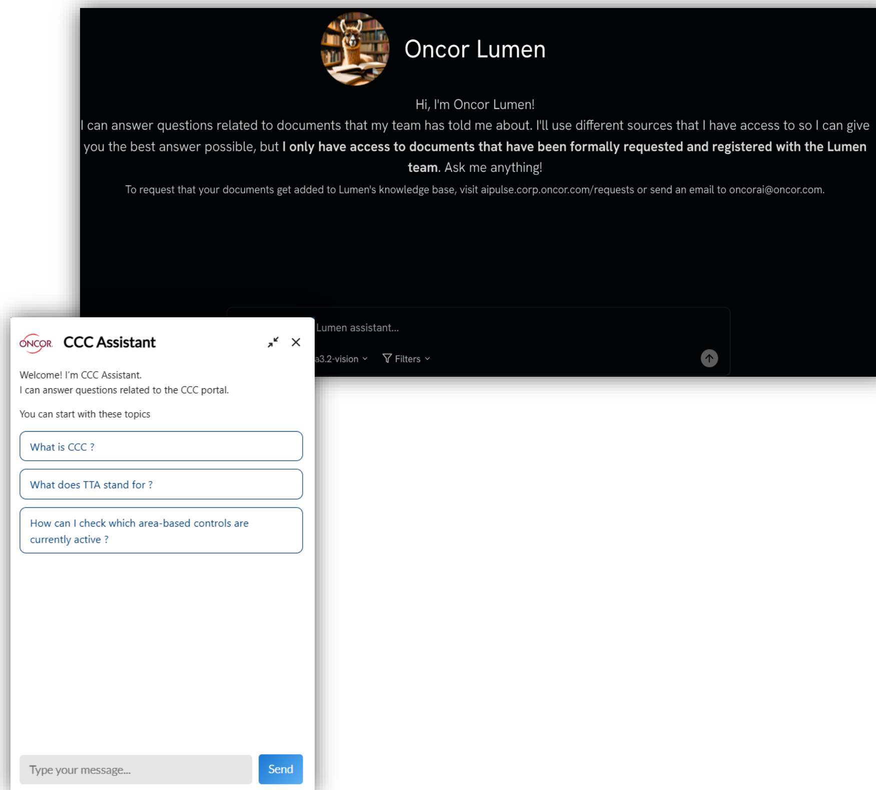
Lumen is an On-Prem Generative AI, hosted on the Analytics GPU and powered by 4 unique models.

Why DIY AI? We chose to DIY for 3 major reasons:

- R&D Cost-Effectiveness
- Data Sovereignty
- Control & Customization

What can Lumen do? Lumen can:

- Chat
- Answer Questions
- Understand Code
- Analyze Images
- Integrate with applications/databases



Customer Solutions: WatsonX.ai

ONCOR

What is WatsonX.ai?

WatsonX.ai is a GenAI Search tool, powered by IBM, that replaces limited keyword matching with contextual, natural language summaries to improve the customer experience and reduce search abandonment.

Why WatsonX.ai?

We chose Watsonx.ai to build upon our existing Watson Discovery framework. Expanding our search engine on Oncor.com to scan the entire website rather than give predetermined FAQs, we integrated watsonx.ai to transform those results into concise, natural language summaries.

What Can WatsonX.ai Do?

By scanning our public website, Watson Discovery creates a knowledge base that Watsonx.ai leverages to produce conversational search summaries. This streamlined approach improves accuracy and helps customers quickly find essential information during high stress storm situations.

Amazon Connect

Amazon Connect is a **cloud-based omnichannel contact center** from AWS that enables personalized customer service through voice, chat, and messaging while integrating AI to automate self-service, provide agents with real-time assistance, and analyze interaction sentiment.

AI Self-Service	AI will sustain natural dialogue by providing intelligent, context-aware responses to proactive user interactions.
Real-Time Support	**Amazon Q** is a customer service assistant that delivers real-time recommendations to help agents resolve issues faster and more accurately.
GenAI Assistance	Agents automatically detect customer intent across calls, chats, and emails and provide real-time generative responses, suggested actions, and links to relevant knowledge/articles.
Automated Analytics	Generates instant post-contact summaries to reduce agent wrap-up time (also available via API integrations)
100% Quality Review	AI analyzes sentiment and compliance across every customer interaction.

Public

Microsoft Copilot Chat

What is Microsoft Copilot Chat?

- AI-powered conversational assistant built into Microsoft 365.
- Enables employees to interact using natural language to get insights, automate tasks, summarize information, generate content, and support everyday productivity.
- Integrated securely within M365, ensuring data stays within Microsoft's enterprise-grade compliance, privacy, and security framework.

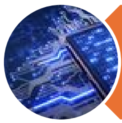
Key Benefits:

- **Boosts Productivity:** Quickly summarizes emails, documents, and meetings; accelerates content creation; reduces time spent searching for information.
- **Enhances Decision Making:** Surfaces relevant insights from organizational data to help employees work smarter and faster.
- **Reduces Operational Load:** Automates routine or repetitive tasks, allowing teams to focus on higher-value work.
- **Secure & Compliant:** Built on Microsoft's trusted cloud and identity platform, using organizational data responsibly and securely.

Oncor Deployment:

- **Rollout Date:** Oncor launched **Microsoft Copilot Chat on 2/17** as our enterprise conversational chatbot for all employees.
- **Why We Did This:**
  - Part of Oncor's continued investment in strengthening our **M365 posture**.
  - Serves as a key **enabler for future M365 enhancements**, including deeper AI-driven workflows and organizational productivity improvements.
  - Establishes a foundation for transforming day-to-day work with secure, intelligent, AI-powered assistance

Lessons Learned



- “Build vs buy” is rarely binary — hybrid models delivered the fastest value with the least long-term regret

- Time-to-value matters more than model sophistication in early GenAI adoption

- Data readiness beats model choice — weak data limits outcomes regardless of approach

- Business alignment beats technical elegance every time

The winning strategy wasn’t choosing homegrown or external — it was knowing when to use each.

Keys to the Future

Key Applications	• Customer Interface • Wildfire Management System • Research • Document Refinement
Key Opportunities	• Intelligent tools for customer and grid operations • Application as workforce multiplier • Integration into regulated workstreams • Enhanced training and employee development
Key Considerations:	• Development and maintenance of employee expertise • Emphasis on information classification and protection • Limited application in real time operations systems • Ongoing training for employees and models

Thanks!

Questions?

PUBLIC

Real-Time Co-optimization Plus Batteries (RTC+B) Program

Gordon Drake
Director, Market Design & Analysis

May 13, 2026

How ERCOT's shift to simultaneous energy and reserve clearing changes the way electricity markets work — and what it means for batteries as market resources.

Outline:

- How the ERCOT market structured energy and reserve procurement before RTC+B
- What real-time co-optimization changes — and why it matters
- Early observations following RTC+B implementation

Key Takeaways

- RTC+B went live on December 5, 2025.
- Thus far, it is providing the benefits that we expected.
- Further stakeholder consultation will be necessary to refine certain parameters once we complete stabilization activities.

ercot

PUBLIC

Before RTC+B: Energy and reserves were procured in separate processes — one looking ahead, one in real-time

Day-Ahead Market

- Co-optimized energy and ancillary services
- Energy awards purely financial, no obligation in real-time
- Ancillary service (AS) awards are binding obligations on a market participant, not resource-specific

Supplemental Ancillary Services Market (SASM)

- If a market participant couldn't fulfill its AS obligation, a SASM would be held to reallocate the awards

Real-Time Market

- Optimized energy dispatch
- Ancillary services fixed from day-ahead, assigned to individual resources

Energy and ancillary service prices were set independently in real-time. Neither fully reflected the real-time opportunity cost of a MW committed to one purpose over the other.

No mechanism existed in real-time to dynamically trade off the value of a megawatt as energy versus its value as a reserve.

Energy Storage Resources (ESRs)

Batteries were modeled as two independent resources: dispatchable generation and controllable load. Offer curves and bid curves were submitted separately for each resource.

PUBLIC

After RTC+B: Every five minutes, energy and reserves priced simultaneously.

Day-Ahead Market

- Co-optimized energy and ancillary services
- Energy awards purely financial, no obligation in real-time
- Ancillary service (AS) awards now resource-specific
- Virtual AS-only offers now available

~~**Supplemental Ancillary Services Market (SASM)**~~

- ~~If a market participant couldn't fulfill its AS obligation, a SASM would reallocate the awards~~

Real-Time Market

- Co-optimized energy and AS dispatch
- All capacity considered eligible for least-cost solution for energy and AS

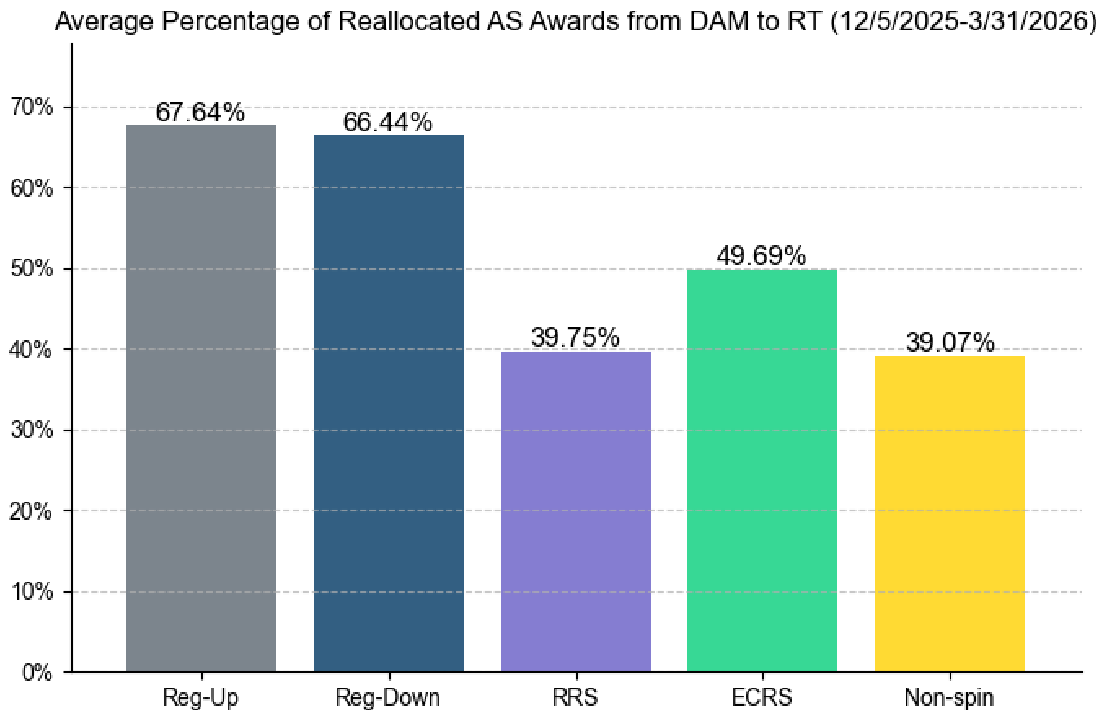
The real-time market now simultaneously determines how much of each reserve product to award, and at what price, using a unified objective function.

For every dispatchable resource, SCED asks in real time: *given current conditions, is this MW worth more as energy or as a reserve?* The answer drives both dispatch and pricing.

Energy Storage Resources (ESRs)

A battery is now modeled as a unified resource for charging and discharging. The engine can simultaneously award it energy and ancillary services, optimizing the split in real-time based on relative market value.

Day-Ahead Market awards frequently changed in Real-Time Market



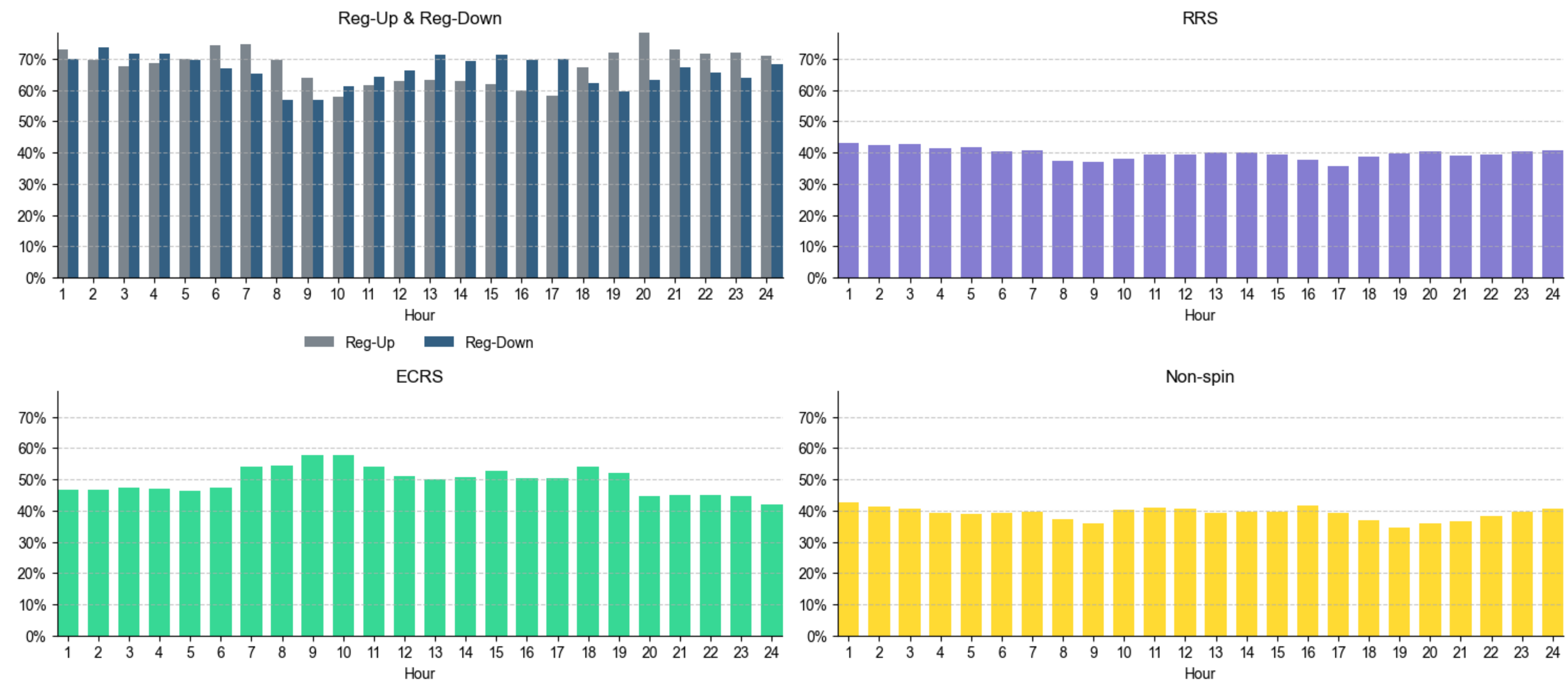
Day-Ahead Market awards frequently changed to different resources in the Real-Time Market, especially for Regulation Up (Reg-Up) and Regulation Down (Reg-Down) services. Similar outcomes, though less frequent, were seen in Responsive Reserve Service (RRS), ERCOT Contingency Reserve Service (ECRS) and Non-Spinning Reserves (Non-Spin).

ercot

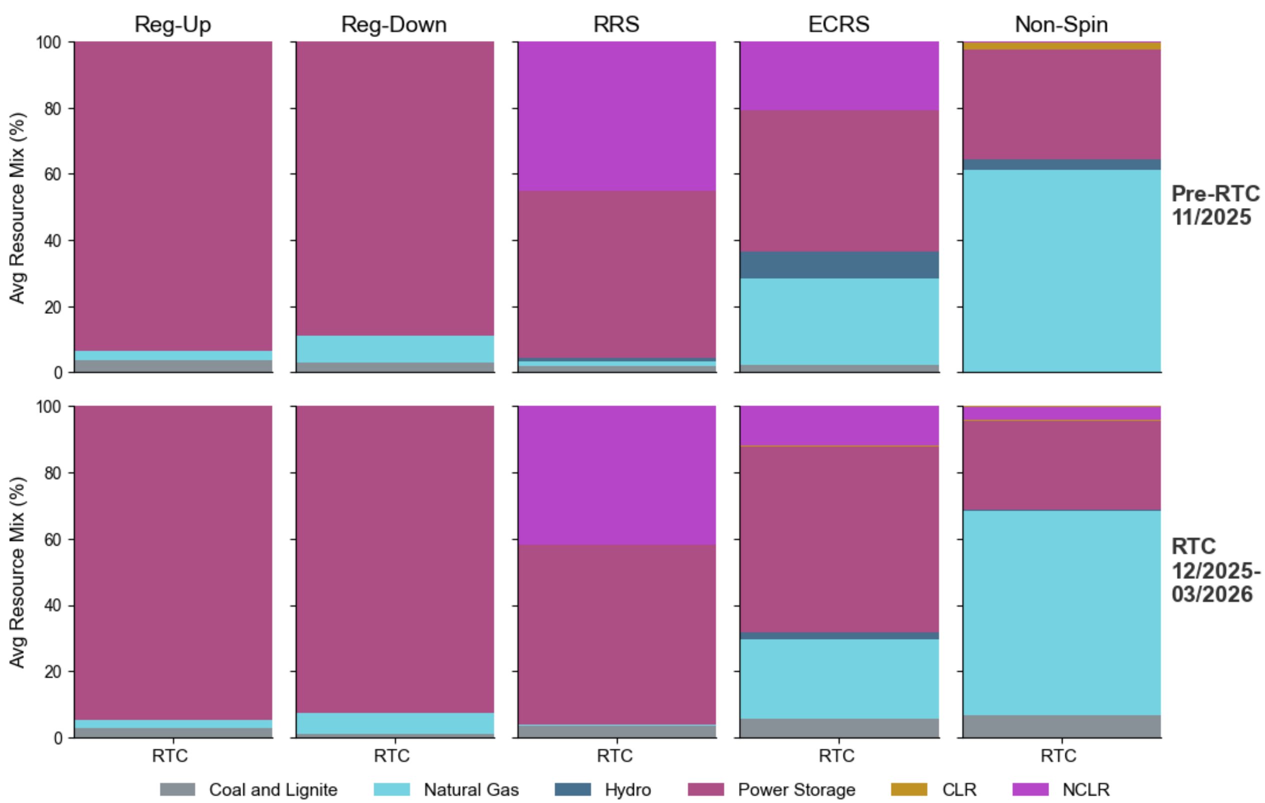
PUBLIC

Redispatch between day-ahead and real-time varies slightly across different hours

Hourly Average Percentage of Reallocated AS Awards from DAM to RT (12/5/2025-3/31/2026)



The supply mix in each Ancillary Service has evolved since the introduction of Real-Time Co-optimization



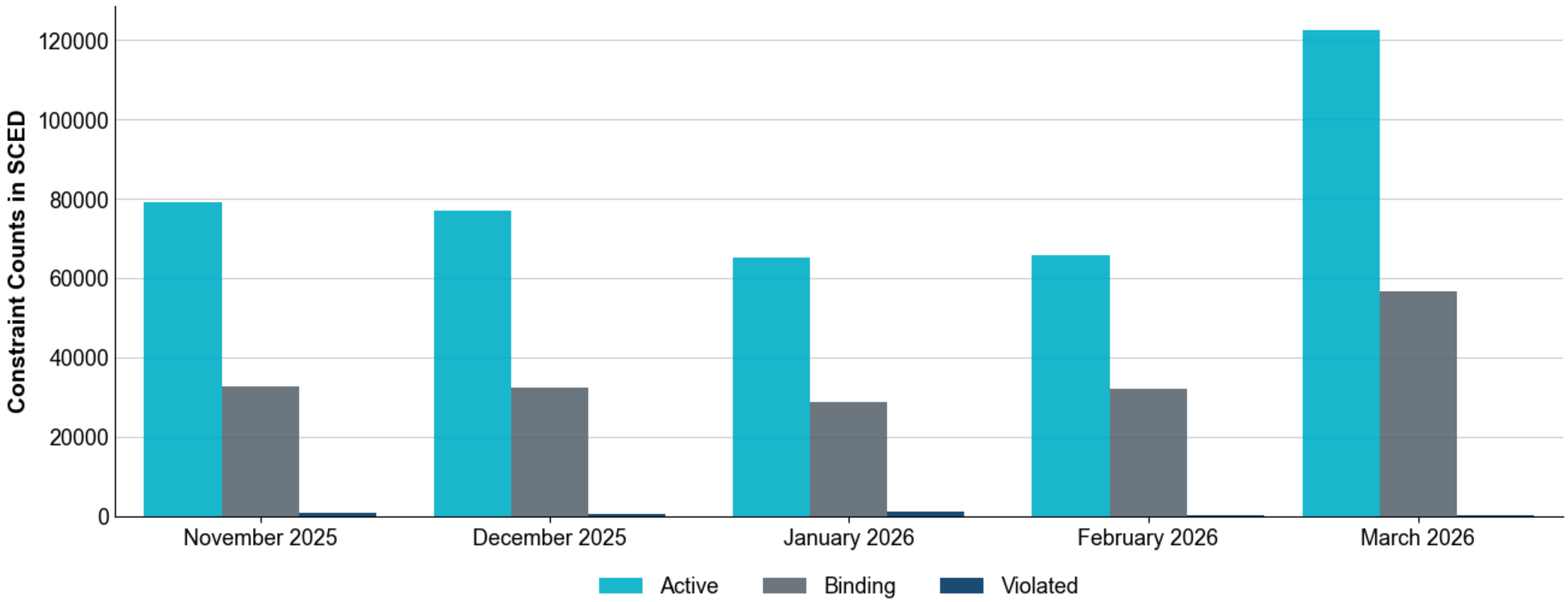
Since RTC+B implementation, Energy Storage Resources (ESRs) have captured a larger share of ECRS, displacing Non-controllable Load Resources (NCLR), Hydro, and Natural Gas.

In contrast, the ESR share in Non-Spin has slightly declined in favor of longer duration resources such as Coal, Natural Gas, and NCLRs.

Note: CLR and NCLR refer to Controllable Load Resources and Non-controllable Load Resources, respectively.

PUBLIC

The number of active transmission constraints considered in real-time declined, as did the number of binding constraints



From December to February, we observed a general decline in the frequency of active and binding transmission constraints in real-time, when compared to November. The frequency of active constraints in March was approximately 20% lower than March 2025.

PUBLIC

While we are pleased with the results, there is more work to be done

System Stabilization

We continue to monitor market outcomes to identify any unintended consequences arising from RTC+B implementation.

Some issues already addressed include:

- Tightened MIP Gap tolerances
- Change of solver model
- Missed data in reporting

Stakeholder Engagement

The Real-Time Co-optimization plus Batteries Task Force (RTCBTF), we accumulated certain issues to revisit after RTC+B implementation, including:

- A review of the Ancillary Service Demand Curves (ASDCs), their individual shapes, and the shape of the aggregate ASDC shape
- Parameters such as the energy market price cap, real-time offer price caps, and proxy offer price floor values.
- Duration requirements for each ancillary service, especially ERCOT Contingency Reserve Service and Non-Spinning Reserves

The RTCBTF has proposed a work plan, adopted by the Technical Advisory Committee, which outlines all the issues, the appropriate stakeholder forum, and tentative timing.

PUBLIC

Thank you!

Gordon.Drake@ercot.com

Learn More

www.ercot.com

Download ERCOT Mobile App

GET IT ON Google Play

Download on the App Store

Connect With Us

facebook.com/ERCOTISO

x.com/ercot_iso

linkedin.com/company/ercot

instagram.com/ercot_iso

NERC Standards Review Forum Update

Texas RE Member Representatives Committee

May 13, 2026

Brad Collard, Pedernales Electric Cooperative

Chair

Thomas Brinckman, CenterPoint Energy

Co Vice-Chair

Manivone Vorabouth, Pedernales Electric Cooperative

Co Vice-Chair

Rachel Coyne, Texas RE

Texas RE Facilitator

Recent NSRF Meetings

- 2/26/2026 – Hybrid
- 3/26/2026 – Remote
- 4/23/2026 – Remote

Open sessions are hosted by Texas RE.

Hybrid session was hosted at Texas RE.

Closed sessions are hosted by Pedernales Electric Cooperative.

Charter Changes

NSRF Charter Changes

Multiple vice-chair format to represent various market segments

Texas RE Chief of Staff as primary point of contact

Strengthened succession planning

Leadership

NSRF participants shall select a ~~chair~~Chair and ~~multiple~~ V~~v~~ice ~~chair~~Chair(s) to serve a calendar-year term, with the goal to have one Vice Chair per market segment not to exceed four (4) Vice Chairs ~~the goal of representing diverse market segments~~ (e.g. RC/BA, ~~Generation~~Resource entities ~~— type 1 and type 2~~, Transmission, Distribution, etc.). The ~~chair~~Chair shall preside over meetings and consult with the ~~vice chair~~Vice Chair(s) and the Texas RE Executive Chief of Staff (ECOS) ~~Manager, Reliability Standards Program (RSM)~~ to develop meeting agendas. ~~The~~ A designated ~~vice chair~~Vice Chair shall act as ~~chair~~Chair at NSRF meetings in the absence of the ~~chair~~Chair. In the event of a vacancy of the ~~chair~~Chair, remaining leadership will select ~~the~~ a ~~vice chair~~Vice Chair that will become ~~chair~~Chair and the NSRF participants will select a new ~~vice chair~~Vice Chair; both will serve the remainder of the term.

The NSRF ~~chair~~Chair or a designee will provide an NSRF report at each MRC meeting. This report will include an overview of items discussed by NSRF, including NERC Reliability Standards open for ballot or comment and any voting recommendations or comments issued by NSRF.

The ECOS ~~RSM~~ shall facilitate the work of the NSRF, including:

- tracking NERC Reliability Standards and other items under the NSRF's review;
- facilitating Texas RE subject-matter expert (SME) participation in meetings as necessary;
- preparing and publishing meeting announcements and agendas; and
- scheduling and facilitating in-person meetings and conference calls/web-meetings.

NSRF Charter Changes

Multiple vice-chair format to represent various market segments → Texas RE Chief of Staff as primary point of contact → Strengthened succession planning

Leadership

NSRF participants shall select a Chair and Vice Chair(s) to serve a calendar-year term, with the goal to have one Vice Chair per market segment not to exceed four (4) Vice Chairs t (e.g. RC/BA, Resource entities, Transmission, Distribution, etc.). The Chair shall preside over meetings and consult with the Vice Chair(s) and the Texas RE Executive Chief of Staff (ECOS) to develop meeting agendas. A designated Vice Chair shall act as Chair at NSRF meetings in the absence of the Chair. In the event of a vacancy of the Chair, remaining leadership will select a Vice Chair that will become Chair and the NSRF participants will select a new Vice Chair; both will serve the remainder of the term.

The NSRF Chair or a designee will provide an NSRF report at each MRC meeting. This report will include an overview of items discussed by NSRF, including NERC Reliability Standards open for ballot or comment and any voting recommendations or comments issued by NSRF.

The ECOS shall facilitate the work of the NSRF, including:

- tracking NERC Reliability Standards and other items under the NSRF's review;
- facilitating Texas RE subject-matter expert (SME) participation in meetings as necessary;
- preparing and publishing meeting announcements and agendas; and
- scheduling and facilitating in-person meetings and conference calls/web-meetings.

