UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)))**	**Docket No. _______**

JOINT PETITION OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
AND TEXAS RELIABILITY ENTITY, INC.
FOR APPROVAL OF PROPOSED REGIONAL RELIABILITY STANDARD
BAL-001-TRE-2 – PRIMARY FREQUENCY RESPONSE IN THE ERCOT REGION

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Pursuant to Section 215(d)(1) of the Federal Power Act ("FPA")[1] and Section 39.5[2] of the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"), the North American Electric Reliability Corporation ("NERC")[3] and the Texas Reliability Entity, Inc. ("Texas RE") hereby submit proposed regional Reliability Standard BAL-001-TRE-2 for Commission approval. NERC and Texas RE request that the Commission approve proposed regional Reliability Standard BAL-001-TRE-2 (**Exhibit A**) as just, reasonable, not unduly discriminatory or preferential, and in the public interest. NERC and Texas RE also request approval of the associated implementation plan (**Exhibit B**), and the associated Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") (**Exhibit A**), as detailed in this petition.

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1 16 U.S.C. § 824o (2018).

2 18 C.F.R. § 39.5 (2019).

3 The Commission certified NERC as the electric reliability organization ("ERO") in accordance with Section 215 of the FPA on July 20, 2006. *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *order on compliance*, 118 FERC ¶ 61,030, *order on compliance*, 118 FERC ¶ 61,190, *order on reh'g*, 119 FERC ¶ 61,046 (2007), *aff'd sub nom.* Alcoa Inc. v. FERC, 564 F.3d 1342 (D.C. Cir. 2009).

As required by Section 39.5(a)[4] of the Commission's regulations, this petition presents the technical basis and purpose of the proposed regional Reliability Standard, a summary of the development proceedings, and a demonstration that the proposed regional Reliability Standard meets the criteria identified by the Commission in Order No. 672[5] (**Exhibit C**). Proposed regional Reliability Standard BAL-001-TRE-2 was approved by the Texas RE Board of Directors on December 11, 2019 and adopted by the NERC Board of Trustees on February 6, 2020.

NERC proposes an effective date of the first day of the first calendar quarter following Commission approval in accordance with the proposed implementation plan **(Exhibit B)**. As with currently effective BAL-001-TRE-1, the proposed regional standard would only be effective within the Texas RE footprint, which consists of the Electric Reliability Council of Texas ("ERCOT") Interconnection.

I. SUMMARY

Currently effective regional Reliability Standard BAL-001-TRE-1 helps to establish and maintain adequate Frequency Response[6] in the ERCOT Interconnection by ensuring prompt and sufficient Frequency Response from generating resources to stabilize frequency during changes in the system generation-demand balance. The regional standard, which was approved by the

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4 18 C.F.R. § 39.5(a).

5 The Commission specified in Order No. 672 certain general factors it would consider when assessing whether a particular Reliability Standard is just and reasonable. *See Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, 114 FERC ¶ 61,104 at PP 321-37 (2006) [hereinafter Order No. 672], *order on reh'g*, Order No. 672-A, 114 FERC ¶ 61,328 (2006).

6 Unless otherwise designated, all capitalized terms have the meaning set forth in the *Glossary of Terms Used in NERC Reliability Standards*, available at https://www.nerc.com/files/Glossary_of_Terms.pdf.

Commission in 2014,[7] was originally developed to respond to a Commission directive in Order No. 693.[8]

In 2018, Texas RE initiated a project to revise the regional standard to make certain clarifications and improvements. Proposed regional Reliability Standard BAL-001-TRE-2 improves upon the currently effective version of the regional standard by: (i) clarifying performance requirements for steam turbines of combined cycle facilities; and (ii) clarifying the responsible entity for addressing Frequency Measurable Event exclusion requests. Additionally, corresponding revisions and clarifications are made in the Primary Frequency Response Reference Document, included as Attachment 1 (formerly Attachment 2) to the regional standard. The proposed regional standard continues to be necessary due to physical differences in the ERCOT Interconnection and continues to provide an alternative, more stringent means of assuring Frequency Response performance than the continent-wide NERC Reliability Standard.

For these reasons, which are discussed more fully in this petition, NERC and Texas RE respectfully request that the Commission approve proposed regional Reliability Standard BAL-001-TRE-2 standard as just, reasonable, not unduly discriminatory or preferential, and in the public interest.

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7 *N. Am. Elec. Reliability Corp.*, 146 FERC ¶ 61,025 (2014).

8 *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, 118 FERC ¶ 61,218 at P 313-315 (2007), [hereinafter Order No. 693], *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[9]

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III. BACKGROUND

A. Regulatory Framework

By enacting the Energy Policy Act of 2005,[10] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the nation's Bulk-Power System, and with the duties of certifying an ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1)[11] of the FPA states that all users, owners, and operators of the Bulk-Power System in the United States will be subject to Commission-approved Reliability Standards. Section 215(d)(5)[12] of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard. Section 39.5(a)[13] of the Commission's regulations requires the ERO to file with the Commission for its approval each Reliability Standard that the ERO proposes should become mandatory and

9 Persons to be included on the Commission's service list are identified by an asterisk. NERC respectfully requests a waiver of Rule 203 of the Commission's regulations, 18 C.F.R. § 385.203, to allow the inclusion of more than two persons on the service list in this proceeding.

10 16 U.S.C. § 824o.

11 *Id.* § 824o(b)(1).

12 *Id.* § 824o(d)(5).

13 18 C.F.R. § 39.5(a).

enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes should be made effective.

The Commission has the regulatory responsibility to approve Reliability Standards that protect the reliability of the Bulk-Power System and to ensure that such Reliability Standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest. Under Section 215(d)(2) of the FPA [14] and Section 39.5(c) [15] of the Commission's regulations, the Commission will give due weight to the technical expertise of the ERO with respect to the content of a Reliability Standard and to the technical expertise of a Regional Entity, like Texas RE, that is organized on an Interconnection-wide basis with respect to a regional Reliability Standard to be applicable within that Interconnection.[16]

A regional Reliability Standard proposed by a Regional Entity must meet the same criteria that NERC's Reliability Standards must meet, *i.e.*, the regional Reliability Standard must be shown to be just, reasonable, not unduly discriminatory or preferential, and in the public interest.[17] Order No. 672 also requires additional criteria that a regional Reliability Standard must satisfy. A regional difference from a continent-wide Reliability Standard must either be (1) more stringent than the continent-wide Reliability Standard (which includes a regional standard that addresses matters that the continent-wide Reliability Standard does not), or (2) necessitated by a physical difference in the Bulk-Power System.[18]

Texas RE is an "interconnection-wide" Regional Entity, and its standards are intended to apply to the ERCOT Interconnection. As discussed in the *Texas Reliability Entity Standards*

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14 16 U.S.C. § 824o(d)(2).

15 18 C.F.R. § 39.5(c)(1).

16 *See also* Order No. 672 at P 344.

17 Section 215(d)(2) of the FPA and 18 C.F.R. §39.5(a).

18 Order No. 672 at P 291.

Development Process,[19] Texas RE's standards are developed according to the following characteristic attributes:

- Developed in a fair and open process that provides an opportunity for all interested parties to participate;
- Does not have an adverse impact on commerce that is not necessary for reliability;
- Provides a level of Bulk-Power System reliability that is adequate to protect public health, safety, welfare, and national security and does not have a significant adverse impact on reliability; and
- Based on a justifiable difference between regions or between sub-regions within the regional geographic area.

Proposed Texas RE regional standards are subject to approval by the Texas RE Board of Directors, NERC, as the ERO, and the Commission before becoming mandatory and enforceable under Section 215 of the FPA.[20] Applicable users, owners, and operators of the Bulk-Power System in the ERCOT Interconnection must adhere to the NERC Reliability Standards as well as the Texas RE regional Reliability Standards.

B. History of the BAL-001-TRE Regional Reliability Standard

The Commission approved currently effective regional Reliability Standard BAL-001-TRE-1 in 2014.[21] The standard was originally developed to respond to a Commission directive in Order No. 693 to develop a regional Reliability Standard as an alternate means of assuring frequency performance in the ERCOT Interconnection.[22] In approving the regional standard, the

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[19] The *Texas Reliability Entity Standards Development Process* (eff. May 30, 2017) is available at: https://www.texasre.org/CPDL/TexasRE_RSDP_20100506_posted20160323.pdf.

[20] 16 U.S.C. 824o.

[21] *N. Am. Elec. Reliability Corp.*, 146 FERC ¶ 61,025 (2014).

[22] *See* Order No. 693 at PP 313-315. In Order No. 693, the Commission approved a regional difference to the continent-wide NERC Reliability Standard BAL-001-0 exempting ERCOT from Requirement R2 of BAL-001-0. The Commission directed NERC to file a modification of the ERCOT regional difference to include the requirements concerning frequency response contained in section five of the ERCOT Protocols, which identified the necessary frequency controls needed for reliable operation in ERCOT.

Commission stated that the standard "is a comprehensive frequency response standard that adequately addresses all applicable Commission directives and we believe it will protect and improve reliability in the ERCOT Interconnection by enabling entities to maintain sufficient frequency response that can be made quickly available to arrest possible frequency excursions."[23]

C. Development of Proposed Regional Reliability Standard BAL-001-TRE-2

Texas RE and ERCOT collaborated to draft a Standard Authorization Request ("SAR") proposing revisions to Reliability Standard BAL-001-TRE-1. The SAR proposed to revise the standard by:

- Removing the governor deadband and droop setting requirements for steam turbines in a combined cycle train in Requirement R6; and
- Clarifying the language in Requirements R9.3 and R10.3 to state that a unit's Primary Frequency Response performance during a Frequency Measuring Events ("FME") may be excluded from the rolling average calculation "by the Balancing Authority."

Proposed regional Reliability Standard BAL-001-TRE-2 was developed to address the issues identified in the SAR. The proposed regional standard was developed in an open, transparent, and inclusive fashion in accordance with the Texas Reliability Entity Standards Development Process.[24] The SAR was posted for comment from July 17 through August 1, 2018. Texas RE's Member Representatives Committee accepted the SAR on September 12, 2018 and appointed the standard drafting team on November 9, 2018.[25] A draft of proposed BAL-001-TRE-2 was posted for formal comment from May 6, 2019 through June 5, 2019, and the drafting team made several minor revisions based on the comments received. The standard was posted for a 15-day voting period from August 21 through September 5, 2019, where it achieved quorum and received 100 percent approval. The parallel non-binding poll of VRFs and VSLs achieved quorum

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[23] *N. Am. Elec. Reliability Corp.*, 146 FERC ¶ 61,025 at P 10 (2014).

[24] **Exhibit D** contains the record of development for the proposed regional standard.

[25] The standard drafting team roster is provided in **Exhibit D** hereto (Item 11).

and received 66 percent positive opinions. The proposed regional Reliability Standard was approved by the Texas RE Board of Directors on December 11, 2019 and by the NERC Board of Trustees on February 6, 2020.

IV. JUSTIFICATION FOR APPROVAL

As discussed in detail in **Exhibit C**, proposed regional Reliability Standard BAL-001-TRE-2 satisfies the Commission's criteria in Order No. 672 and is just, reasonable, not unduly discriminatory or preferential, and in the public interest. The following section provides (1) a discussion of the purpose of the proposed regional Reliability Standard, (2) a description of the revisions in proposed BAL-001-TRE-2, (3) a discussion of the enforceability of the proposed regional standard, and (4) a discussion of the proposed effective date.

A. Purpose and Overview of Proposed BAL-001-TRE-2

The purpose of proposed BAL-001-TRE-2, which is unchanged from the currently effective standard, is to maintain ERCOT Interconnection steady-state frequency within defined limits. The proposed regional standard, like the currently effective version, consists of ten requirements that relate to:

- identifying and posting Frequency Measureable Events (Requirement R1);
- calculating the primary frequency response of each resource in the Interconnection (Requirement R2);
- calculating the Interconnection minimum Frequency Response and monitoring the actual Frequency Response of the Interconnection (Requirements R3-R5);
- requiring resources to operate in accordance with specified governor deadband and droop parameters and to promptly notify the Balancing Authority of any change in governor status (Requirements R6-R8); and
- providing Primary Frequency Response performance requirements for each generator (Requirements R9-R10).

These requirements are designed to work together to help ensure that generation and load remain balanced, or are quickly returned to balance, in the ERCOT Interconnection so that system frequency is restored to stability and near-normal frequency even after a significant event occurs on the system.

B. Revisions in Proposed BAL-001-TRE-2

The revisions in proposed regional Reliability Standard BAL-001-TRE-2 primarily consist of: (1) revisions in Requirement R6, Table 6.2 relating to governor droop settings for certain generating resources; and (2) revisions in Requirements R9 and R10 relating to Frequency Measuring Events. Additionally, minor clarifications, corrections, and abbreviations are made throughout the document, and corresponding revisions are made in Attachment 1, Primary Frequency Response Reference Document. These changes are discussed in more detail below and in the Summary of Changes included in **Exhibit D**.[26]

1. Revisions in Requirement R6 – Governor Droop Settings

In proposed regional Reliability Standard BAL-001-TRE-2, Texas RE has revised Table 6.2 under Requirement R6 to correct internal inconsistencies in the standard and align to current operational practices in the ERCOT Interconnection, particularly with respect to steam turbines in a combined cycle train.

Historically, most combined cycle resources in the ERCOT Region have operated with the combustion turbines able to respond to frequency deviations using governor controls, with associated steam turbines not providing a response. The BAL-001-TRE-1 drafting team accounted for the lack of Primary Frequency Response from the steam turbines in a combined cycle resource

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[26] *See* **Exhibit D**, Item 7 (BAL-001-TRE-2 Summary of Changes).

train by requiring an overall 5.78 percent Primary Frequency Response performance for the entire train. Requirement R2 Part 2.1 of regional Reliability Standard BAL-001-TRE-1 provides:

> **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. 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.
>
> **2.1.** The performance of a combined cycle facility will be determined using an expected performance droop of 5.78%.[27]

In the currently effective regional standard, however, Requirement R6 Table 6.2 provides a separate maximum governor droop setting of five percent for steam turbines in a combined cycle. As the Balancing Authority for the ERCOT Region, ERCOT has already used its directive authority under BAL-001-TRE-1 Requirement R6 to explicitly exempt Generator Operators with steam turbines in combined-cycle trains from the droop and deadband settings in Requirement R6 Parts 6.1 and 6.2, pending a clarification to the standard.[28] In proposed Reliability Standard BAL-001-TRE-2, Requirement R6 Table 6.2 and the associated footnote are revised to remove the inconsistency with Requirement R2 Part 2.1, as shown below:

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

27 Footnote omitted.

28 *See* ERCOT Market Notice W-C050418-01 (May 4, 2018), http://www.ercot.com/content/wcm/key_documents_lists/89338/Combined_Cycle_Steam_Turbine_Exemption_for_Governeor_Deadband_and_Droop_Setting_Requirements.docx.

Table 6.2 Governor Droop Settings

Generator Type	Max. Droop % Setting
Hydro	5%
~~Nuclear~~	~~5%~~
~~Coal and Lignite~~	~~5%~~
Combustion Turbine (Simple Cycle and Single-Shaft Combined Cycle)	5%
Combustion Turbine (Combined Cycle)~~*~~	4%
Steam Turbine* ~~(Simple Cycle)~~	5%
~~Steam Turbine (Combined Cycle)*~~	~~5%~~
Diesel	5%
~~Wind Powered Generator~~	~~5%~~
DC Tie Providing Ancillary Services	5%
Variable Renewable (Non-Hydro)	5%

~~**Steam Turbines of combined cycle resources are required to comply with Requirements R6.1, R6.2 and R6.3. Compliance with Requirements R9 and R10 will be determined through evaluation of the combined cycle facility using an expected performance droop of 5.78%.~~

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

As shown above, Table 6.2 is also revised to consolidate line items for specific fuel sources. The separate line items for Nuclear and Coal and Lignite are removed, as plants with these fuel types operate as steam turbines. The separate line item for Wind Powered Generator is also removed, as such resources are included in the revised Variable Renewable (Non-Hydro) category.

2. Revisions to Requirements R9 and R10 Relating to Frequency Measurable Events

In proposed Reliability Standard BAL-001-TRE-2, revisions are made to Requirements R9 and R10 to clarify the responsibilities performed in the standard by the Balancing Authority with respect to Frequency Measurable Events, or FMEs.

The revisions in Requirements R9 and R10 are shown below:

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.

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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 ~~Compliance Enforcement Authority~~Balancing Authority may request raw data from the Generator Owner as a substitute.

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.

***

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 ~~Compliance Enforcement Authority~~ may request raw data from the Generator Owner as a substitute.

By replacing reference to the "Compliance Enforcement Authority" with "Balancing Authority" and clarifying who excludes FMEs from the average calculations, the proposed standard will achieve alignment with current operational practices with respect to Frequency Measurable Events. The revisions would also clarify that, in Requirement R9 Part 9.3 and Requirement R10 Part 10.3, the two bulleted items are not intended to represent an exhaustive list of "legitimate operating conditions that may support exclusion of FMEs."

3. Additional Revisions in Primary Frequency Response Reference Document

A series of revisions are made in Attachment 1 to the standard, Primary Frequency Response Reference Document, to align the document to the revisions made in the proposed regional standard, clarify language, and correct capitalization. These changes, which are shown in redline in **Exhibit A** and summarized in **Exhibit D** (item 7), are presented to the Commission for informational purposes only in accordance with the revision process set forth in the reference document.[29]

C. Enforceability of Proposed BAL-001-TRE-2

The proposed regional Reliability Standard includes VRFs and VSLs, which are unchanged from the currently effective version of the regional standard. The VRFs and VSLs provide guidance on the way that NERC will enforce the requirements of the proposed regional Reliability

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[29] *See* proposed regional Reliability Standard BAL-001-TRE-2 Attachment 1 Primary Frequency Response Reference Document at 2, Revision Process.

Standard and they continue to comport with NERC and Commission guidelines related to their assignment.

The proposed regional Reliability Standard also includes measures that support each requirement by clearly identifying what is required and how the requirement will be enforced. The measures are substantively unchanged from the currently effective version of the standard. These measures help ensure that the requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.[30]

D. Effective Date

NERC and Texas RE respectfully request that the Commission approve the proposed implementation plan, attached to this petition as **Exhibit B**. Under this plan, proposed regional Reliability Standard BAL-001-TRE-2 would become effective on the first day of the first calendar quarter following Commission approval. Currently effective regional Reliability Standard BAL-001-TRE-1 would be retired immediately prior to the effective date of BAL-001-TRE-2.

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[30] *See* Order No. 672 at P 327.

V. CONCLUSION

For the reasons set forth above, NERC respectfully requests that the Commission:

- approve proposed regional Reliability Standard BAL-001-TRE-2 and associated elements included in **Exhibit A,** effective as proposed herein;
- approve the implementation plan included in **Exhibit B**; and
- approve the retirement of regional Reliability Standard BAL-001-TRE-1.

Respectfully submitted,

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Date: March 11, 2020

Exhibit A1

Proposed Reliability Standard BAL-001-TRE-2
Clean

A. Introduction

1. **Title:** Primary Frequency Response in the ERCOT Region
2. **Number:** BAL-001-TRE-2
3. **Purpose:** To maintain Interconnection steady-state frequency within defined limits.
4. **Applicability:**
   - **4.1.** Functional Entities:
     - **4.1.1** Balancing Authority
     - **4.1.2** Generator Owners
     - **4.1.3** Generator Operators
   - **4.2.** Exemptions
     - **4.2.1** Existing generating facilities regulated by the U.S. Nuclear Regulatory Commission prior to the Effective Date are exempt from Standard BAL-001-TRE-2.
     - **4.2.2** Generating units/generating facilities while operating in synchronous condenser mode are exempt from Standard BAL-001-TRE-2.
     - **4.2.3** Any generators that are not required by the Balancing Authority to provide primary frequency response are exempt from this standard.
5. **Effective Date:** See Implementation Plan for Regional Standard BAL-001-TRE-2.
6. **Background:** The ERCOT Interconnection was initially given a waiver of BAL-001 R2 (Control Performance Standard CPS2). In FERC Order 693, NERC was directed to develop a Regional Standard as an alternate means of assuring frequency performance in the ERCOT Interconnection. NERC was explicitly directed to incorporate key elements of the existing Protocols, Section 8.5. This required governors to be in service and performing with an un-muted response to assure an Interconnection minimum Frequency Response to a Frequency Measurable Event (FME) (that starts at t(0)).

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

   Under this standard, two Primary Frequency Response (PFR) performance measures are calculated: "initial" and "sustained." The initial PFR performance (R9) measures the actual response compared to the expected response in the period from 20 to 52

seconds after an FME starts. The sustained PFR performance (R10) measures the best actual response between 46 and 60 seconds after t(0) compared to the expected response based on the system frequency at a point 46 seconds after t(0).

In this Regional Standard the term “resource” is synonymous with “generating unit/generating facility”.

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 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%.

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

2.3. If a generating unit/generating facility has not participated in a minimum of (8) eight 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.

[1] The 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.

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

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

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

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

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

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

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

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

Table 6.1 Governor Deadband Settings

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

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

Table 6.2 Governor Droop Settings

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

*

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

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

Where

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

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

MWGCS is the maximum megawatt control range of the Governor control system. For mechanical Governors, droop will be proportional from the deadband by design. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

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

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

R7. Each Generator Owner shall operate each generating unit/generating facility 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.

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. *[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" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Compliance Monitoring Period and Reset Time Frame: If a generating unit/generating facility completes a mitigation plan and implements corrective action(s) to meet requirements R9 and R10 of the standard, and if approved by the BA and Compliance Enforcement Authority, then the generating unit/generating facility may begin a new rolling event average performance on the next performance during an FME. This will count as the first event in the performance calculation and the entity will have an average frequency performance score after 12 successive months or eight events per R9 and R10.

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

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

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

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

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

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

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 notified of the discovery of the change.	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 notified of the discovery of the change.	The Generator Operator notified the Balancing Authority of a change in Governor status more than 4 hours but within 24 hours after the Generator Operator was notified of the discovery of the change.	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.

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

D. Regional Variances

None

E. Associated Documents

Regional Standard BAL-001-TRE-2 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.
2	2/6/2020	Adopted by the NERC Board of Trustees	

Standard Attachments

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

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

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

Attachment 1

Primary Frequency Response Reference Document

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

I. Introduction

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

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

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

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

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

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

[1] These spreadsheets are available at www.TexasRE.org.

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.

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

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

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

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

Initial Primary Frequency Response Performance Calculation Methodology

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

This process calculates the initial Per Unit Primary Frequency Response of a resource [$P.U.PFR_{Resource}$] as a ratio between the Adjusted Actual Primary Frequency Response ($APFR_{Adj}$),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 Primary Frequency Response [$P.U.PFR_{Resource}$] for any Frequency Measurable Event (FME).

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

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

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

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

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

The Adjusted Actual Primary Frequency Response ($APFR_{Adj}$) and the Final Expected Primary Frequency Response ($EPFR_{final}$) 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

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

[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 Adjustment: The Actual Primary Frequency Response 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 = (MW_{T-4} – MW_{T-60})*0.59

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

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:

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

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

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

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

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

For each formula, when frequency is within the Governor deadband the appropriate EPFR value is zero. The $deadband_{max}$ and $droop_{max}$ 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 NDC (Net Dependable Capacity) 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 Capacity for wind-powered generators is the real time HSL of the wind plant at the time the FME occurred.

<u>Power Augmentation:</u> 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

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

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:

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

Where:

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

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

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

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

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

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

III. Sustained Primary Frequency Response Calculations

Requirement 10

R10. The 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.

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 by the Balancing Authority from the rolling average calculation due to a legitimate operating condition that prevented normal Primary Frequency Response performance. Examples of legitimate operating conditions that may support exclusion of FMEs include, but are not limited to:

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

Sustained Primary Frequency Response Performance Calculation Methodology

This portion of this PFR Reference Document establishes the process used to calculate sustained Primary Frequency Response performance for each Frequency Measurable Event (FME), and then average the events over a 12-month period (or 8-event minimum) to establish whether a resource is compliant with Requirement R10.