Standards Report

Standards Report

- <u>Newly Effective Reliability Standards</u>
  - 4/1/2026
    - *MOD-026-2: Verification and Validation of Dynamic Models and Data*
    - *MOD-033-3: Steady-State and Dynamic System Model Validation*
    - *TPL-008-1: Transmission System Planning Performance Requirements for Extreme Temperature Events*

Standards Report

- <u>Effective Dates for Upcoming Reliability Standards:</u>
  - October 1, 2026
    - *PRC-024-4: Frequency and Voltage Protection Settings for Synchronous Generators, Type 1 and Type 2 Wind Resources, and Synchronous Condensers*
    - *PRC-029-1: Frequency and Voltage Ride-through Requirements for Inverter-based Resources*
    - *PRC-030-1: Unexpected Inverter-Based Resource Event Mitigation*
    - *TOP-003-7: Transmission Operator and Balancing Authority Data and Information Specification and Collection*

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

Standards Report

- <u>Effective Dates for Upcoming Reliability Standards:</u>
  - April 1, 2027
    - *BAL-007-1.1: Near-Term Reliability Assessments*
  - April 1, 2028
    - *MOD-032-2: Data for Power System Modeling and Analysis*
  - April 1, 2029
    - *IRO-010-6: Reliability Coordinator Data and Information Specification and Collection*
    - *TOP-003-8: Transmission Operator and Balancing Authority Data and Information Specification and Collection*

Ongoing NERC Reliability Standard Projects

High Priority Projects

1. 2023-06 CIP-014 Risk Assessment Refinement
2. 2024-02 Planning Energy Assurance
3. 2025-03 FERC Order 901 Operational Studies
4. 2025-04 FERC Order 901 Planning Studies
5. 2025-05 Ride-Through Revisions (PRC-024-4 and PRC-029-1)
6. 2026-02 Computational Loads

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

Continues

Medium Priority Projects

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

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

Low Priority Projects

1. 2017-01 Modifications to BAL-003 Phase II
2. 2019-04 Modifications to PRC-005-6
3. 2020-06 Verifications of Models and Data for Generators
4. 2021-02 Modifications to VAR-002-4.1 IBR
5. 2021-08 Modifications to FAC-008
6. 2022-01 Uniform Modeling Framework for IBR IBR
7. 2023-05 Modifications to FAC-001 and FAC-002 IBR
8. 20203-07 Transmission System Planning Performance Requirements for Extreme Weather
9. 2023-08 Modifications of MOD-031 Demand and Energy Data IBR
10. 2026-01 PRC-006 Standard Updates

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

Recent NERC Filings

- RD26-4-000: BAL-007-1 Errata. This petition sought approval for typographical corrections to the GMD Vulnerability Assessment standard. FERC issued a Letter Order approving these errata on March 26, 2026.
- RD26-5-000: BAL-002-WECC-3 Retirement. This joint petition (NERC and WECC) seeks the retirement of the Western Interconnection Contingency Reserve regional standard, which is now redundant to continent-wide standards.
- EL25-49-000: NERC Motion to Intervene and Comments. Filed on March 30, 2026, regarding the complaint by the Center for Security Policy concerning large load reliability risks.
- RR26-2-000: 2026 Rules of Procedure (ROP) Revisions. This docket covers the proposed changes to registration criteria for "Computational Load Entities" (CLEs). NERC issued draft registration criteria on April 1, 2026, aiming to register data centers and crypto-mining facilities with 100 MW or more of load.

Recent FERC Orders/Rules

- RD26-5-000 Order Approving Retirement of Regional Reliability Standard BAL-002-WECC-3 - FERC issues a Letter Order approving the retirement of Regional Reliability Standard BAL-002-WECC-3.
- RR26-1-000 Letter Order Approving Amendments to the WECC Bylaws – 4/21/2026 FERC issues a letter order approving amendments to the WECC bylaws.
- RD26-4-000 | BAL-007-4 Errata Approval (March 26, 2026): FERC issued a Letter Order approving NERC's petition to correct typographical discrepancies in BAL-007-1 (GMD Vulnerability Assessments). This ensures the technical requirements for geomagnetically induced current (GIC) assessments are legally enforceable as intended.
- RM25-3-000 | IBR Ride-Through Standards (March 2026): FERC issued an Order Approving IBR Ride-Through Standards. This formal regulatory approval covers performance requirements developed under the Inverter-Based Resource (IBR) work plan, affecting standards such as PRC-024-4 and PRC-029-1.
- EL25-49-000 docket (Center for Security Policy complaint), noting that FERC’s handling of the motion to intervene has shifted focus toward the accelerated "Computational Load" standards tracked in the O&P projects.

Recent Discussion Topics

- Chief Engineer Reports: A technical report provided by Mark Henry.
- Grid Transformation Perspectives: Discussion on the risk perspective of grid transformation led by Jeff Hargis and the compliance perspective by Joseph Williams.
- Modeling and Standards Changes: Updates on MOD-026-1, MOD-027-1, and upcoming changes to verification requirements.
- Planning Responsibilities: A review of PC and TP responsibilities under TPL-008-1 presented by Matt Stout from ERCOT.
- Standard Performance Requirements: A focus on PRC-028 and PRC-029 led by Blake Ianni.

Recent Discussion Topics

- Discussion on extreme weather response risks led by Tyreke Griffin.
- A presentation on FAC-008 Inventory Change Management by Stephen Bradford.
- Discussion regarding the Level 3 NERC Alert.
- Updates on the Large Load SAR and a report on NERC's motion to intervene regarding a complaint from the Center for Security Policy.
- Updates to the NSRF Charter and plans for the NSRF leadership transition.

Closed Session Topics

- Open Session Carry Over
- ERCOT Updates
- NERC Alert – Level 3
- Audit Experiences
- Discussion about EOP-011, MOD-026, PRC-023, PRC-028, and PRC-029/PRC-027 Best Practices
- Other Discussion Items – Industry experiences, best practices and lessons learned with internal controls

Upcoming NSRF Meetings

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

- May 28, 2026: Hybrid meeting at AOC CenterPoint with breakfast tacos provided by CenterPoint.
- June 25, 2026.
- July 23, 2026.
- August 27, 2026.
- September 17, 2026: Hybrid meeting with breakfast tacos.
- October 22, 2026.
- November 19, 2026: Hybrid meeting with breakfast tacos provided by CPS.

Questions or Comments?

Thank you!

Public

NERC Standards Review Forum Charter

Purpose and Scope

The NERC Standards Review Forum (NSRF) is a stakeholder group reporting to the Member Representatives Committee (MRC). The purpose of the NSRF is to provide a regional stakeholder forum for discussion, collaboration, and research on NERC Standard Authorization Request forms (SARs), standards under development, interpretations, and existing Reliability Standards. The NSRF may also provide advice and recommendations to the MRC regarding the development of ERCOT region Regional Reliability Standards and variances. The NSRF will provide regular updates to the MRC to assist the MRC in regional industry analyses of standards being developed and balloted by NERC.

Additionally, the NSRF serves as a forum for stakeholders to share information regarding compliance with NERC Reliability Standards. Topics for discussion may include:

- Best compliance practices
- Audit experiences
- Violations and possible violations of standards
- Lessons learned
- Industry policies, direction, and trends
- Current compliance-related events and programs of general interest
- Compliance with new or modified NERC Reliability Standards
- The ERCOT protocols and Guides as they relate to NERC requirements

Leadership

NSRF participants shall select a ~~chair~~Chair and ~~multiple~~ V~~v~~ice ~~chair~~Chair(s) to serve a calendar-year term, with the goal to have one Vice Chair per market segment not to exceed four (4) Vice Chairs ~~the goal of representing diverse market segments~~ (e.g. RC/BA, ~~Generation~~Resource entities~~ – type 1 and type 2~~, Transmission, Distribution, etc.). The ~~chair~~Chair shall preside over meetings and consult with the ~~vice chair~~Vice Chair(s) and the Texas RE Executive Chief of Staff (ECOS) ~~Manager, Reliability Standards Program (RSM)~~ to develop meeting agendas. ~~The~~ A designated ~~vice chair~~Vice Chair shall act as ~~chair~~Chair at NSRF meetings in the absence of the ~~chair~~Chair. In the event of a vacancy of the ~~chair~~Chair, remaining leadership will select ~~the~~ a ~~vice chair~~Vice Chair that will become ~~chair~~Chair and the NSRF participants will select a new ~~vice chair~~Vice Chair; both will serve the remainder of the term.

The NSRF ~~chair~~Chair or a designee will provide an NSRF report at each MRC meeting. This report will include an overview of items discussed by NSRF, including NERC Reliability Standards open for ballot or comment and any voting recommendations or comments issued by NSRF.

The ECOS ~~RSM~~ shall facilitate the work of the NSRF, including:

- tracking NERC Reliability Standards and other items under the NSRF's review;
- facilitating Texas RE subject-matter expert (SME) participation in meetings as necessary;
- preparing and publishing meeting announcements and agendas; and
- scheduling and facilitating in-person meetings and conference calls/web-meetings.

Participation

Participation in NSRF is voluntary and open to interested entities and individuals in the ERCOT region. The NSRF should strive for diverse participation from all sectors and from large and small

Formatted: Not Expanded by / Condensed by

Formatted: Not Expanded by / Condensed by

Formatted: Not Expanded by / Condensed by companies. There is no formal voting structure associated with NSRF, which will operate on a voluntary, consensus-based model.

All positions adopted by NSRF and recommendations made by NSRF are non-binding on any party, and are intended for the benefit of and consideration by any interested party. No one is obligated to vote on NERC ballots in accordance with NSRF recommendations or to join in NSRF comments.

NSRF may designate an NSRF member or observer as the "point of contact" for any standard or other item that it takes up for consideration and possible action by NSRF. The point of contact will collect and organize comments, propose action on the item (if desired) and lead NSRF discussion of the item.

Meetings

The NSRF will meet as determined by the NSRF ~~chair~~Chair, but typically once a month. NSRF meetings are broken up into two segments: an open session and a closed session.

All meeting notices with the open meeting agenda will be sent to the Texas Reliability Entity, Inc. (Texas RE) Standards listserv and posted to the Texas RE website one week prior to the meeting.

NSRF open meetings are open to all stakeholders, including ERCOT staff, the Public Utility Commission of Texas (PUCT) staff, Texas RE staff, and any other appropriate governing agency staff who wish to participate.

The open session is an opportunity to discuss issues with Texas RE representatives. Time may be allocated for discussion of standard retirements, projects, guidelines, Standards Committee Updates, Standards Report from Texas RE, Upcoming Implementation dates and deadlines, and any other publicly-available or non-confidential information as needed.

The closed session may be used to discuss confidential information, including Critical Energy Infrastructure Information (CEII) or registered entities' experiences and practices related to compliance such as discussions of audit and compliance events, member interpretation of upcoming standards, guidance and how registered entities comply, as well as potential concerns related to upcoming standard implementations.

The NSRF ~~chair~~Chair and ~~vice chair~~Vice Chair(s) are responsible for determining when NSRF meetings should be held in closed session. When NSRF meetings are held in a closed session, only NSRF members meeting the following requirements may participate:

- The member signed the Non-Disclosure Agreement (NDA);
- The Texas RE Legal Department reviewed the signed NDA; and
- The member:
    - Is directly employed by a NERC Registered Entity operating in the ERCOT region, or
    - Is directly employed by an Affiliate of an above-referenced entity, or
    - Is a consultant or contract laborer authorized to represent a specific NERC registered entity in the ERCOT Region by that entity and who does not represent the business interests of the company with which s/he is directly employed.

The Texas RE Legal Department will maintain a list of members who have signed the appropriate NDA and will provide it to the NSRF ~~chair~~Chair and V~~v~~ice ~~chair~~Chair(s) for the determination of attendance at closed session meetings.

Periodically, NSRF Chair or a designated Vice Chair will send a request of confirmation to the NSRF Restricted email listserv members for confirmation that the individual is continues to meet NSRF requirements to attend close session and receive restricted information via the NSRF Restricted email listserv. The NSRF Chair or designated Vice Chair will attempt at least twice within 60 days before the non-responding individuals are removed from the NSRF NDA list and NSRF Restricted email listserv list.

On a case-by-case basis, invited guests by the NSRF Chair or Vice Chair(s) will be permitted in closed sessions to provide information on a defined topic to the NSRF. Such invited guests may not need to execute the NSRF NDA (aka NSRF Confidentiality Agreement) for this limited purpose and will be asked to leave at the conclusion of the discussion on the defined topic.

Email Lists

Texas RE ~~External Relations~~Communications and Training staff maintains a standards email listserv, which disseminates NSRF open session announcements and meetings notices. Any stakeholder may join the Texas RE listserv. ERCOT maintains the NSRF-Restricted email listserv. NSRF members who have an approved NDA and meet the requirements for participation in closed session may request to be added to the NSRF-restricted email listserv. This list may share compliance-related information that members consider to be confidential, including but not limited to content discussed in closed sessions, including closed meeting agendas and presentations approved by the author for dissemination.

Amendments

Amendments to this Charter must be approved by the MRC.

If anything in this Charter is inconsistent with Texas RE governing documents, including the Delegation Agreement, Bylaws, and the Standards Development Process, the governing documents shall take precedence.

Amendment History

Revision Description	MRC Approval Date
Updated the leadership section to account for multiple ~~vice chair~~~~Chair~~Vice Chairs.	

NERC Standards Review Forum Charter

Purpose and Scope

The NERC Standards Review Forum (NSRF) is a stakeholder group reporting to the Member Representatives Committee (MRC). The purpose of the NSRF is to provide a regional stakeholder forum for discussion, collaboration, and research on NERC Standard Authorization Request forms (SARs), standards under development, interpretations, and existing Reliability Standards. The NSRF may also provide advice and recommendations to the MRC regarding the development of ERCOT region Regional Reliability Standards and variances. The NSRF will provide regular updates to the MRC to assist the MRC in regional industry analyses of standards being developed and balloted by NERC.

Additionally, the NSRF serves as a forum for stakeholders to share information regarding compliance with NERC Reliability Standards. Topics for discussion may include:

- Best compliance practices
- Audit experiences
- Violations and possible violations of standards
- Lessons learned
- Industry policies, direction, and trends
- Current compliance-related events and programs of general interest
- Compliance with new or modified NERC Reliability Standards
- The ERCOT protocols and Guides as they relate to NERC requirements

Leadership

NSRF participants shall select a Chair and Vice Chair(s) to serve a calendar-year term, with the goal to have one Vice Chair per market segment not to exceed four (4) Vice Chairs (e.g. RC/BA, Resource entities, Transmission, Distribution, etc.). The Chair shall preside over meetings and consult with the Vice Chair(s) and the Texas RE Executive Chief of Staff (ECOS) to develop meeting agendas. A designated Vice Chair shall act as Chair at NSRF meetings in the absence of the Chair. In the event of a vacancy of the Chair, remaining leadership will select a Vice Chair that will become Chair and the NSRF participants will select a new Vice Chair; both will serve the remainder of the term.

The NSRF Chair or a designee will provide an NSRF report at each MRC meeting. This report will include an overview of items discussed by NSRF, including NERC Reliability Standards open for ballot or comment and any voting recommendations or comments issued by NSRF.

The ECOS shall facilitate the work of the NSRF, including:

- tracking NERC Reliability Standards and other items under the NSRF's review;
- facilitating Texas RE subject-matter expert (SME) participation in meetings as necessary;
- preparing and publishing meeting announcements and agendas; and
- scheduling and facilitating in-person meetings and conference calls/web-meetings.

Participation

Participation in NSRF is voluntary and open to interested entities and individuals in the ERCOT region. The NSRF should strive for diverse participation from all sectors and from large and small companies. There is no formal voting structure associated with NSRF, which will operate on a voluntary, consensus-based model.

All positions adopted by NSRF and recommendations made by NSRF are non-binding on any party, and are intended for the benefit of and consideration by any interested party. No one is obligated to vote on NERC ballots in accordance with NSRF recommendations or to join in NSRF comments.

NSRF may designate an NSRF member or observer as the “point of contact” for any standard or other item that it takes up for consideration and possible action by NSRF. The point of contact will collect and organize comments, propose action on the item (if desired) and lead NSRF discussion of the item.

Meetings

The NSRF will meet as determined by the NSRF Chair, but typically once a month. NSRF meetings are broken up into two segments: an open session and a closed session.

All meeting notices with the open meeting agenda will be sent to the Texas Reliability Entity, Inc. (Texas RE) Standards listserv and posted to the Texas RE website one week prior to the meeting.

NSRF open meetings are open to all stakeholders, including ERCOT staff, the Public Utility Commission of Texas (PUCT) staff, Texas RE staff, and any other appropriate governing agency staff who wish to participate.

The open session is an opportunity to discuss issues with Texas RE representatives. Time may be allocated for discussion of standard retirements, projects, guidelines, Standards Committee Updates, Standards Report from Texas RE, Upcoming Implementation dates and deadlines, and any other publicly-available or non-confidential information as needed.

The closed session may be used to discuss confidential information, including Critical Energy Infrastructure Information (CEII) or registered entities’ experiences and practices related to compliance such as discussions of audit and compliance events, member interpretation of upcoming standards, guidance and how registered entities comply, as well as potential concerns related to upcoming standard implementations.

The NSRF Chair and Vice Chair(s) are responsible for determining when NSRF meetings should be held in closed session. When NSRF meetings are held in a closed session, only NSRF members meeting the following requirements may participate:

- The member signed the Non-Disclosure Agreement (NDA);
- The Texas RE Legal Department reviewed the signed NDA; and
- The member:
  - Is directly employed by a NERC Registered Entity operating in the ERCOT region, or
  - Is directly employed by an Affiliate of an above-referenced entity, or
  - Is a consultant or contract laborer authorized to represent a specific NERC registered entity in the ERCOT Region by that entity and who does not represent the business interests of the company with which s/he is directly employed.

The Texas RE Legal Department will maintain a list of members who have signed the appropriate NDA and will provide it to the NSRF Chair and Vice Chair(s) for the determination of attendance at closed session meetings.

Periodically, NSRF Chair or a designated Vice Chair will send a request of confirmation to the NSRF Restricted email listserv members for confirmation that the individual is continues to meet NSRF requirements to attend close session and receive restricted information via the NSRF Restricted email listserv. The NSRF Chair or designated Vice Chair will attempt at least twice within 60 days before the non-responding individuals are removed from the NSRF NDA list and NSRF Restricted email listserv list.

On a case-by-case basis, invited guests by the NSRF Chair or Vice Chair(s) will be permitted in closed sessions to provide information on a defined topic to the NSRF. Such invited guests may not need to execute the NSRF NDA (aka NSRF Confidentiality Agreement) for this limited purpose and will be asked to leave at the conclusion of the discussion on the defined topic.

Email Lists

Texas RE Communications and Training staff maintains a standards email listserv, which disseminates NSRF open session announcements and meetings notices. Any stakeholder may join the Texas RE listserv. ERCOT maintains the NSRF-Restricted email listserv. NSRF members who have an approved NDA and meet the requirements for participation in closed session may request to be added to the NSRF-restricted email listserv. This list may share compliance-related information that members consider to be confidential, including but not limited to content discussed in closed sessions, including closed meeting agendas and presentations approved by the author for dissemination.

Amendments

Amendments to this Charter must be approved by the MRC.

If anything in this Charter is inconsistent with Texas RE governing documents, including the Delegation Agreement, Bylaws, and the Standards Development Process, the governing documents shall take precedence.

Amendment History

Revision Description	MRC Approval Date
Updated the leadership section to account for multiple Vice Chairs.	

ERCOT CIP WORKING GROUP UPDATE

For the Texas RE Member Representatives Committee (MRC)
May 13, 2026

Thomas Standifur, Austin Energy
CIPWG Chair

Danté Jackson, CenterPoint
CIPWG Vice Chair

Public

RECENT MEETINGS

- March 13, 2026 – Virtual Only
- April 10, 2026 – Virtual Only
- May 1, 2026 – Virtual (Open), In-Person (Closed)

- E-ISAC briefings
- PUCT – Review of upcoming Cyber Security Conference in October 2026
- TxDPS presentation on Infrastructure Liaison Officer program/course
- Ask TRE
  - CIP-006-6 R1 (Physical Security)
    - Physical Security risks (2026 CMEP IP Risk Element)
  - CIP-012-2 R1 (Comms between Control Centers)
    - Remote connectivity considerations (2026 CMEP IP Risk Element)
  - CIP-014-3 R4 R5 (Physical Security)
    - Physical security considerations (2026 CMEP IP Risk Element)
  - Question about CIP-002
    - Engagement common questions - identifying and evaluating devices that perform serial/IP protocol translation
  - Question about Project 2016-02 effective date and early adoption options

OPEN SESSION TOPICS SUMMARY

Public

- Standards typically tracked during the open sessions

HIGH PRIORITY

- 2025-02 Internal Network Security Monitoring Standard Revision (CIP-015-2)
  - Initial ballots for the Standards and Implementation Plan closed: January 7 – 16, 2026
- 2023-06 CIP-014 Risk Assessment Refinement
  - Additional ballots for the standard and implementation plan will be conducted May 5 – 14, 2026
- 2023-09 Risk Management for Third-Party Cloud Services
  - Project moved to High
  - A supplemental nomination period for additional drafting team members was open through Friday, March 20, 2026
- 2025-06 Supply Chain Risk Management
  - Project moved to High
  - Drafting team will review all responses received during the comment period and determine the next steps of the project

MEDIUM PRIORITY

- 2021-03 CIP-002 Transmission Owner Control Centers
  - Drafting team will review all responses received during the comment period and determine the next steps of the project

LOW PRIORITY

- 2022-05 Modifications to CIP-008 Reporting Threshold
  - Informal comment period closed in October 2025

WITH FERC

- 2021-03 CIP-002 Transmission Owner Control Centers under docket number RM25-7-000

OPEN SESSION CIP STANDARDS TRACKED

Public

- Subject To Future Enforcement

CIP-012-2 (Communications between Control Centers)

- July 1, 2026

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

- July 1, 2028

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

Public

- **NERC Project 2016-02 approved/filed**
  - Effective date: 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
  - 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
    - For example, changes in CIP-005-8 will allow more flexibility for virtual networks and software-defined networks (SDN)
  - Some of the new terms/asset classes/definitions that are being added include:
    - Cyber System
    - Management Interface
    - Share Cyber Infrastructure (SCI)
    - Virtual Cyber Asset (VCI)
  - The definitions for Electronic Security Perimeter (ESP), Interactive Remote Access (IRA), and Intermediate System are changing

OPEN SESSION
NERC REPORTS, GUIDELINES, UPDATES

CLOSED SESSION TOPICS SUMMARY

- Security Topics
  - CIP-011 R2 – Relay device classification – BCSI storage locations
  - CIP-015 (INSM) solutions, approach, implementation, asset classification
    - Peer share on approaches
  - Physical Access Control Systems (PACS) - using SCADA to grant/open access to control house doors
  - Iran-affiliated advanced persistent threat (APT) actors conducting exploitation activity targeting internet-facing operational technology (OT) devices – also discussed by E-ISAC in Open session
  - ERCOT
    - GINR/RIOO/REC authentication changes
    - SMS Pumping awareness/discussion
  - Cloud/AI Security Questionnaire share and discussion
- Compliance Topics
  - Audit experience share
  - Peer share
  - Peer check
- Administrative
  - Upcoming in-person meeting planning and presentation solicitation

Public

- Texas Cyber Command to provide a presentation on who/what/why/how
- Quarterly In-Person Meetings
  - Dallas (Sharyland Utilities) – Q1
  - Houston (CenterPoint) – Q2
  - Austin (Austin Energy) –Q3
  - San Antonio (UTSA) – Q4

LOOK AHEAD IN 2026

Public

ANY QUESTIONS?

Public

COMPLIANCE AND CERTIFICATION COMMITTEE

Update to Texas RE Member Representatives Committee
May 2026

- **CCC Meeting** (CCC Agenda Package) – April 29-30, 2029
  - Q2 Focus Discussion – Facility Ratings
  - Standing Committee Governance Guidelines
  - 2026 Compliance Monitoring and Enforcement Program Implementation Plan Revision
  - Internal Audit Update
  - Q3 Meeting – July 22-23, 2026 (virtual)

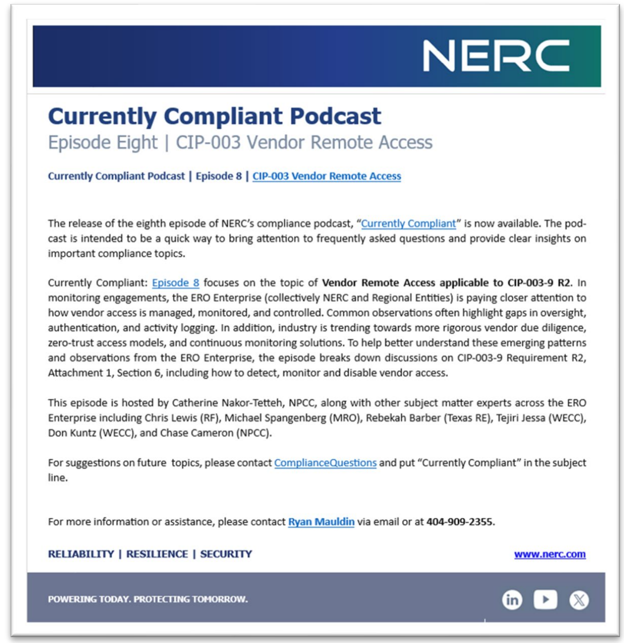
CIP and O&P Compliance Monitoring and Risk Assessment Report

Member Representatives Committee Meeting

May 13, 2026


Critical Infrastructure Protection Compliance Monitoring

Q1 2026: Workshop, Webinar, Training, and Conference Highlights



NERC

Currently Compliant Podcast

Episode Eight | CIP-003 Vendor Remote Access

Currently Compliant Podcast | Episode 8 | CIP-003 Vendor Remote Access

The release of the eighth episode of NERC's compliance podcast, "Currently Compliant" is now available. The podcast is intended to be a quick way to bring attention to frequently asked questions and provide clear insights on important compliance topics.

Currently Compliant: Episode 8 focuses on the topic of **Vendor Remote Access applicable to CIP-003-9 R2**. In monitoring engagements, the ERO Enterprise (collectively NERC and Regional Entities) is paying closer attention to how vendor access is managed, monitored, and controlled. Common observations often highlight gaps in oversight, authentication, and activity logging. In addition, industry is trending towards more rigorous vendor due diligence, zero-trust access models, and continuous monitoring solutions. To help better understand these emerging patterns and observations from the ERO Enterprise, the episode breaks down discussions on CIP-003-9 Requirement R2, Attachment 1, Section 6, including how to detect, monitor and disable vendor access.

This episode is hosted by Catherine Nakor-Tetteh, NPCC, along with other subject matter experts across the ERO Enterprise including Chris Lewis (RF), Michael Spangenberg (MRO), Rebekah Barber (Texas RE), Tejiri Jessa (WECC), Don Kuntz (WECC), and Chase Cameron (NPCC).

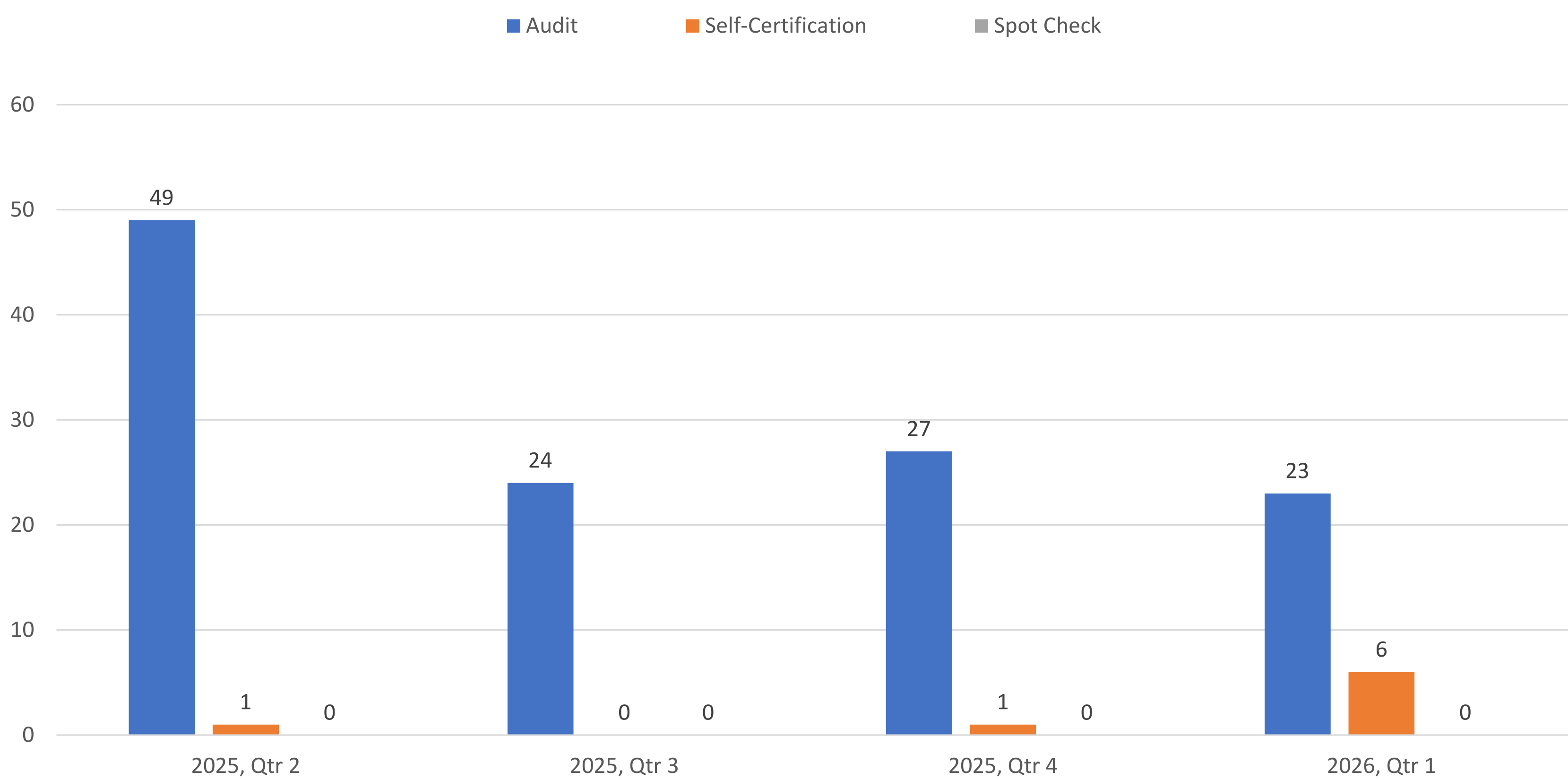
For suggestions on future topics, please contact ComplianceQuestions and put "Currently Compliant" in the subject line.

For more information or assistance, please contact **Ryan Mauldin** via email or at **404-909-2355.**

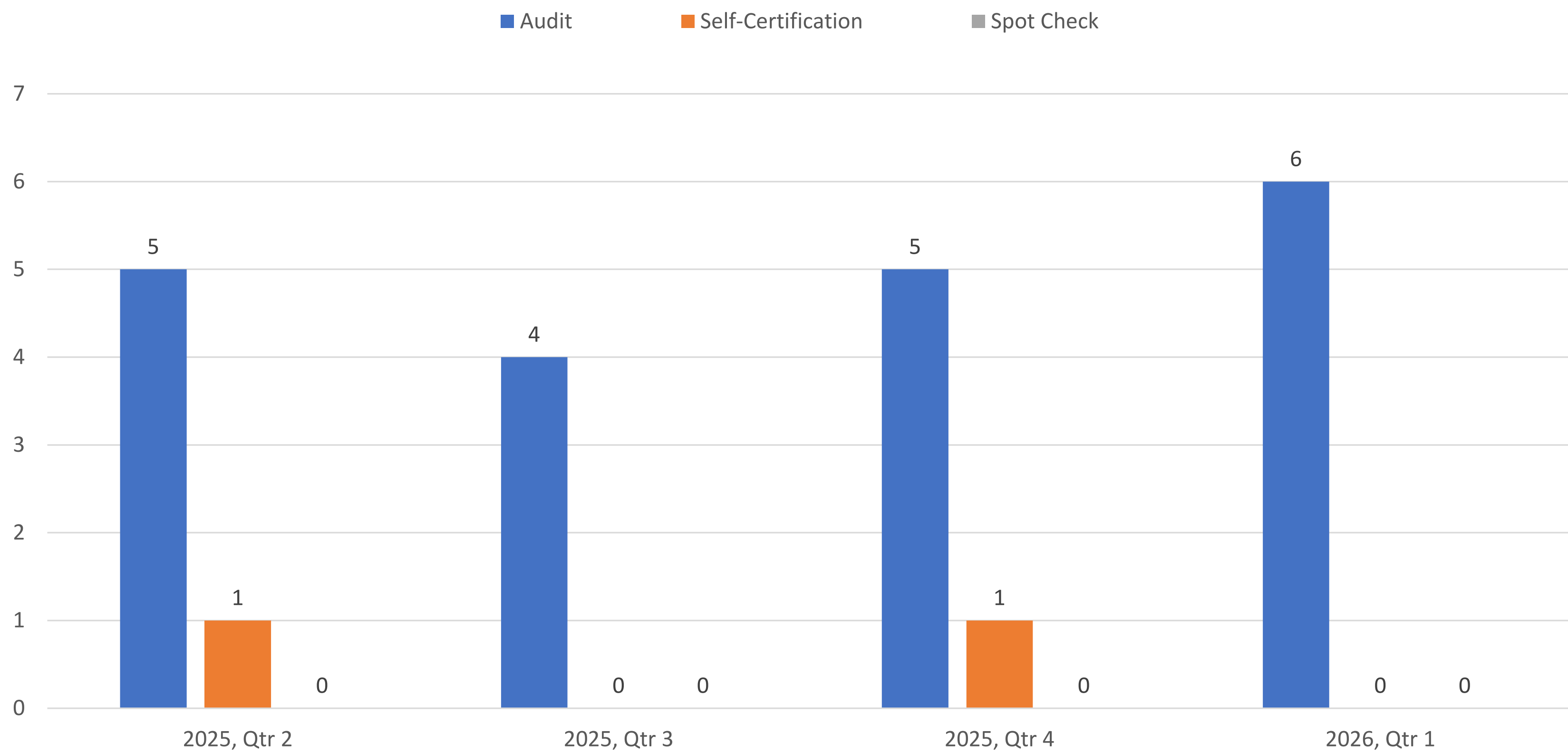
RELIABILITY | RESILIENCE | SECURITY www.nerc.com

POWERING TODAY. PROTECTING TOMORROW.

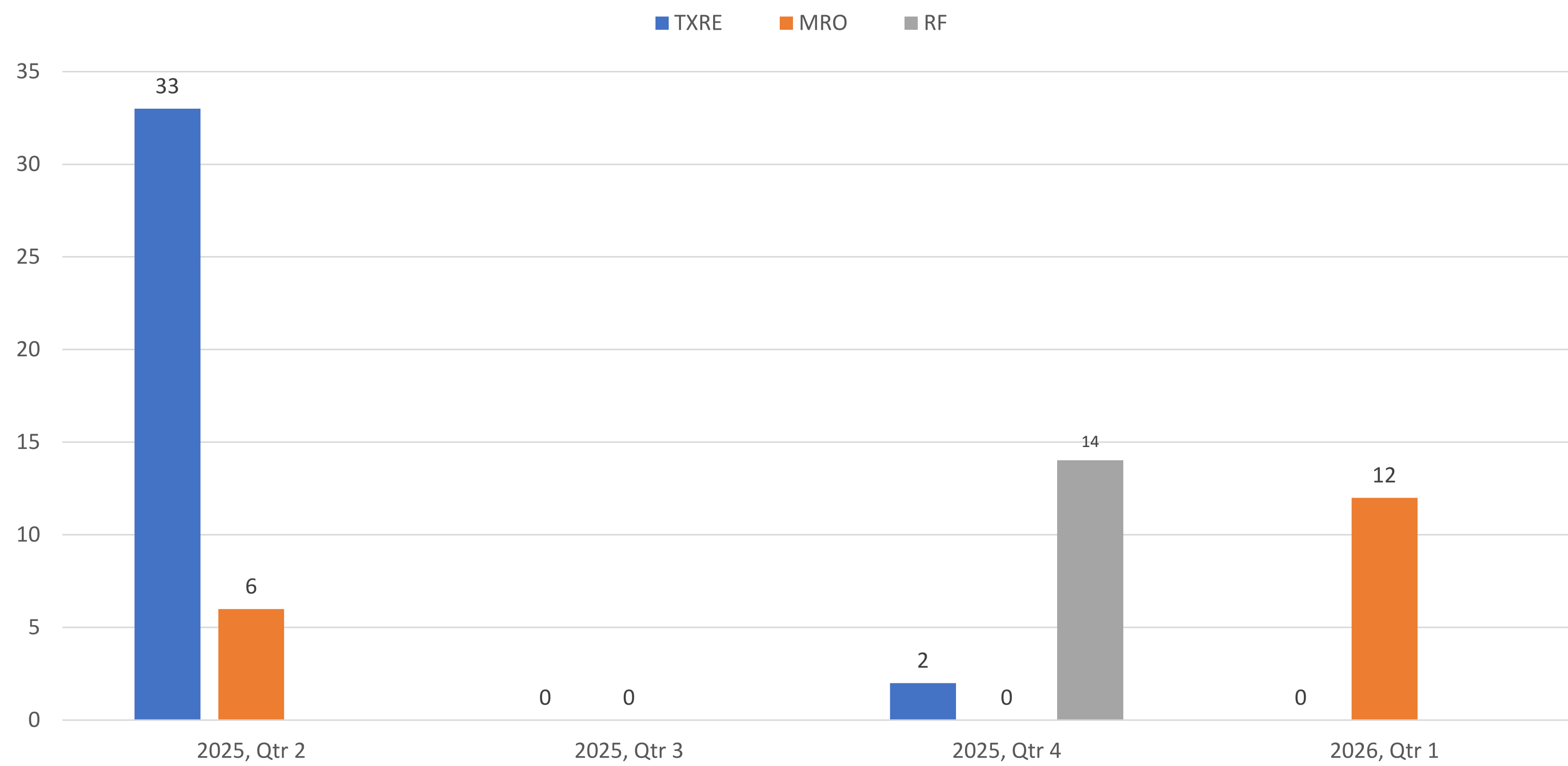
Total CIP Requirements by Engagement Type



Total CIP Engagements



Total CIP Requirements Coordinated Oversight



Operations and Planning Compliance Monitoring

Q1 2026: Workshop, Webinar, Training, and Conference Highlights

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.

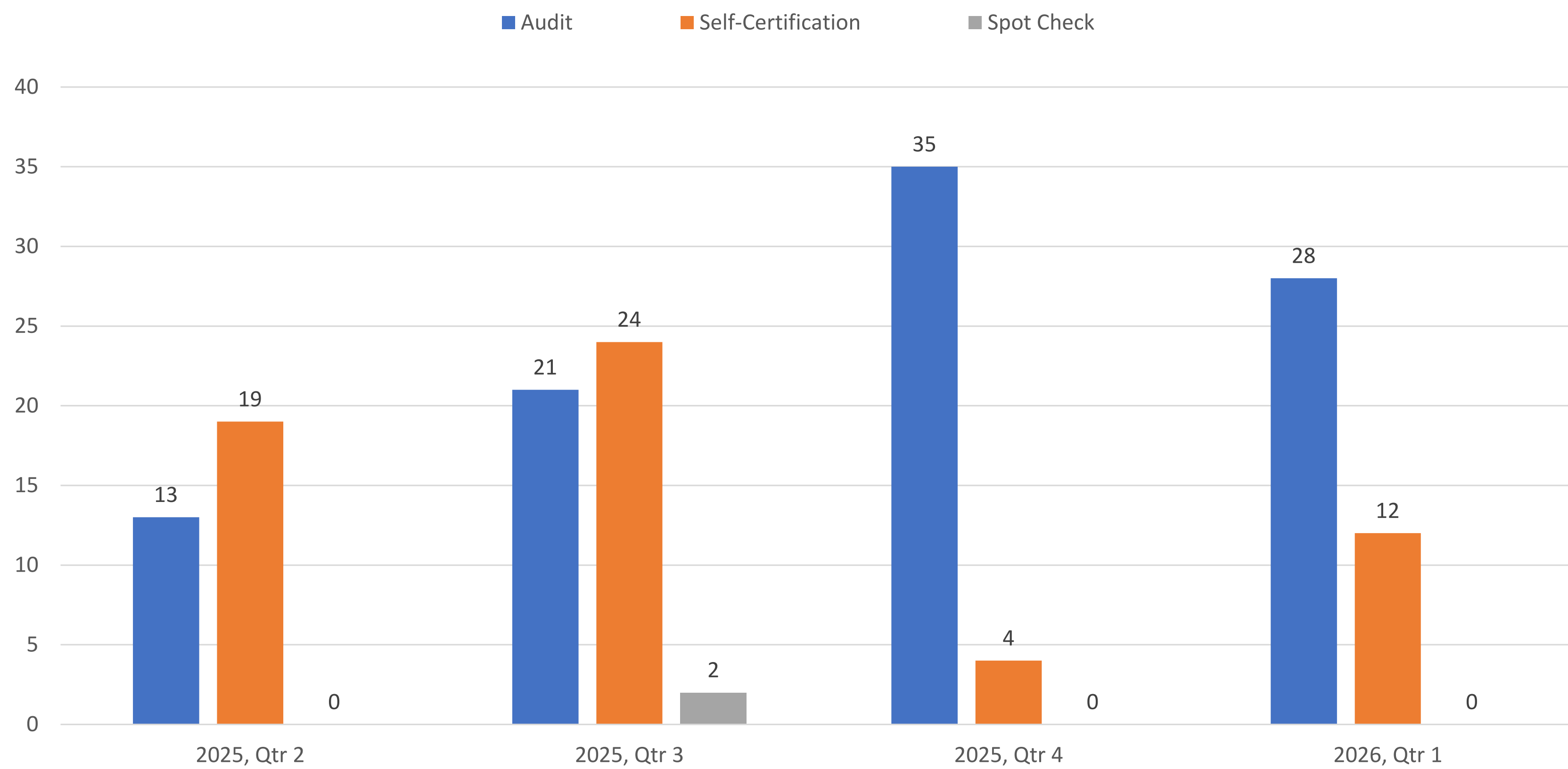
This SGAS will help GO-2s and GOP-2s understand their compliance obligations and prepare for implementation. Specifically, the SGAS will cover the set of Reliability Standards that GO-2s and GOP-2s must comply with in 2026.

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**.

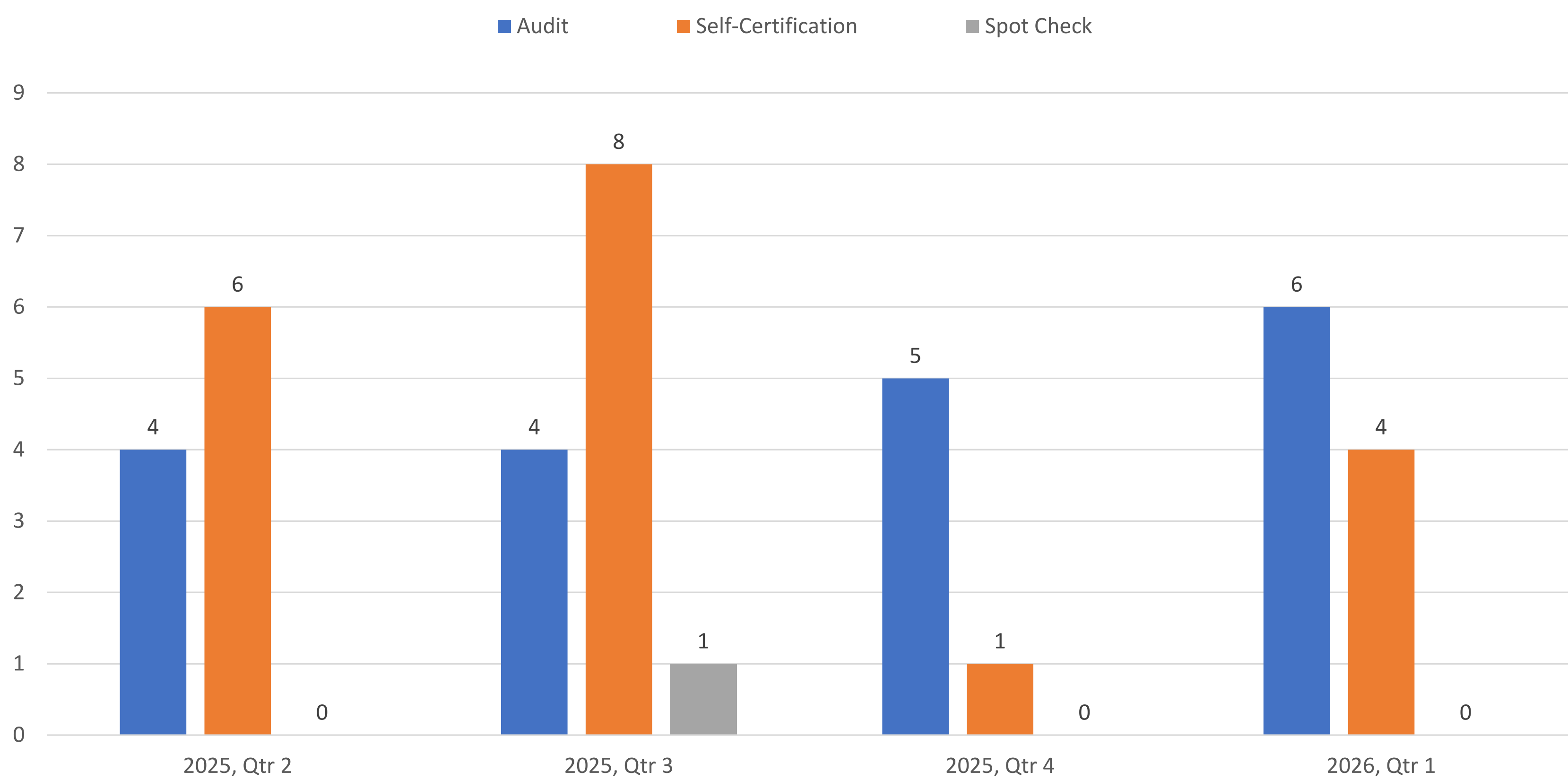
The SGAS will consist of two parts:

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.**

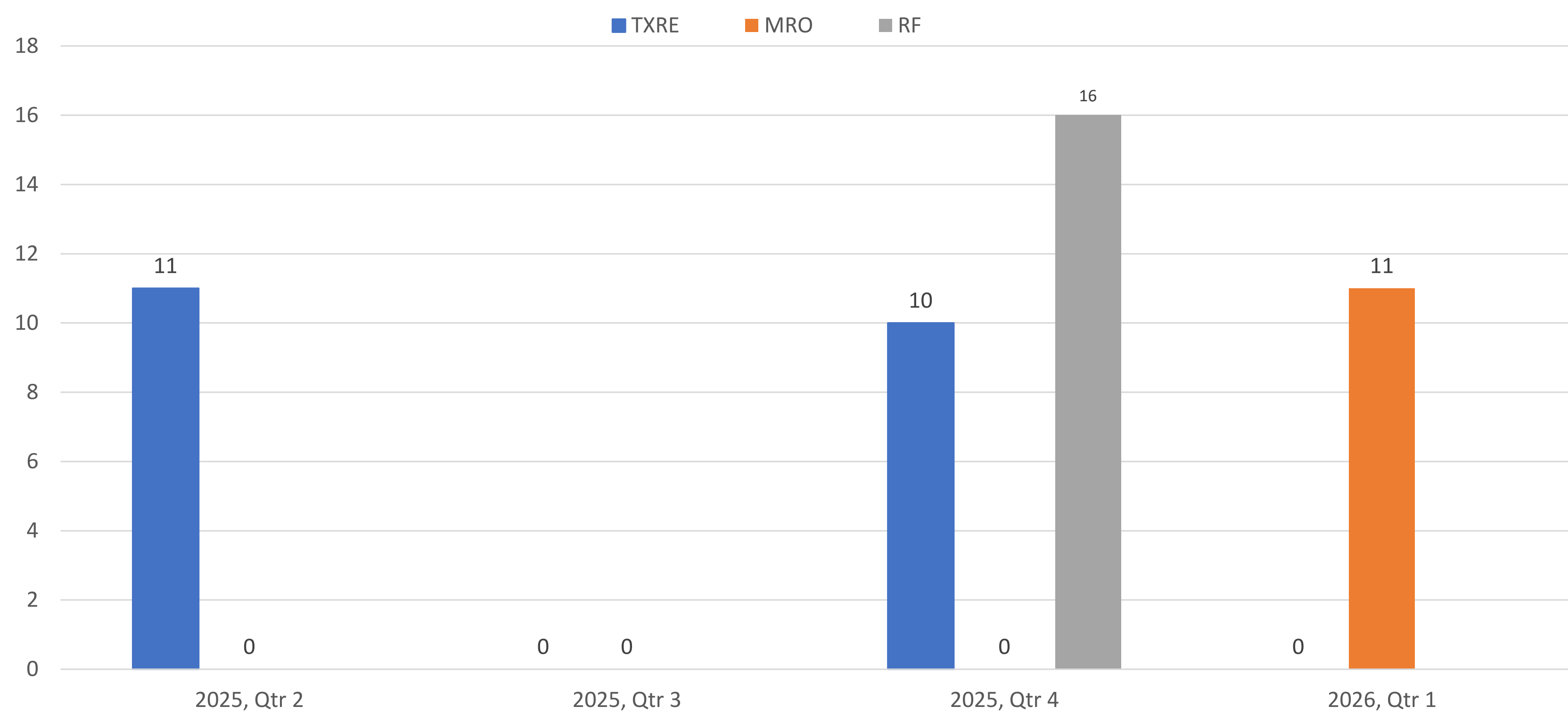
Total O&P Requirements by Engagement Type



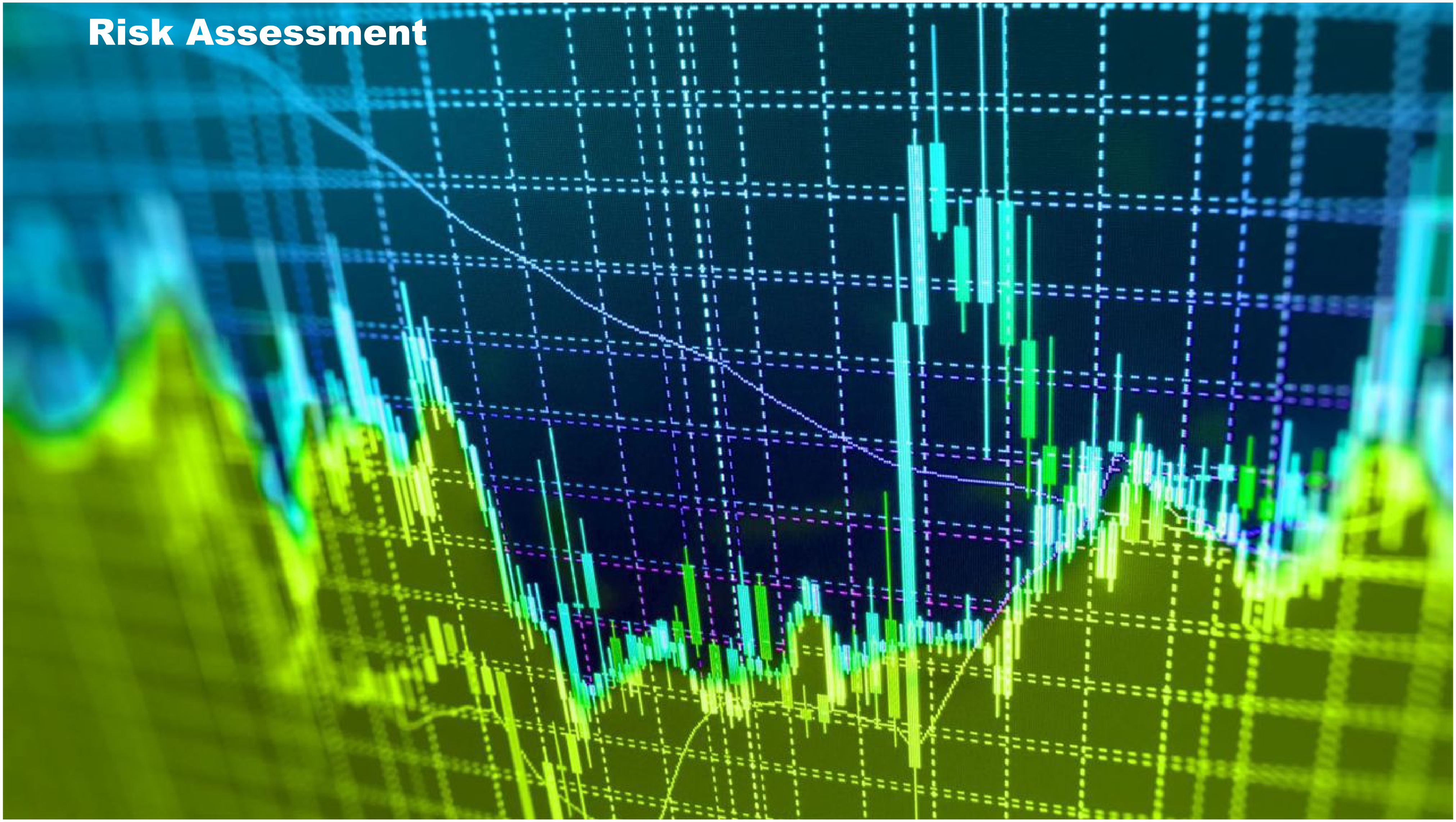
Total O&P Engagements



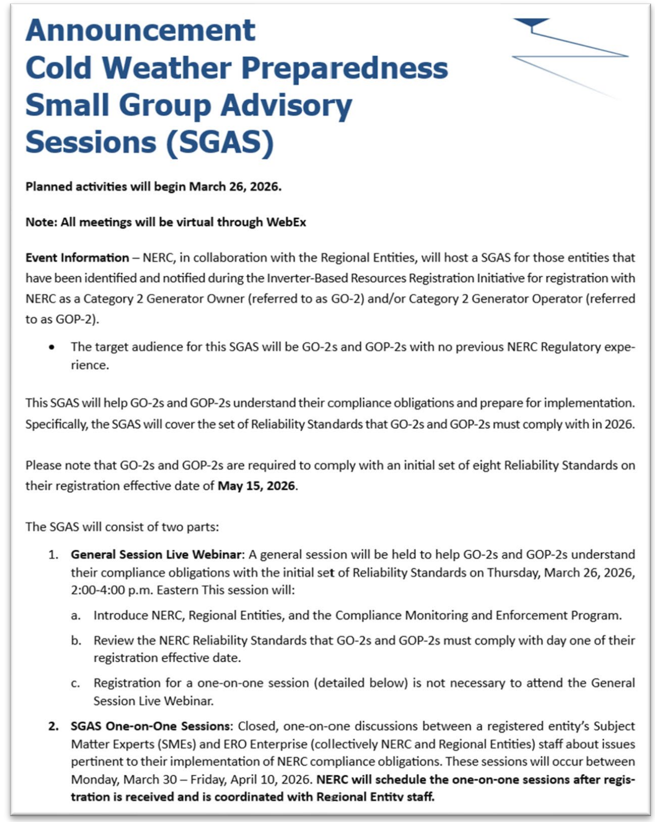
Total O&P Requirements in Coordinated Oversight



Risk Assessment



Q1 2026: Workshop, Webinar, Training, and Conference Highlights



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.

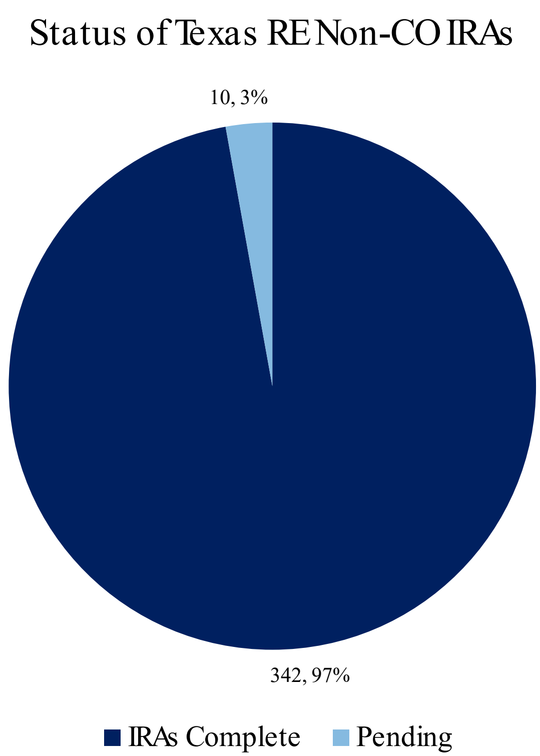
This SGAS will help GO-2s and GOP-2s understand their compliance obligations and prepare for implementation. Specifically, the SGAS will cover the set of Reliability Standards that GO-2s and GOP-2s must comply with in 2026.

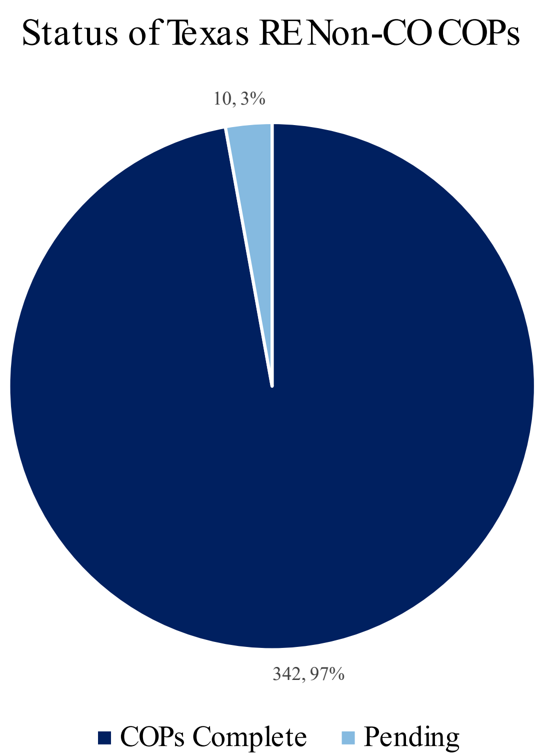
Please note that GO-2s and GOP-2s are required to comply with an initial set of eight Reliability Standards on their registration effective date of **May 15, 2026**.