This process calculates the Per Unit Sustained Primary Frequency Response of a resource [$P.U.SPFR_{Resource}$] as a ratio between the maximum actual unit response at any time during the period from T+46 to T+60, adjusted for the pre-event ramping of the unit, and the *Final* Expected Primary Frequency Response (EPFR) value at time T+46.[3]

This comparison of actual performance to a calculated target value establishes, for each type of resource, the Per Unit Sustained Primary Frequency Response [$P.U.SPFR_{Resource}$] for any Frequency Measurable Event (FME).

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

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

[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.

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

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

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

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

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

P.U.SPFR$_{Resource}$ is the per unit (P.U.) measure of the sustained Primary Frequency Response of a resource during identified Frequency Measurable Events. 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 Primary Frequency Response 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 (MW_{T-4} – MW_{T-60}) by a modifier. This extrapolates to an equivalent number of MWs the generator would have changed if it had been allowed to continue on its ramp to T+46 unencumbered by the FME. The modifier is $\frac{46\text{ seconds}}{56\text{ seconds}}$ or 0.821.

Expected Sustained Primary Frequency Response (*ESPFR*) Calculations

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

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

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

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

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

Capacity and Net Dependable Capability (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 capacity for wind-powered generators is the real-time HSL of the wind plant at the time the FME occurred. The $deadband_{max}$ and $droop_{max}$ quantities come from Requirement R6.

For Combined Cycle facilities, determination of Capacity includes subtracting Power Augmentation (PA) Capacity, if any, from the original 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 is required to provide the BA with documentation and identify conditions when this augmentation is in service.

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

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

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:

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

Where:

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

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

Throttle Pressure = Interpolatio*n* o*f* Pressur*e* curv*e* a*t* $MW_{pre\text{-}perturbation}$

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

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

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

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

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

If the generating unit/generating facility is operating within 2% of its (HSL – PA Capacity) or within 5 MW (whichever is greater) 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:

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

then Primary Frequency Response is not evaluated for this FME.

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

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

then Primary Frequency Response is not evaluated for this FME.

Final Expected Primary Frequency Response (EPFRfinal) is greater than Operating Margin:

Caps and limits exist for resources operating with adequate reserve margin to be evaluated (at least 2% of (HSL less PA Capacity) or 5 MW), 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 Expected Primary Frequency Response$_{final}$ is greater than the generating unit/generating facility's available frequency responsive Capacity[4]; and
    c. The generating unit/generating facility's APFR$_{adj}$ response is in the correct direction.

2. When calculation of the P.U.PFR$_{Resource}$ uses the resource's (HSL less PA Capacity) 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 Primary Frequency Response measures.

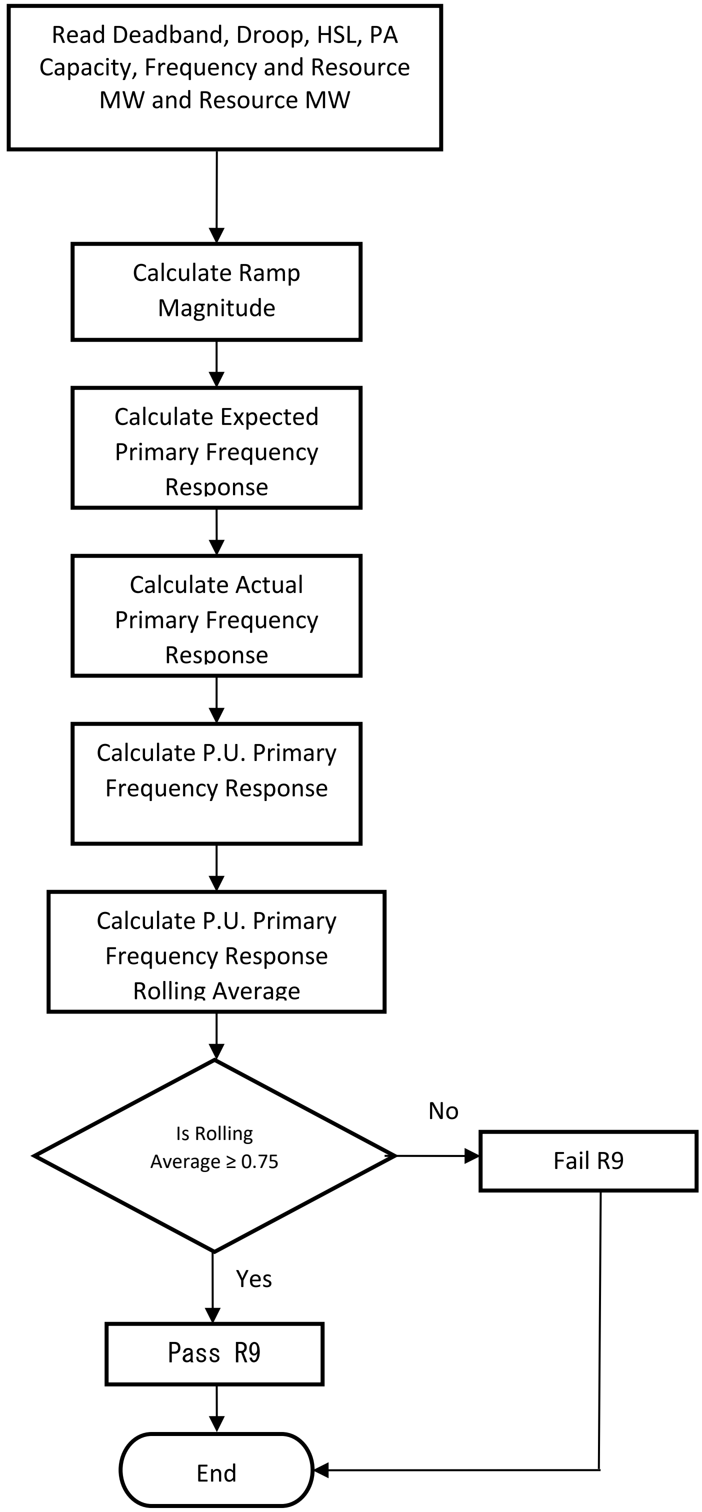
[4] In this circumstance, when frequency is below 60 Hz, the EPFR$_{final}$ is set to operating margin based on HSL (adjusted for any augmentation capacity) AND when frequency is above 60 Hz, the EPFR$_{final}$ is set to operating margin based on LSL for the purpose of calculating PUPFR$_{resource}$.

Attachment A to
Primary Frequency Response Reference Document

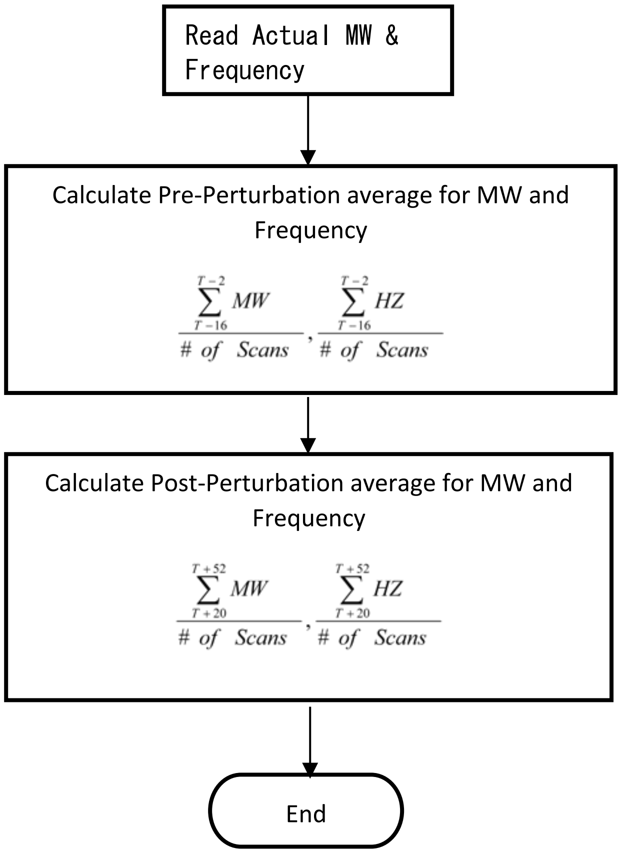
Initial Primary Frequency Response Methodology for
BAL-001-TRE-2

Primary Frequency Response Measurement and Rolling Average Calculation – Initial Response

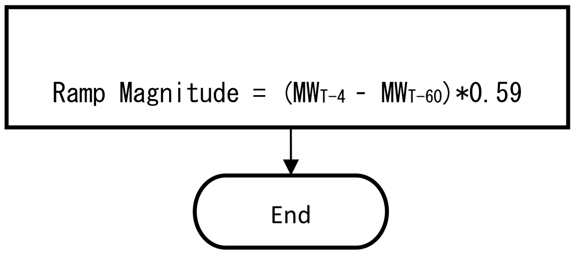
PA=Power Augmentation
HSL=High Sustained Limit



Pre/Post-Perturbation Average MW and Average Frequency Calculations

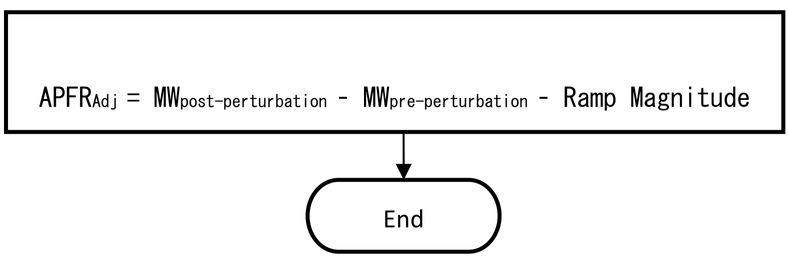


Ramp Magnitude Calculation



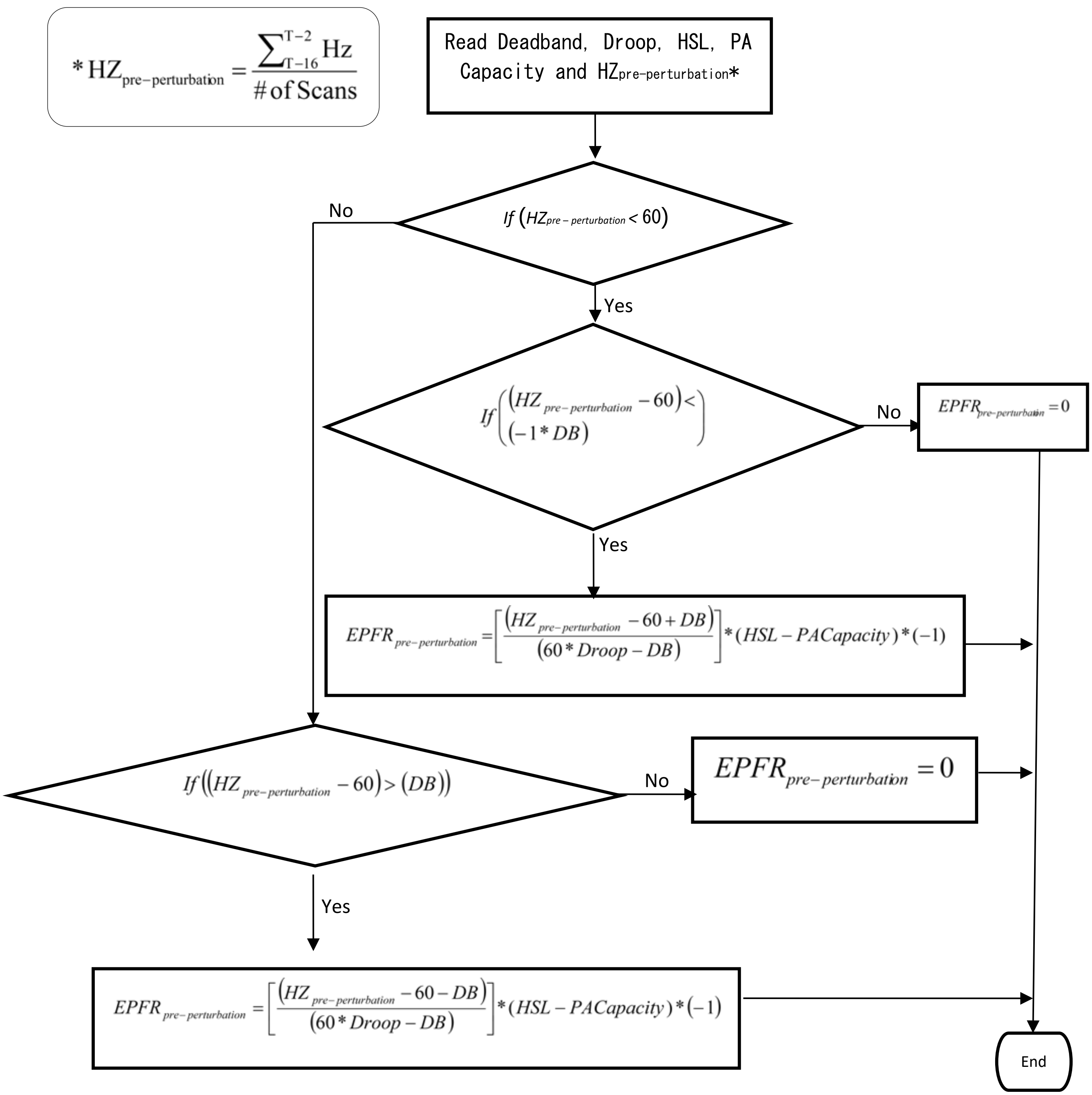
$(MW_{T-4} – MW_{T-60})$ represents the MW ramp of the generator resource/generator facility for a full minute prior to the event. The factor 0.59 adjusts this full minute ramp to represent the ramp that should have been achieved during the post-perturbation measurement period.

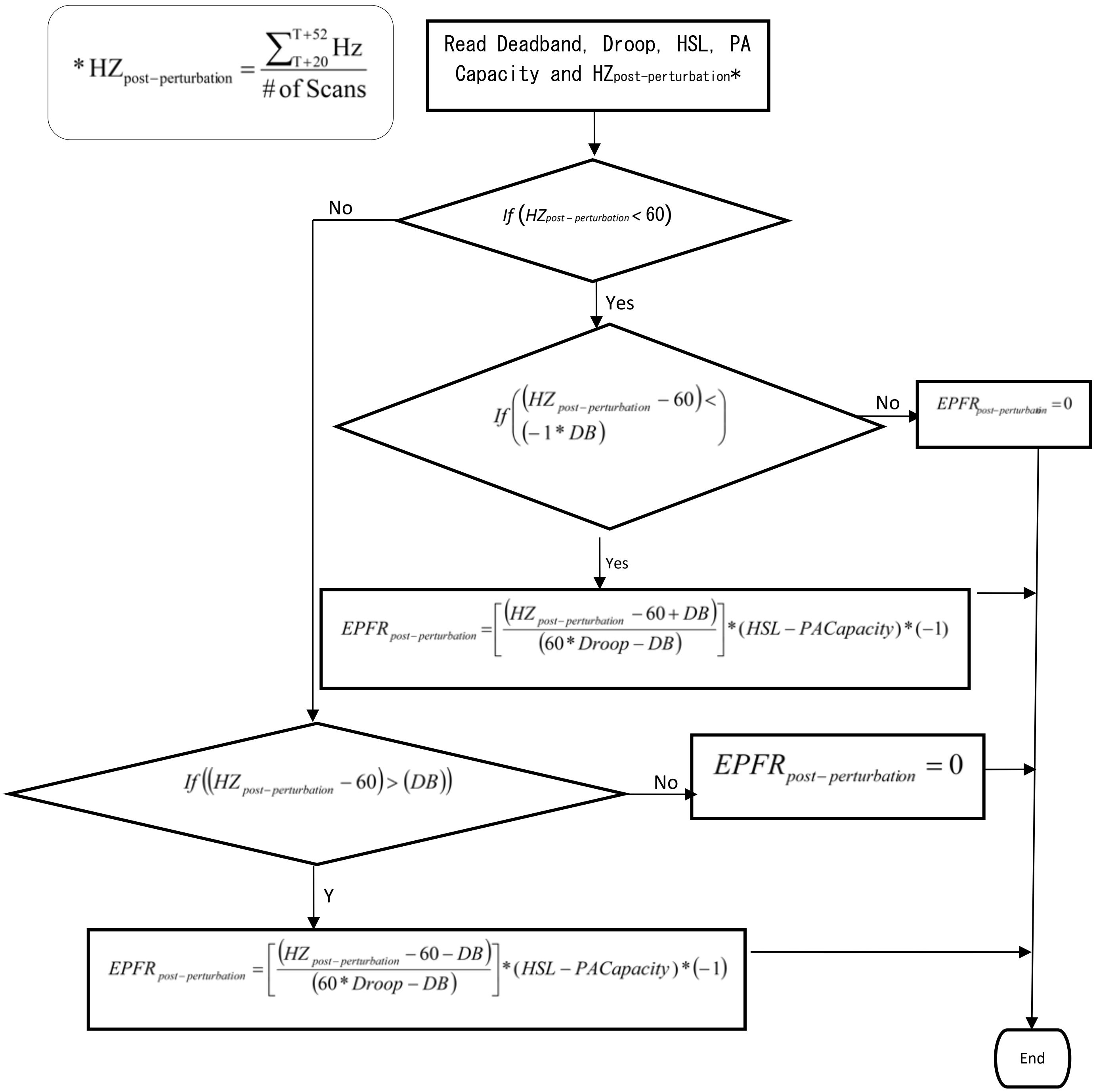
Actual Primary Frequency Response ($APFR_{Adj}$)



Expected Primary Frequency Response Calculation

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





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

Adjustment for Steam Turbine

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

↓

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

↓

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

↓

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

↓

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

↓

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

↓

End

Adjustment for Combustion Turbines and Combined Cycle Facilities

Read HSL, PA Capacity, $HZ_{post\text{-}perturbation}$*

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

End

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

Adjustment for Other Units

Read Limiting Factor

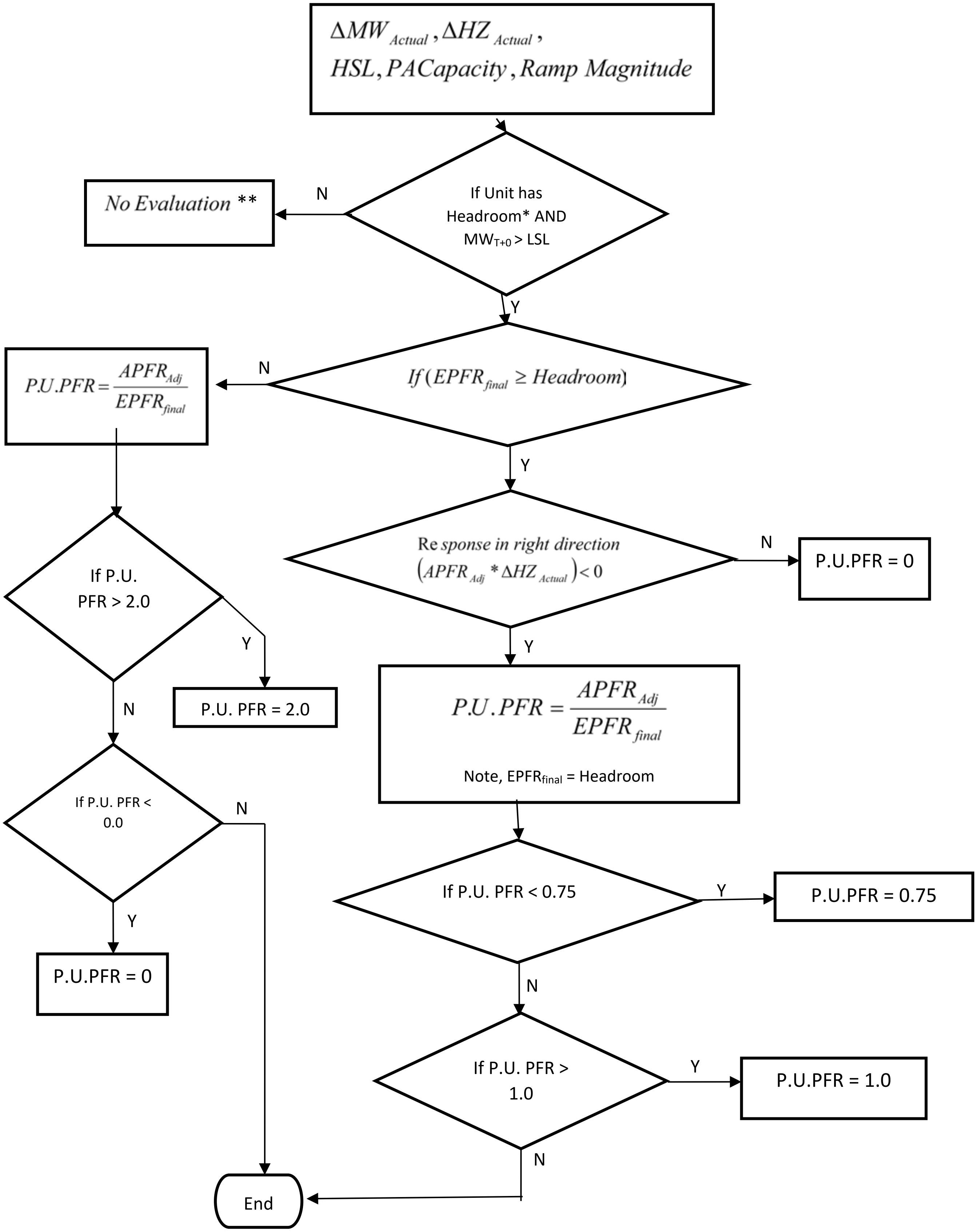
$$EPFR_{final} = EPFR_{Ideal} + X$$

End

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

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



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

*Check for adequate up headroom, low frequency events. Headroom must be greater than either 5MW or 2% of (HSL less PA Capacity), whichever is larger. If a unit does not have adequate up headroom, the unit is considered operating at full capacity and will not be evaluated for low frequency events.

Check for adequate down headroom, high frequency events. Headroom must be greater than either 5MW or 2% of (HSL less PA Capacity), whichever is larger. If a unit does not have adequate down headroom, the unit is considered operating at low capacity and will not be evaluated for high frequency events.