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.**

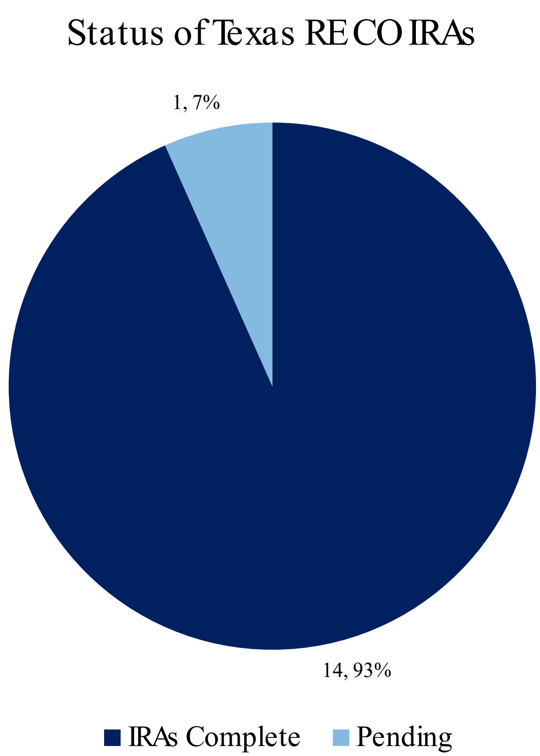
Q1 2026: Texas RE Non-Coordinated Oversight

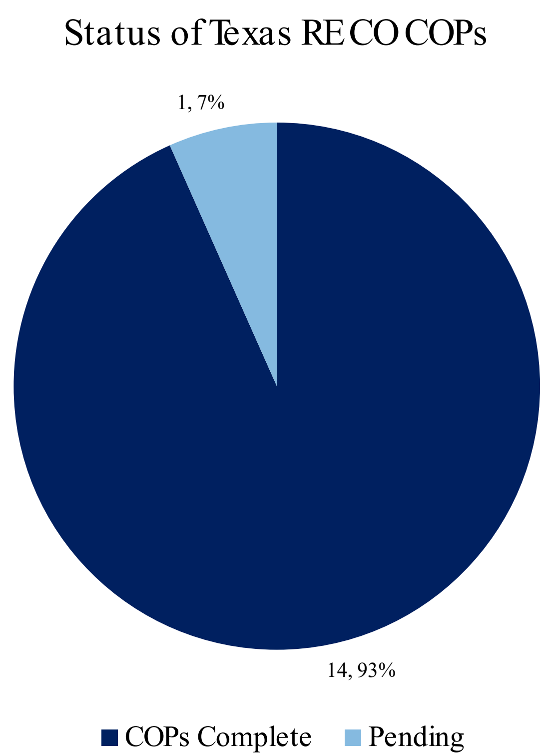




As of March 31, 2026

Q1 2026: Texas RE Coordinated Oversight

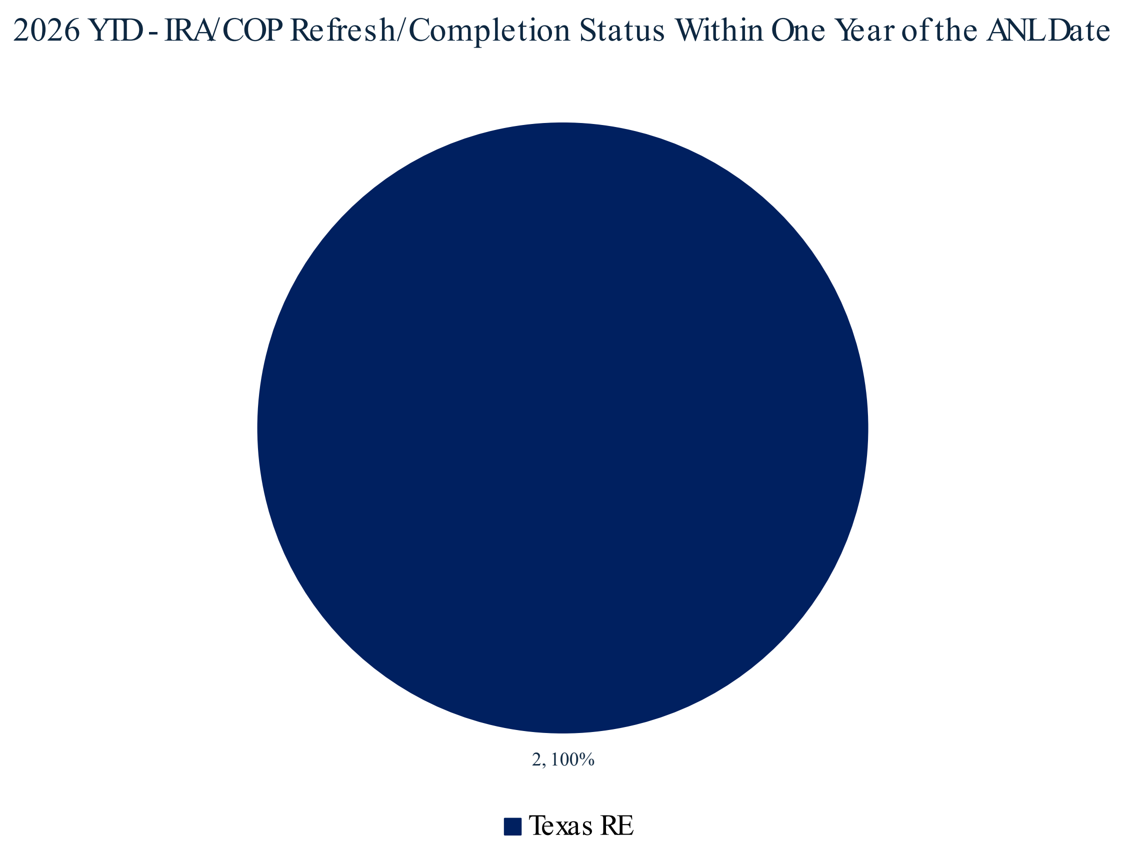




As of March 31, 2026

Public

Q1 2026: IRA/COP Completed Prior to Audit

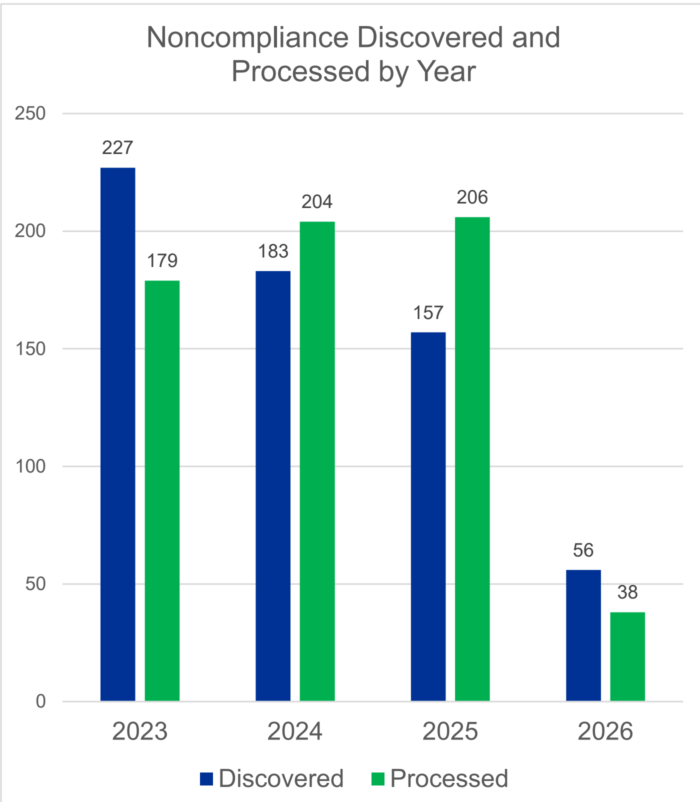


As of March 31, 2026

Enforcement Report

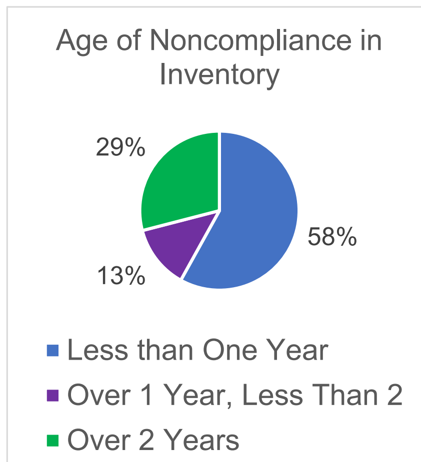
Member Representatives Committee Meeting
May 13, 2026

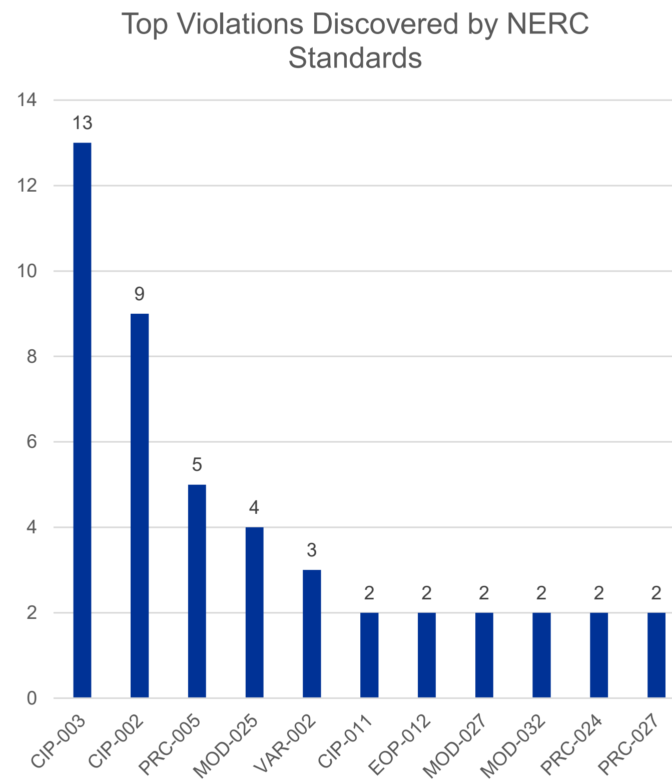
Enforcement Inventory Dashboard



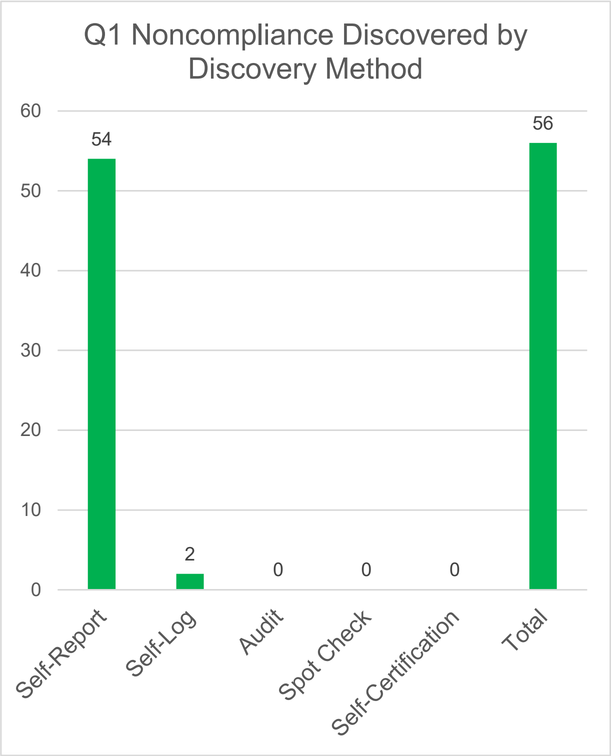
Inventory as of 4/1/2026:

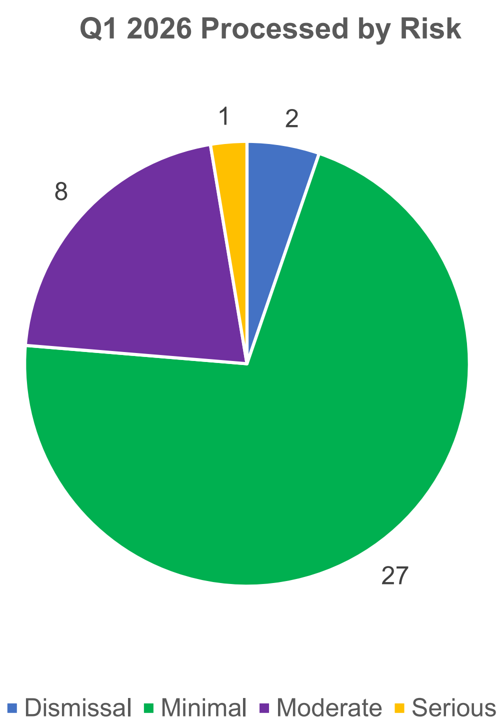
186

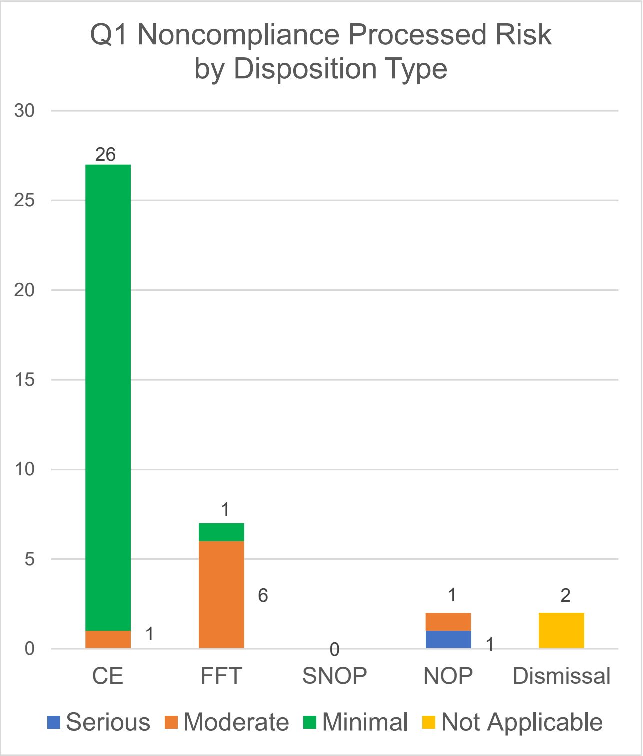




Enforcement Processing Quarterly Dashboard





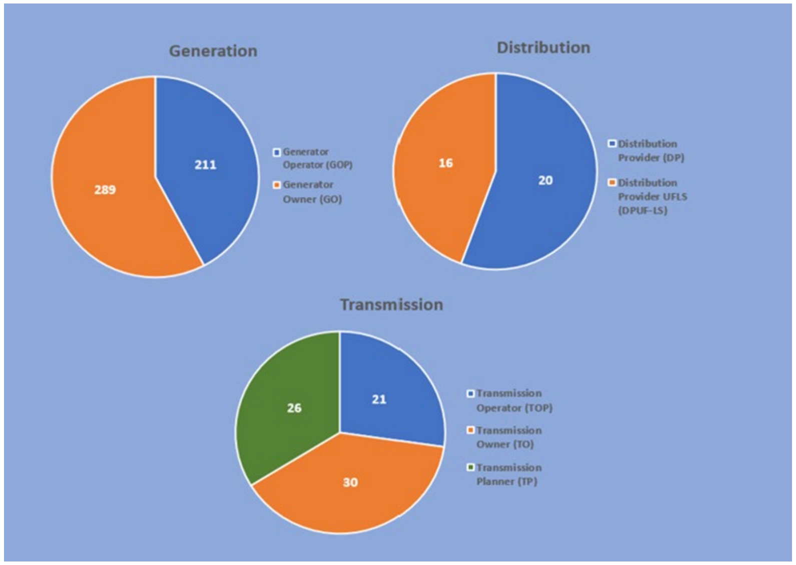


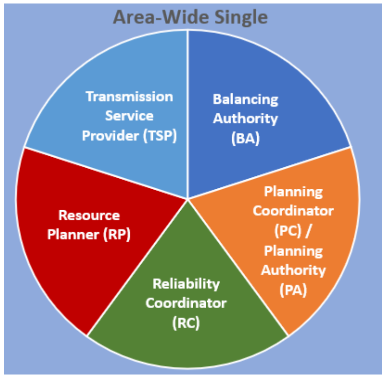
Registration Report

Member Representatives Committee Meeting
May 13, 2026

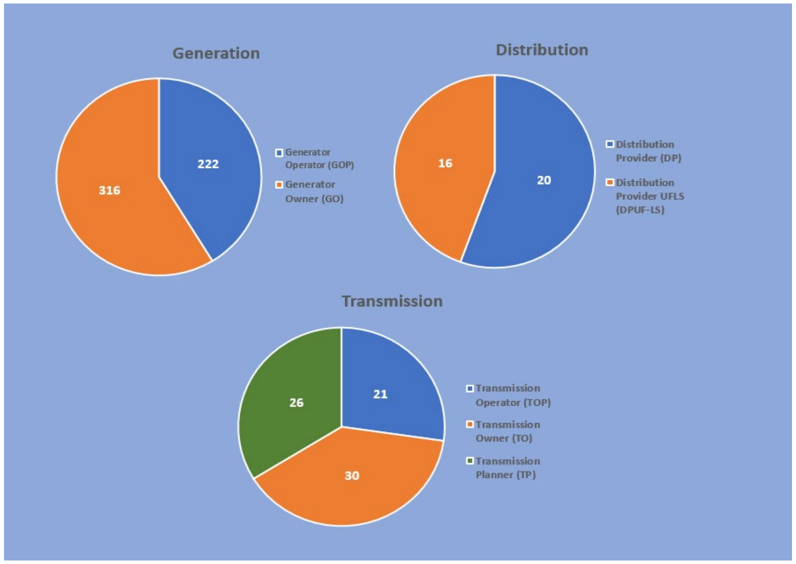
Number of Registered Entities by Function – Texas RE Region

370 Registered Entities | 618 Functions
As of April 1, 2025



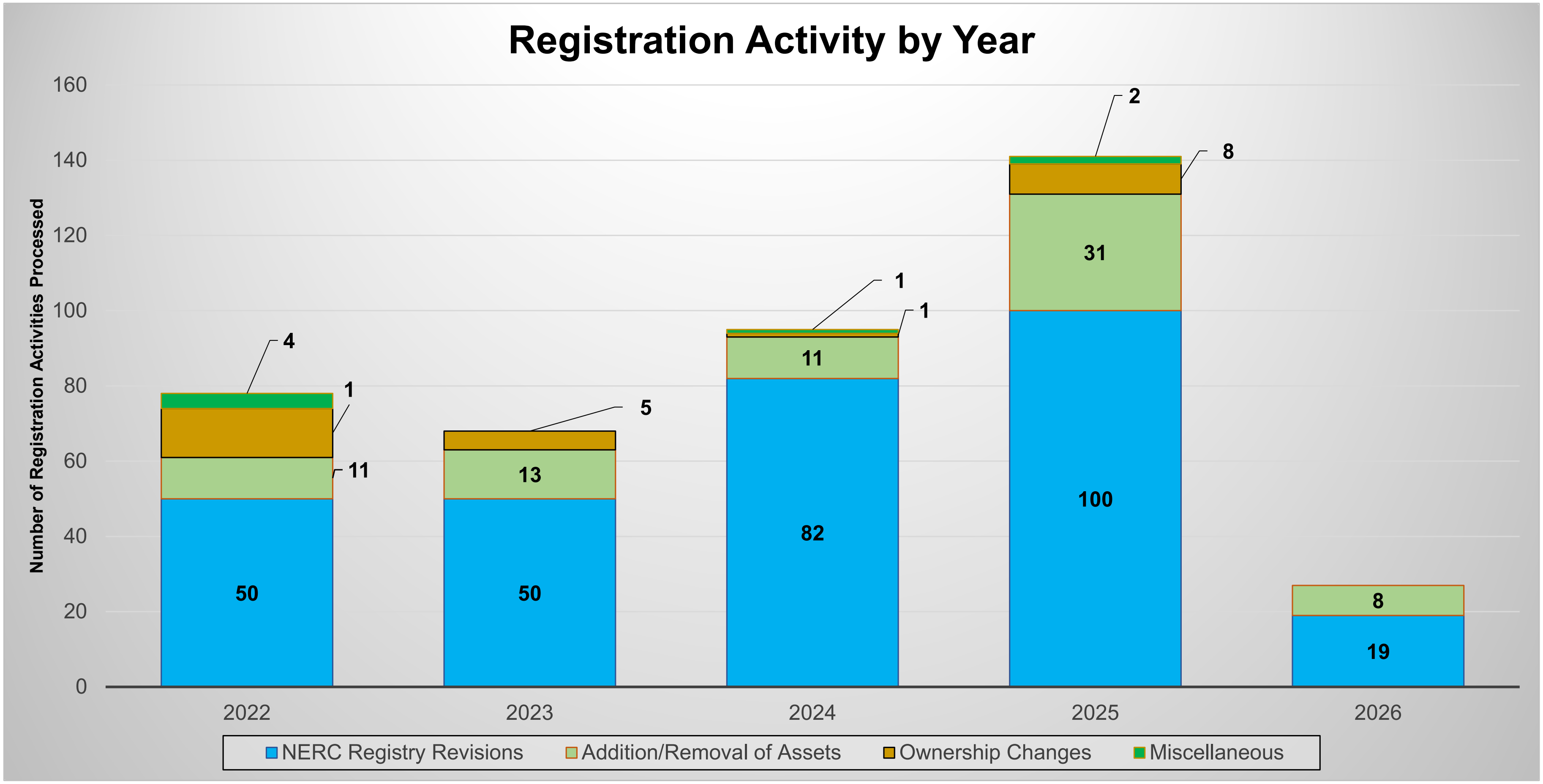


408 Registered Entities | 656 Functions
As of April 1, 2026



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

Growth in Registration Activity



Other Registration Activities – CFR and JRO Agreements

Coordinated Functional Registration (CFR)

Voluntary Written Agreement

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

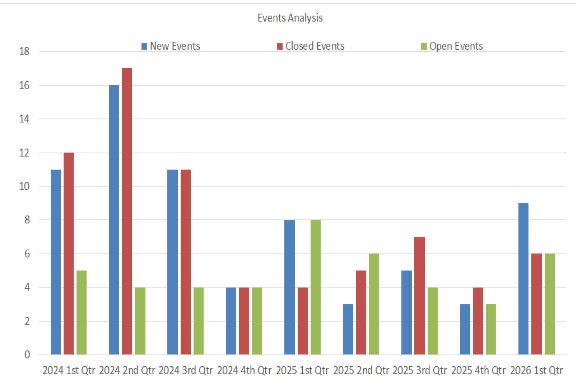
May 13, 2026

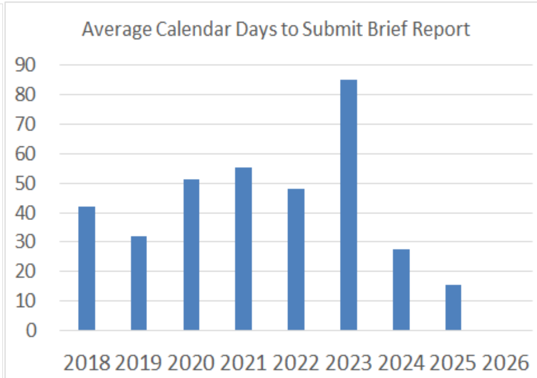
Key Activities in Q1 2026

- Scoping for 2026 Energy Assessment
- 2025 LTRA and 2026 SRA
- NERC MAST Group Activities
- 2025 Assessment of Reliability Performance
- 2026 RAPA Oversight and ERM Updates

Reliability Services Functional Dashboard as of April 1, 2026

EVENTS ANALYSIS





SITUATIONAL AWARENESS

Through 4/1/2026

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

PERFORMANCE ANALYSIS

On-Time Section 1600 Reporting Status as of 4/1/2026

	2025 Q1	2025 Q2	2025 Q3	2025 Q4
TADS	100%	100%	100%	100%
GADS	100%	100%	100%	100%
MIDAS	100%	99%	98%	97%
Wind GADS	93%	92%	96%	92%
Solar GADS	88%	84%	92%	94%

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

*** Q1 data due on 5/15 for GADS-Conventional, Wind and Solar

** Q1 data due 5/31 for MIDAS

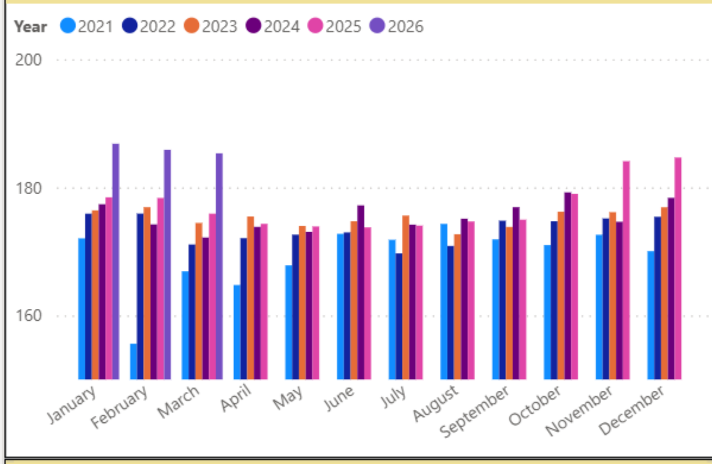
Q1 data reporting in progress

RELIABILITY ASSESSMENTS

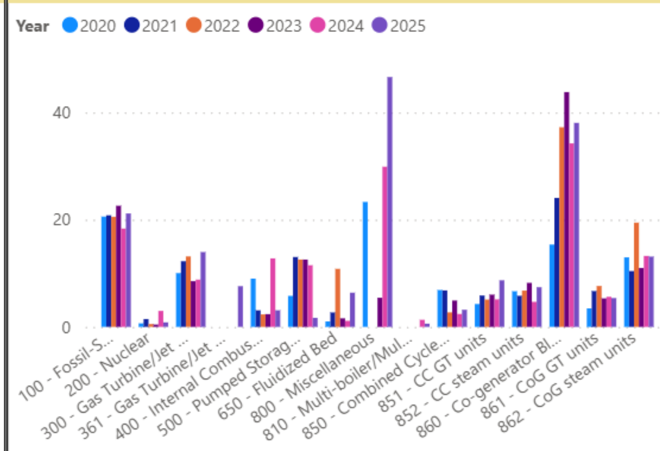
2025 Oversight Plan Expectation	MRO	NPCC	RF	SERC	Texas-RE	WECC
Expectation 1. RE provides assessment materials that meet ERO Guidelines (Yes / No | narratives and data complete and submitted on or before the September deadline?)	Y	Y	Y	N[1]	Y	Y
Expectation 2. RE supports the RA program in identifying risks. (Yes/No | When actual capacity or energy deficiency occurs, the RE analyzes conditions to inform future assessments (Outcome Analysis))	Evaluation Performed After Winter Season					
Expectation 3. RE works collaboratively to assess risks (Yes/No | The Regional Entity participates in RAS and ERO RA, and uses professional judgement to identify regional risks and includes them in assessment reports)	Y	Y	Y	Y	Y	Y

Grid Reliability Dashboard as of April 1, 2026

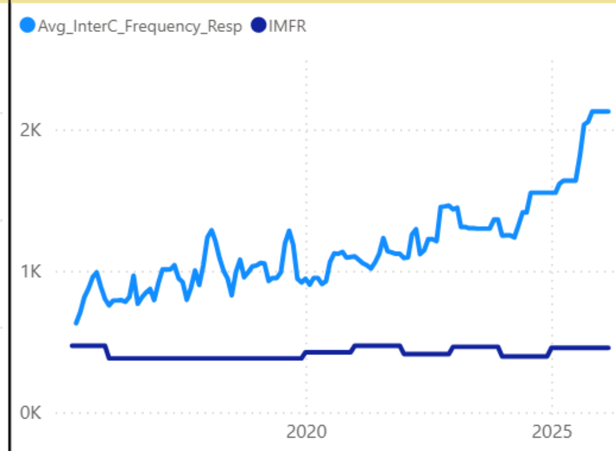
CPS1 by Month



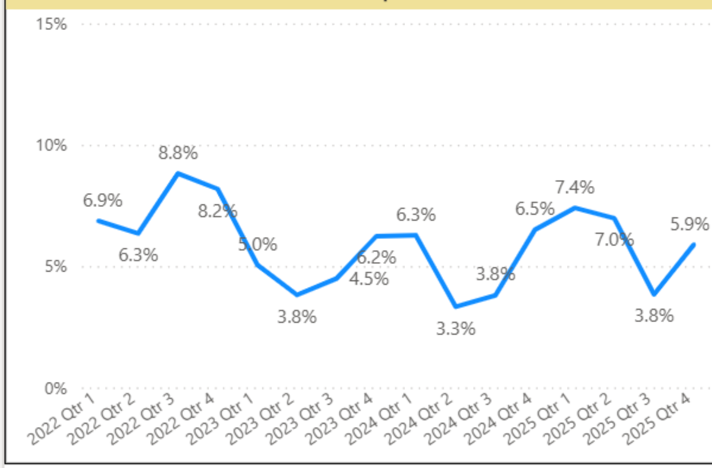
Avg EFOR by Unit Type



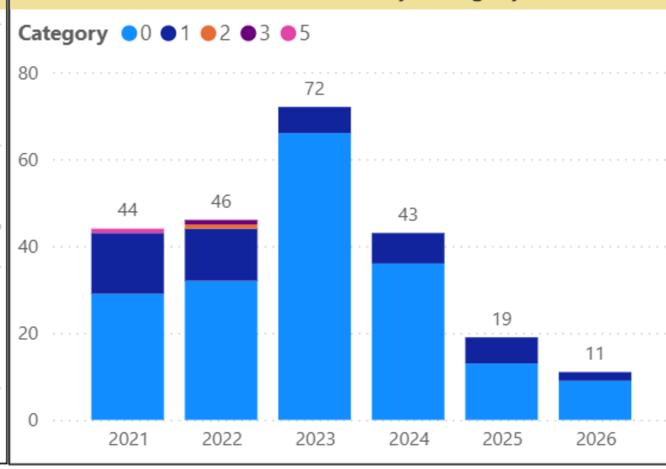
Avg Interconnection Frequency Response



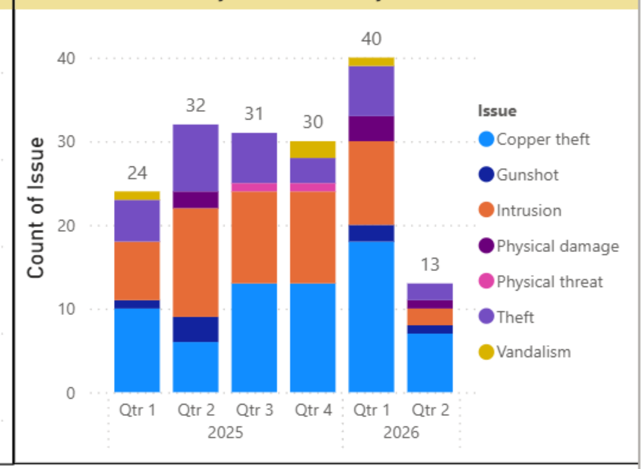
Percent Misoperations



Number of Events by Category

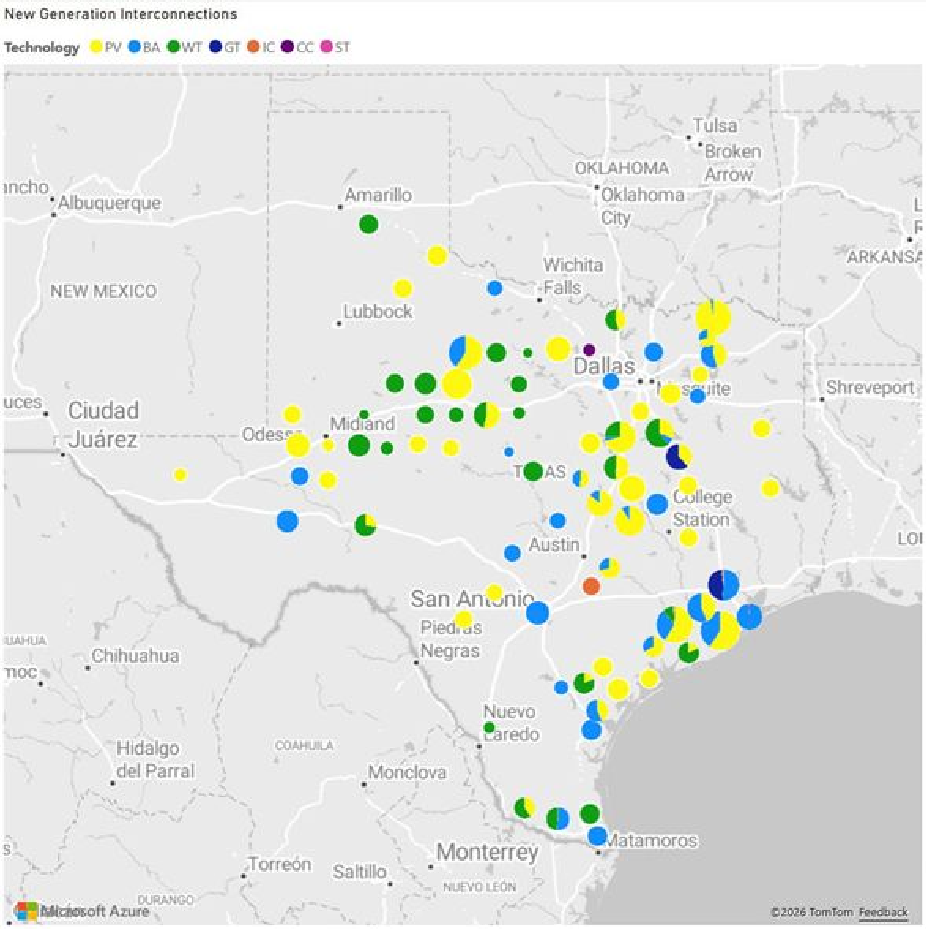


Physical Security Issues



APPENDIX:
Reliability and Performance Indicators Update

New Generation Interconnections as of April 1, 2026



Technology	Year	Count of Capacity (MW)	Sum of Capacity (MW)
WT	2023	1	7.20
WT	2024	1	7.30
BA	2025	1	154.20
GT	2025	1	16.10
PV	2025	12	1,786.34
ST	2025	1	14.00
WT	2025	6	842.41
BA	2026	50	7,261.60
CC	2026	1	21.00
GT	2026	4	1,055.70
IC	2026	2	218.40
PV	2026	67	15,216.01
WT	2026	26	3,554.36
BA	2027	4	638.27
PV	2027	8	1,732.22
WT	2027	5	1,400.10
BA	2028	2	650.60
Total		**192**	**34,575.81**

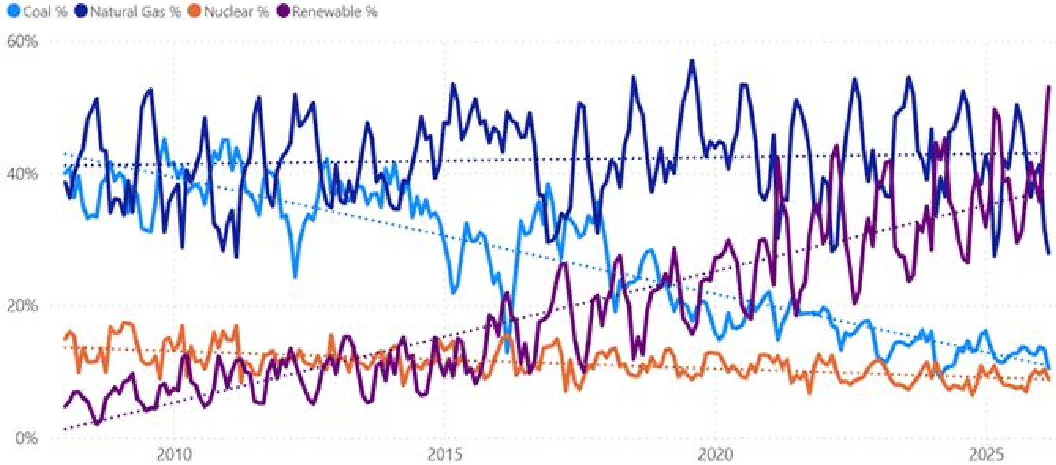
Approved for Synchronization/No COD

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	9	2,195.50
2023	7	1,682.44
2024	16	3,402.60
2025	39	7,337.50
2026	28	4,763.29
Total	**124**	**22,375.56**

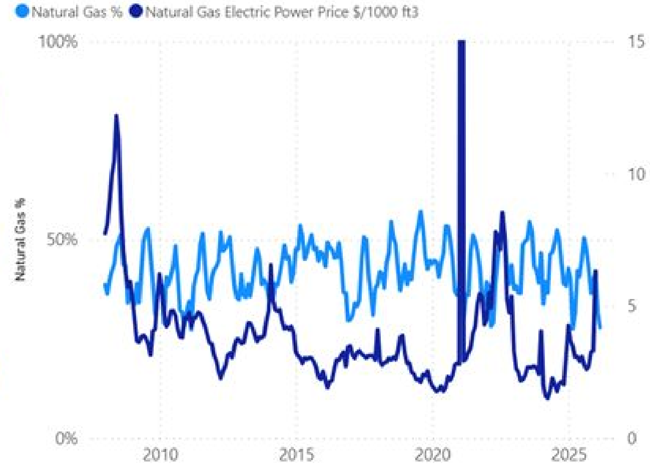
New Generation interconnections with a signed interconnection agreement and meeting all Planning Guide requirements

Generation Mix Trends

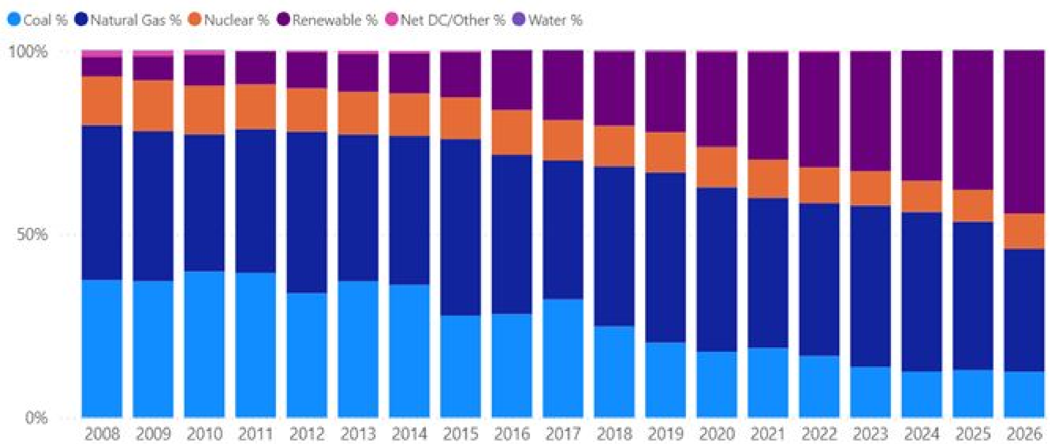
Coal %, Natural Gas %, Nuclear % and Renewable % by Year and Month



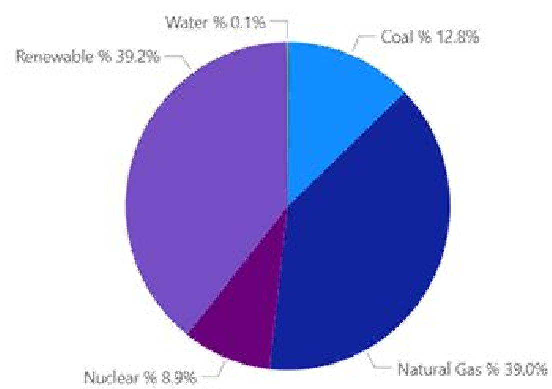
Natural Gas % and Natural Gas Electric Power Price $/1000 ft3



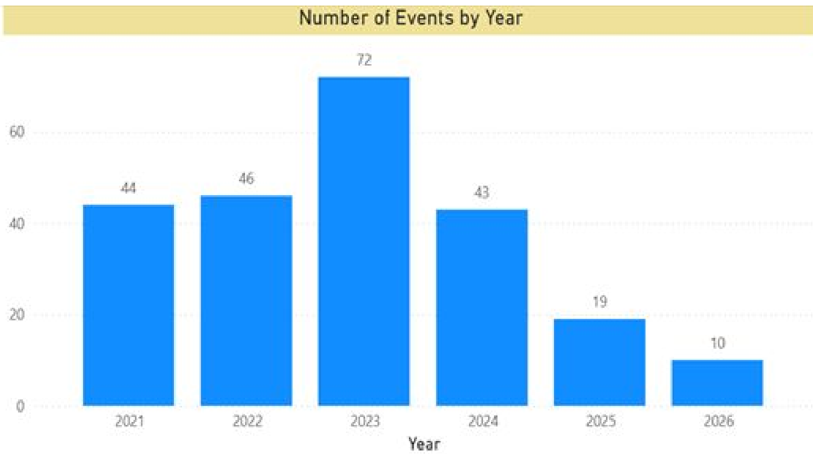
Coal %, Natural Gas %, Nuclear %, Renewable %, Net DC/Other % and Water % by Year



2025 Generation Mix by Fuel Type



System Events Dashboard as of April 1, 2026



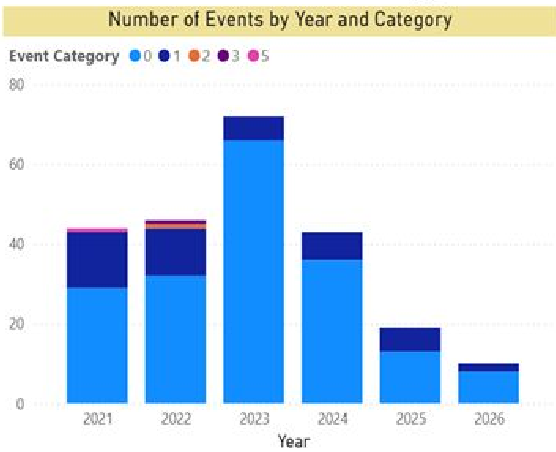
Events By Year and Category

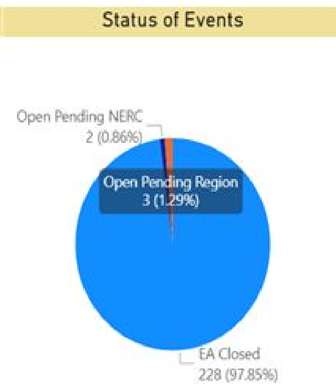
Year	0	1	2	3	5	Total
2021	29	14			1	44
2022	32	12	1	1		46
2023	66	6				72
2024	36	7				43
2025	13	6				19
2026	8	2				10
Total	184	47	1	1	1	234

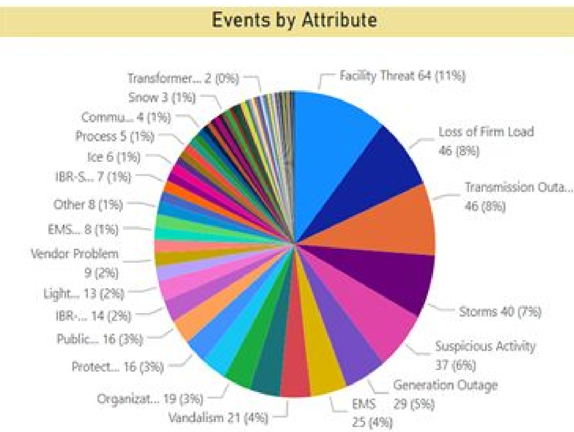
Reports Received

Year	Brief Report	EOP-004	OE-417	Other	Total
2021	16	12	57		85
2022	19	7	39	1	66
2023	9	17	59		85
2024	7	10	41		58
2025	6	4	18		28
2026		1	10		11
Total	57	51	224	1	333

Year
Select all
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026



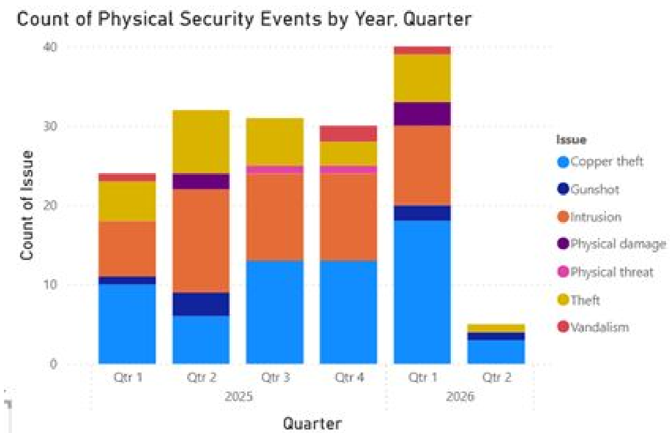


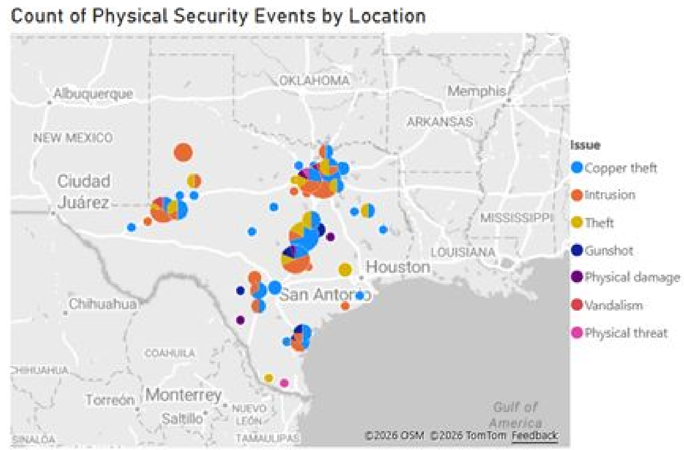


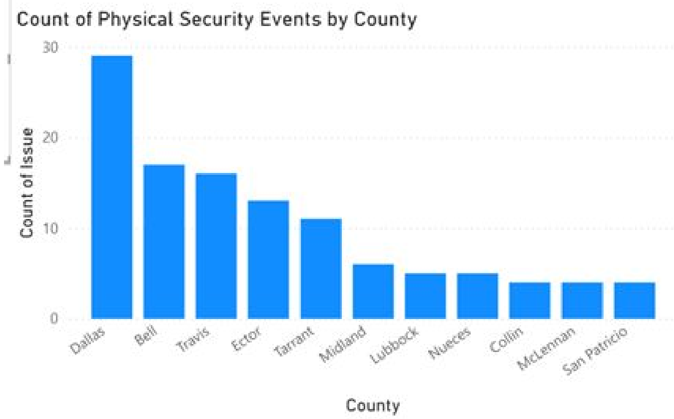
Key 2026 System Events

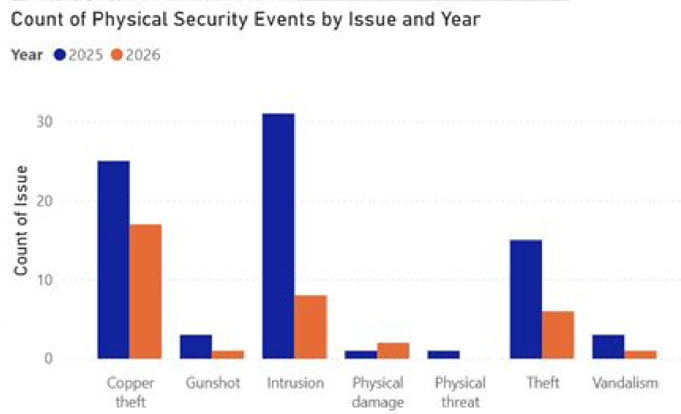
- Two reported loss of monitoring and control events
- Multiple reported physical security events
- Two cyber events

Infrastructure Protection – 2025-2026



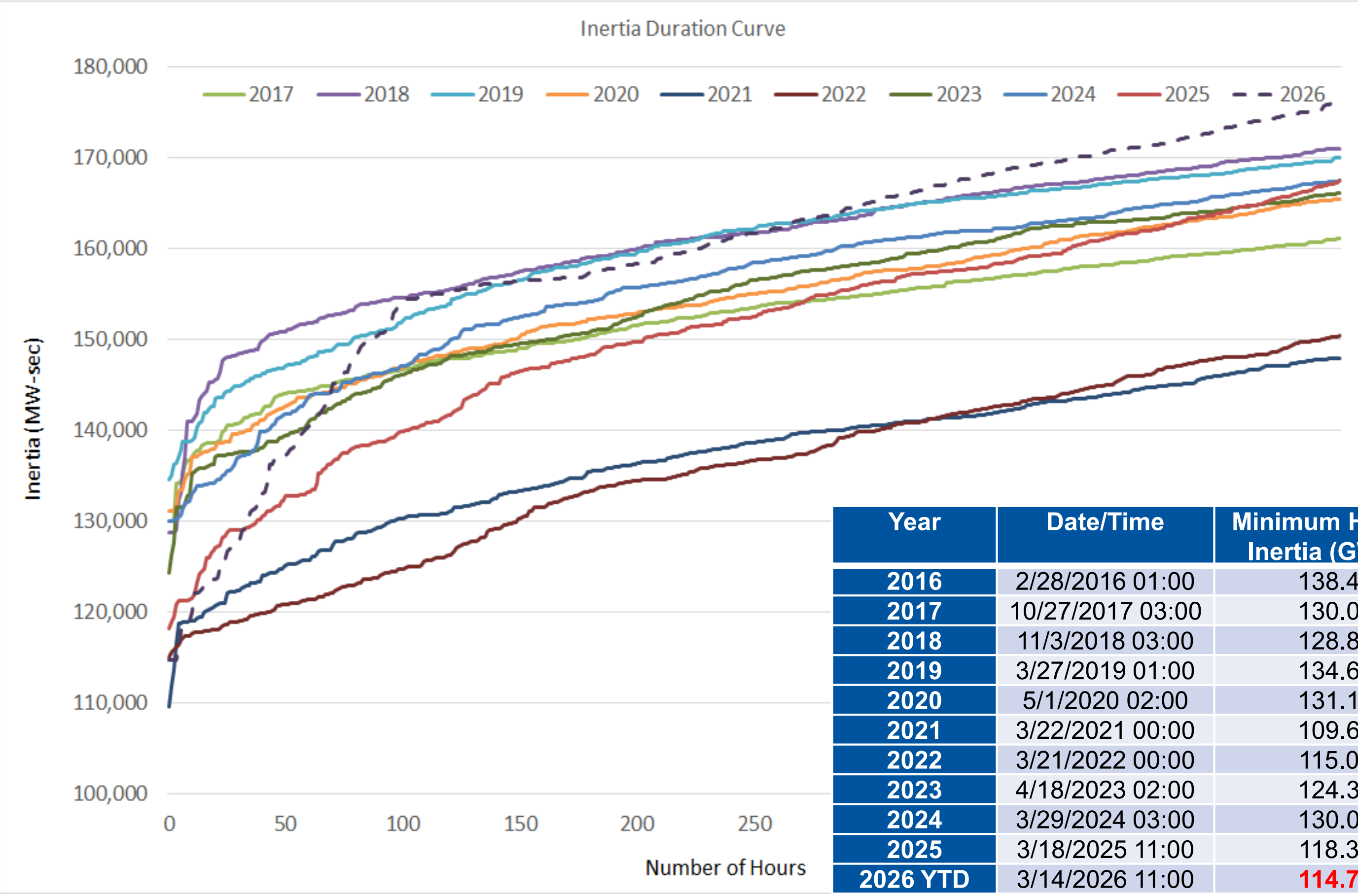






Incidents reported to System Security Response Group (SSRG)

System Inertia as of April 1, 2026

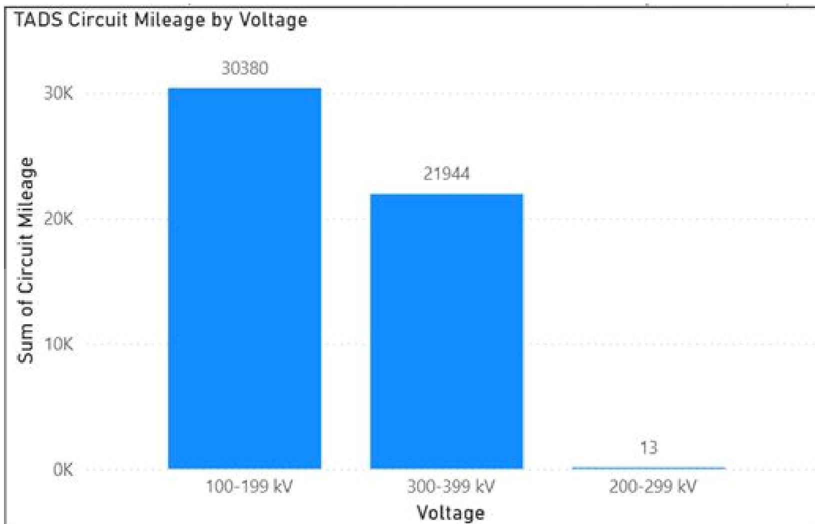


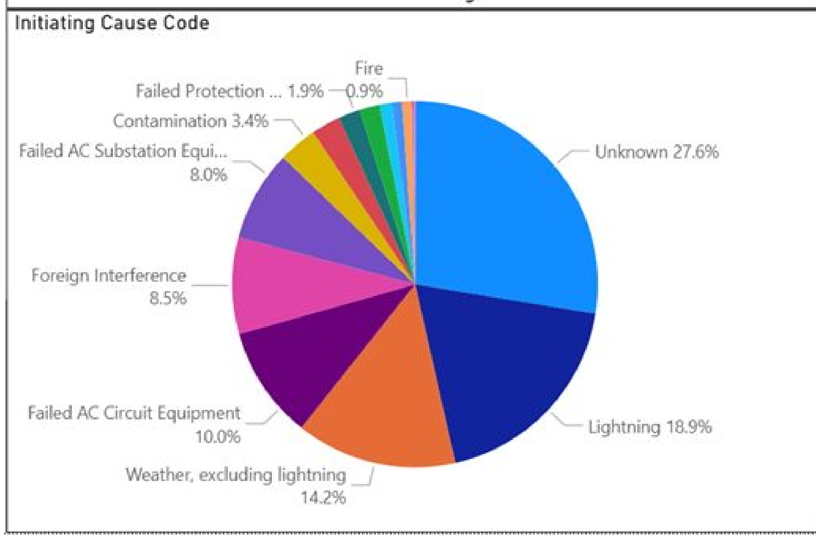
2026 Inertia Duration Curve

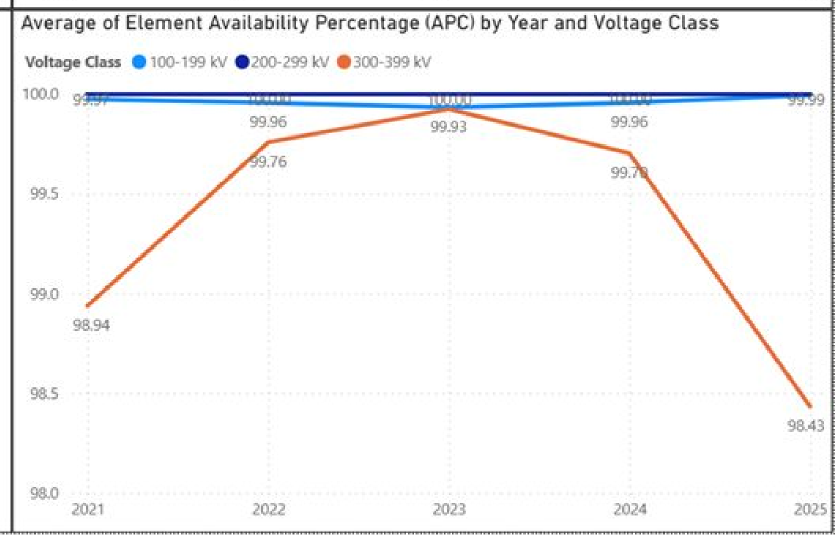
Year	# Hours > 70% Renewables	Maximum Hourly IRR%
2021	0	65.8%
2022	1	70.5%
2023	0	68.1%
2024	39	75.0%
2025	163	75.6%
2026 YTD	231	85.1%