For low frequency events:

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

For high frequency events:

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

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

T = Time in Seconds

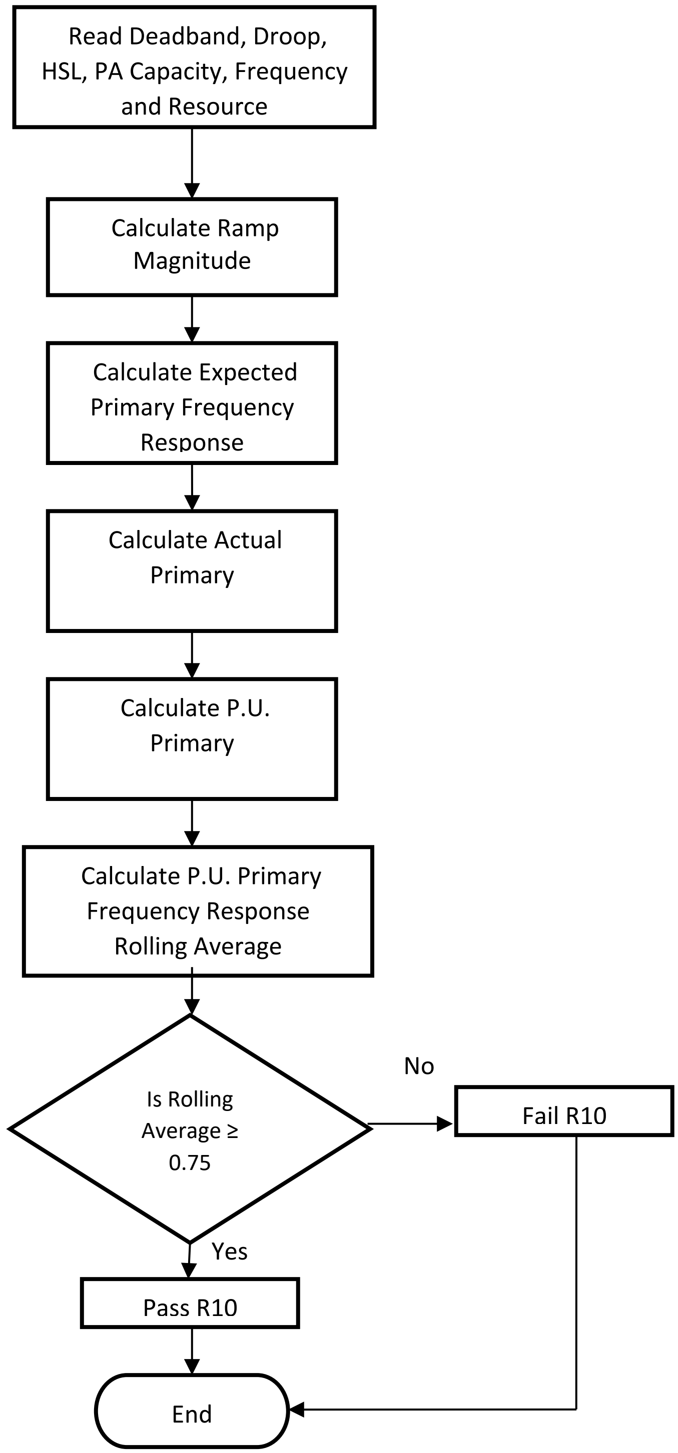
Attachment B to

Primary Frequency Response Reference Document

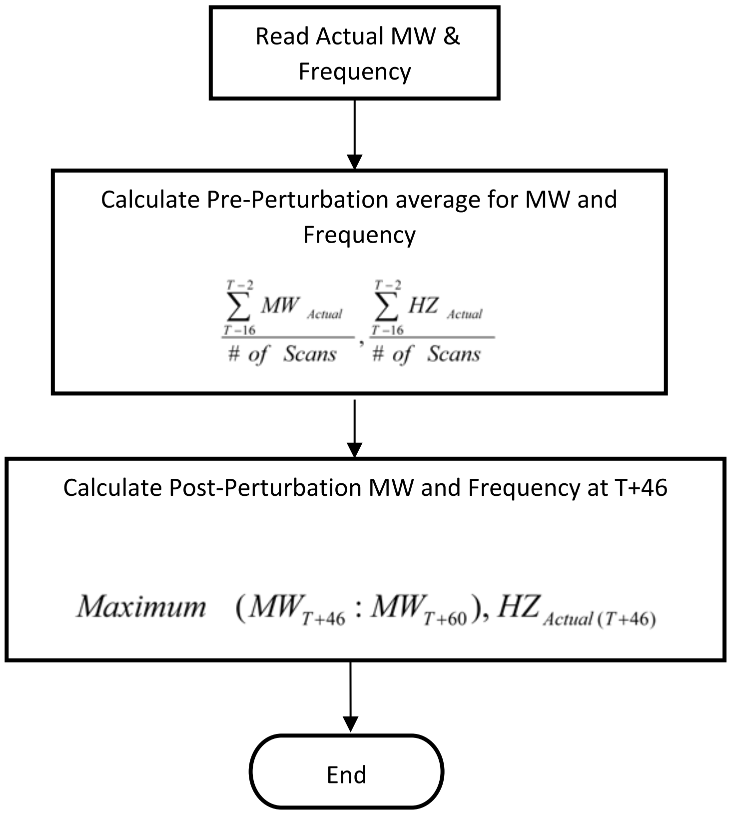
Sustained Primary Frequency Response Methodology for

BAL-001-TRE-2

Primary Frequency Response Measurement and Rolling Average Calculation–Sustained Response



Pre/Post-Perturbation Average MW and Average Frequency Calculations



Ramp Magnitude Calculation - Sustained

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

End

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

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

For low frequency events:

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

End

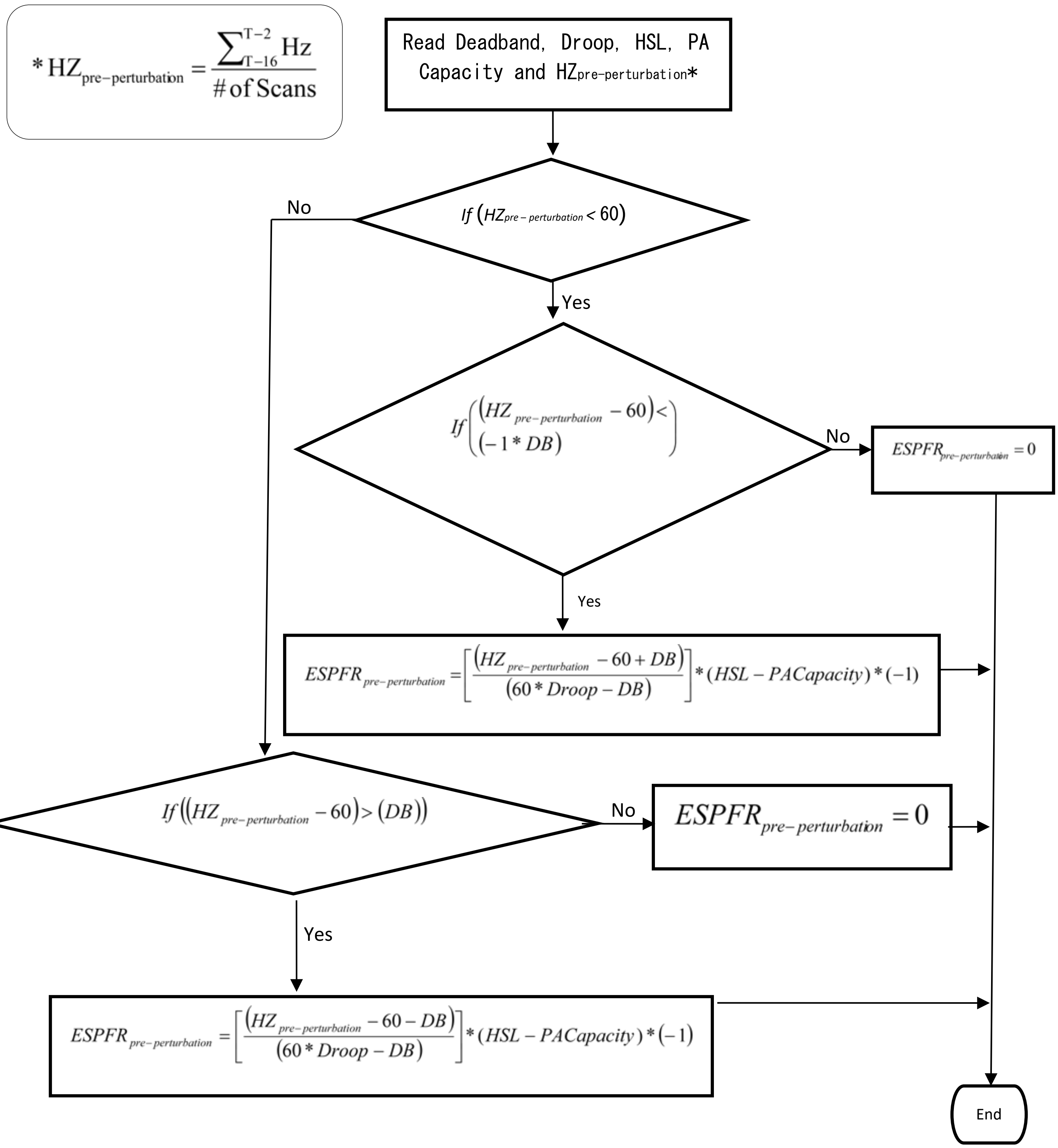
For high frequency events:

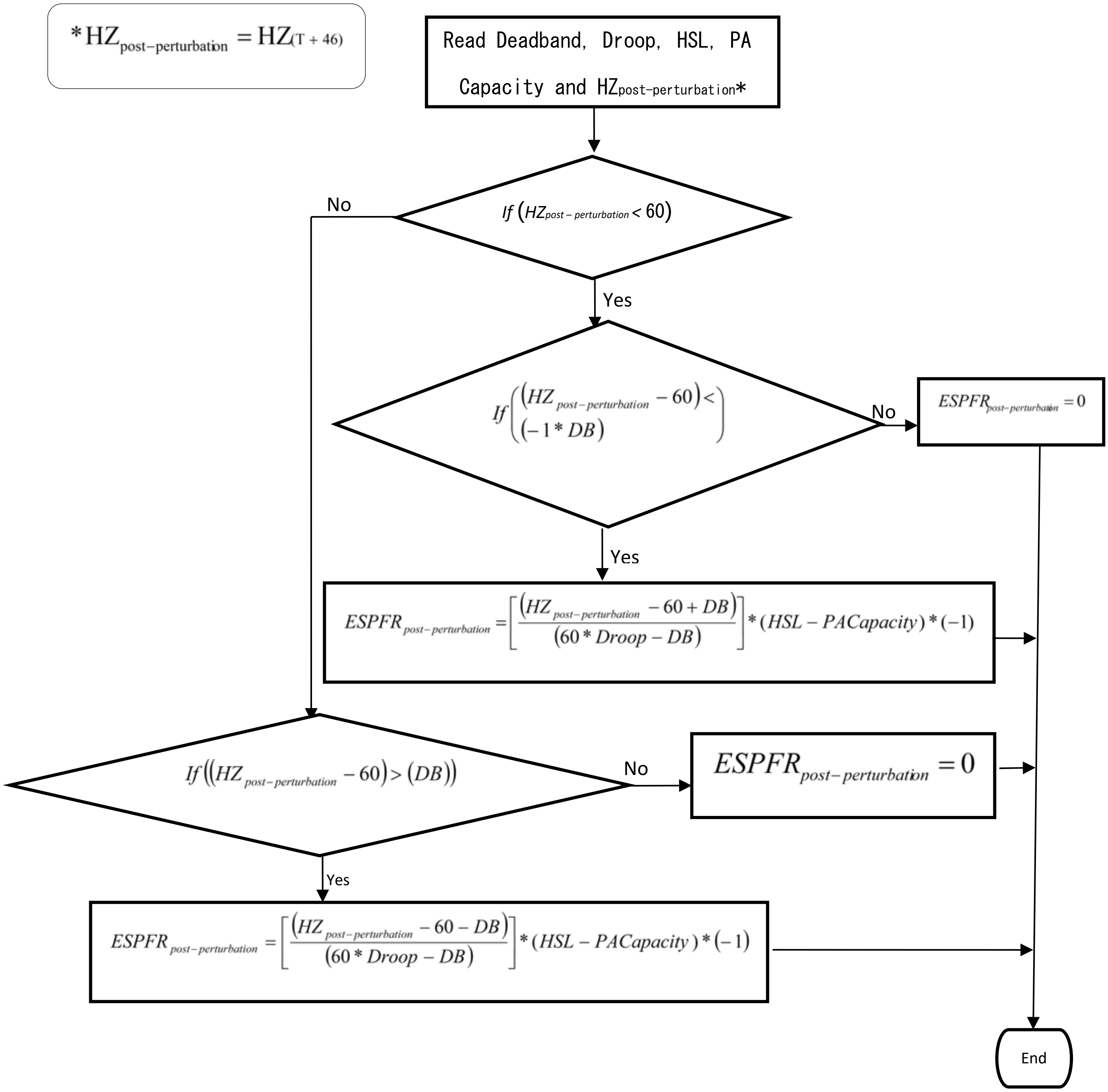
$$ASPFR_{Adj} = Minimum(MW_{T+46} : MW_{T+60}) - MW_{pre\text{-perturbation}} - Ramp\ Magnitude_{Sustained}$$

End

Expected Sustained Primary Frequency Response Calculation

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





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

Adjustment for Steam Turbine

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

↓

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

↓

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

↓

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

↓

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

↓

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

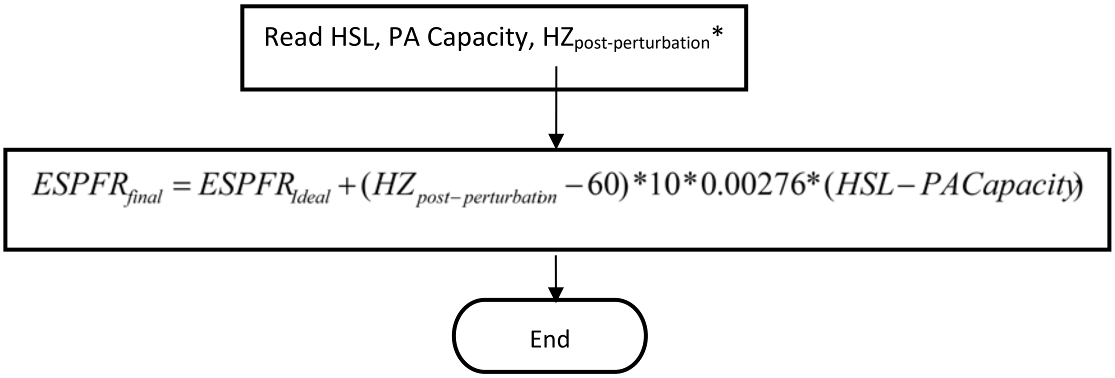
↓

End

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

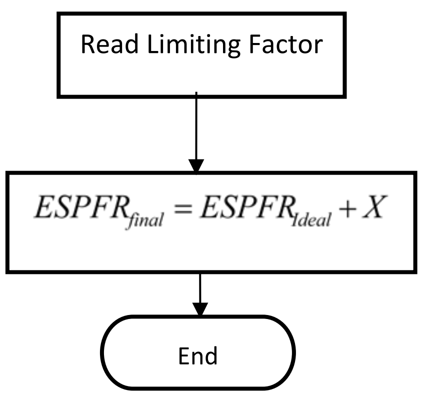
$MW_{post-perturbation}$ = Minimum (MW_{T+46} : MW_{T+60}) for high frequency events.

Adjustment for Combustion Turbines and Combined Cycle Facilities



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

Adjustment for Other Units

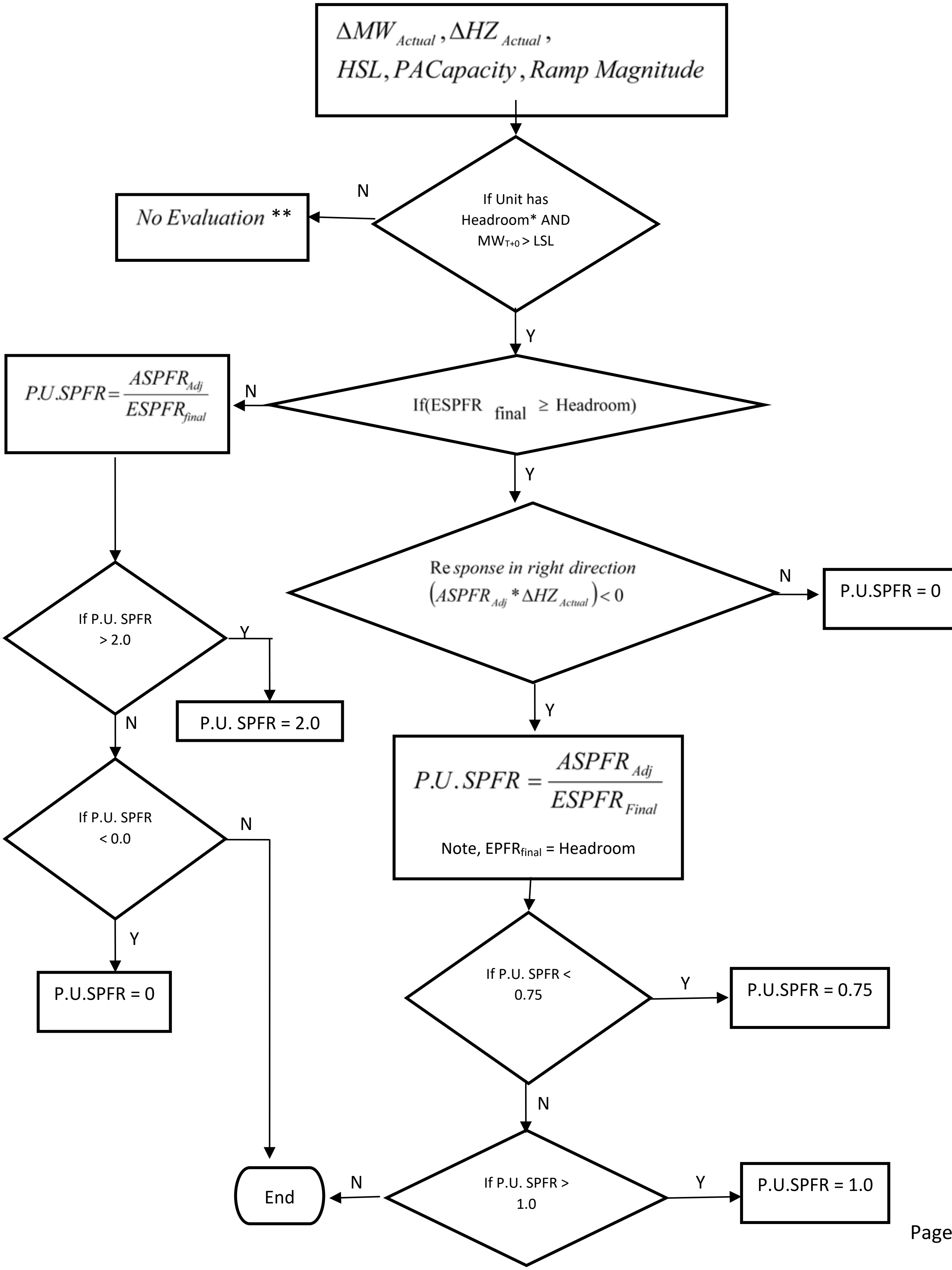


$* HZ_{Actual} = HZ_{(T+46)}$

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

P.U. Sustained Primary Frequency Response Calculation

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


ΔMW Actual, ΔHZ Actual, HSL, PACapacity, Ramp Magnitude
If Unit has Headroom* AND MWT+0 > LSL
N
No Evaluation **
Y
If(ESPFR final ≥ Headroom)
N
P.U.SPFR = ASPFRAdj / ESPFRfinal
Y
Response in right direction (ASPFRAdj * ΔHZ Actual) < 0
N
P.U.SPFR = 0
If P.U. SPFR > 2.0
Y
P.U. SPFR = 2.0
N
Y
P.U.SPFR = ASPFRAdj / ESPFRFinal
Note, EPFRfinal = 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
Y
P.U.SPFR = 1.0
N
End

*Check for adequate up headroom, low frequency events. Headroom must be greater than either 5MW or 2% of (HSL less PA Capacity), whichever is larger. If a unit does not have adequate up headroom, the unit is considered operating at full capacity and will not be evaluated for low frequency events.

Check for adequate down headroom, high frequency events. Headroom must be greater than either 5MW or 2% of (HSL less PA Capacity), whichever is larger. If a unit does not have adequate down headroom, the unit is considered operating at low capacity and will not be evaluated for high frequency events.

For low frequency events:

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

For high frequency events:

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

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

T = Time in Seconds

Revision History

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

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit A2

Proposed Reliability Standard BAL-001-TRE-2
Redline to Last Approved (BAL-001-TRE-1)

A. Introduction

1. **Title:** Primary Frequency Response in the ERCOT Region
2. **Number:** BAL-001-TRE-2~~1~~
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-2~~1~~.

   4.2.2 Generating units/generating facilities while operating in synchronous condenser mode are exempt from Standard BAL-001-TRE-2~~1~~.

   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-2.
6. **Background:** The ERCOT Interconnection was initially given a waiver of BAL-001 R2 (Control Performance Standard CPS2). In FERC Order 693, NERC was directed to develop a Regional Standard as an alternate means of assuring frequency performance in the ERCOT Interconnection. NERC was explicitly directed to incorporate key elements of the existing Protocols, Section ~~5.9~~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 R~~r~~egional S~~s~~tandard provides requirements related to identifying Frequency Measureable 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 R~~r~~egional S~~s~~tandard the term “resource” is synonymous with “generating unit/generating facility”.

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 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%.

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

2.3. If a generating unit/generating facility has not participated in a minimum of (8) eight 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.

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[1] The 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.

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

M3. The Balancing Authority shall demonstrate that the IMFR was determined in December of each year per per ~~r~~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 occurs, the Balancing Authority shall determine and make publicly available the Interconnection's combined Frequency Response performance for a rolling average of the last six (6) FMEs by the end of the following calendar month. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

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

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

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

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

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

Table 6.1 Governor Deadband Settings

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

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

Table 6.2 Governor Droop Settings

Generator Type	Max. Droop % Setting
Hydro	5%
~~Nuclear~~	~~5%~~
~~Coal and Lignite~~	~~5%~~
Combustion Turbine (Simple Cycle and Single-Shaft Combined Cycle)	5%
Combustion Turbine (Combined Cycle)*	4%
Steam Turbine* ~~(Simple Cycle)~~	5%
~~Steam Turbine (Combined Cycle)*~~	~~5%~~
Diesel	5%
~~Wind Powered Generator~~	~~5%~~
DC Tie Providing Ancillary Services	5%
Variable Renewable (Non-Hydro)	5%

*~~*Steam Turbines of combined cycle resources are required to comply with Requirements R6.1, R6.2 and R6.3. Compliance with Requirements R9 and R10 will be determined through evaluation of the combined cycle facility using an expected performance droop of 5.78%.~~

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

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

Where

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

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

MWGCS is the maximum megawatt control range of the Governor control system. For mechanical Governors, droop will be proportional from the deadband by design. *[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
- Governo~~e~~r setting sheets
- Performance monitoring reports

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.

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 ~~Compliance Enforcement Authority~~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 ~~should be~~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. *[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 ~~Compliance Enforcement 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 ~~should be~~was excluded from the rolling average calculation.

C. Compliance

1. Compliance Monitoring Process

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

1.2. Compliance Monitoring Period and Reset Time Frame: If a generating unit/generating facility completes a mitigation plan and implements corrective action(s) to meet requirements R9 and R10 of the standard, and if approved by the BA and Compliance Enforcement Authority, then the generating unit/generating facility may begin a new rolling event average performance on the next performance during an FME. This will count as the first event in the performance calculation and the entity will have an average frequency performance score after 12 successive months or eight events per R9 and R10.

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

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

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

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

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

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

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

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	The Balancing Authority reported an FME more than 14 days but less than 31 days after identification of the event.	The Balancing Authority reported an FME more than 30 days but less than 51 days after identification of the event.	The Balancing Authority reported an FME more than 50 days but less than 71 days after identification of the event.	The Balancing Authority reported an FME more than 70 days after identification of the event.
R2.	The Balancing Authority submitted a monthly report more than one month but less than 51 days after the end of the reporting month.	The Balancing Authority submitted a monthly report more than 50 days but less than 71 days after the end of the reporting month.	The Balancing Authority submitted a monthly report more than 70 days but less than 91 days after the end of the reporting month.	The Balancing Authority failed to submit a monthly report within 90 days after the end of the reporting month.
R3.	The Balancing Authority did not make the calculation and criteria for determination of the IMFR publicly available.	The Balancing Authority did not make the IMFR publicly available.	The Balancing Authority did not calculate the IMFR for the following year in December.	The Balancing Authority did not calculate the IMFR for a calendar year.
R4.	N/A	N/A	The Balancing Authority did not make public the six-FME rolling average Interconnection combined Frequency Response by the end of the following month.	The Balancing Authority did not calculate the six- FME rolling average Interconnection combined Frequency Response for any month in which an FME occurred.
R5.	N/A	N/A	N/A	The Balancing Authority did not take action to improve

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

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

D. Regional Variances

None

E. Associated Documents

Regional Standard BAL-001-TRE-2 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.
2	2/6/2020	Adopted by the NERC Board of Trustees	

Standard Attachments

~~1. Attachment 1 – Implementation Plan.~~

1~~2~~. Attachment 1~~2~~ – 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~~2~~

Primary Frequency Response Reference Document

Texas Reliability Entity, Inc.
BAL-001-TRE-~~1~~2
Requirements R2, R9, and R10
Performance Metric Calculations

I. Introduction

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

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

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

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

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

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

[1] These spreadsheets are available at www.TexasRE.org.