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%

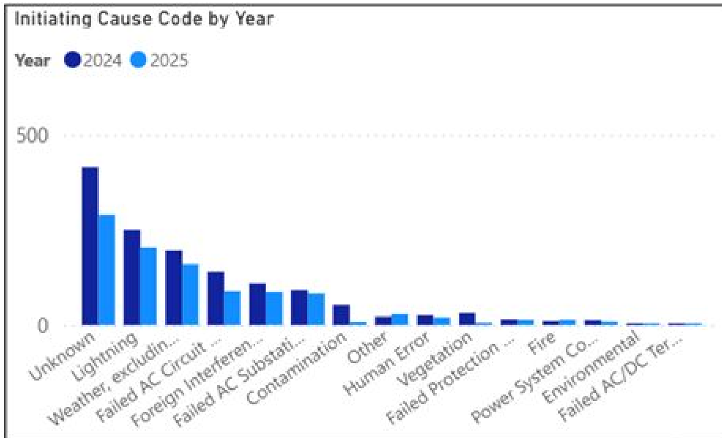
Transmission Performance Dashboard

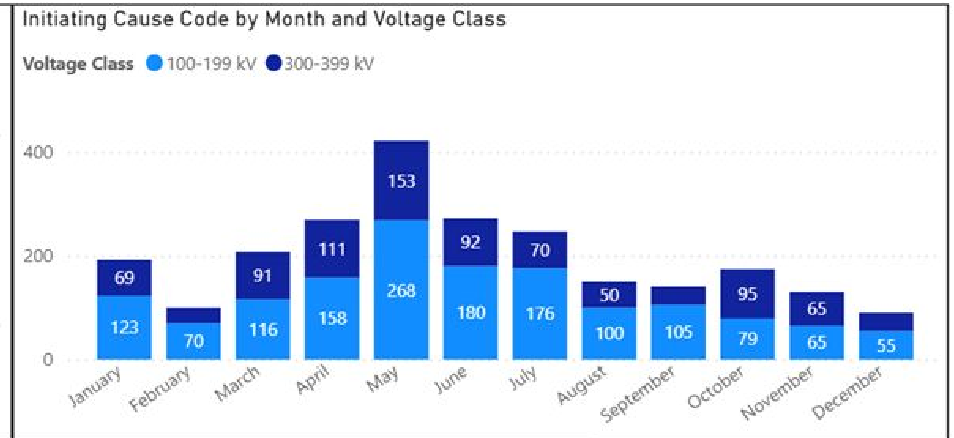


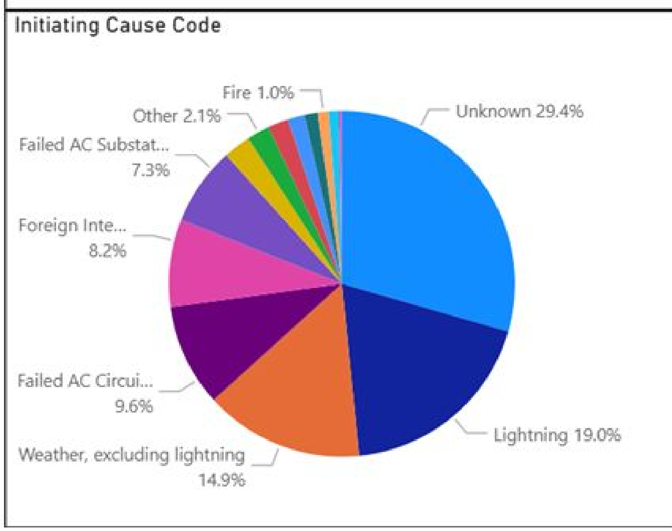


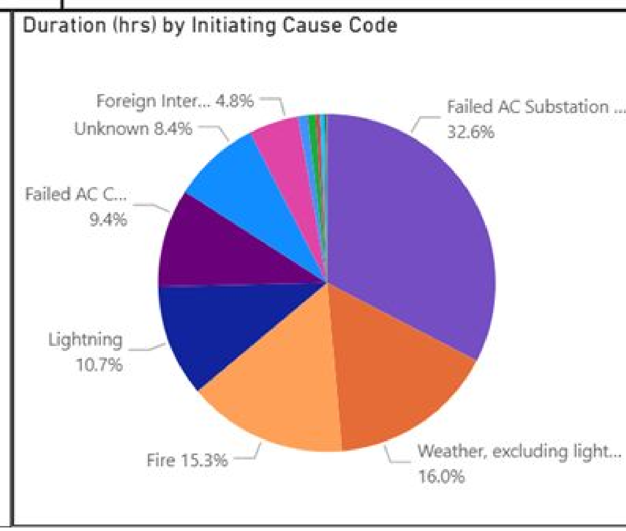


Transmission Performance Dashboard



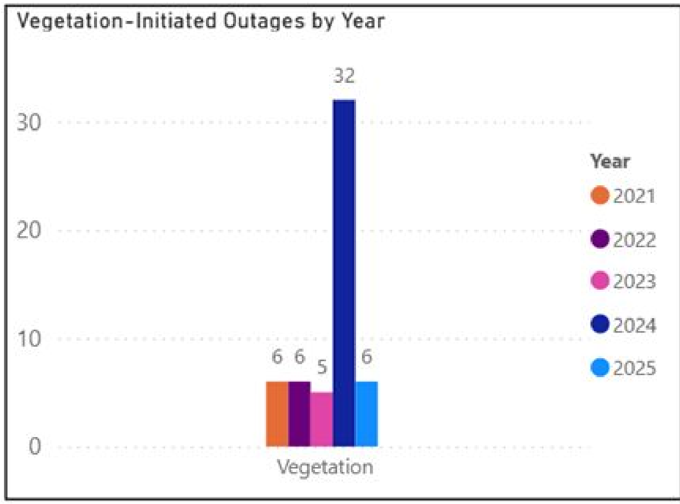


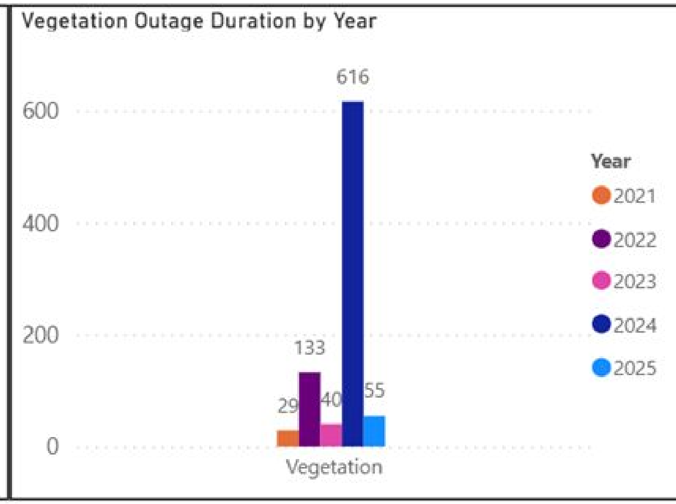


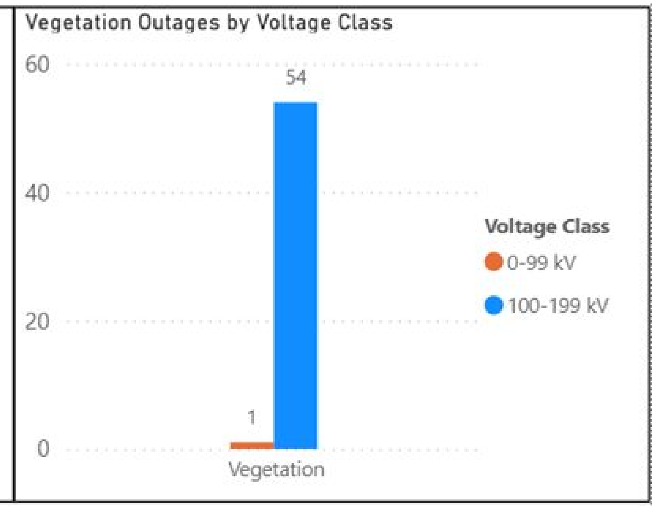


Transmission Event Data by Cause, Month, and Duration 2024 – 2025

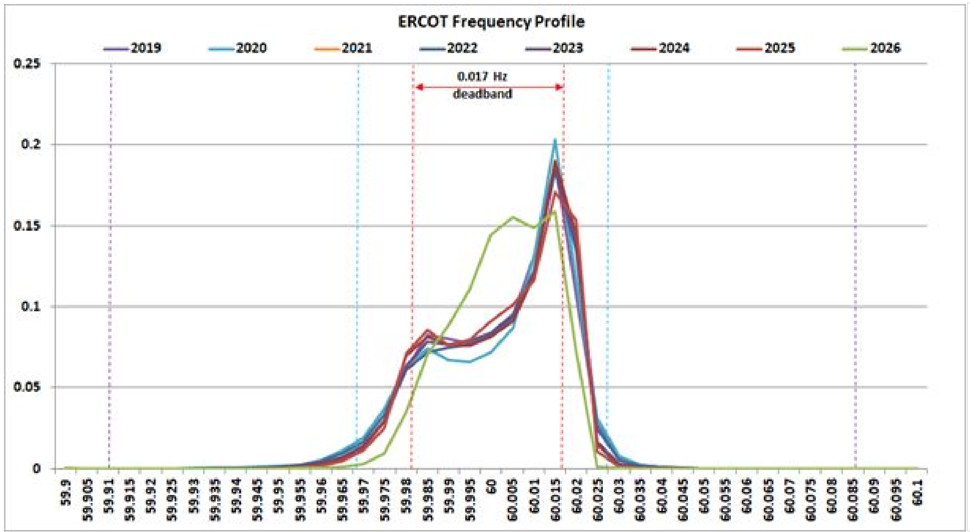
Vegetation Outage Trends – Available Data

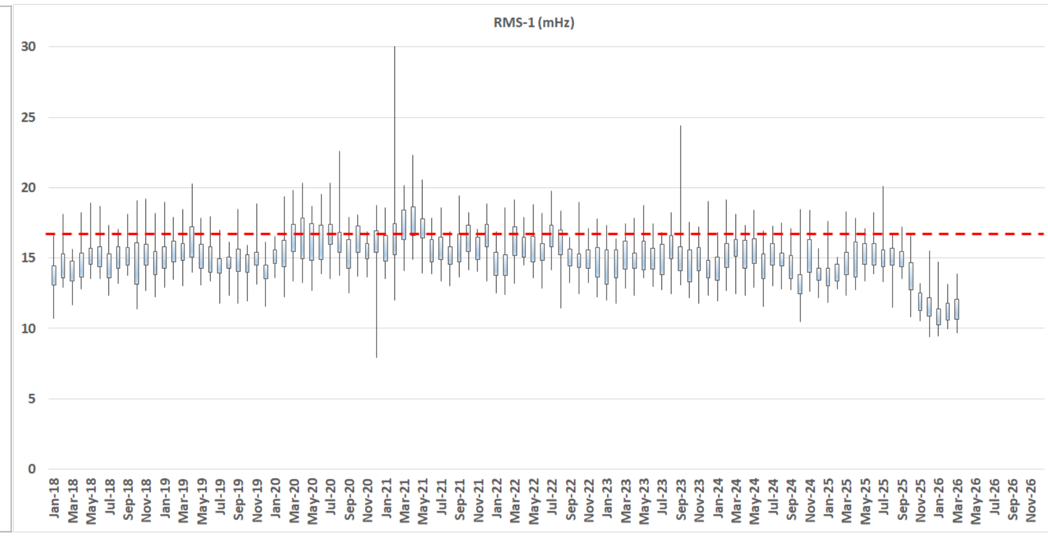






Frequency Control as of April 1, 2026

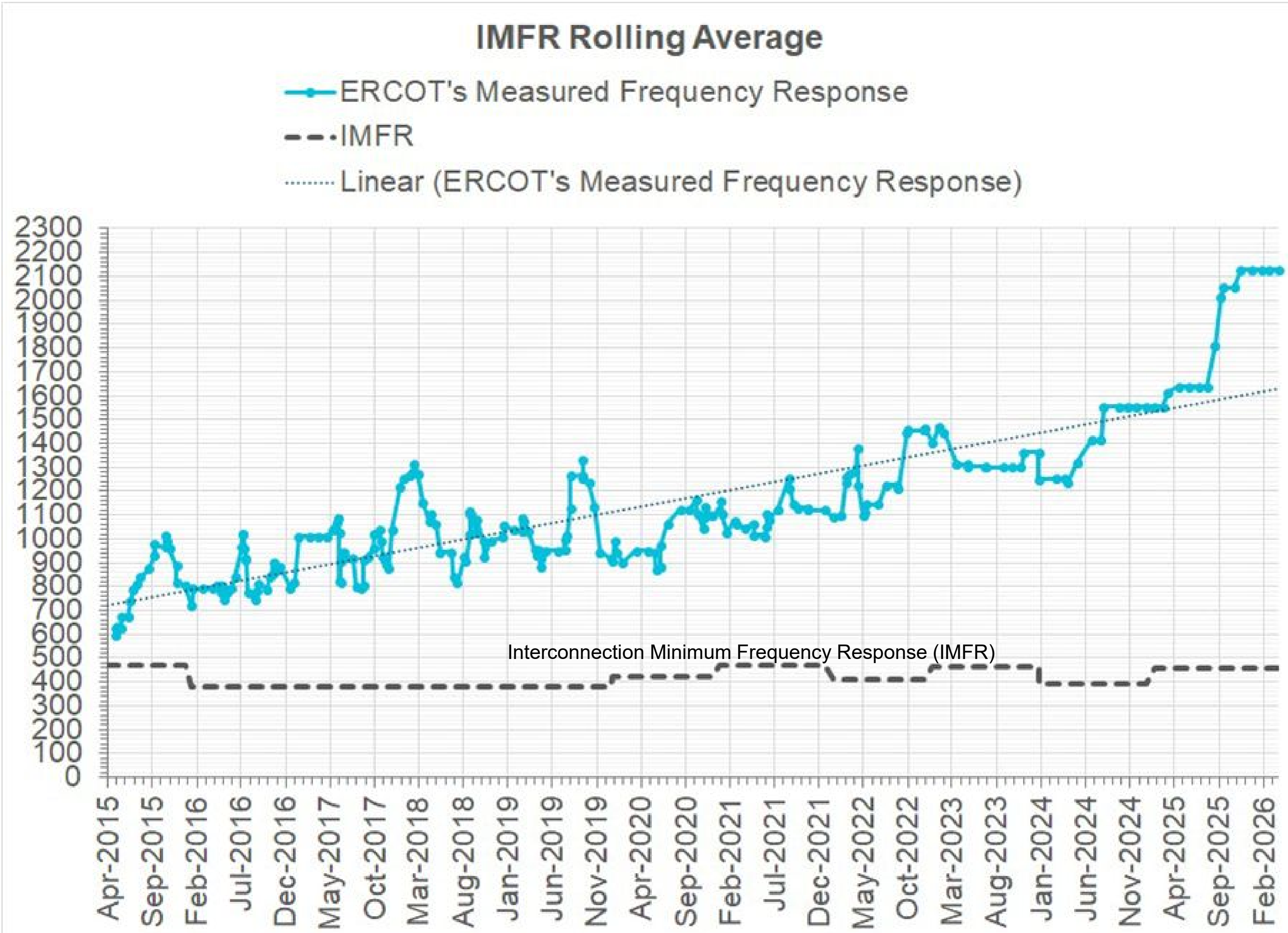




<u>Balancing Authority ACE Limit (BAAL) Exceedances</u>
72 clock-minutes of BAAL Exceedances in 2021
1 clock-minute of BAAL Exceedances in 2022
21 clock-minutes of BAAL Exceedances in 2023
5 clock-minutes of BAAL Exceedances in 2024
0 clock-minutes of BAAL Exceedances in 2025
0 clock-minutes of BAAL Exceedances in 2026

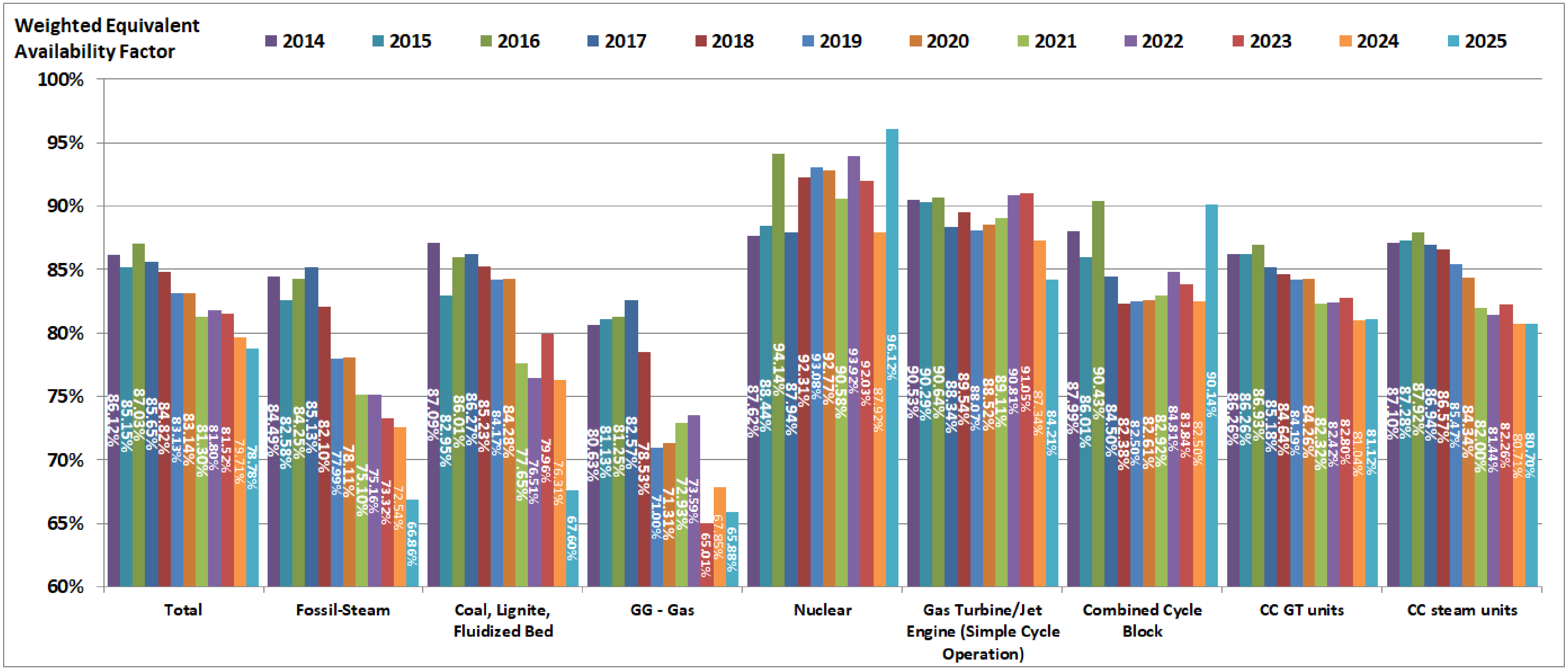
Red dashed line indicated 17 mHz governor dead-band

Primary Frequency Response – BAL-001-TRE



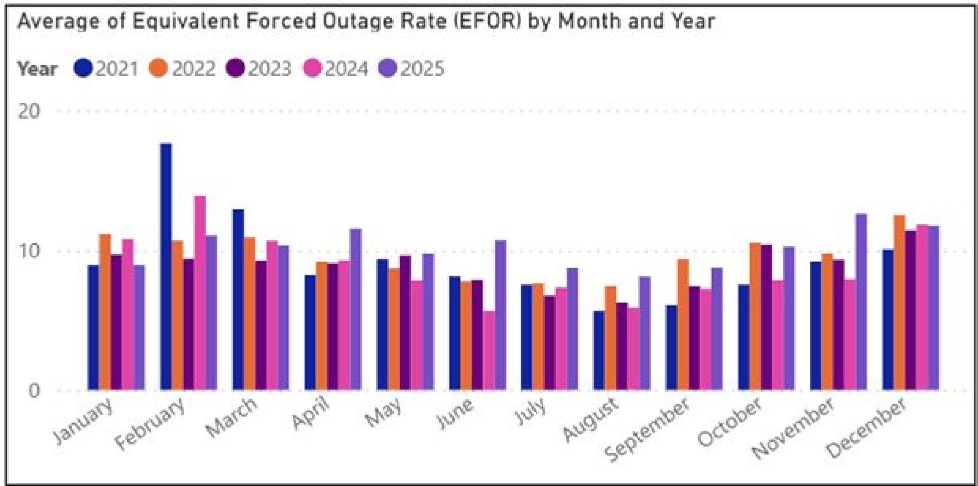
Public

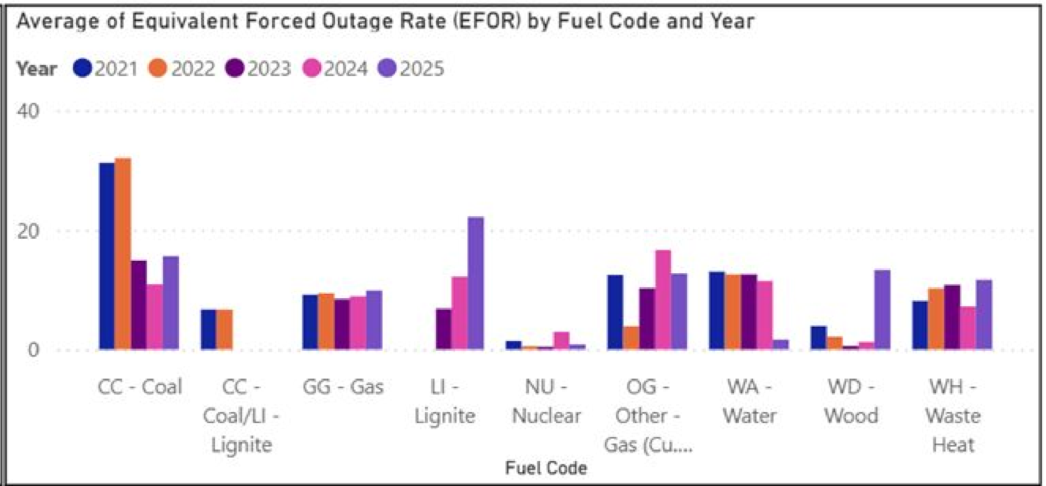
Generation Availability (Conventional)

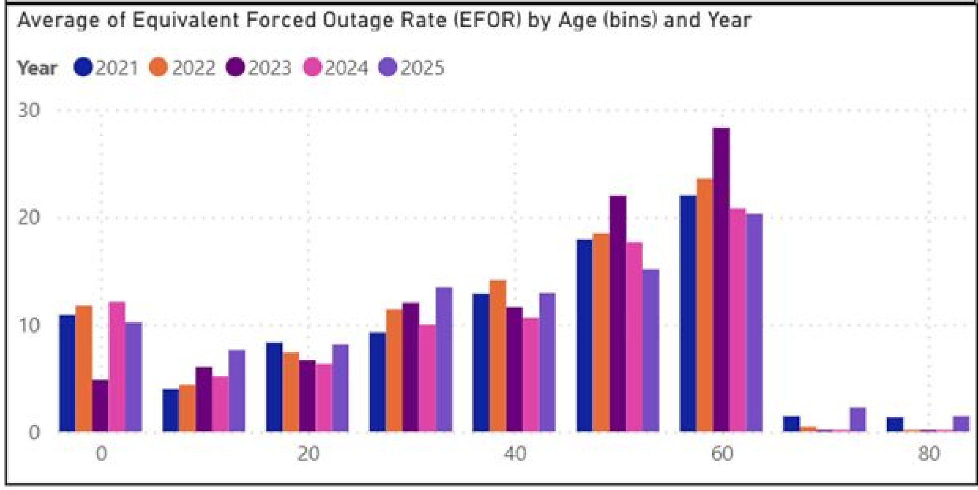


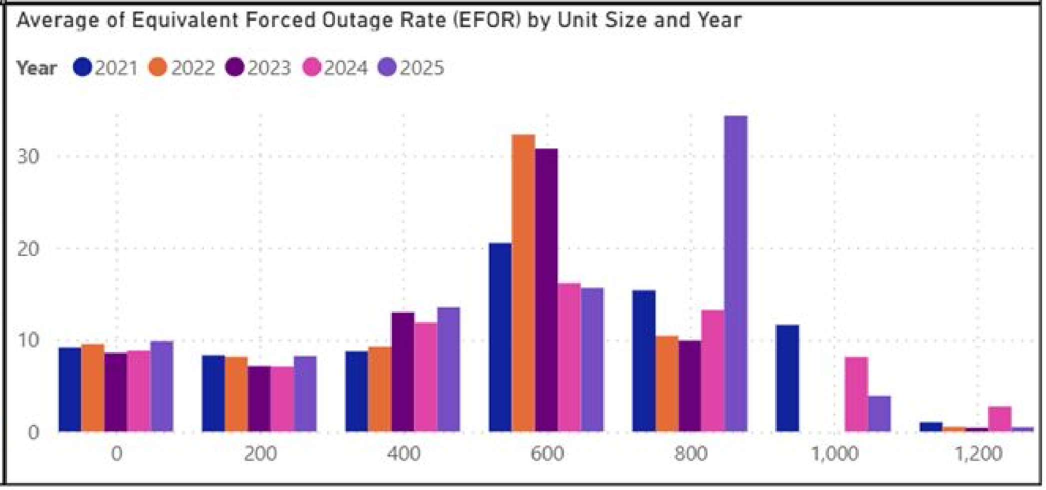
Generation Equivalent Forced Outage Rates (Conventional)