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.

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

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

9.3. A generating unit/generating facility's initial Primary Frequency Response performance during an FME may be excluded by the Balancing Authority from the rolling average calculation 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 ~~Compliance Enforcement Authority~~Balancing Authority may request raw data from the Generator Owner as a substitute.

Initial Primary Frequency Response Performance Calculation Methodology

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

This process calculates the initial Per Unit Primary Frequency Response of a resource [$P.U.PFR_{Resource}$] as a ratio between the Adjusted Actual Primary Frequency Response ($APFR_{Adj}$),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 Primary Frequency Response [$P.U.PFR_{Resource}$] for any Frequency Measurable Event (FME).

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

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

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

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

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

The Adjusted Actual Primary Frequency Response ($APFR_{Adj}$) and the Final Expected Primary Frequency Response ($EPFR_{final}$) 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~~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

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

[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 Adjustment: The Actual Primary Frequency Response 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 = (MW_{T-4} – MW_{T-60})*0.59

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

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:

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

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

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

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

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

For each formula, when frequency is within the Governor deadband the appropriate EPFR value is zero. The $deadband_{max}$ and $droop_{max}$ 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 NDC (Net Dependable Capacity) 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 Capacity for wind-powered generators is the real time HSL of the wind plant at the time the FME occurred.

Power Augmentation: For Combined Cycle 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

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

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~~Where:

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

~~where~~Where:

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

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

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

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

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

~~where~~ 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. The 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.

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 by the Balancing Authority from the rolling average calculation 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 ~~Compliance Enforcement Authority~~ may request raw data from the Generator Owner as a substitute.

Sustained Primary Frequency Response Performance Calculation Methodology

This portion of this PFR Reference Document establishes the process used to calculate sustained Primary Frequency Response performance for each Frequency Measurable Event (FME), and then average the events over a 12-~~-~~month period (or 8-~~-~~event minimum) to establish whether a resource is compliant with Requirement R10.

This process calculates the Per Unit Sustained Primary Frequency Response of a resource [$P.U.SPFR_{Resource}$] as a ratio between the maximum actual unit response at any time during the period from T+46 to T+60, adjusted for the pre-event ramping of the unit, and the *Final* Expected Primary Frequency Response (EPFR) value at time T+46.[3]

This comparison of actual performance to a calculated target value establishes, for each type of resource, the Per Unit Sustained Primary Frequency Response [$P.U.SPFR_{Resource}$] for any Frequency Measurable Event (FME).

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

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

[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.

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

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

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

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

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

$P.U.SPFR_{Resource}$ is the per unit (P.U.) measure of the sustained Primary Frequency Response of a resource during identified Frequency Measurable Events. 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~~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~~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 Primary Frequency Response 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:

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

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

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

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

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

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

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

Capacity and Net Dependable Capability (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 capacity for wind-powered generators is the real-time HSL of the wind plant at the time the FME occurred. The $deadband_{max}$ and $droop_{max}$ quantities come from Requirement R6.

For Combined Cycle facilities, determination of Capacity includes subtracting Power Augmentation (PA) Capacity, if any, from the original 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 is required to provide the BA with documentation and identify conditions when this augmentation is in service.

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

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

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~~Where:

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

~~w~~Where:

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

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

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

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

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

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

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

If the generating unit/generating facility is operating within 2% of its (HSL – PA Capacity) or within 5 MW (whichever is greater) 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:

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

then Primary Frequency Response is not evaluated for this FME.

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

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

then Primary Frequency Response is not evaluated for this FME.

Final Expected Primary Frequency Response (EPFRfinal) is greater than Operating Margin:
Caps and limits exist for resources operating with adequate reserve margin to be evaluated (at least 2% of (HSL less PA Capacity) or 5 MW), 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 Expected Primary Frequency Response$_{\text{f}\cancel{\text{F}}\text{inal}}$ is greater than the generating unit/generating facility's available frequency responsive Capacity[4]; and
    c. The generating unit/generating facility's APFR$_{adj}$ response is in the correct direction.

2. When calculation of the P.U.PFR$_{Resource}$ uses the resource's (HSL less PA Capacity) 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 Primary Frequency Response measures.

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

Attachment A to

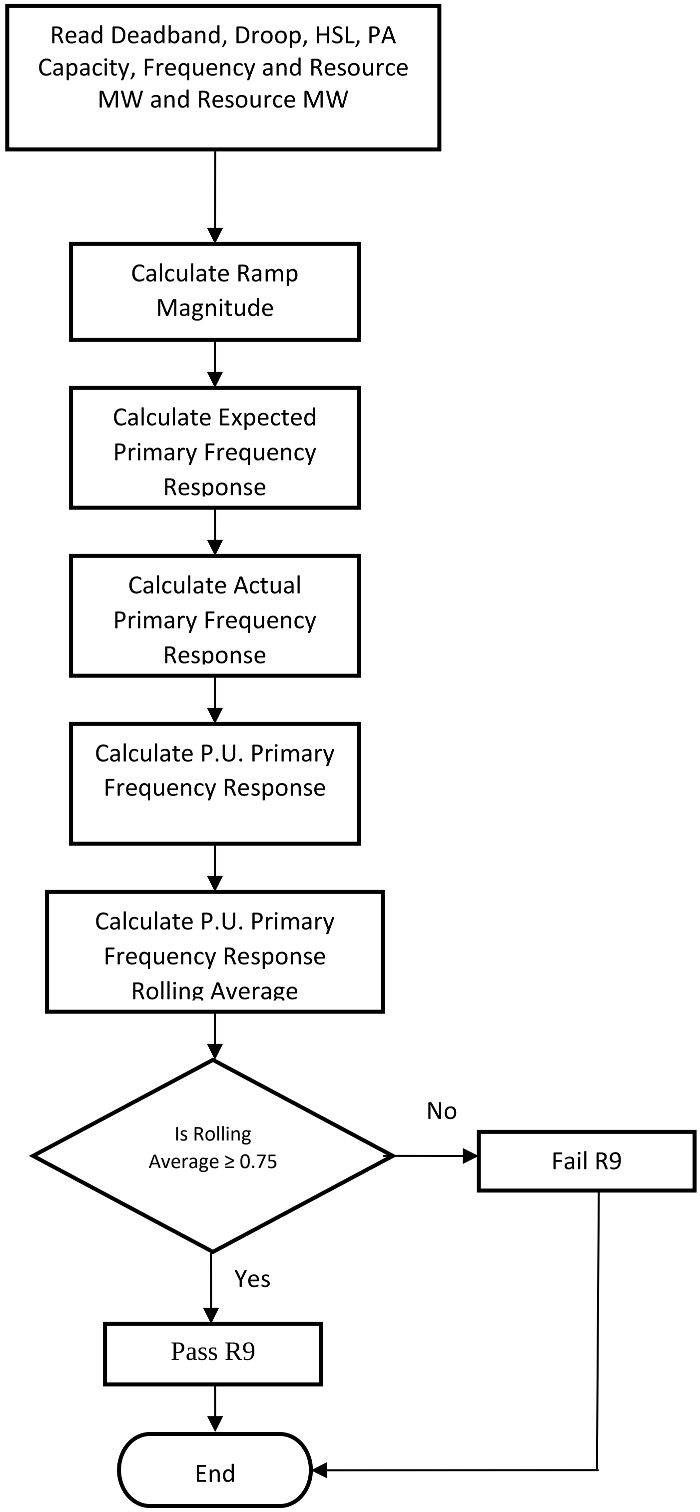
Primary Frequency Response Reference Document

Initial Primary Frequency Response Methodology for

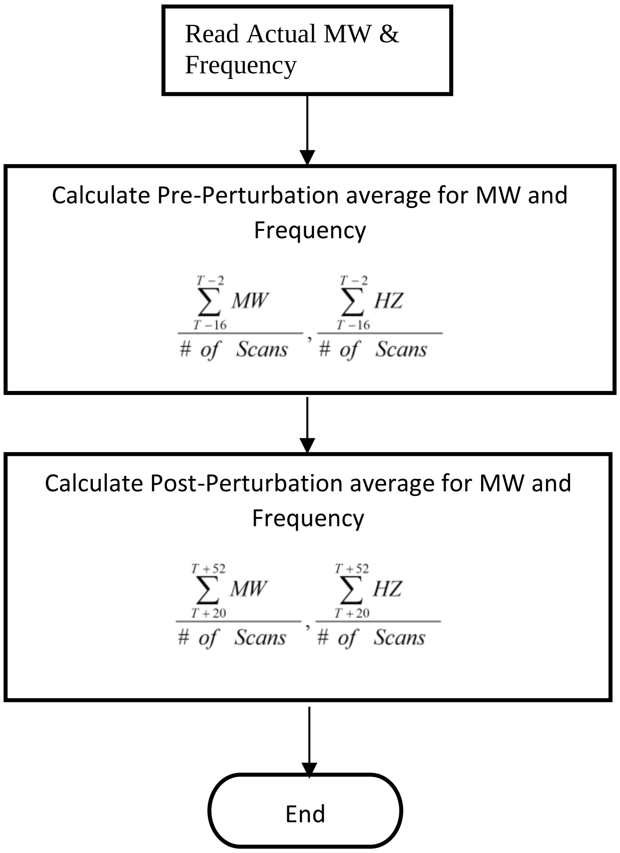
BAL-001-TRE-2~~1~~

Primary Frequency Response Measurement and Rolling Average Calculation – Initial Response

PA=Power Augmentation
HSL=High Sustained Limit



Pre/Post-Perturbation Average MW and Average Frequency Calculations



Ramp Magnitude Calculation

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

↓

End

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

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

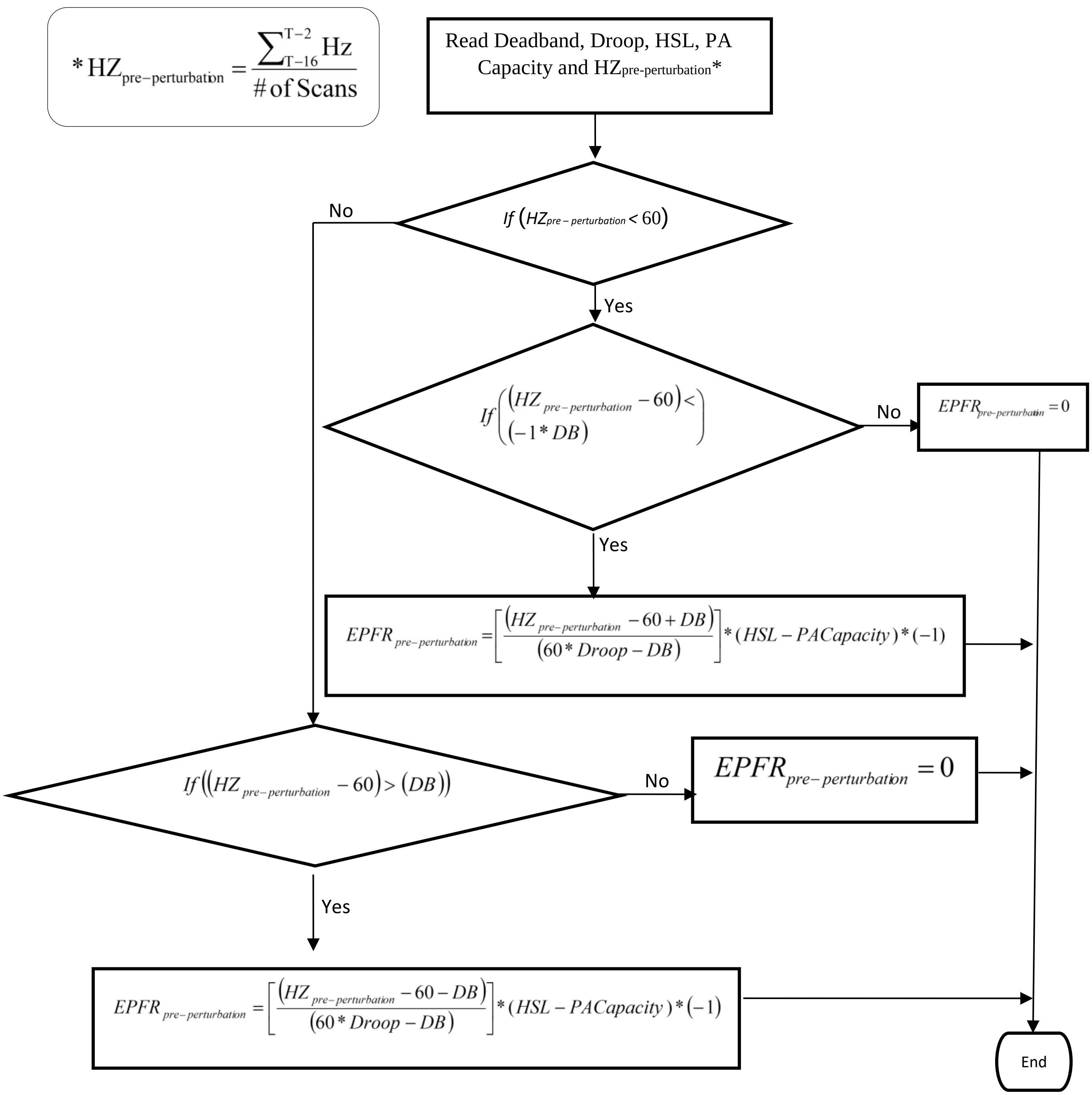
$$APFR_{Adj} = MW_{post\text{-}perturbation} - MW_{pre\text{-}perturbation} - \text{Ramp Magnitude}$$

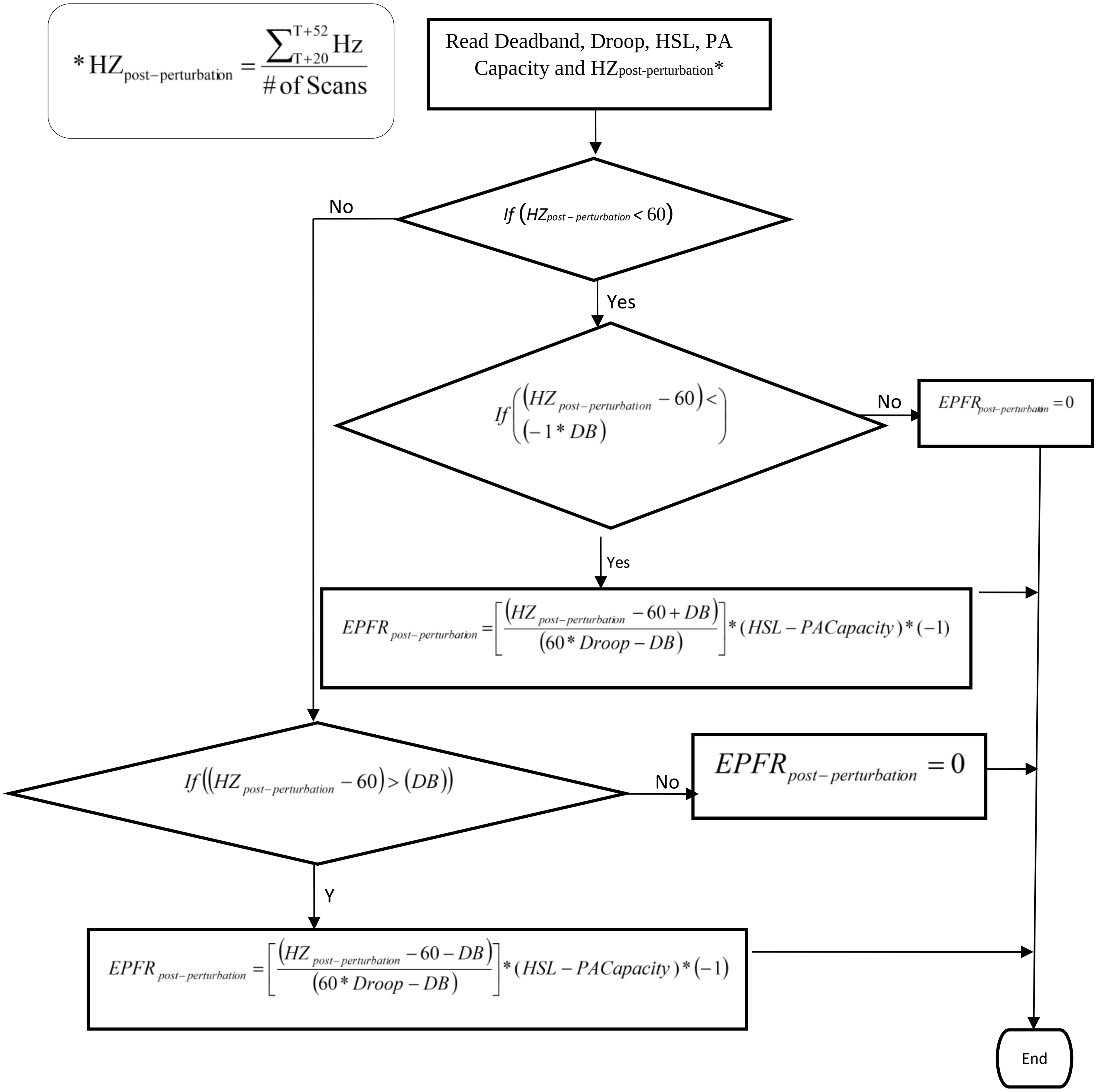
↓

End

Expected Primary Frequency Response Calculation

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





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

Adjustment for Steam Turbine

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

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

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

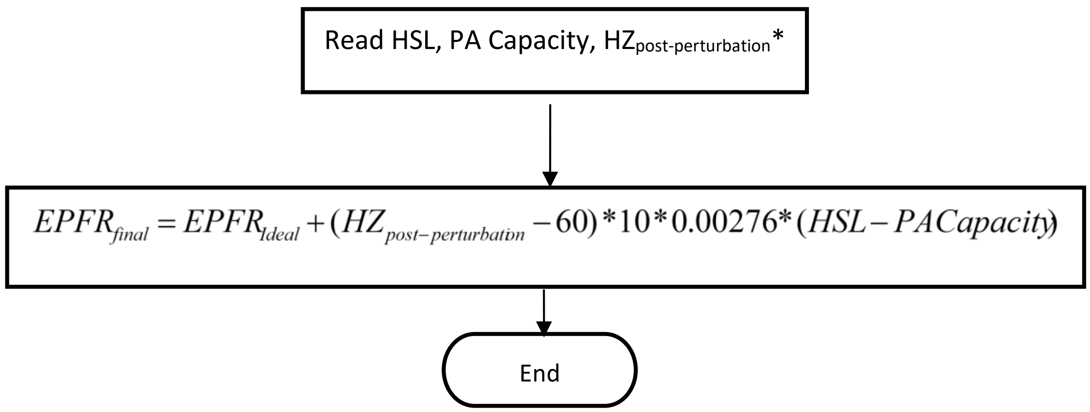
$$MW_{Adjustment} = EPFR_{Ideal} * \frac{K}{Rated\ Throttle\ Pressure} * (HSL - PACapacity) * Steam\ Flow\ Change\ Factor * (-1)$$

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

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

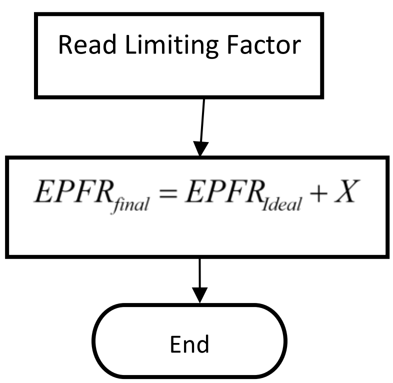
End

Adjustment for Combustion Turbines and Combined Cycle Facilities



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

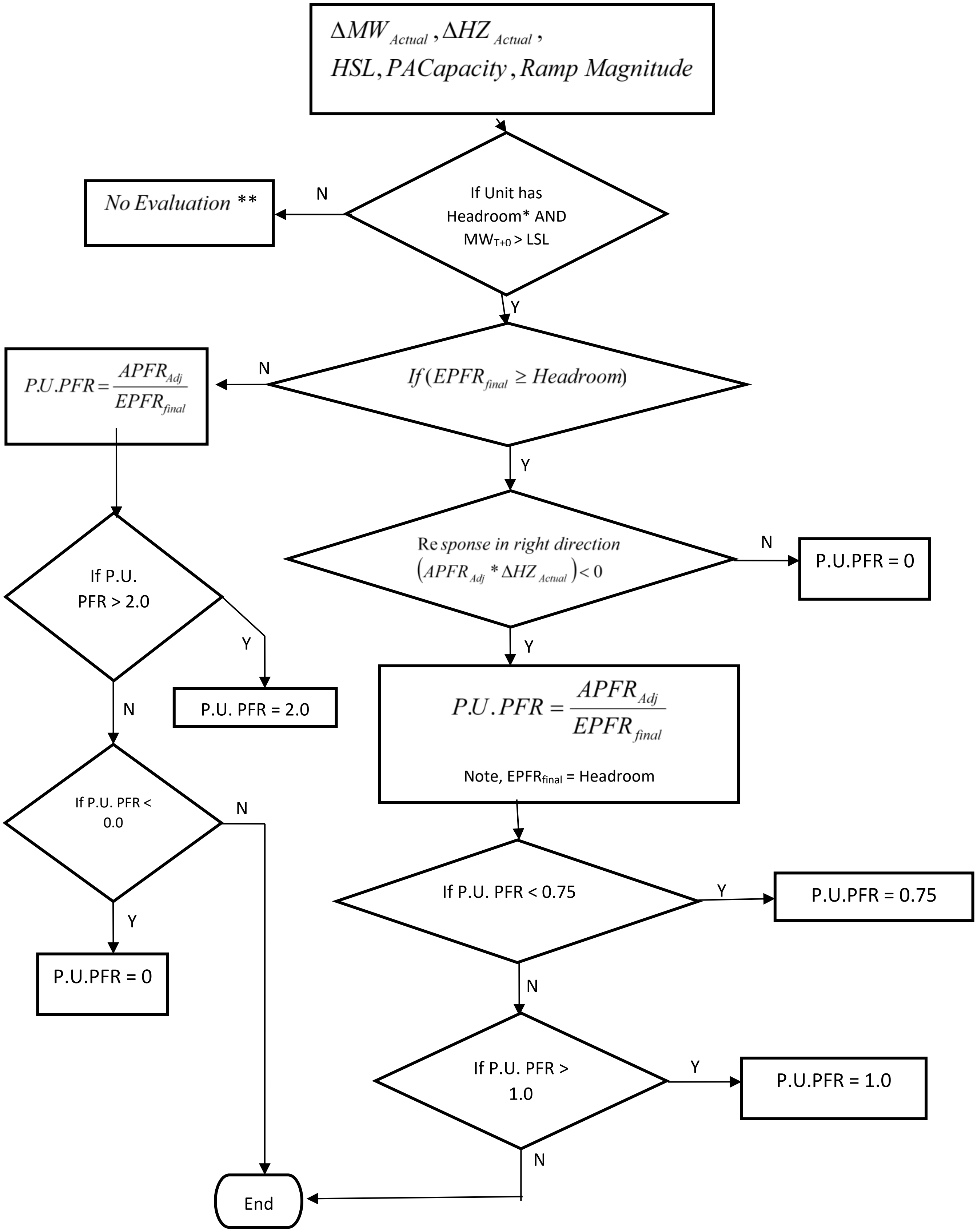
Adjustment for Other Units



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

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


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

*Check for adequate up headroom, low frequency events. Headroom must be greater than either 5MW or 2% of (HSL less PA Capacity), whichever is larger. If a unit does not have adequate up headroom, the unit is considered operating at full capacity and will not be evaluated for low frequency events.

Check for adequate down headroom, high frequency events. Headroom must be greater than either 5MW or 2% of (HSL less PA Capacity), whichever is larger. If a unit does not have adequate down headroom, the unit is considered operating at low capacity and will not be evaluated for high frequency events.

For low frequency events:

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

For high frequency events:

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

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

T = Time in Seconds

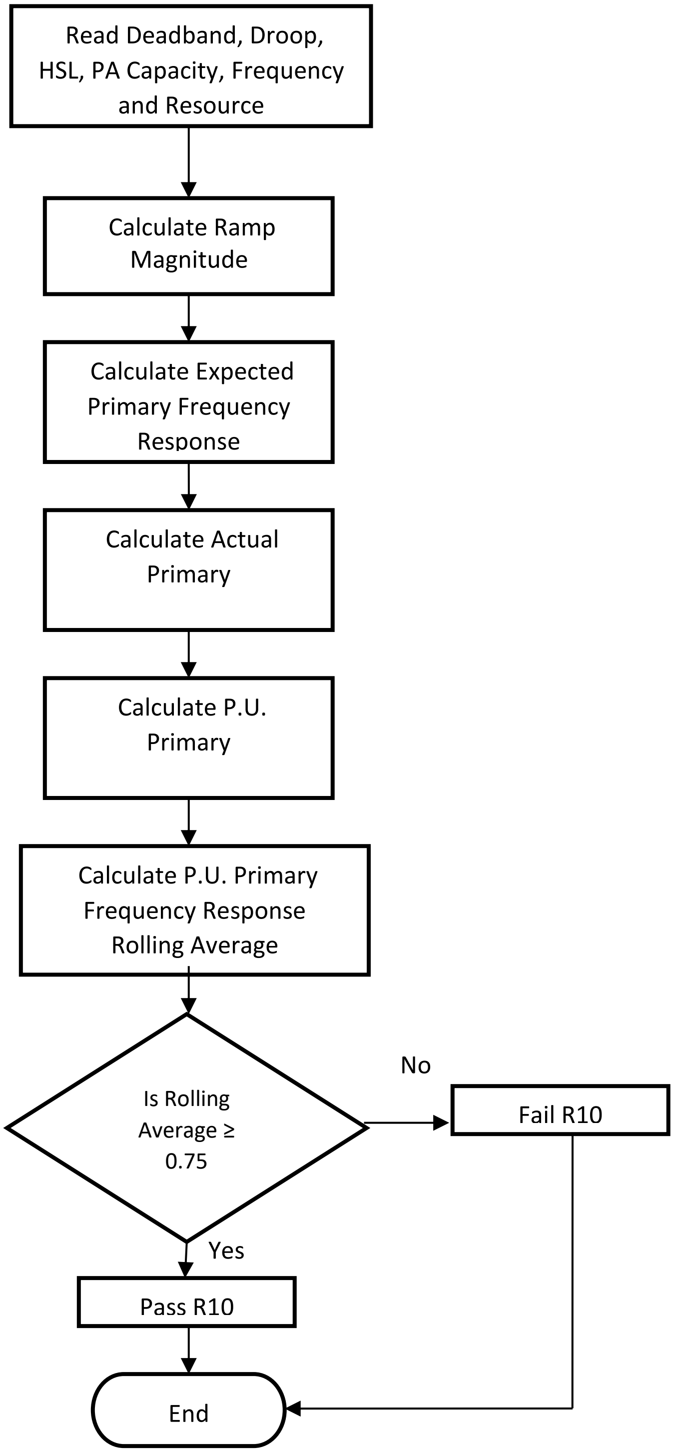
Attachment B to

Primary Frequency Response Reference Document

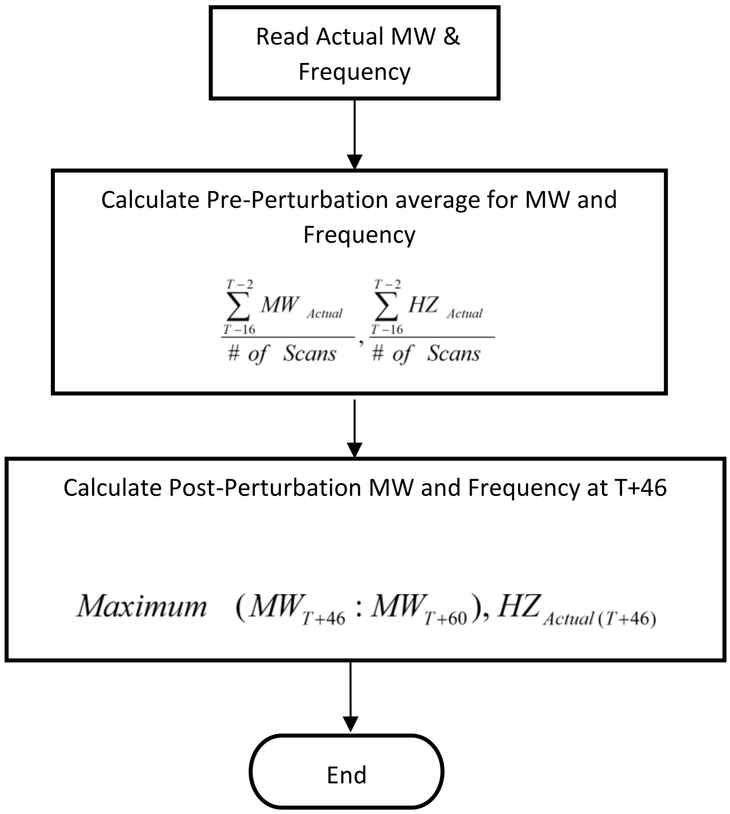
Sustained Primary Frequency Response Methodology for

BAL-001-TRE-2~~1~~

Primary Frequency Response Measurement and Rolling Average Calculation–Sustained Response



Pre/Post-Perturbation Average MW and Average Frequency Calculations



Ramp Magnitude Calculation - Sustained

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

↓

End

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

Actual Sustained Primary Frequency Response (ASPFRa~~A~~dj)

For low frequency events:

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

↓

End

For high frequency events:

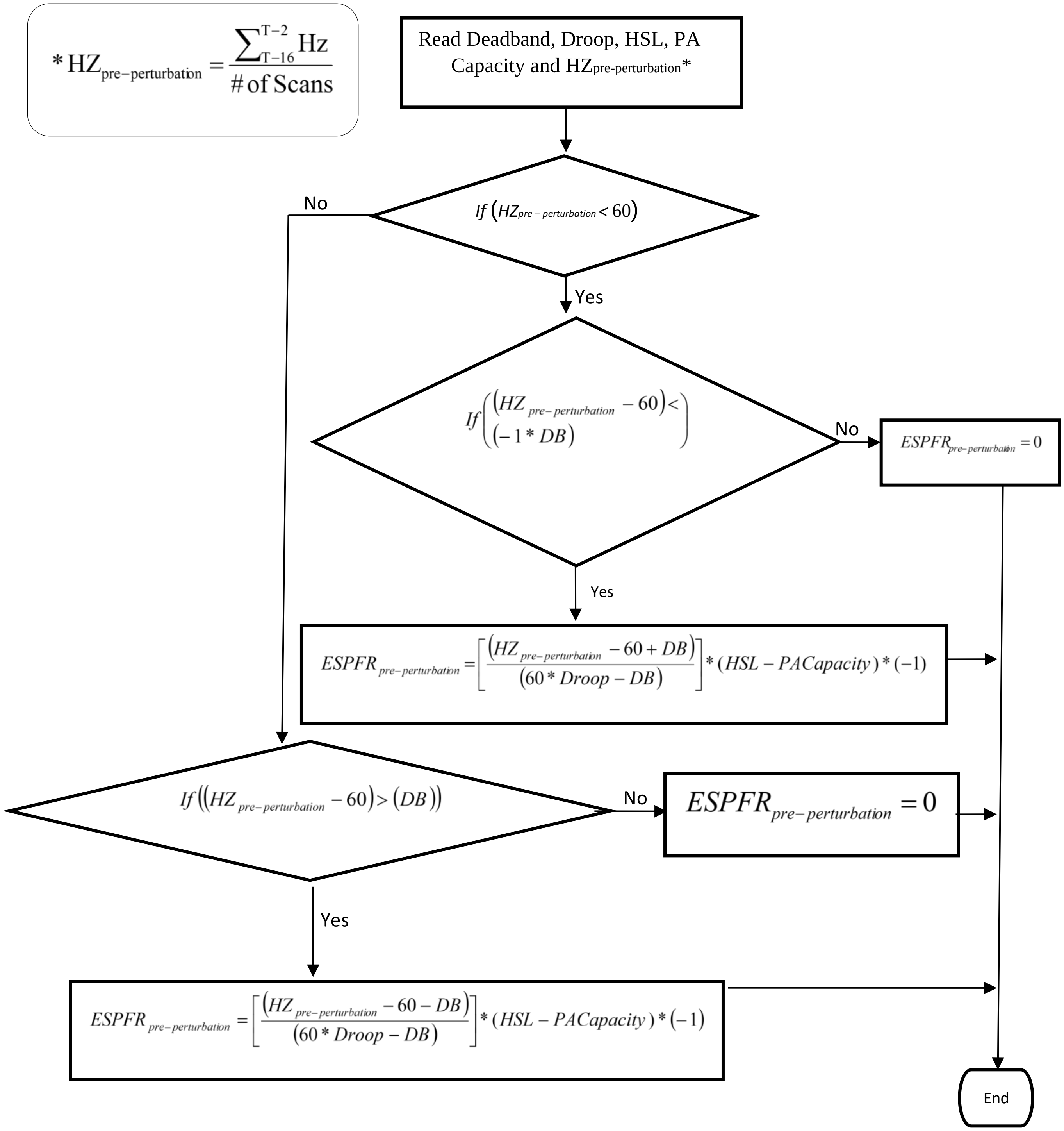
$$ASPFR_{Adj} = Minimum(MW_{T+46} : MW_{T+60}) - MW_{pre\text{-}\mathrm{perturbation}} - Ramp\ Magnitude_{Sustained}$$

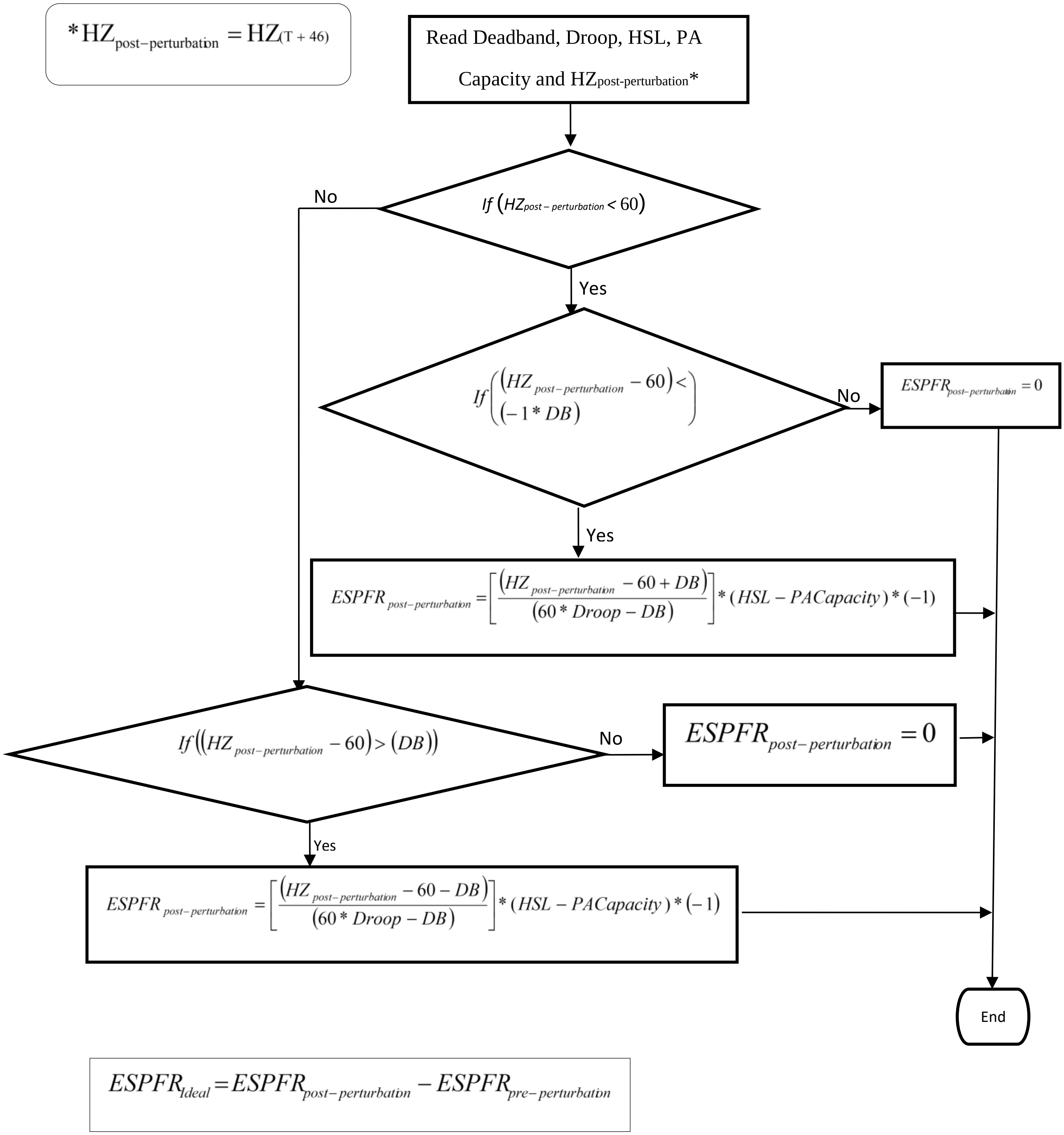
↓

End

Expected Sustained Primary Frequency Response Calculation

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




$^{*}HZ_{post-perturbation} = HZ_{(T+46)}$
Read Deadband, Droop, HSL, PA Capacity and $HZ_{post\text{-}perturbation}$*
$If\ (HZ_{post-perturbation} < 60)$
No
Yes
$If\left((HZ_{post-perturbation} - 60) < (-1 * DB)\right)$
No
$ESPFR_{post-perturbation} = 0$
Yes
$ESPFR_{post-perturbation} = \left[\frac{(HZ_{post-perturbation} - 60 + DB)}{(60 * Droop - DB)}\right] * (HSL - PACapacity) * (-1)$
$If((HZ_{post-perturbation} - 60) > (DB))$
No
$ESPFR_{post-perturbation} = 0$
Yes
$ESPFR_{post-perturbation} = \left[\frac{(HZ_{post-perturbation} - 60 - DB)}{(60 * Droop - DB)}\right] * (HSL - PACapacity) * (-1)$
End
$ESPFR_{Ideal} = ESPFR_{post-perturbation} - ESPFR_{pre-perturbation}$

Adjustment for Steam Turbine

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

↓

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

↓

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

↓

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

↓

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 HSL, PA Capacity, $HZ_{post\text{-}perturbation}$*

↓

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

↓

End

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

Adjustment for Other Units

Read Limiting Factor

↓

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

↓

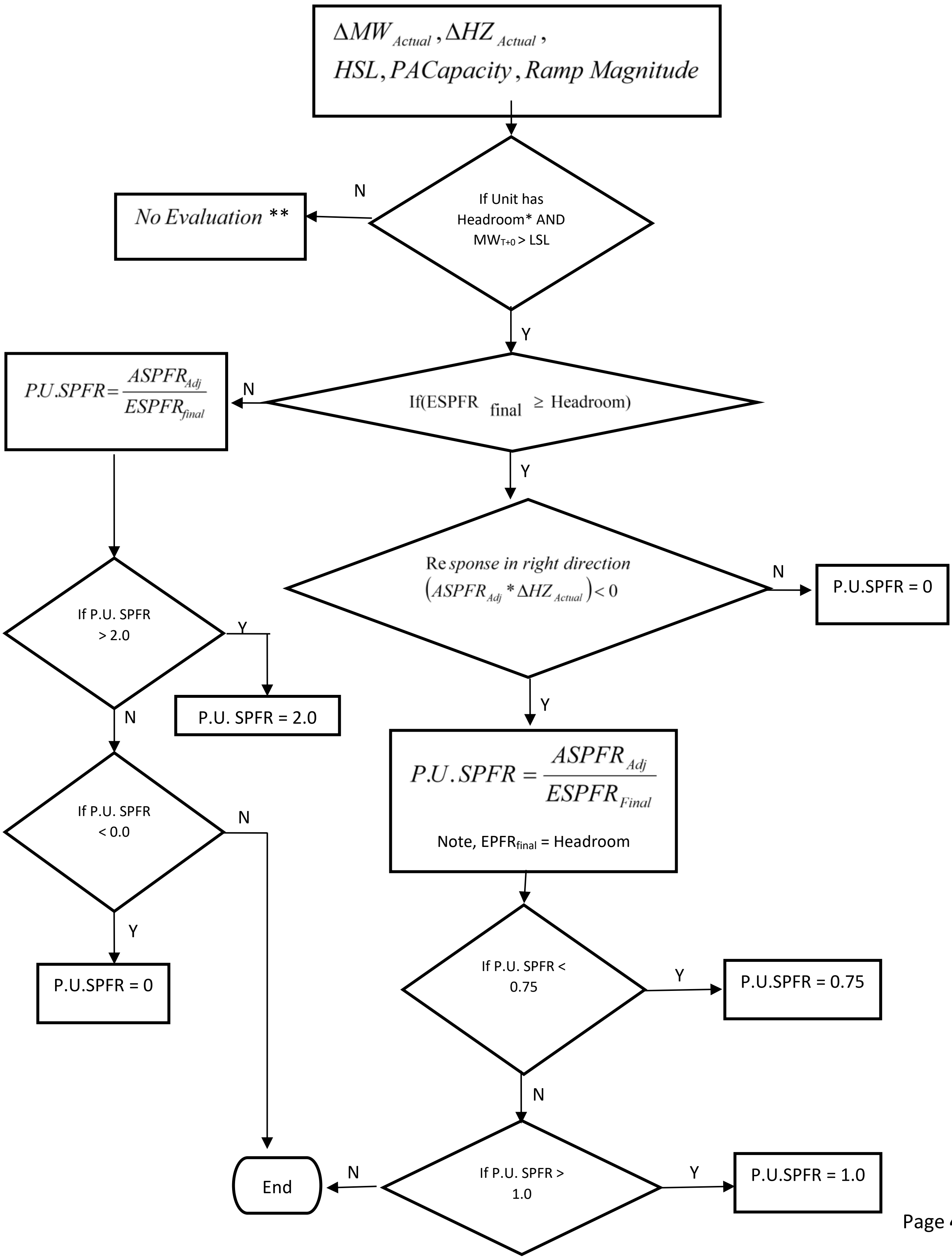
End

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

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

P.U. Sustained Primary Frequency Response Calculation

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


$\Delta MW_{Actual}, \Delta HZ_{Actual},$
$HSL, PACapacity, Ramp\ Magnitude$
If Unit has Headroom* AND MW_{T+0} > LSL
N
No Evaluation **
Y
If(ESPFR final ≥ Headroom)
N
$P.U.SPFR = \frac{ASPFR_{Adj}}{ESPFR_{final}}$
Y
$Re\,sponse\ in\ right\ direction$
$(ASPFR_{Adj} * \Delta HZ_{Actual}) < 0$
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 5MW or 2% of (HSL less PA Capacity), whichever is larger. If a unit does not have adequate up headroom, the unit is considered operating at full capacity and will not be evaluated for low frequency events.

Check for adequate down headroom, high frequency events. Headroom must be greater than either 5MW or 2% of (HSL less PA Capacity), whichever is larger. If a unit does not have adequate down headroom, the unit is considered operating at low capacity and will not be evaluated for high frequency events.

For low frequency events:

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

For high frequency events:

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

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

T = Time in Seconds

Revision History

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

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit B

Implementation Plan

Implementation Plan
Project SAR-011 Revisions to BAL-001-TRE
BAL-001-TRE-2

Requested Approval
BAL-001-TRE-2 – Primary Frequency Response in the ERCOT Region

Requested Retirement
BAL-001-TRE-1 – Primary Frequency Response in the ERCOT Region

Approvals Required
None.

Prerequisite Approvals
None.

Revisions to Glossary Terms
None.

Applicable Entities

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

Effective Date
The 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.

Standard for Retirement
Regional Standard BAL-001-TRE-1 shall be retired immediately prior to the Effective Date of BAL-001-TRE-2.

Exhibit C

Order No. 672 Criteria for BAL-001-TRE-2

Exhibit C — Order No. 672 Criteria

<u>Order No. 672 Criteria</u>

In Order No. 672,[1] the Commission identified a number of criteria it will use to analyze Reliability Standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The discussion below identifies these factors and explains how the proposed Reliability Standard has met or exceeded the criteria.

1. Proposed Reliability Standards must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve that goal.[2]

The proposed regional Reliability Standard achieves the specific reliability goal of establishing and maintaining adequate frequency response in the ERCOT Interconnection. The proposed regional Reliability Standard provides for the maintenance of steady-state frequency within defined limits by balancing real-power demand and supply in real-time. Proposed BAL-001-TRE-2 improves upon the currently effective standard by removing internal inconsistencies regarding performance requirements for steam turbines of combined cycle facilities, and clarifying responsibilities for Frequency Measurable Event exclusion requests.

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1 *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, 114 FERC ¶ 61,104, *order on reh'g*, Order No. 672-A, 114 FERC ¶ 61,328 (2006) [hereinafter Order No. 672].

2 *See* Order No. 672 at P 321 ("The proposed Reliability Standard must address a reliability concern that falls within the requirements of section 215 of the FPA. That is, it must provide for the reliable operation of Bulk-Power System facilities. It may not extend beyond reliable operation of such facilities or apply to other facilities. Such facilities include all those necessary for operating an interconnected electric energy transmission network, or any portion of that network, including control systems. The proposed Reliability Standard may apply to any design of planned additions or modifications of such facilities that is necessary to provide for reliable operation. It may also apply to Cybersecurity protection.").

See Order No. 672 at P 324 ("The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal. Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons.").

2. Proposed Reliability Standards must be applicable only to users, owners, and operators of the Bulk-Power System, and must be clear and unambiguous as to what is required and who is required to comply.[3]

The proposed regional Reliability Standard is clear and unambiguous as to what is required and who is required to comply, in accordance with Order No. 672. The proposed regional Reliability Standard applies to the Balancing Authority, Generator Owner, and Generator Operator in the Texas RE footprint (ERCOT Interconnection). The proposed regional standard clearly articulates the actions that such entities must take to comply with proposed BAL-001-TRE-2.

3. A proposed Reliability Standard must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation.[4]

The Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") for the proposed regional Reliability Standard are unchanged from the currently effective version of the standard. As such, they continue to comport with NERC and Commission guidelines related to their assignment. The assignment of the severity level for each VSL is consistent with the corresponding requirement and the VSLs should ensure uniformity and consistency in the determination of penalties. The VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. For these reasons, the proposed regional Reliability Standard includes clear and understandable consequences in accordance with Order No. 672.

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3 *See* Order No. 672 at P 322 ("The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others.").

See Order No. 672 at P 325 ("The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability.").

4 *See* Order No. 672 at P 326 ("The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply.").

4. A proposed Reliability Standard must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non preferential manner.[5]

The proposed regional Reliability Standard contains measures that support each requirement by clearly identifying what is required and how the requirement will be enforced. These measures help provide clarity regarding how the requirements will be enforced and help ensure that the requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party. The measures are substantively unchanged from the currently effective version of the standard.