Public

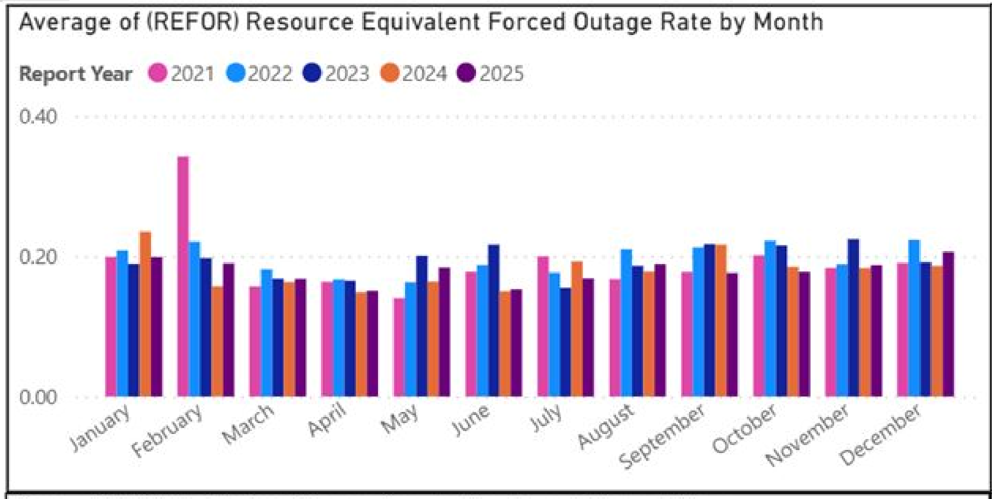


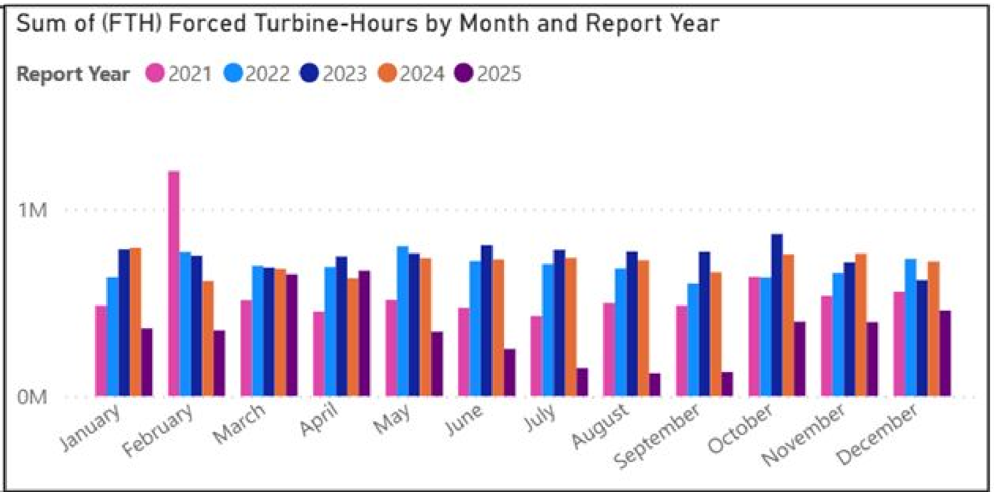


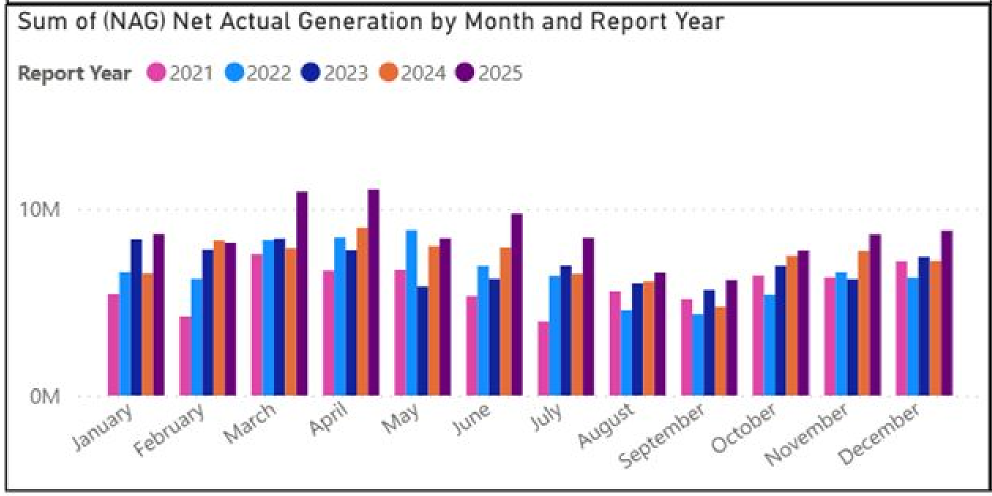


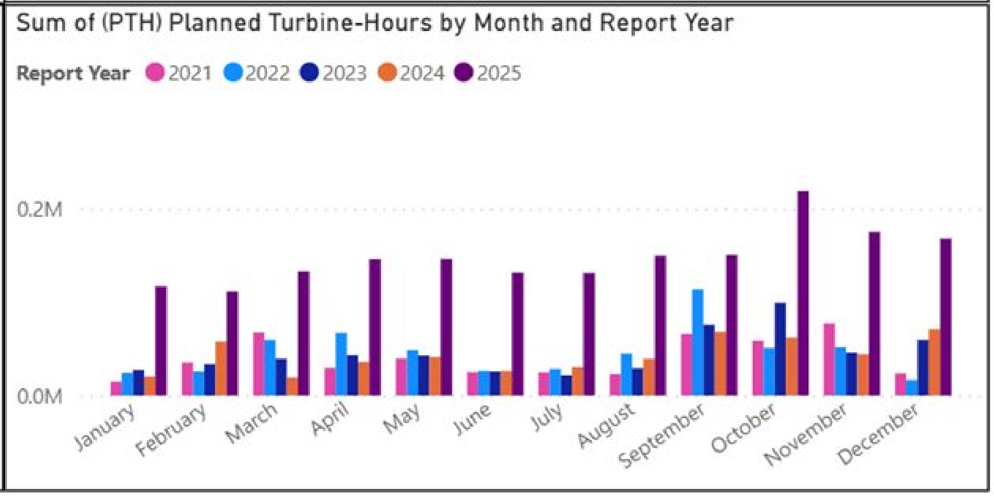


Wind GADS Metrics

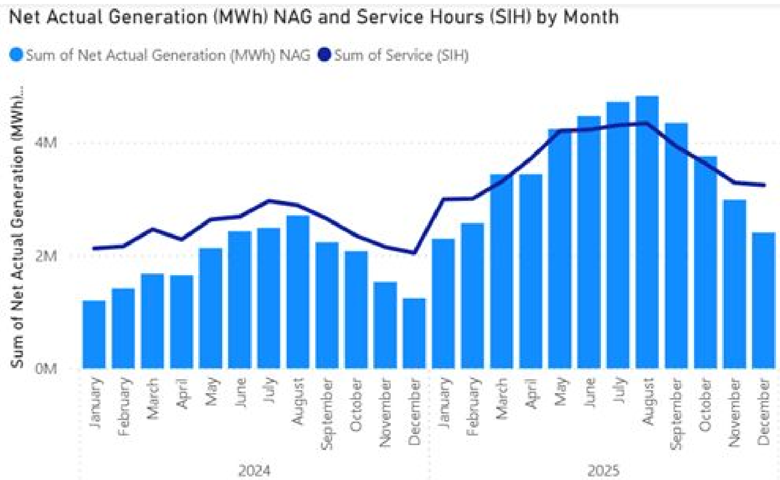


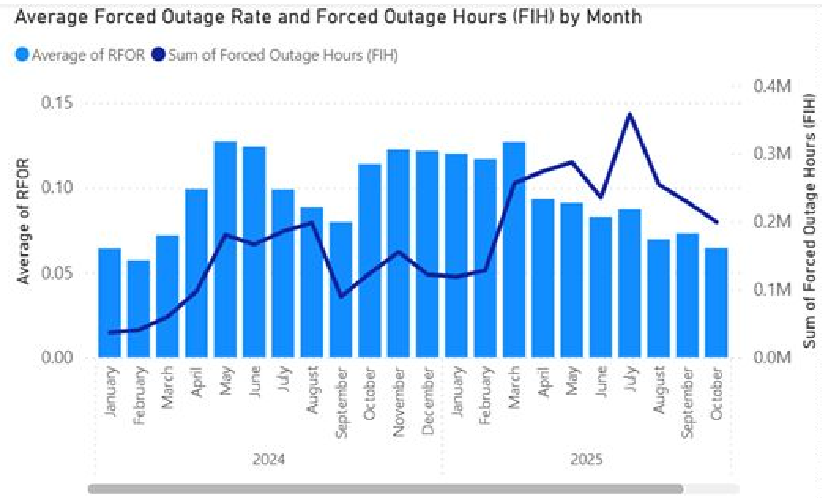


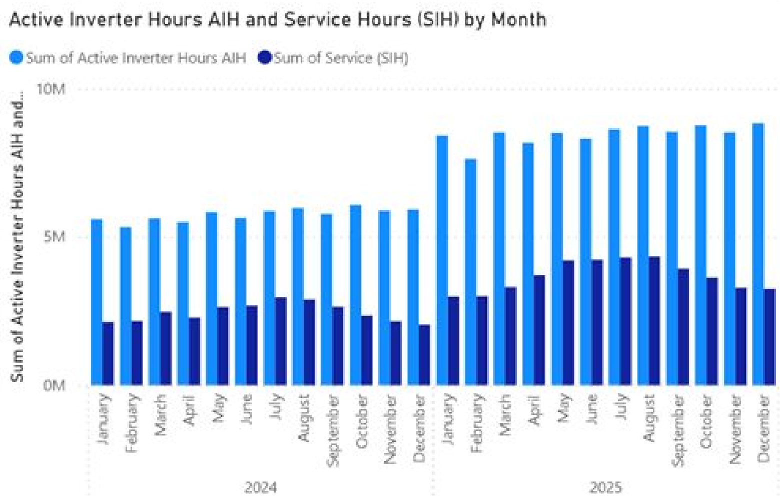


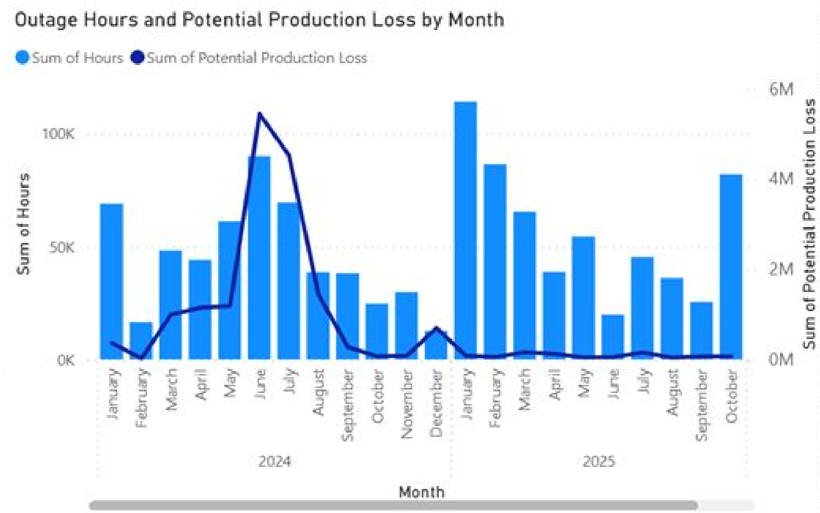


Solar GADS Metrics

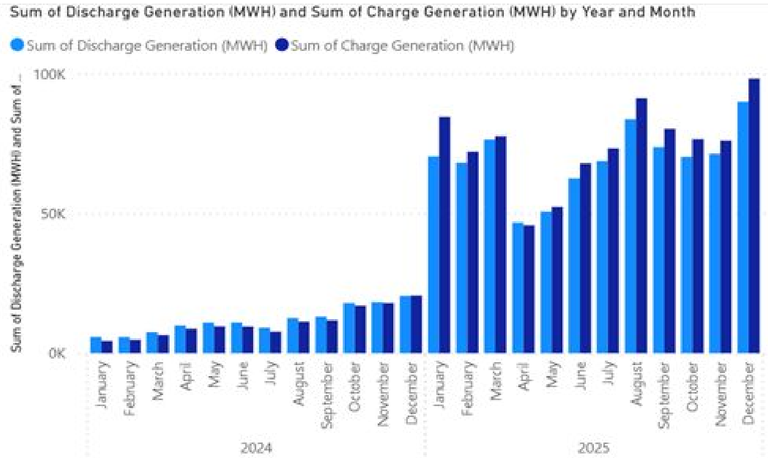


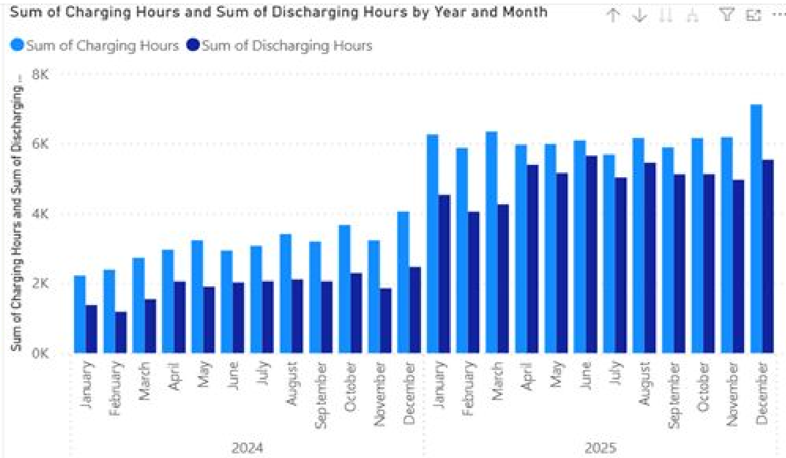


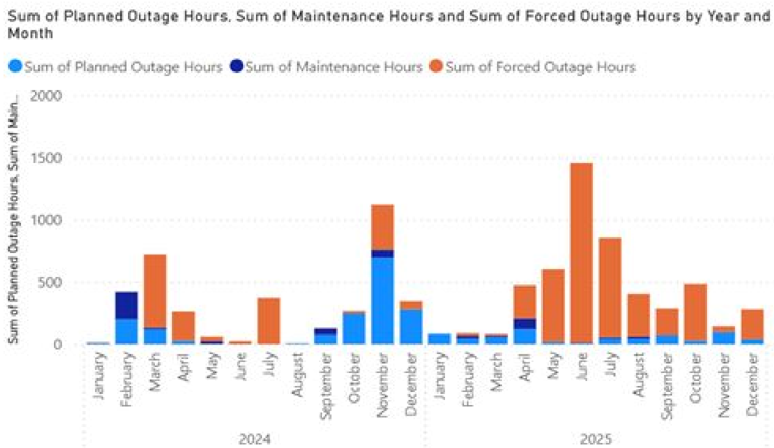


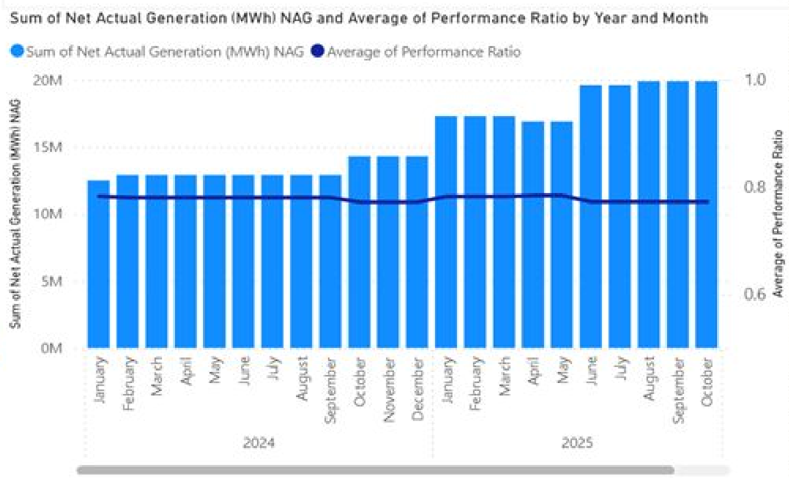


BESS GADS Metrics





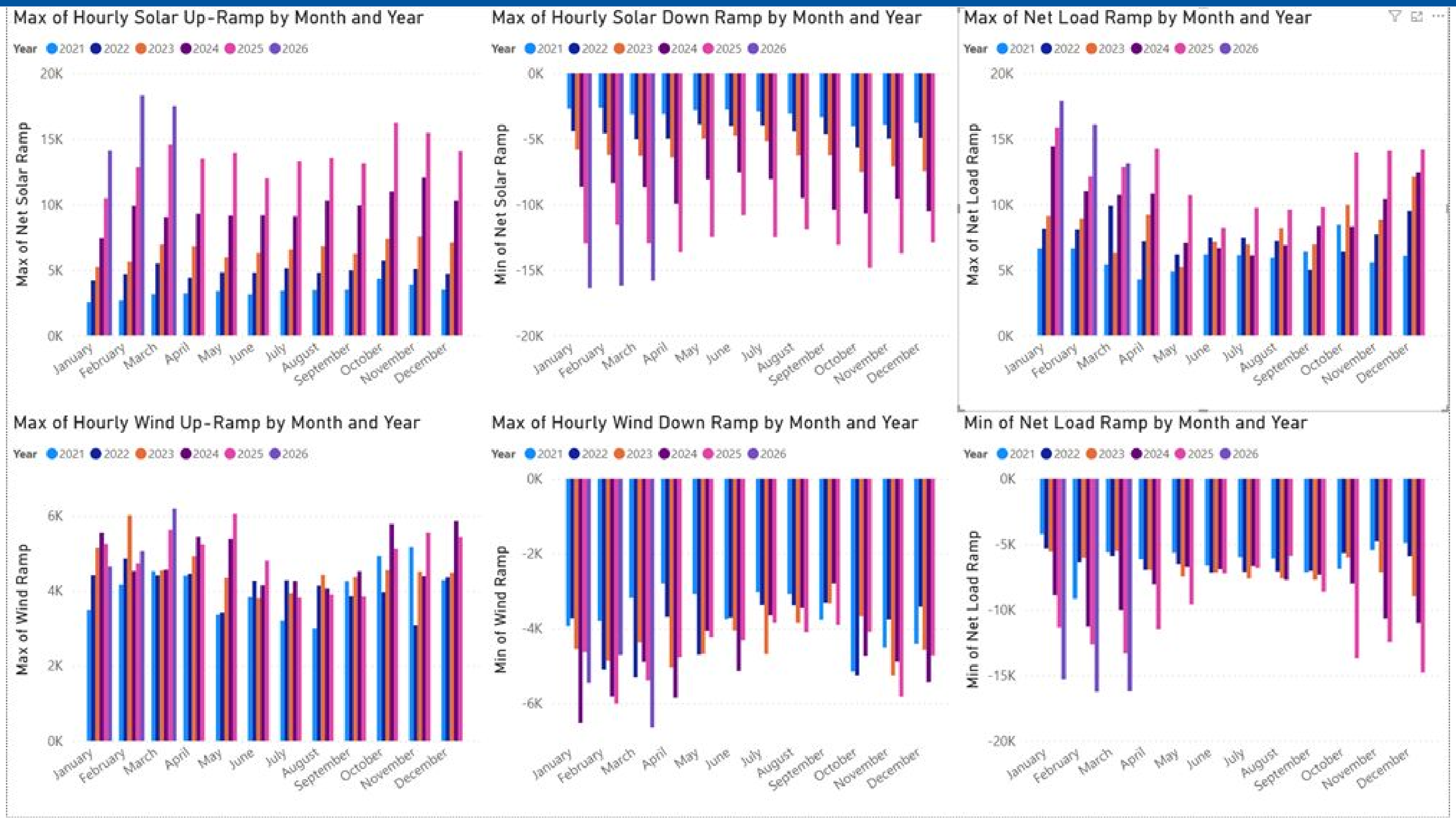




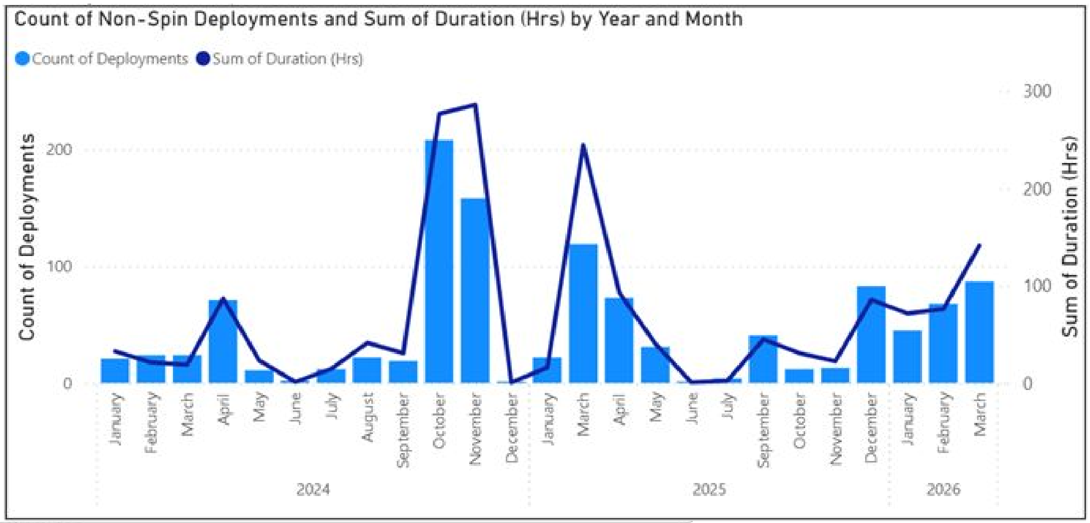
Metrics for Battery Energy Storage System (BESS) facilities co-located with solar or wind generation facilities

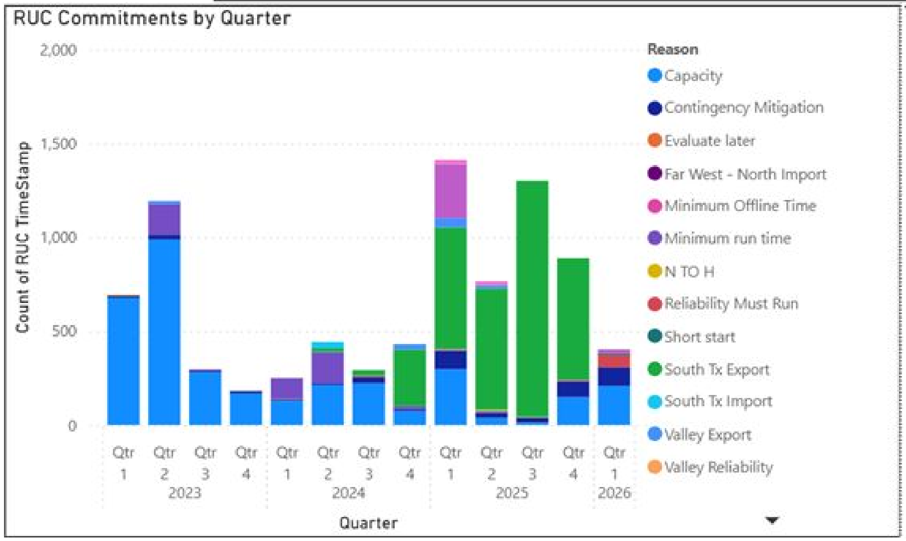
Ramping as of April 1, 2026

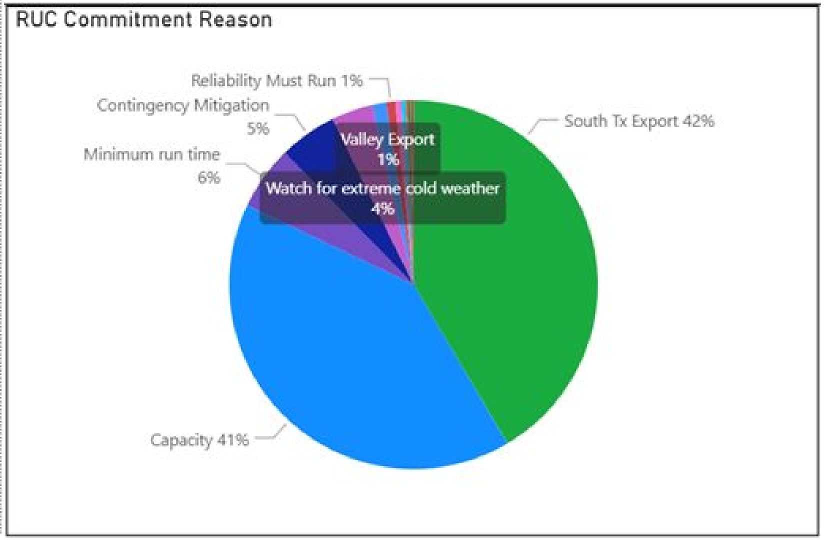
2026 maximum solar up and down ramps now exceeding 16,000 MW per hour



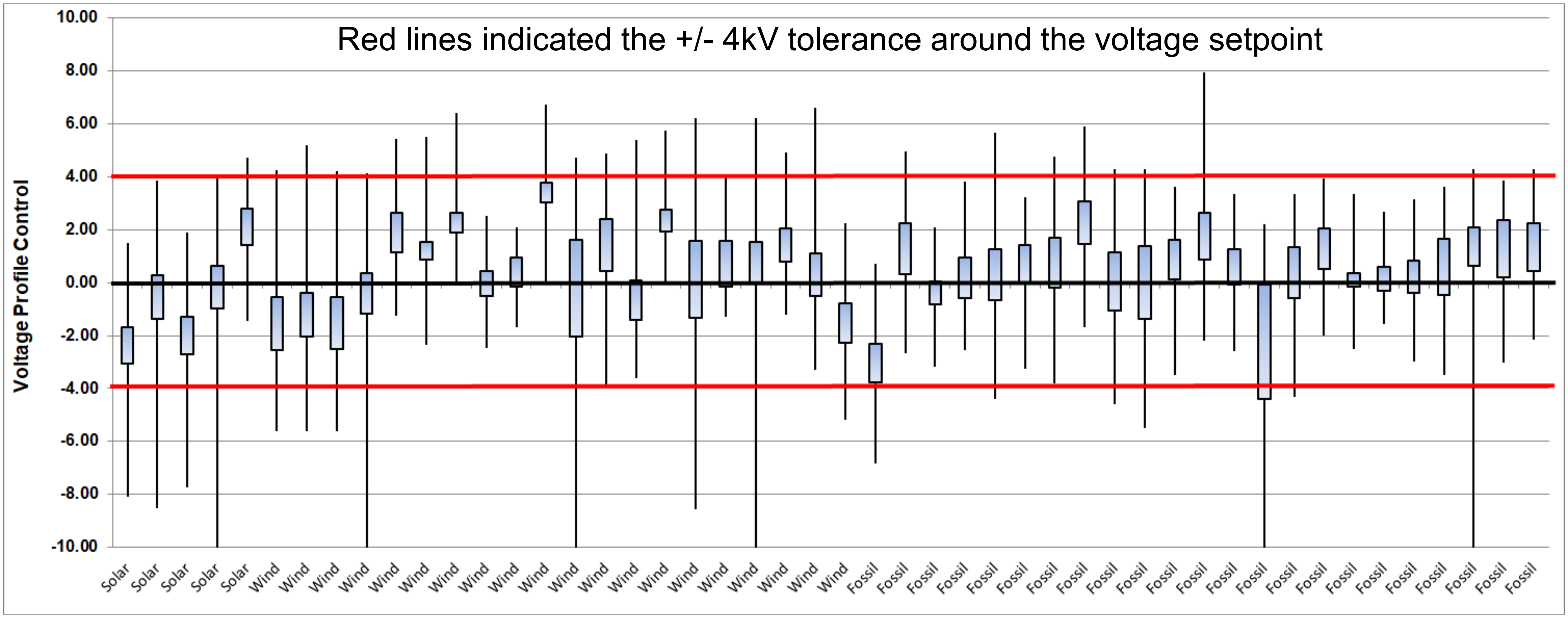
Non-Spin and RUC Deployments as of April 1, 2026



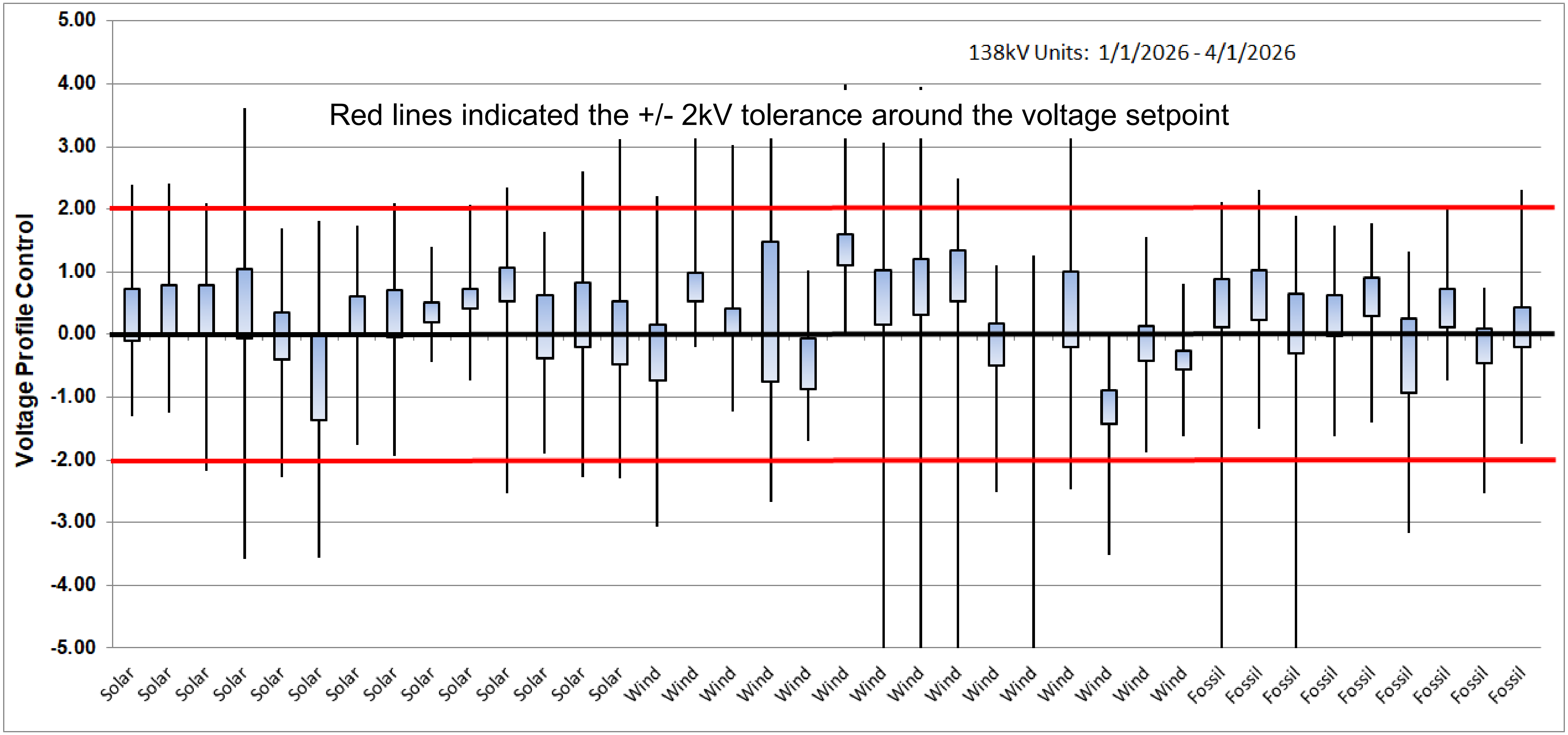




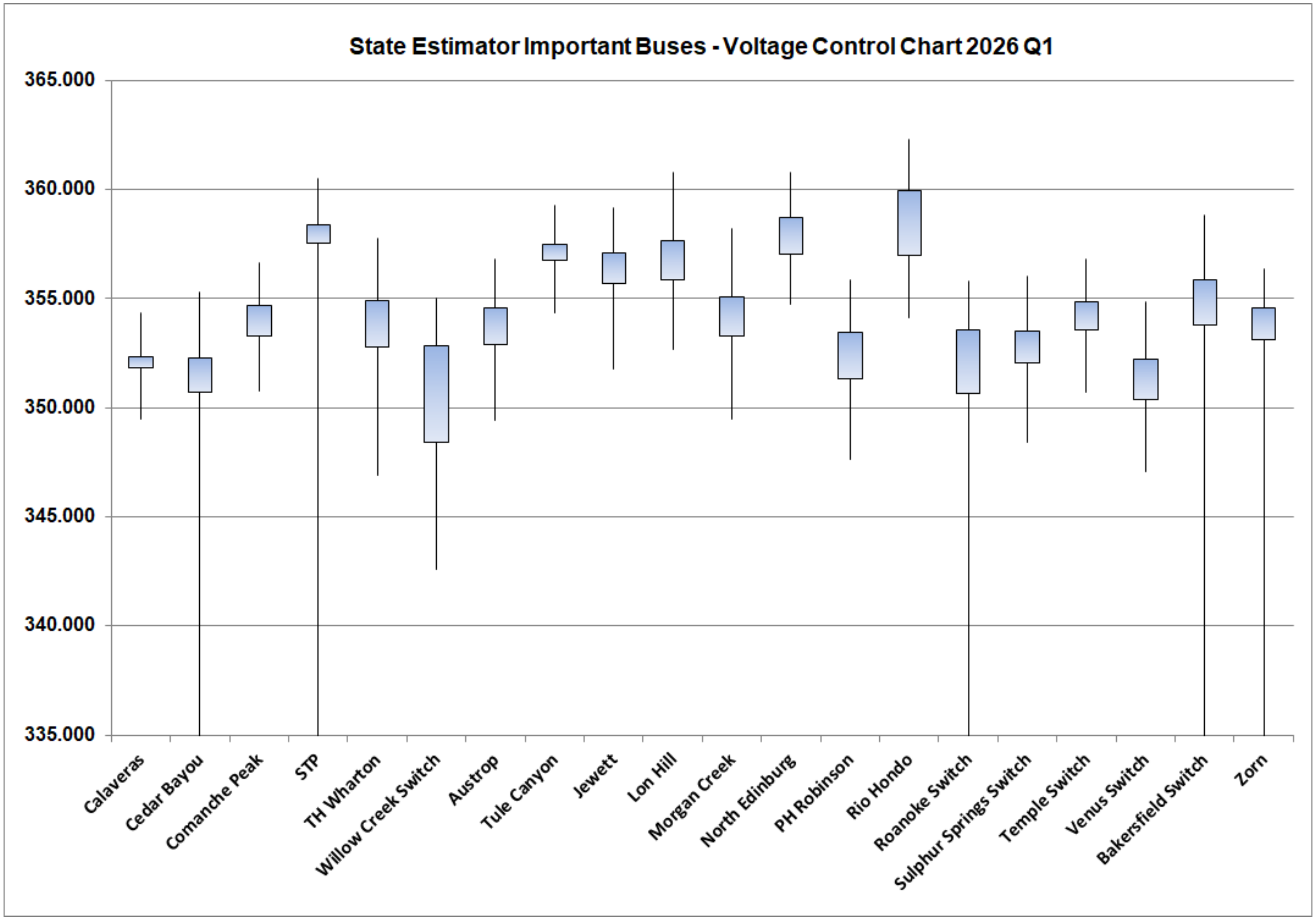
Voltage Control Metrics – 345kV Units for Jan-Mar 2026