5. Proposed Reliability Standards should achieve a reliability goal effectively and efficiently, but do not necessarily have to reflect "best practices" without regard to implementation cost or historical regional infrastructure design.[6]

The proposed regional Reliability Standard achieves its reliability goals effectively and efficiently in accordance with Order No. 672. The proposed regional Reliability Standard clarifies obligations and responsible entities and is intended to reflect current operational practice. The proposed regional standard continues to be necessitated by physical differences in the ERCOT system and continues to represent an alternative, more stringent means of assuring Frequency Response performance in ERCOT than the continent-wide NERC Reliability Standard.

6. Proposed Reliability Standards cannot be "lowest common denominator," i.e., cannot reflect a compromise that does not adequately protect Bulk-Power System reliability.

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[5] *See* Order No. 672 at P 327 ("There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.").

[6] *See* Order No. 672 at P 328 ("The proposed Reliability Standard does not necessarily have to reflect the optimal method, or 'best practice,' for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently.").

Proposed Reliability Standards can consider costs to implement for smaller entities, but not at consequences of less than excellence in operating system reliability.[7]

The proposed regional Reliability Standard does not reflect a "lowest common denominator" approach. To the contrary, the proposed regional Reliability Standard continues to represent a more stringent standard than the continent-wide NERC standard for assuring Frequency Response.

7. Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one geographic area or regional model. It should take into account regional variations in the organization and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.[8]

The proposed regional Reliability Standard is specific to the ERCOT Interconnection and is necessitated by physical differences in the ERCOT system.

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7 *See* Order No. 672 at P 329 ("The proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice—the so-called 'lowest common denominator'—if such practice does not adequately protect Bulk-Power System reliability. Although the Commission will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect reliability.").

See Order No. 672 at P 330 ("A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a 'lowest common denominator' Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk-Power System must bear the cost of complying with each Reliability Standard that applies to it.").

8 *See* Order No. 672 at P 331 ("A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk-Power System, to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or regional model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.").

8. Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid beyond any restriction necessary for reliability.[9]

The proposed regional Reliability Standard will not cause undue negative effect on competition or result in any unnecessary restrictions. As with the currently effective standard, the proposed standard would not restrict the Balancing Authority's ability to employ other sources of Frequency Response to meet the Interconnection's required level of performance.

9. The implementation time for the proposed Reliability Standard is reasonable.[10]

The proposed effective date for the proposed regional Reliability Standard is just and reasonable. NERC and Texas RE propose an effective date of the first day of the first calendar quarter following applicable regulatory approval. The currently effective version of the regional standard would be retired immediately prior to the effective date of the revised regional Reliability Standard. The proposed implementation plan is attached as **Exhibit B** to this petition.

10. The Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[11]

The proposed regional Reliability Standard was developed in accordance with the Texas Reliability Entity Standards Development Process. **Exhibit D** includes a summary of the regional

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[9] *See* Order No. 672 at P 332 ("As directed by section 215 of the FPA, FERC itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue negative effect on competition. Among other possible considerations, a proposed Reliability Standard should not unreasonably restrict available transmission capability on the Bulk-Power System beyond any restriction necessary for reliability and should not limit use of the Bulk-Power System in an unduly preferential manner. It should not create an undue advantage for one competitor over another.").

[10] *See* Order No. 672 at P 333 ("In considering whether a proposed Reliability Standard is just and reasonable, the Commission will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability.").

[11] *See* Order No. 672 at P 334 ("Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by the Commission.").

Reliability Standard development proceedings, and details the processes followed to develop the proposed regional Reliability Standard. These processes included, among other things, comment periods and a balloting period. Additionally, all meetings of the standard drafting team were properly noticed and open to the public.

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.[12]

NERC has identified no competing public interests regarding the request for approval of the proposed regional Reliability Standard. No comments were received that indicated that the proposed regional Reliability Standard conflicts with other vital public interests.

12. Proposed Reliability Standards must consider any other appropriate factors.[13]

No other negative factors relevant to whether the proposed regional Reliability Standard is just and reasonable were identified.

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12 *See* Order No. 672 at P 335 ("Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard.").

13 *See* Order No. 672 at P 323 ("In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed.").

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit D

Record of Development of BAL-001-TRE-2

Summary of Development History

The following is a summary of the development record for the proposed regional Reliability Standard BAL-001-TRE-2.

I. Overview of the Standard Drafting Team

When evaluating a proposed Reliability Standard, the Commission is expected to give "due weight" to the technical expertise of the ERO.[1] The technical expertise of the ERO is derived from the standard drafting team ("SDT") selected to lead each project. For this project, the SDT consisted of industry experts, all with a diverse set of experiences. A roster of the BAL-001-TRE-2 SDT members is included in **Exhibit D**, item 11.

II. Standard Development History

A. Standard Authorization Request Development

Texas Reliability Entity, Inc. ("Texas RE") and the Electric Reliability Council of Texas ("ERCOT") collaborated to draft a Standard Authorization Request ("SAR") proposing revisions to Reliability Standard BAL-001-TRE-1.

The SAR was posted for a 15-day comment period from July 17 through August 1, 2018 and received three responses.[2] Texas RE's Member Representatives Committee accepted the SAR on September 12, 2018 and appointed the standard drafting team on November 9, 2018.

B. First Posting – Comment Period and Initial Ballot

An initial draft of proposed regional Reliability Standard BAL-001-TRE-2, the implementation plan, and a summary of changes were posted for a 30-day public comment period

[1] Section 215(d)(2) of the Federal Power Act; 16 U.S.C. § 824(d)(2) (2018).

[2] Texas RE, *Consolidated Comments — Project SAR-011 Revisions to Regional Standard BAL-001-TRE-1*, https://www.texasre.org/CPDL/SAR%20Comments%20BAL-001-TRE-1%20Consolidated.pdf.

from May 6, 2019 through June 5, 2019. The posting received five sets of responses.[3] Subsequently, the drafting team made several minor revisions based on the comments received.

C. Final Ballot

The standard was posted for a 15-day final ballot from August 21, 2019 through September 5, 2019, where it achieved quorum and received 100 percent approval.[4] The parallel non-binding poll of VRFs and VSLs achieved quorum and received 66 percent positive opinions.[5]

D. Board of Trustees Adoption

The proposed regional Reliability Standard was approved by the Texas RE Board of Directors on December 11, 2019 and by the NERC Board of Trustees on February 6, 2020.[6]

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[3] Exhibit D, Item 3.
[4] Exhibit D, Item 10.
[5] Exhibit D, Item 8.
[6] NERC, *Agenda — Board of Trustees*, Item 7d (BAL-001-TRE-2 Primary Frequency Response in the ERCOT Region), Feb. 6, 2020, https://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Board_Open_Meeting_Agenda_Package_February_6_2020.pdf.

<u>Complete Record of Development</u>

Standard Authorization Request Form
Regional Standard or Variance
Texas Reliability Entity, Inc.

E-mail completed form to rsm@texasre.org

Texas RE to Complete
SAR No: SAR-011

Title of Proposed Regional Standard: BAL-001-TRE-1

SAR Requester Information

Name: Colleen Frosch

Registered Entity: ERCOT

E-mail: colleen.frosch@ercot.com

Telephone: 512-248-4219

SAR Requester Information

Name: David Penney

Registered Entity: Texas Reliability Entity, Inc.

E-mail: david.penney@texasre.org

Telephone: 512-583-4958

SAR Type (Check a box for each one that applies.)

☐ New Standard
☒ Revision to Existing Standard
☐ Revision to the Standard Development Process
☐ Withdrawal of existing standard
☐ Variance to a NERC Reliability Standard
Which one? Click or tap here to enter text.
☐ Urgent Action

Purpose (Describe what the standard action will achieve in support of bulk power system reliability.)

This SAR serves two purposes:

- The removal of governor deadband and droop setting requirements for steam turbines in a combined cycle train will resolve an inconsistency in the language of BAL-001-TRE and conform the language of the standard to the intent of the Standard Drafting Team and customary industry practice.

- The clarification of the responsible entity for FME exclusion requests (Requirements R9 and R10) will resolve an inconsistency in the language of BAL-001-TRE-1 and conform the language of the standard to the intent of the Standard Drafting Team and current processes.

Industry Need (Provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.) Historically, most combined cycle resources in the ERCOT Region have operated with the combustion turbines able to respond to frequency deviations using governor controls, with associated steam turbines not providing a response. The original BAL-001-TRE drafting team accounted for the lack of Primary Frequency Response (PFR) from the steam turbines in a combined cycle resource train by requiring an overall 5.78% PFR performance for the entire train. See BAL-001-TRE-1 R2.1; footnote to R6.2. However, the standard also states that steam turbines are required to comply with the droop and deadband settings in R6 of the standard, and the standard also explicitly references a 5% droop setting for steam turbines in combined-cycle facilities. See BAL-001-TRE-1 R6.2, footnote to R6.2. ERCOT desires to correct this inconsistency and to align the standard's requirements with current operational practices. As the Balancing Authority for the ERCOT Region, ERCOT has already used its directive authority under R6 of the standard to explicitly exempt Generator Operators with steam turbines in combined-cycle trains from the droop and deadband settings in R6.1 and R6.2, pending a clarification to the standard. See ERCOT Market Notice W-C050418-01 (May 4, 2018). Because this change would simply codify current operational practices, ERCOT has concluded it would not have any material reliability impact or market impact. ERCOT, as the Balancing Authority (BA) for the ERCOT region, is responsible for calculation of the Primary Frequency Response performance for the interconnection (R4) as well as each generating unit (R2). ERCOT created a procedure document to allow generation entities to request exclusions for FME's when a legitimate operating condition prevented normal Primary Frequency Response (http://www.ercot.com/content/wcm/key_documents_lists/89338/BAL-001-TRE-1_PFR_Exclusion_Process.docx). Texas RE desires to correct the inconsistency in Requirements R9.3 and R10.3 to align the standard's requirements with current processes for FME exclusion requests. This change will clarify the requirements within the standard to be in-line with current procedures. It will not have any material reliability impact or market impact.
Brief Description (Provide a paragraph that describes the scope of this standard action.) ERCOT proposes clarifying BAL-001-TRE-1 to eliminate language in R6 stating that steam turbines in combined-cycle generation facilities must comply with specified deadband and droop settings. Texas RE proposes clarifying BAL-001-TRE-1 to revise language in R9.3 and R10.3 to state that a unit's Primary Frequency Response performance during an FME may be excluded from the rolling average calculation "by the BA". Texas RE also proposes to revise the

second bullet of R9.3 and R10.3 to state "Data telemetry failure. The BA may request raw data from the GO as a substitute."
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR.) BAL-001-TRE-1 R6 mandates governor parameters for each generation resource. This includes the requirement that the steam turbines of combined cycle resources comply with Requirements R6.1, R6.2, and R6.3, which specify the required Governor deadband and droop settings. Requirement R6.2 also notes that compliance with Requirements R9 and R10 for combined cycle facilities will be determined through evaluation of PFR with a droop characteristic equal to 5.78. To get the maximum thermal efficiency, steam turbines in combined-cycle generation facilities are operated on inlet pressure control mode with a pressure setpoint that will keep the valves essentially wide open, leaving them unable to respond to governor controls from frequency deviations. The history of the development of Requirement R6 indicates that the Standard Drafting Team did not intend that steam turbines would provide governor response, given that combined-cycle generation facilities would be evaluated on a facility-wide basis. The September 2011 consideration of comments states: "The proposed 5.78% droop figure is not a Governor setting, but rather an amount used in the PFR evaluation calculation to account for the steam turbine of the combined cycle train that is not responding to frequency." The standard also imposes a stricter 4% droop setting requirement on combustion turbines of combined cycle resources. The Standard Drafting Team noted this more aggressive droop setting was required to compensate for the lack of governor response from the steam turbine of the combined cycle resource. This SAR proposes to remove language in the current standard that mandates that the steam turbine of a combined cycle resource comply with governor droop and deadband characteristics prescribed in R6.1 and R6.2. Texas RE proposes clarifying BAL-001-TRE-1 to revise language in R9.3 and R10.3 to state that a unit's Primary Frequency Response performance during an FME may be excluded from the rolling average calculation "by the BA". Texas RE also proposes to revise the second bullet of R9.3 and R10.3 to state "Data telemetry failure. The BA may request raw data from the GO as a substitute."

Reliability Functions

For a more detailed description of the Reliability Functions, please refer to ***NERC Function Model_V5***

The Regional Standard will apply to the following functions: (Check all that apply.)

☒ Balancing Authority	☐ Resource Planner
☐ Distribution Provider	☐ Transmission Operator

☒ Generator Operator	☐ Transmission Owner
☒ Generator Owner	☐ Transmission Planner
☐ Planning Coordinator/Planning Authority	☐ Transmission Service Provider
☐ Reliability Coordinator	

Reliability and Market Interface Principles

Applicable Reliability Principles (Check all that apply.)	
☐	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles?
1. A reliability standard shall not give any market participant an unfair competitive advantage. ☒ Yes ☐ No
2. A reliability standard shall neither mandate nor prohibit any specific market structure. ☒ Yes ☐ No

3.	A reliability standard shall not preclude market solutions to achieving compliance with that standard. ☒ Yes ☐ No
4.	A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. ☒ Yes ☐ No

Related Standards

Standard No.	Explanation
BAL-001-TRE-1	Primary Frequency Response in the ERCOT Region

Related SARs

SAR ID	Explanation

Modification Report
Standard Drafting Team's Responses to Comments
Comment Period: May 5 – June 6, 2019
Project SAR-011 Revisions to Regional Standard BAL-001-TRE-1

Introduction

The Electric Reliability Council of Texas (ERCOT) and Texas Reliability Entity, Inc, (Texas RE) collaborated to draft a Standard Authorization Request (SAR) proposing revision to Regional Standard BAL-001-TRE-1. The SAR proposes the following:

- Remove the governor deadband and droop setting requirements for steam turbines in a combined cycle train in Requirement R6; and
- Clarify the language in Requirements R9.3 and R10.3 to state that a unit's Primary Frequency Response performance during an FME may be excluded from the rolling average calculation "by the BA".

The standard drafting team has met and discussed the revisions to Regional Standard BAL-001-TRE-1 standard. The SDT posted the following documents for a 30-day public comment period.

- BAL-001-TRE-2 Draft Standard Redline to Last Approved
- BAL-001-TRE-2 Draft Reference Document Redline to Last Approved
- BAL-001-TRE-2 Draft Implementation Plan
- BAL-001-TRE-2 Summary of Changes

Summary of Comments

Texas RE conducted a comment period from May 6 – June 5, 2019. Texas RE received five responses from five individual commenters. The standard drafting team (SDT) appreciates industry's consideration of Project SAR-011 Revisions of Regional Standard BAL-001-TRE-1. The SDT did not make any changes to the Primary Frequency Response Reference Document or the Implementation plan.

Based on the comments received, the SDT made the following non-substantive change to the standard:

- Capitalized Regional Standard in the last paragraph of Section 5. Background.

Based on the comments received, the SDT made the following changes to the Summary of Changes document:

- Added "Removed Wind Powered Generator from the table" and the rationale.
- Added "Revised 'Renewable (Non-Hydro)' to 'Variable Renewable (Non-Hydro)'" and rationale.

Standard Drafting Team's Responses to Comments
Comment Period: May 6 – June 5, 2019
Project SAR-011 Revisions to Regional Standard BAL-001-TRE-1

Question 1	Draft Regional Standard - Do you agree with the changes to Requirement R6 to remove the applicability to steam turbine(s) of a combined cycle resource?

Answers	Frequency
Yes	3
No	None
No Answer	2

Commenter	Answer	Comment	SDT Response
Deb Reichard Steitz, Buffalo Gap Wind Farm, LLC.	[none]	[none]	
Thomas Foltz, American Electric Power	Yes	[none]	
Daniel Gacek, Exelon	Yes	NERC has followed the lead of CIGRE (International Council on Large Electric Systems (French: Conseil International des Grands Réseaux Électriques, CIGRÉ)) and other expertise in the grid modeling sciences regarding the effective contribution of a combined cycle steam turbine governor during frequency measurable events. They have concluded that the MW yield from a steam turbine in combined cycle is negligible in most circumstances, particularly in the short term where frequency response is	Thank you for your comment.

		relevant. The change reflected in the subject document reflects this technical reality.	
Brandon Gleason, ERCOT	Yes	[none]	
Pamela Hunter	[none]	[none]	

Question 2	**Draft Regional Standard – Do you agree with the revisions to Requirements R9 and R10 for the Balancing Authority to request data from the GO?**

Answers	Frequency
Yes	3
No	None
No Answer	2

Commenter	Answer	Comment	SDT Response
Deb Reichard Steitz, Buffalo Gap Wind Farm, LLC.	[none]	[none]	N/A
Thomas Foltz, American Electric Power	Yes	[none]	N/A
Daniel Gacek, Exelon	Yes	[none]	N/A
Brandon Gleason, ERCOT	Yes	[none]	N/A
Pamela Hunter	[none]	[none]	N/A

Question 3	**Draft Reference Document – The standard drafting team made changes to the attached reference document consistent with the changes in the draft standard, including some errata changes. Do you agree with the changes to the draft reference document?**

Answers	Frequency
Yes	3
No	None
No Answer	2

Commenter	Answer	Comment	SDT Response

Deb Reichard Steitz, Buffalo Gap Wind Farm, LLC.	[none]	[none]	N/A
Thomas Foltz, American Electric Power	Yes	[none]	N/A
Daniel Gacek, Exelon	Yes	[none]	N/A
Brandon Gleason, ERCOT	Yes	[none]	N/A
Pamela Hunter	[none]	[none]	N/A

Question 4	**Implementation Plan - Do you agree Regional Standard BAL-001-TRE-2 should be effective the first day of the first calendar quarter after the effective date of the applicable governmental authority's order approving the standard?**

Answers	Frequency
Yes	3
No	None
No Answer	2

Commenter	Answer	Comment	SDT Response
Deb Reichard Steitz, Buffalo Gap Wind Farm, LLC.	[none]	[none]	N/A
Thomas Foltz, American Electric Power	Yes	[none]	N/A
Daniel Gacek, Exelon	Yes	[none]	N/A
Brandon Gleason, ERCOT	Yes	[none]	N/A
Pamela Hunter	[none]	[none]	N/A

Question 5	**Do you have any additional comments for the standard drafting team?**

Answers	Frequency
Yes	3
No	2
No Answer	None

Commenter	Answer	Comment	SDT Response
Deb Reichard Steitz, Buffalo Gap Wind Farm, LLC.	Yes	BAL-001-TRE-2 Draft Standard – Redline Table 6.2 strikes “Wind-Powered Generator”. This change is **not** noted on the BAL-001-TRE-2 Summary of Changes with Rationale. Confirming, does this mean that Wind-Powered Generator GO is exempt from R6?	Wind-Powered Generators and Solar Generators are now covered under the type “Variable Renewable” in Table 6.2. They are not exempt from Requirement R6. The SDT revised the Summary of Changes document to capture this change.
Thomas Foltz, American Electric Power	Yes	AEP appreciates the efforts of the SAR-011 drafting team and offers the following suggestions for helping shape the scope and direction eventually chosen for future SARs involving BAL-001-TRE. We believe opening the standard for revision also allows an opportunity to make improvements to the attachments as well. We suggest pursuing such revisions within the standards development process itself rather than doing so independently. Associated Attachments: * More detailed instructions should be included for calculating the K-factor for throttle pressure change, due to steam turbine control valve response to FME. * Attachments could benefit from some general clean up using the latest WORD equation tools to replace the pasted	Thank you for your comment. The SDT notes these suggestions for consideration in the next SAR involving BAL-001-TRE. To make changes to the Primary Frequency Response Reference Document (Attachment 1), please submit a revisions request per the Revision Process noted in the Attachment.

		graphics representing equations. * Improve the load ramp calculation in the pre-event period to ignore normal variation in MW output from resources. Standard: * Add a requirement for the BA to maintain tighter control of frequency (two standard deviations of frequency data within the maximum deadband for governors) through LFC/AGC to minimize the impact on generators. * Modify R9 and R10 to explicitly allow the BA to exempt a generator whose load ramp is interrupted during the FME period. * Modify R2 to allow expected droop performance to be based on the actual combined cycle resource configuration at the time of the FME.	
Daniel Gacek, Exelon	No		N/A
Brandon Gleason, ERCOT	No		N/A
Pamela Hunter	Yes	The change indicates “regional standard” is capitalized in the Background section, but it is not capitalized in the last paragraph. The expected performance droop of 5.78% shown in Requirement R2, section 2.1 is not valid for all configurations of combined cycle	Thank you for your comment. The SDT has capitalized “regional standard” in the last paragraph of the background section. That is correct. The 5.78% droop performance criteria was based on the

		units and on all sizes of gas turbine generators and steam turbine generators used. This value is valid for only a small subset of possible unit sizes and configurations (e.g. 1-on-1, 2-on-1, 3-on-1, 4-on-1, etc.).	aggregated results of a field trial using multiple combined units under various configurations. This is explained in footnote 2 in the Primary Frequency Response Reference Document (Attachment 1). To date, ERCOT has not received an exemption request stating the combined-cycle configuration caused a unit to fail.

A. Introduction

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

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Generator Owners

   4.1.3 Generator Operators

   4.2. Exemptions

   4.2.1 Existing generating facilities regulated by the U.S. Nuclear Regulatory Commission prior to the Effective Date are exempt from Standard BAL-001-TRE-2.

   4.2.2 Generating units/generating facilities while operating in synchronous condenser mode are exempt from Standard BAL-001-TRE-2.

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

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

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

   Under this standard, two Primary Frequency Response (PFR) performance measures are calculated: "initial" and "sustained." The initial PFR performance (R9) measures the actual response compared to the expected response in the period from 20 to 52

seconds after an FME starts. The sustained PFR performance (R10) measures the best actual response between 46 and 60 seconds after t(0) compared to the expected response based on the system frequency at a point 46 seconds after t(0).

In this Regional Standard the term "resource" is synonymous with "generating unit/generating facility".

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 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%.

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

2.3. If a generating unit/generating facility has not participated in a minimum of (8) eight 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.

[1] The 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.

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

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

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

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

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

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

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

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

Table 6.1 Governor Deadband Settings

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

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

Table 6.2 Governor Droop Settings

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

*

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

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

Where

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

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

MWGCS is the maximum megawatt control range of the Governor control system. For mechanical Governors, droop will be proportional from the deadband by design. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

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

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

R7. Each Generator Owner shall operate each generating unit/generating facility 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.

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. *[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" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Compliance Monitoring Period and Reset Time Frame: If a generating unit/generating facility completes a mitigation plan and implements corrective action(s) to meet requirements R9 and R10 of the standard, and if approved by the BA and Compliance Enforcement Authority, then the generating unit/generating facility may begin a new rolling event average performance on the next performance during an FME. This will count as the first event in the performance calculation and the entity will have an average frequency performance score after 12 successive months or eight events per R9 and R10.

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

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

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

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

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

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

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

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	The Balancing Authority reported an FME more than 14 days but less than 31 days after identification of the event.	The Balancing Authority reported an FME more than 30 days but less than 51 days after identification of the event.	The Balancing Authority reported an FME more than 50 days but less than 71 days after identification of the event.	The Balancing Authority reported an FME more than 70 days after identification of the event.
R2.	The Balancing Authority submitted a monthly report more than one month but less than 51 days after the end of the reporting month.	The Balancing Authority submitted a monthly report more than 50 days but less than 71 days after the end of the reporting month.	The Balancing Authority submitted a monthly report more than 70 days but less than 91 days after the end of the reporting month.	The Balancing Authority failed to submit a monthly report within 90 days after the end of the reporting month.
R3.	The Balancing Authority did not make the calculation and criteria for determination of the IMFR publicly available.	The Balancing Authority did not make the IMFR publicly available.	The Balancing Authority did not calculate the IMFR for the following year in December.	The Balancing Authority did not calculate the IMFR for a calendar year.
R4.	N/A	N/A	The Balancing Authority did not make public the six-FME rolling average Interconnection combined Frequency Response by the end of the following month.	The Balancing Authority did not calculate the six- FME rolling average Interconnection combined Frequency Response for any month in which an FME occurred.
R5.	N/A	N/A	N/A	The Balancing Authority did not take action to improve

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

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

D. Regional Variances

None

E. Associated Documents

Regional Standard BAL-001-TRE-2 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.

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.

Primary Frequency Response Reference Document

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

I. Introduction

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

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

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

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

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

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

[1] These spreadsheets are available at www.TexasRE.org.

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.

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

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

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

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

Initial Primary Frequency Response Performance Calculation Methodology

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

This process calculates the initial Per Unit Primary Frequency Response of a resource [$P.U.PFR_{Resource}$] as a ratio between the Adjusted Actual Primary Frequency Response ($APFR_{Adj}$),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 Primary Frequency Response [$P.U.PFR_{Resource}$] for any Frequency Measurable Event (FME).

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

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

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

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

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

The Adjusted Actual Primary Frequency Response ($APFR_{Adj}$) and the Final Expected Primary Frequency Response ($EPFR_{final}$) 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

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

[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 Adjustment: The Actual Primary Frequency Response 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 = (MW_{T-4} – MW_{T-60})*0.59

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

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:

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

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

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

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

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

For each formula, when frequency is within the Governor deadband the appropriate EPFR value is zero. The $deadband_{max}$ and $droop_{max}$ 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 NDC (Net Dependable Capacity) 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 Capacity for wind-powered generators is the real time HSL of the wind plant at the time the FME occurred.

Power Augmentation: For Combined Cycle 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

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

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:

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

Where:

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

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

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

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

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

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

III. Sustained Primary Frequency Response Calculations

Requirement 10

R10. The 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.

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 by the Balancing Authority from the rolling average calculation due to a legitimate operating condition that prevented normal Primary Frequency Response performance. Examples of legitimate operating conditions that may support exclusion of FMEs include, but are not limited to:

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

Sustained Primary Frequency Response Performance Calculation Methodology

This portion of this PFR Reference Document establishes the process used to calculate sustained Primary Frequency Response performance for each Frequency Measurable Event (FME), and then average the events over a 12-month period (or 8-event minimum) to establish whether a resource is compliant with Requirement R10.

This process calculates the Per Unit Sustained Primary Frequency Response of a resource [$P.U.SPFR_{Resource}$] as a ratio between the maximum actual unit response at any time during the period from T+46 to T+60, adjusted for the pre-event ramping of the unit, and the *Final* Expected Primary Frequency Response (EPFR) value at time T+46.[3]

This comparison of actual performance to a calculated target value establishes, for each type of resource, the Per Unit Sustained Primary Frequency Response [$P.U.SPFR_{Resource}$] for any Frequency Measurable Event (FME).

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

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

[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.

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

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

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

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

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

$P.U.SPFR_{Resource}$ is the per unit (P.U.) measure of the sustained Primary Frequency Response of a resource during identified Frequency Measurable Events. 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 Primary Frequency Response 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 ($MW_{T\text{-}4} - MW_{T\text{-}60}$) 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 Primary Frequency Response ($ESPFR_{final}$) is calculated using the actual frequency at T+46, HZ_{T+46}.

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

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

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

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

Capacity and Net Dependable Capability (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 capacity for wind-powered generators is the real-time HSL of the wind plant at the time the FME occurred. The $deadband_{max}$ and $droop_{max}$ quantities come from Requirement R6.

For Combined Cycle facilities, determination of Capacity includes subtracting Power Augmentation (PA) Capacity, if any, from the original 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 is required to provide the BA with documentation and identify conditions when this augmentation is in service.

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

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

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:

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

Where:

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

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

Throttle Pressure = Interpolatio*n* o*f* Pressur*e* curve a*t* $MW_{pre\text{-}perturbation}$

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

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

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

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

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

If the generating unit/generating facility is operating within 2% of its (HSL – PA Capacity) or within 5 MW (whichever is greater) 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:

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

then Primary Frequency Response is not evaluated for this FME.

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

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

then Primary Frequency Response is not evaluated for this FME.

Final Expected Primary Frequency Response (EPFRfinal) is greater than Operating Margin:

Caps and limits exist for resources operating with adequate reserve margin to be evaluated (at least 2% of (HSL less PA Capacity) or 5 MW), 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 Expected Primary Frequency Response$_{final}$ is greater than the generating unit/generating facility's available frequency responsive Capacity[4]; and
    c. The generating unit/generating facility's $APFR_{adj}$ response is in the correct direction.

2. When calculation of the $P.U.PFR_{Resource}$ uses the resource's (HSL less PA Capacity) 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 Primary Frequency Response measures.

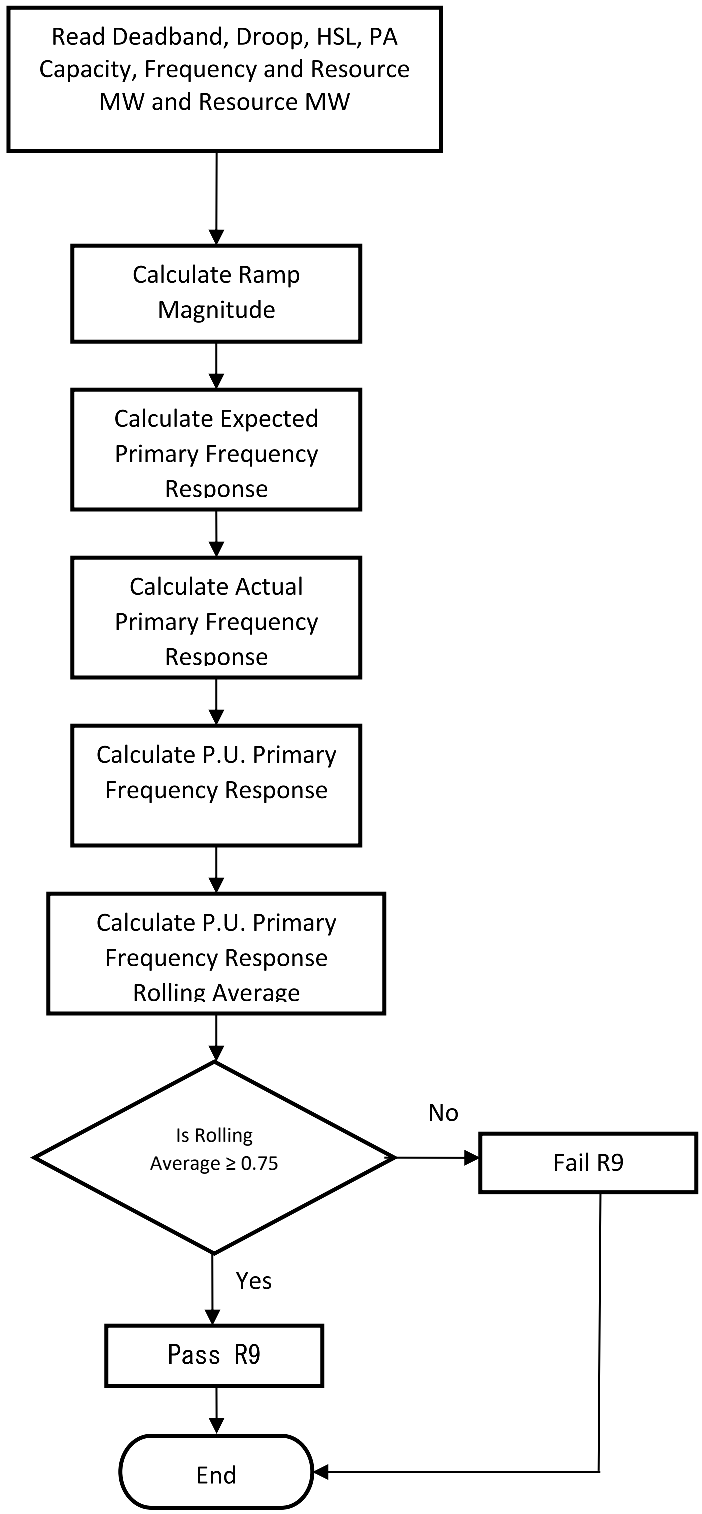
[4] In this circumstance, when frequency is below 60 Hz, the $EPFR_{final}$ is set to operating margin based on HSL (adjusted for any augmentation capacity) AND when frequency is above 60 Hz, the $EPFR_{final}$ is set to operating margin based on LSL for the purpose of calculating $PUPFR_{resource}$.

Attachment A to
Primary Frequency Response Reference Document

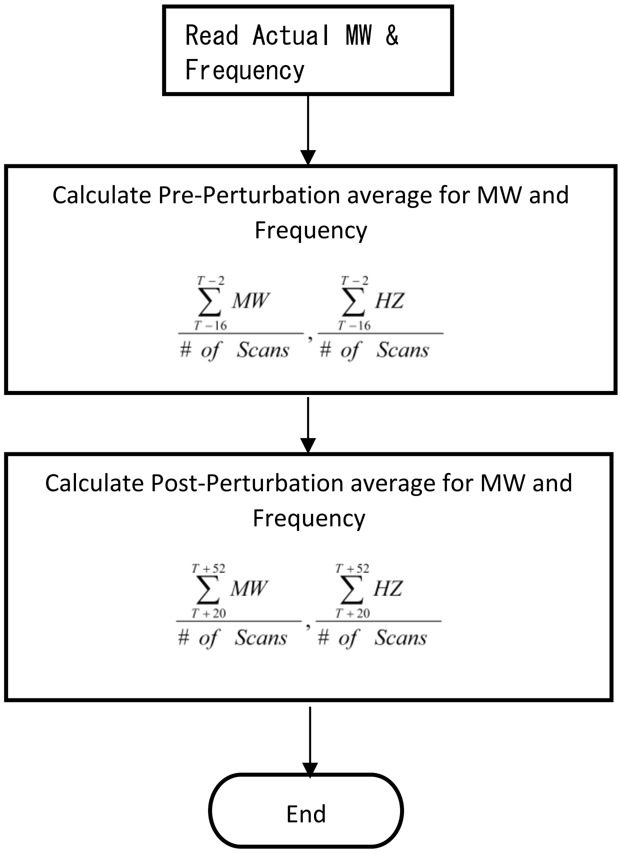
Initial Primary Frequency Response Methodology for
BAL-001-TRE-2

Primary Frequency Response Measurement and Rolling Average Calculation – Initial Response

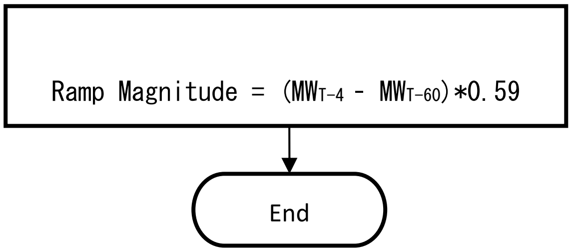
PA=Power Augmentation
HSL=High Sustained Limit



Pre/Post-Perturbation Average MW and Average Frequency Calculations

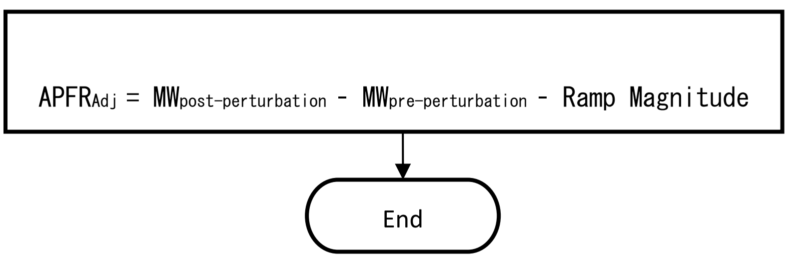


Ramp Magnitude Calculation



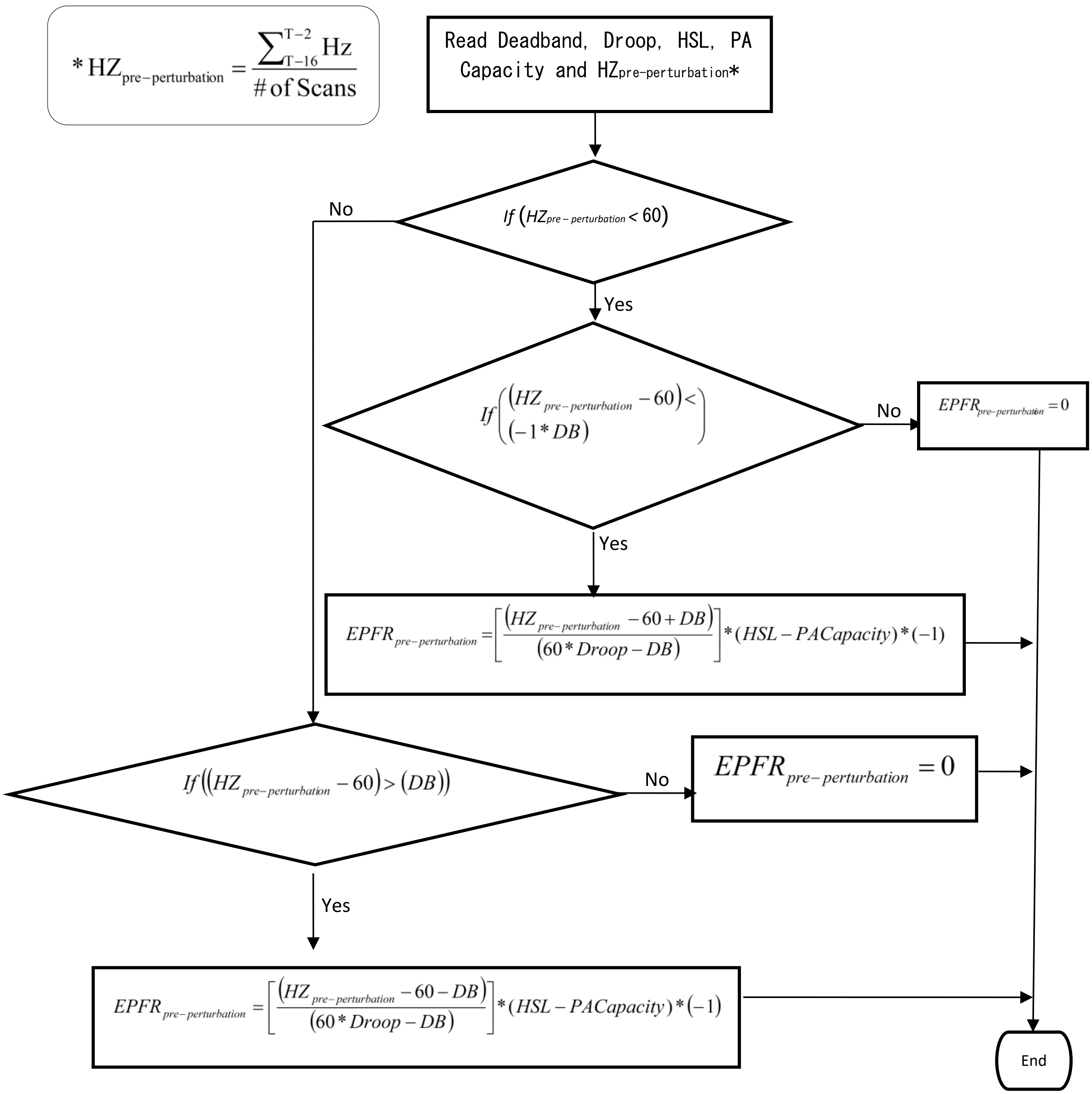
$(MW_{T-4} – MW_{T-60})$ represents the MW ramp of the generator resource/generator facility for a full minute prior to the event. The factor 0.59 adjusts this full minute ramp to represent the ramp that should have been achieved during the post-perturbation measurement period.

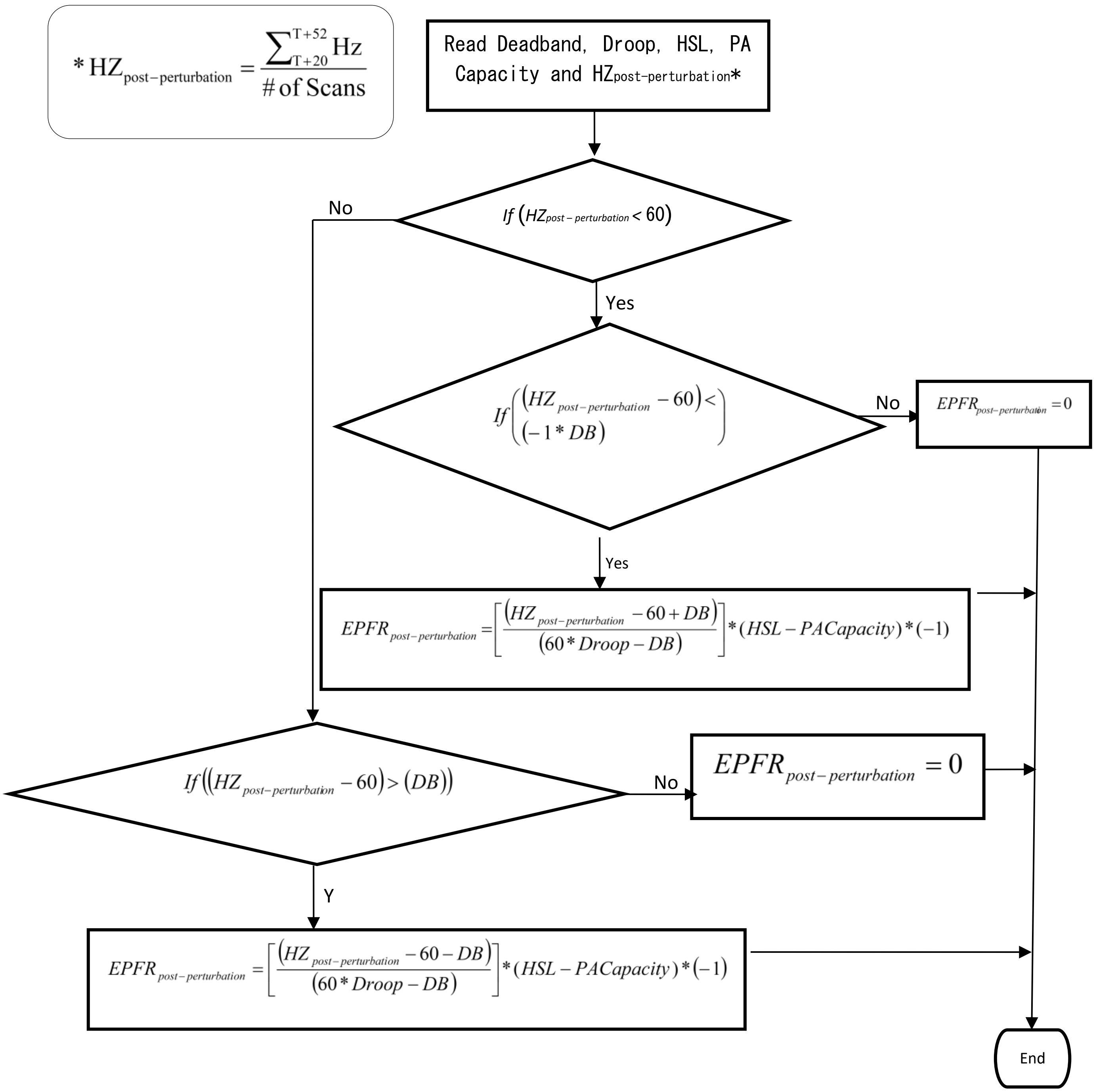
Actual Primary Frequency Response ($APFR_{Adj}$)



Expected Primary Frequency Response Calculation

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





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

Adjustment for Steam Turbine

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

↓

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

↓

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

↓

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

↓

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

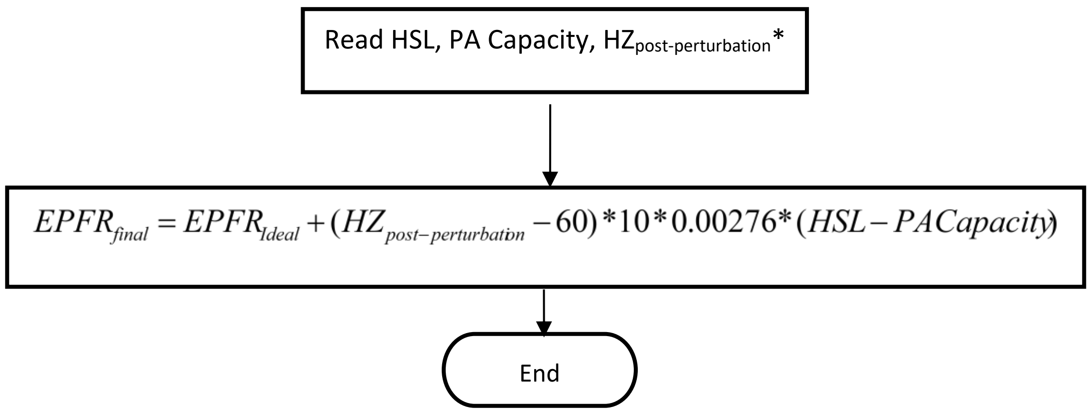
↓

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

↓

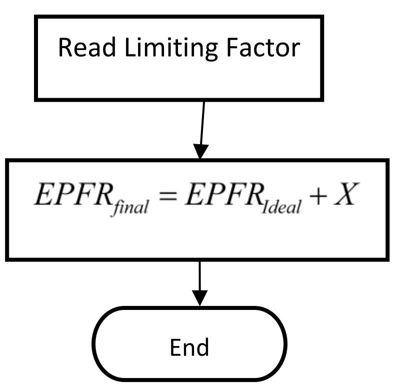
End

Adjustment for Combustion Turbines and Combined Cycle Facilities



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

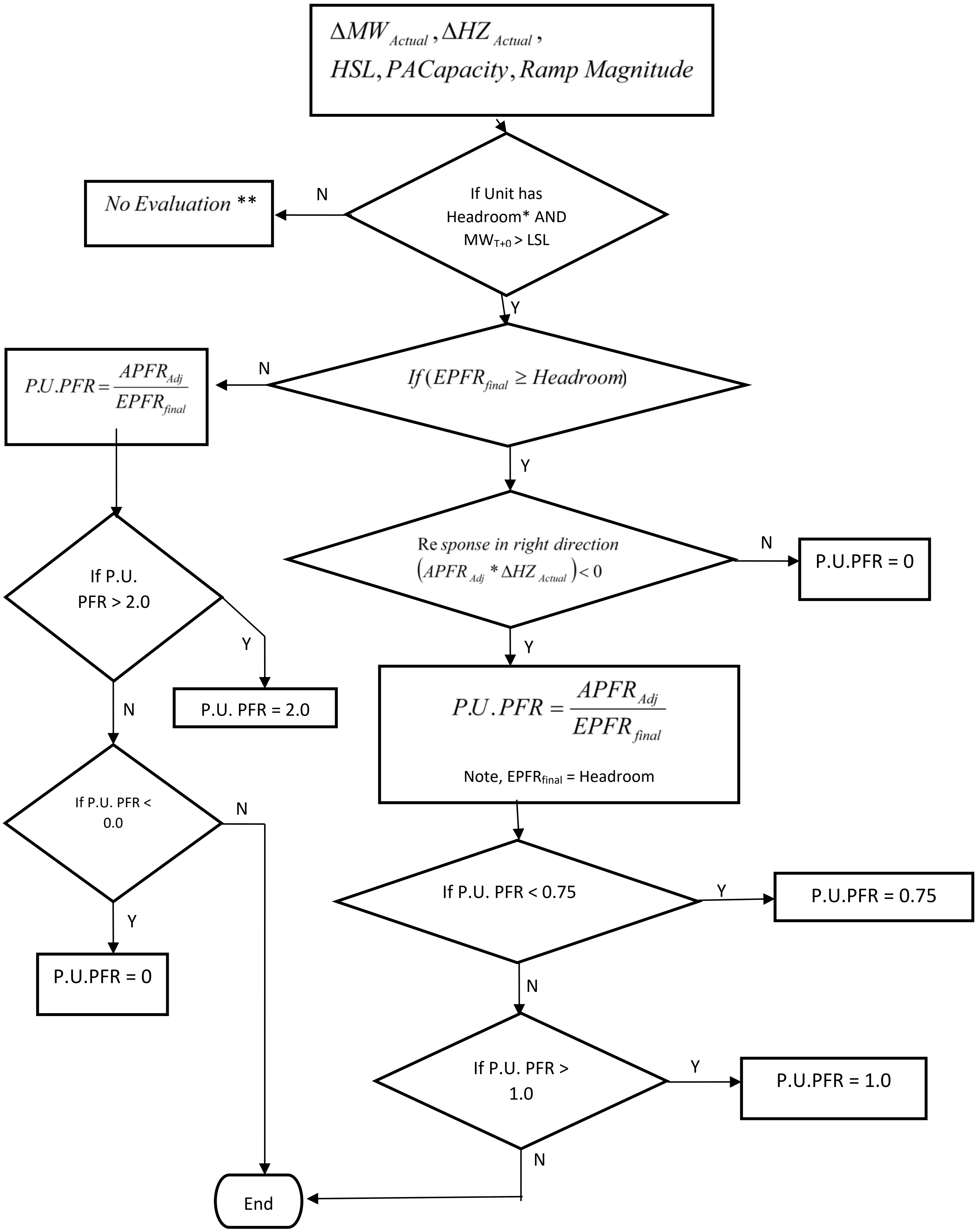
Adjustment for Other Units



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

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

P.U. Initial Primary Frequency Response Calculation


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

*Check for adequate up headroom, low frequency events. Headroom must be greater than either 5MW or 2% of (HSL less PA Capacity), whichever is larger. If a unit does not have adequate up headroom, the unit is considered operating at full capacity and will not be evaluated for low frequency events.