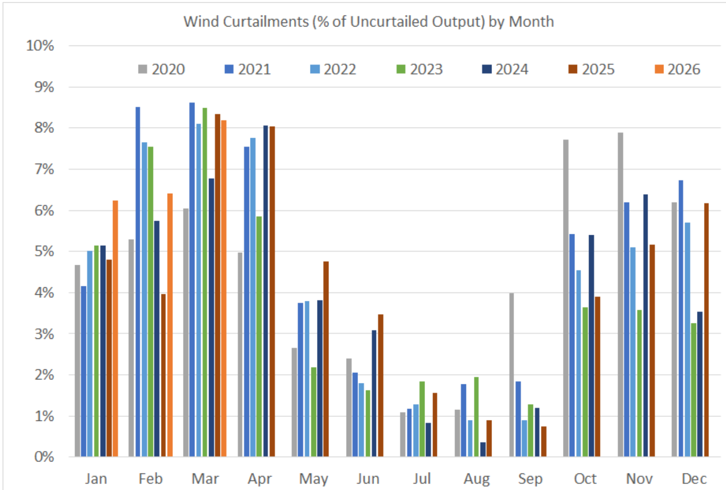
Voltage Control Metrics – 138kV Units for Jan-Mar 2026

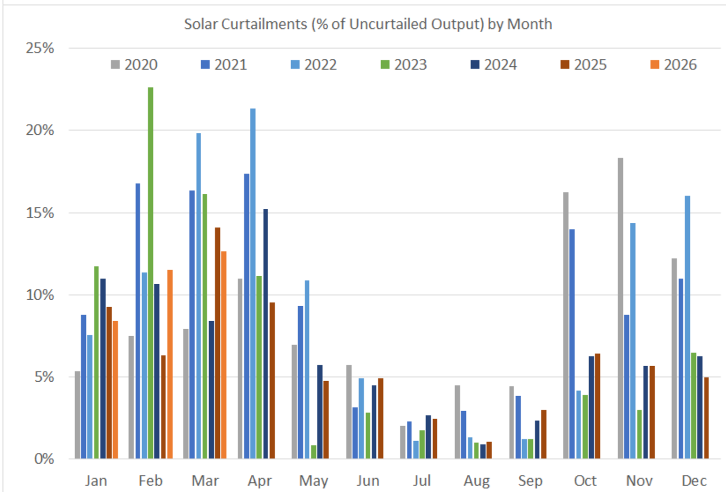


Voltage Control Metrics – State Estimator Important Buses

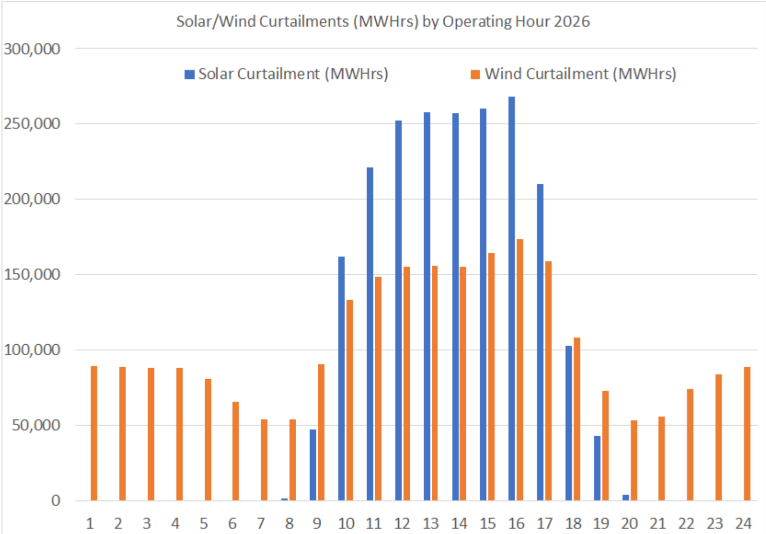


Curtailments as of April 1, 2026



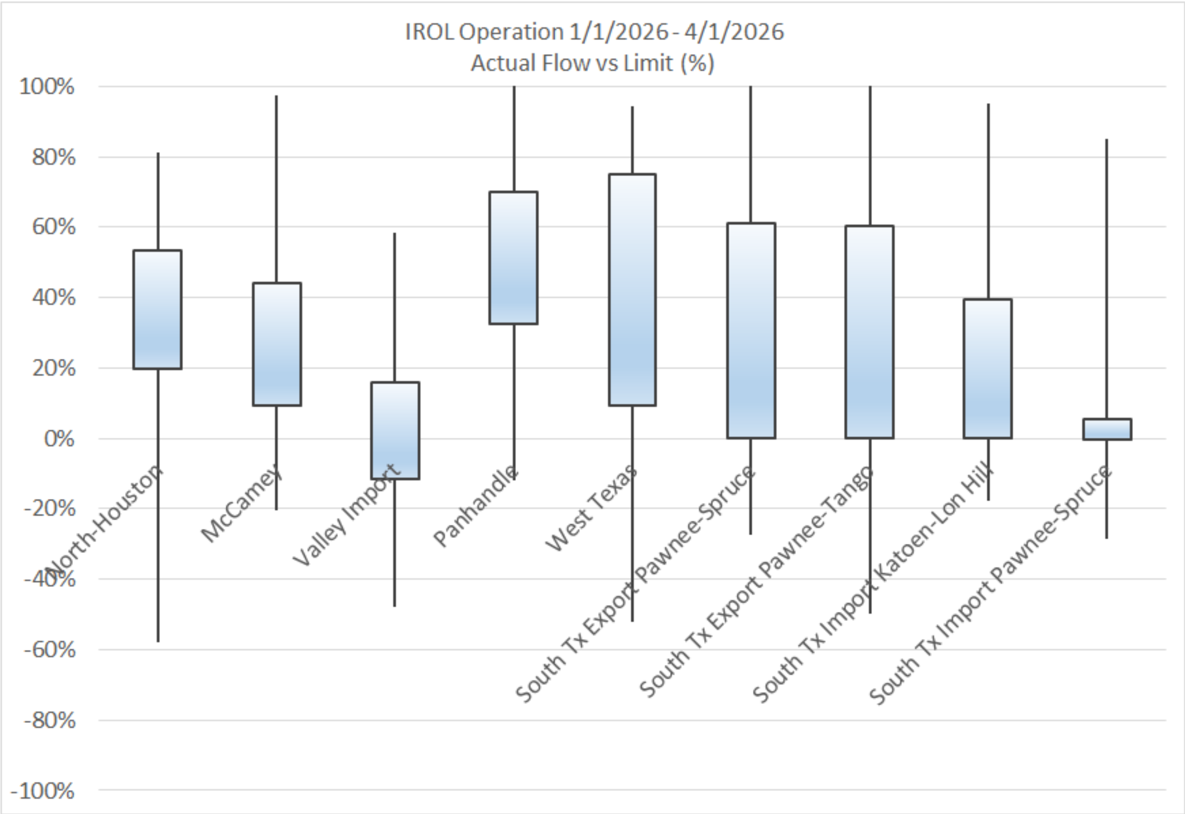


2026 YTD	Wind	Solar
GWHrs	2,484.1	2,087.7
Max Hourly MW Curtailment	8,813	15,593
Avg % of Uncurtailed Output	7.1%	11.2%



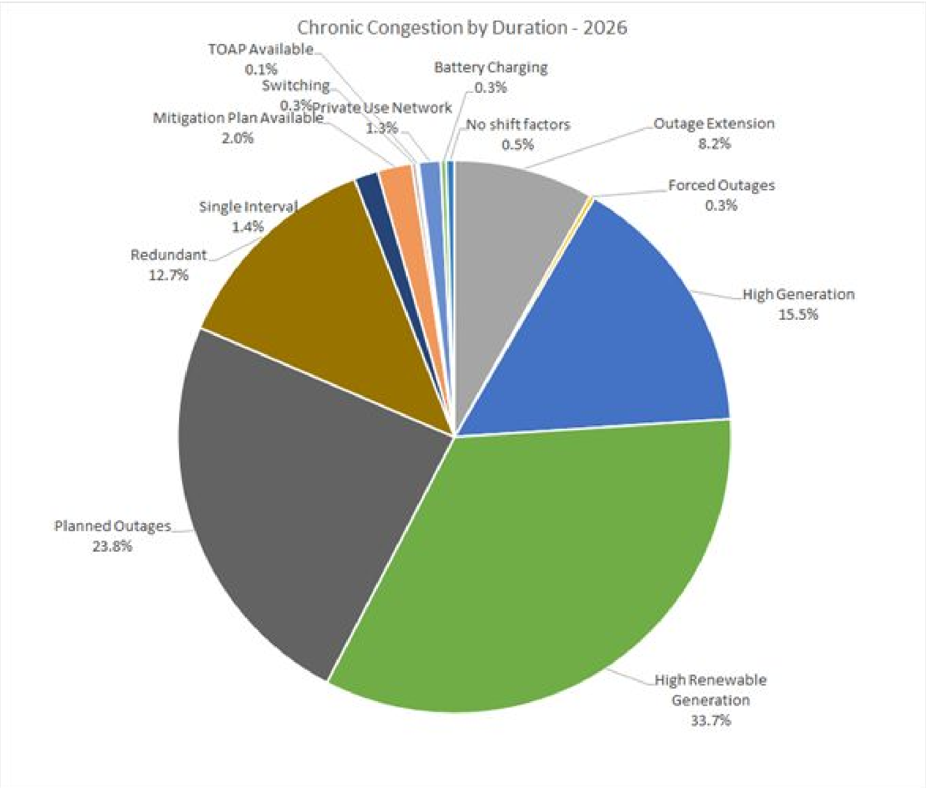
Public

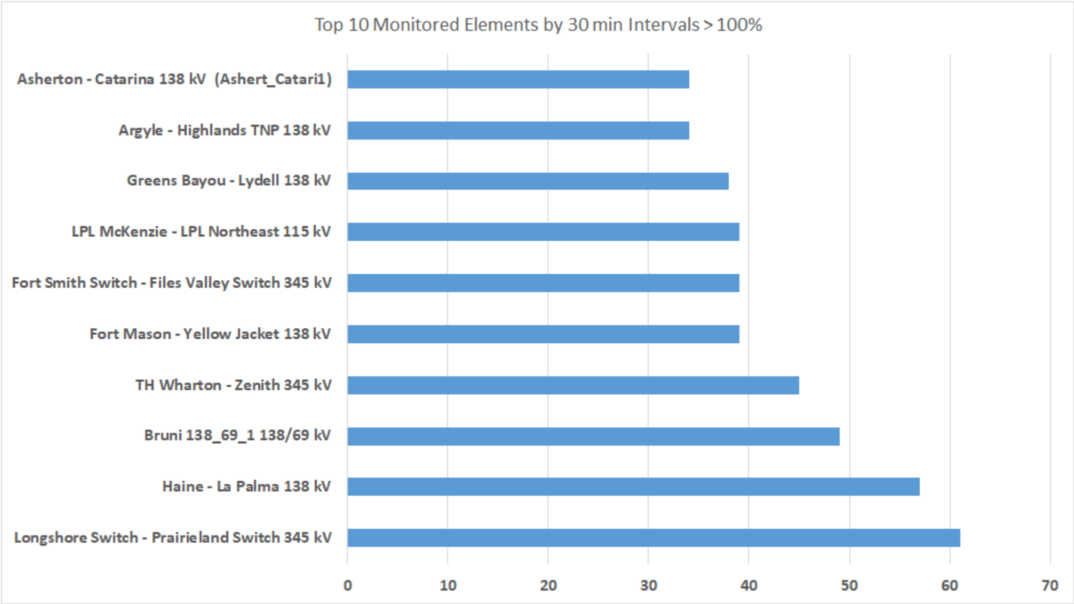
Generic Transmission Constraints



	North-Houston	McCamey	Valley Import	Panhandle	West Texas	South Tx Export Pawnee-Spruce	South Tx Import Pawnee-Spruce	South Tx Export Pawnee-Tango	South Tx Export Katoen-Lon Hill
# Minutes > 90%	0	14	0	275	441	400	0	59	106
# Minutes > 100%	0	0	0	3	0	2	0	4	0

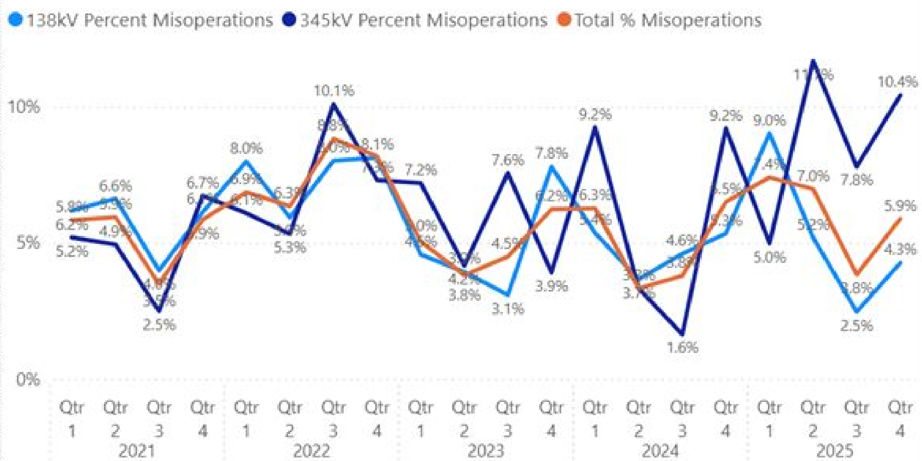
Transmission Congestion as of April 1, 2026



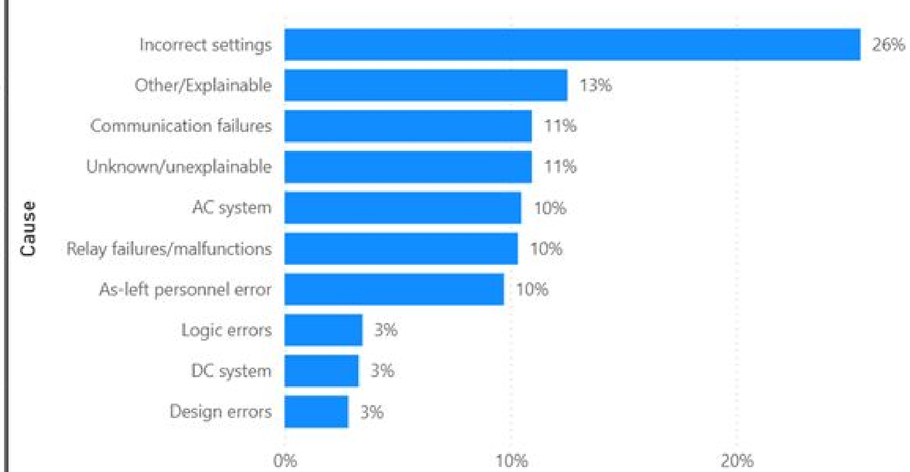


Protection System Misoperations Dashboard as of April 1, 2026

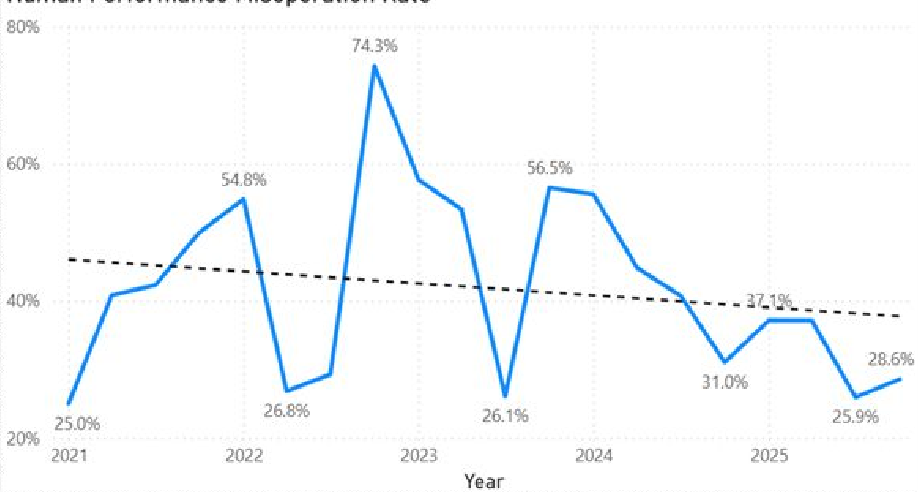
138kV Percent Misoperations and 345kV Percent Misoperations by Quarter



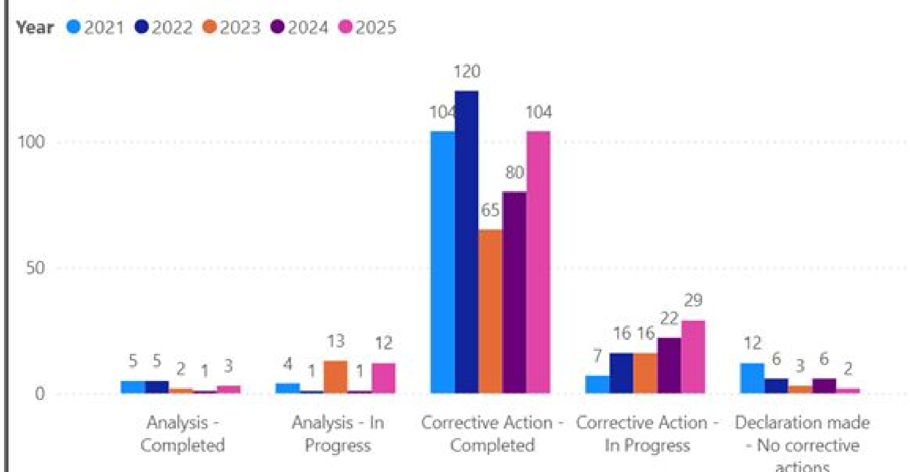
% of Total Misoperations by Cause



Human Performance Misoperation Rate

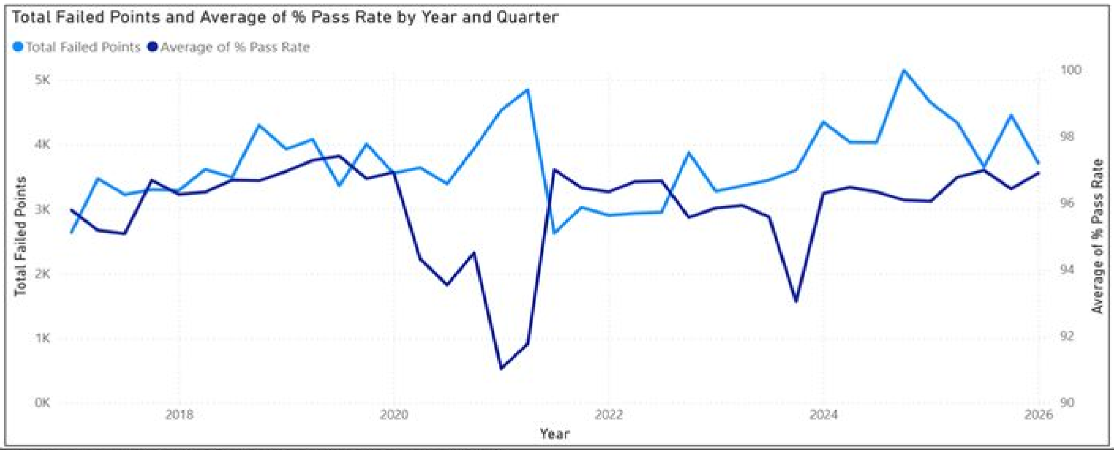


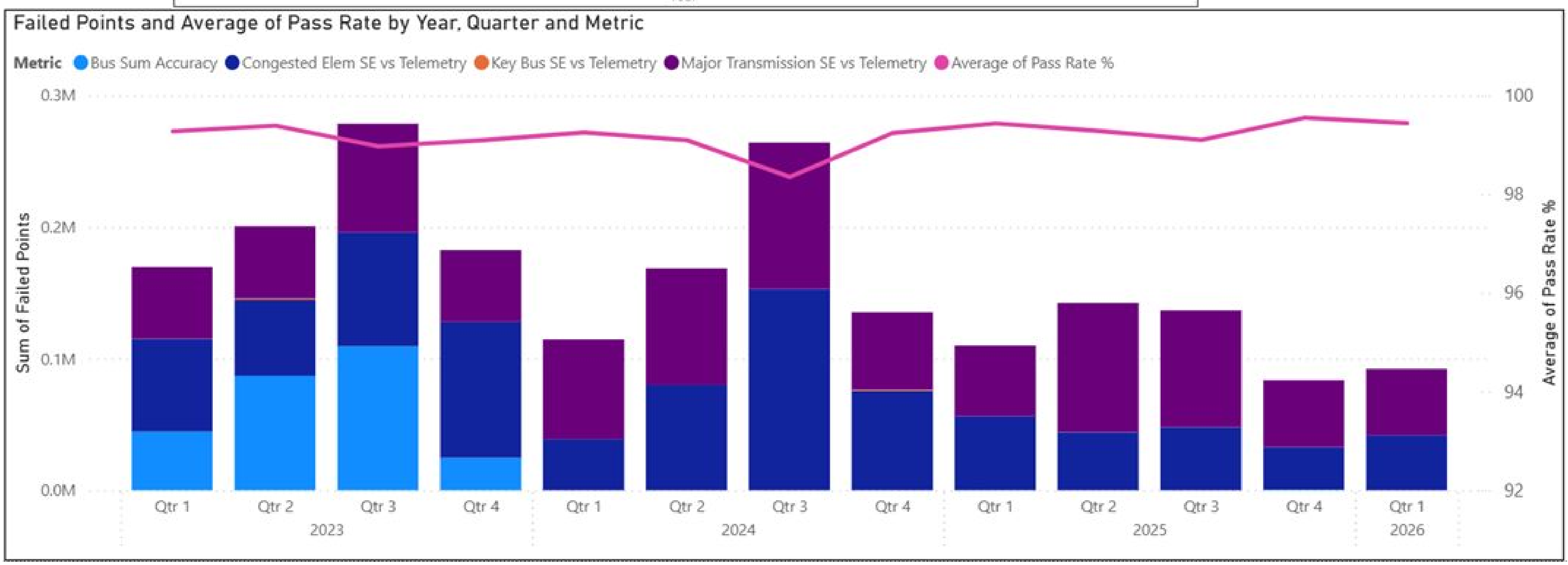
Corrective Action Status by Year



Telemetry Availability and Accuracy as of April 1, 2026

Public





TEXAS RE

Standards Report

Member Representatives Committee Meeting
May 13, 2026

Executive Summary

Texas RE took action on six NERC Reliability Standards Projects Phases

25 Projects in Active Standards Development

Texas RE Comments Submitted

Project Number	Project Name	Action
2023-06	CIP-014 Risk Assessment Refinement	Additional Ballot and Comment Period
2025-02	Internal Network Security Monitoring	Final Ballot
2025-03	Order No. 901 Operational Studies	Initial Ballot and Comment Period
2025-04	Order No. 901 Planning Studies	Initial Ballot and Comment Period
2026-01	PRC-006 Standard Updates	SARs Comment Period
2026-02	Computational Loads	SAR Comment Period

Recent NERC Filings to FERC

FERC Docket Number	Filing	FERC Submittal Date
RD22-4-001	IBR Work Plan January 2026 Update	1/29/2026
FA11-21-000	Compliance Filing Response to January 2013 Order	2/13/2026
RD26-4-000	Petition for Approval of BAL-007-1 Errata	2/23/2026
RD26-5-000	Joint Petition for Approval of BAL-002-WECC-3 Retirement	2/27/2026
RR26-1-000	Joint Petition for Approval of Amendments to the WECC Bylaws	3/11/2026
RR09-6-003	2026 NERC Standards Report, Status and Timetable for Addressing Regulatory Directives	3/18/2026
RM26-4-000	Additional Comments on Large Loads ANOPR	3/20/2026
RM18-2-000	Annual Report on Cyber Security Incidents	3/20/2026
EL26-49-000	NERC Motion to Intervene and Comments	3/30/2026

High Priority Active Projects

2023-06 CIP-014 Risk Assessment	2023-09 Risk Management for Third-Party Cloud Services	2024-02 Planning Energy Assurance
2025-02 Internal Network Security Monitoring Standard Revision	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

Public

Medium Priority Active Projects

2021-03	• CIP-002
2022-04	• EMT Modeling
2023-01	• EOP-004 IBR Event Reporting
2025-01	• Canadian-Specific Revisions to EOP-012-3

Public

Low Priority Active Projects

2017-01 Modifications to BAL-003 Phase II	2019-04 Modifications to PRC-005-6	2020-06 Verifications of Models and Data for Generators (IBR Definitions)	2021-01 Modifications to MOD-025 and PRC-019
2021-02 Modifications to VAR-002-4.1	2021-08 Modifications to FAC-008	2022-02 Uniform Modeling Framework for IBR	2022-05 Modifications to CIP-008 Reporting Threshold
2023-05 Modifications to FAC-001 and FAC-002	2023-07 Transmission System Planning Performance Requirements for Extreme Weather	2023-08 Modifications to MOD-031 Demand and Energy Data	2026-01 PRC-006 Standard Updates