Check for adequate down headroom, high frequency events. Headroom must be greater than either 5MW or 2% of (HSL less PA Capacity), whichever is larger. If a unit does not have adequate down headroom, the unit is considered operating at low capacity and will not be evaluated for high frequency events.

For low frequency events:

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

For high frequency events:

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

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

T = Time in Seconds

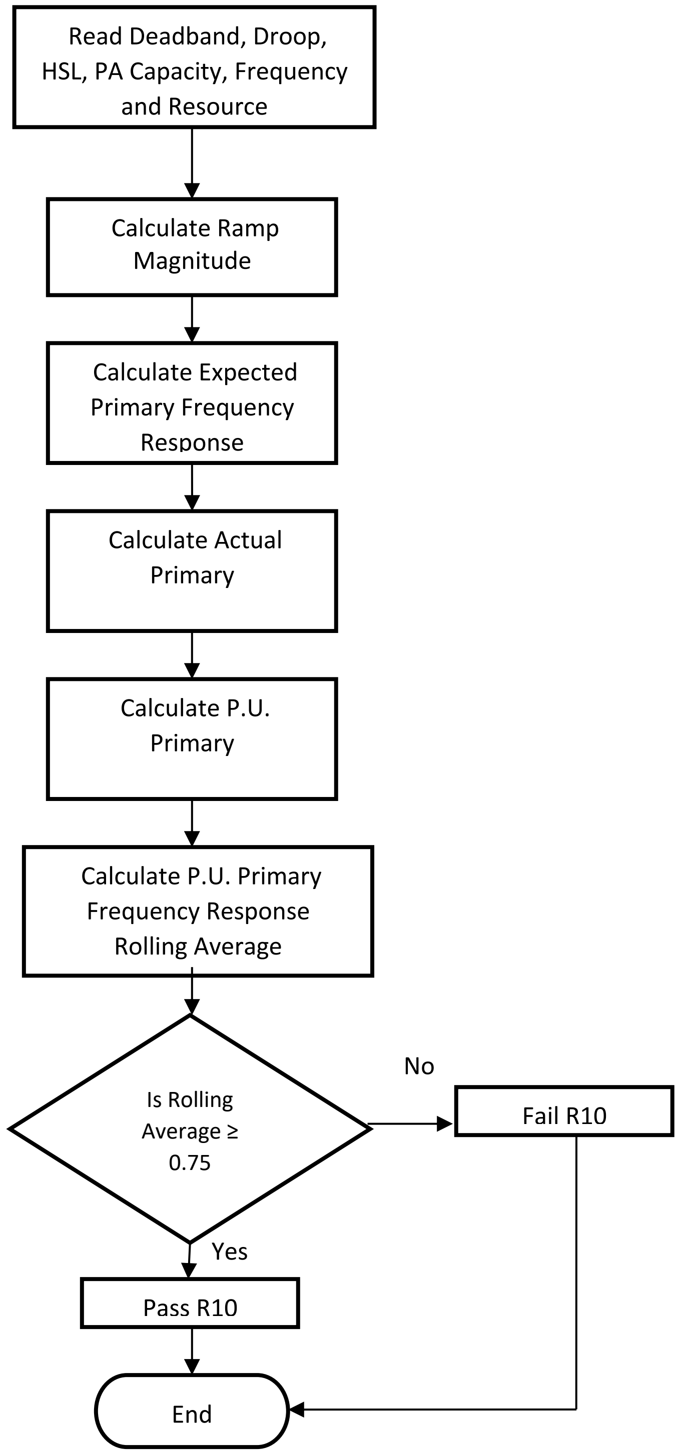
Attachment B to

Primary Frequency Response Reference Document

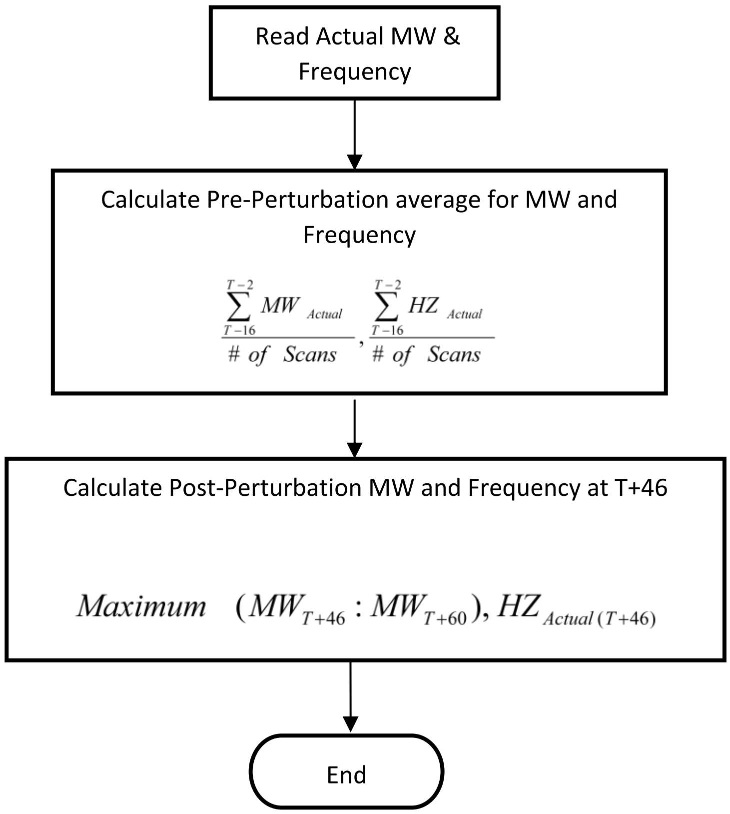
Sustained Primary Frequency Response Methodology for

BAL-001-TRE-2

Primary Frequency Response Measurement and Rolling Average Calculation–Sustained Response



Pre/Post-Perturbation Average MW and Average Frequency Calculations



Ramp Magnitude Calculation - Sustained

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

$$\downarrow$$

End

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

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

For low frequency events:

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

$$\downarrow$$

End

For high frequency events:

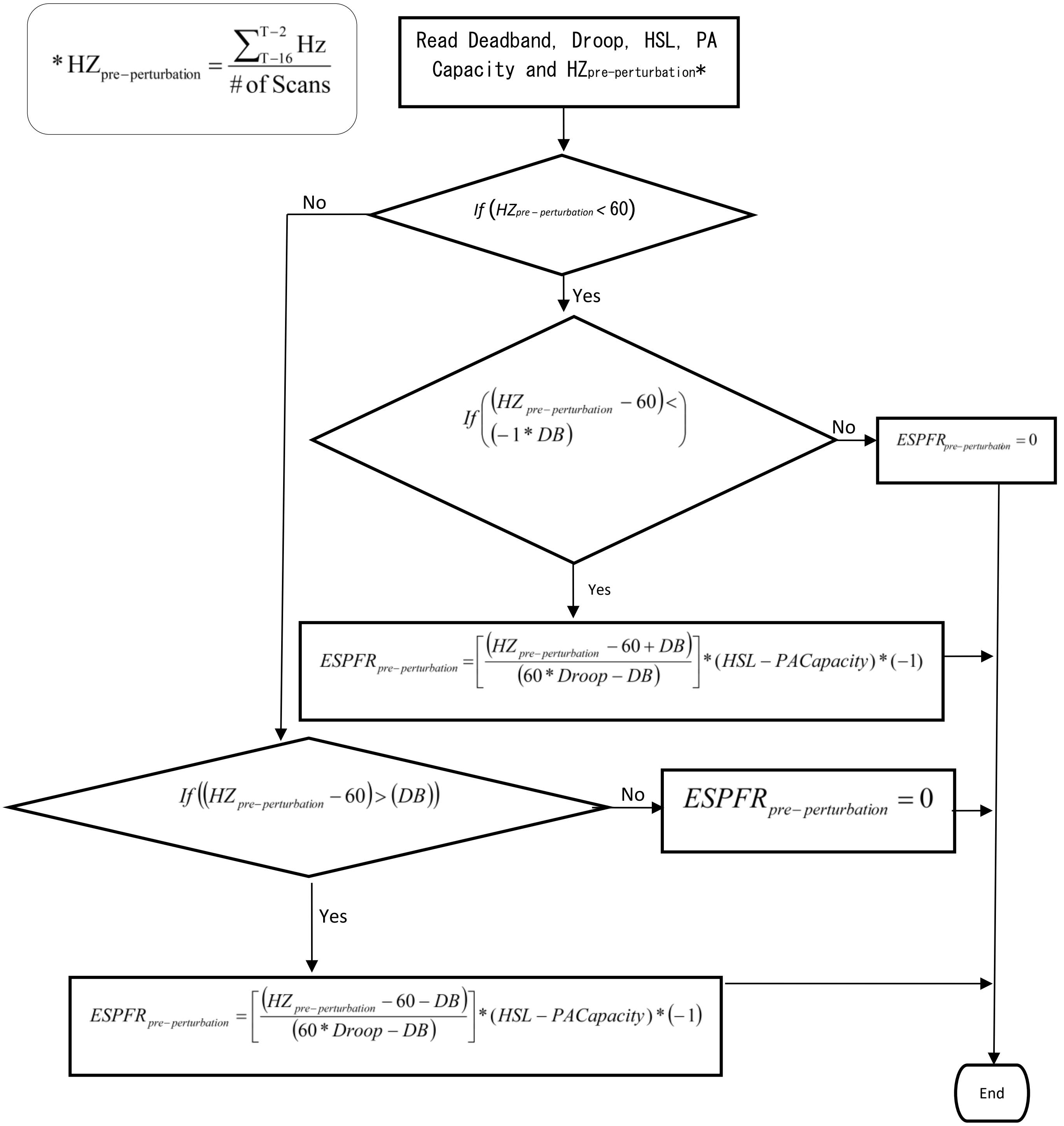
$$\boxed{ASPFR_{Adj} = Minimum(MW_{T+46} : MW_{T+60}) - MW_{pre\text{-perturbation}} - Ramp\ Magnitude_{Sustained}}$$

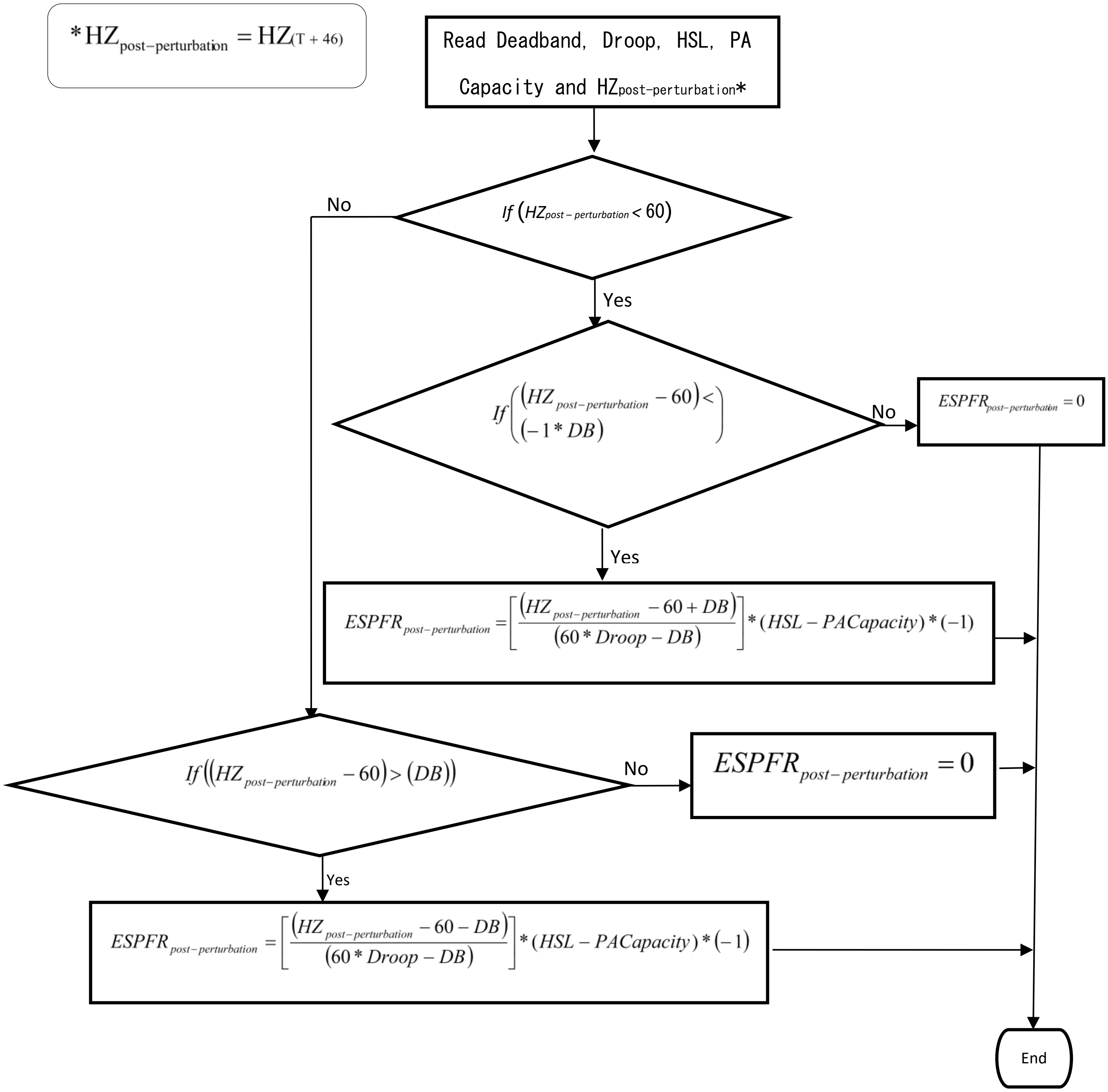
$$\downarrow$$

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, HSL, $MW_{pre-perturbation}$ and $MW_{post-perturbation}$

↓

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

↓

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

↓

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

↓

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

↓

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

↓

End

$MW_{post-perturbation}$ = 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 HSL, PA Capacity, $HZ_{post\text{-}perturbation}$*

↓

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

↓

End

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

Adjustment for Other Units

Read Limiting Factor

↓

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

↓

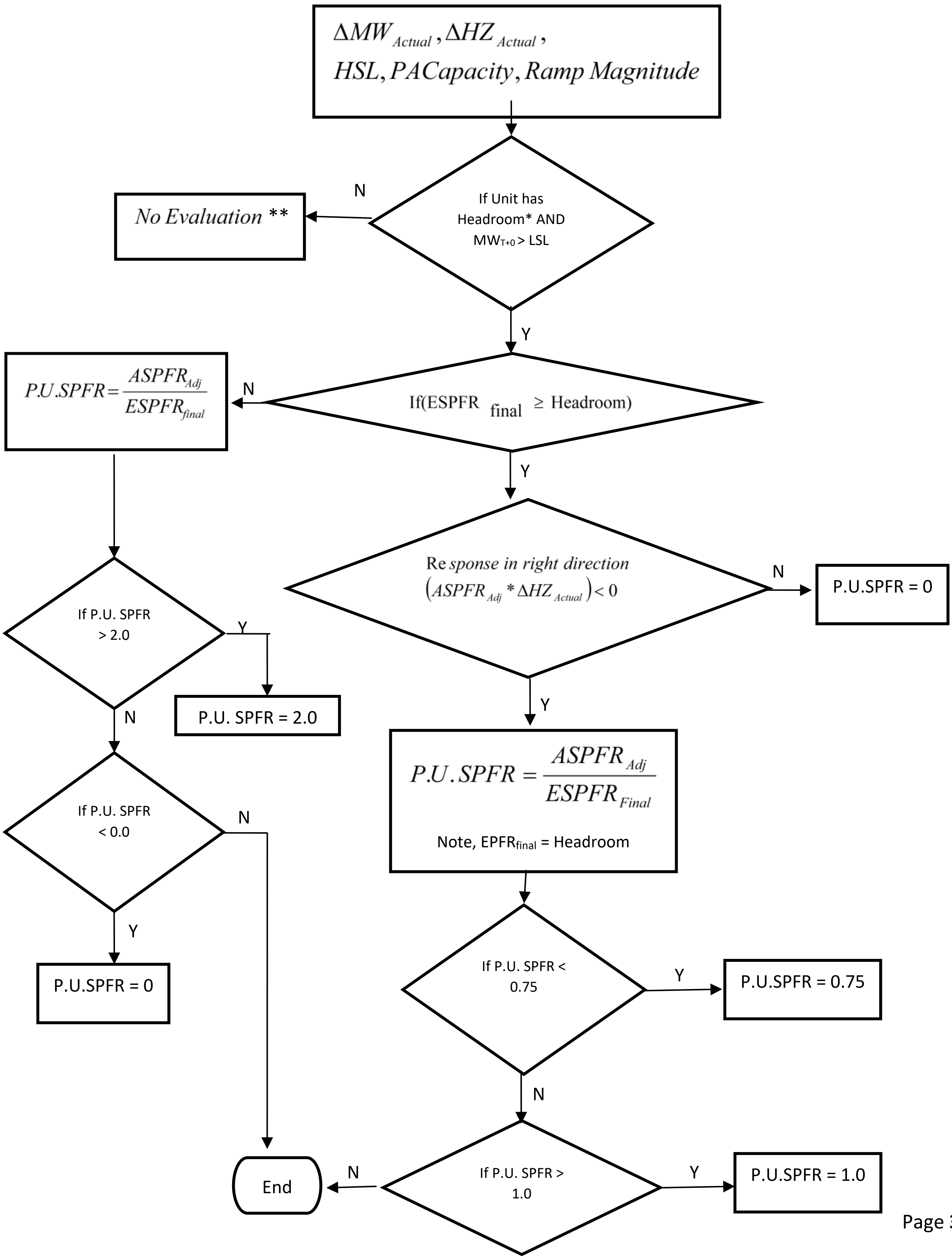
End

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

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

P.U. Sustained Primary Frequency Response Calculation

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



$\Delta MW_{Actual}, \Delta HZ_{Actual},$
$HSL, PACapacity, Ramp\ Magnitude$
If Unit has Headroom* AND MW_{T+0} > LSL
N
No Evaluation **
Y
If(ESPFR $_{final}$ ≥ Headroom)
N
$P.U.SPFR = \frac{ASPFR_{Adj}}{ESPFR_{final}}$
Y
Response in right direction
$(ASPFR_{Adj} * \Delta HZ_{Actual}) < 0$
N
P.U.SPFR = 0
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 5MW or 2% of (HSL less PA Capacity), whichever is larger. If a unit does not have adequate up headroom, the unit is considered operating at full capacity and will not be evaluated for low frequency events.

Check for adequate down headroom, high frequency events. Headroom must be greater than either 5MW or 2% of (HSL less PA Capacity), whichever is larger. If a unit does not have adequate down headroom, the unit is considered operating at low capacity and will not be evaluated for high frequency events.

For low frequency events:

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

For high frequency events:

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

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

T = Time in Seconds

Revision History

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

A. Introduction

1. **Title:** Primary Frequency Response in the ERCOT Region
2. **Number:** BAL-001-TRE-2~~1~~
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-2~~1~~.
    - **4.2.2** Generating units/generating facilities while operating in synchronous condenser mode are exempt from Standard BAL-001-TRE-2~~1~~.
    - **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-2.
6. **Background:** The ERCOT Interconnection was initially given a waiver of BAL-001 R2 (Control Performance Standard CPS2). In FERC Order 693, NERC was directed to develop a Regional Standard as an alternate means of assuring frequency performance in the ERCOT Interconnection. NERC was explicitly directed to incorporate key elements of the existing Protocols, Section ~~5.9~~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 R~~r~~egional S~~s~~tandard provides requirements related to identifying Frequency Measureable 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 R~~r~~egional S~~s~~tandard the term “resource” is synonymous with “generating unit/generating facility”.

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 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%.

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

2.3. If a generating unit/generating facility has not participated in a minimum of (8) eight 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.

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[1] The 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.

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

M3. The Balancing Authority shall demonstrate that the IMFR was determined in December of each year per per ~~r~~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 occurs, the Balancing Authority shall determine and make publicly available the Interconnection's combined Frequency Response performance for a rolling average of the last six (6) FMEs by the end of the following calendar month. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

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

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

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

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

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

Table 6.1 Governor Deadband Settings

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

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

Table 6.2 Governor Droop Settings

Generator Type	Max. Droop % Setting
Hydro	5%
~~Nuclear~~	~~5%~~
~~Coal and Lignite~~	~~5%~~
Combustion Turbine (Simple Cycle and Single-Shaft Combined Cycle)	5%
Combustion Turbine (Combined Cycle)*	4%
Steam Turbine* ~~(Simple Cycle)~~	5%
~~Steam Turbine (Combined Cycle)*~~	~~5%~~
Diesel	5%
~~Wind Powered Generator~~	~~5%~~
DC Tie Providing Ancillary Services	5%
Variable Renewable (Non-Hydro)	5%

*~~*Steam Turbines of combined cycle resources are required to comply with Requirements R6.1, R6.2 and R6.3. Compliance with Requirements R9 and R10 will be determined through evaluation of the combined cycle facility using an expected performance droop of 5.78%.~~

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

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

Where

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

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

MWGCS is the maximum megawatt control range of the Governor control system. For mechanical Governors, droop will be proportional from the deadband by design. *[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
- Governo~~e~~r setting sheets
- Performance monitoring reports

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.

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 ~~Compliance Enforcement Authority~~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 ~~should be~~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. *[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 ~~Compliance Enforcement 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 ~~should be~~was excluded from the rolling average calculation.

C. Compliance

1. Compliance Monitoring Process

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

1.2. Compliance Monitoring Period and Reset Time Frame: If a generating unit/generating facility completes a mitigation plan and implements corrective action(s) to meet requirements R9 and R10 of the standard, and if approved by the BA and Compliance Enforcement Authority, then the generating unit/generating facility may begin a new rolling event average performance on the next performance during an FME. This will count as the first event in the performance calculation and the entity will have an average frequency performance score after 12 successive months or eight events per R9 and R10.

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

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

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

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

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

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

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

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Balancing Authority reported an FME more than 14 days but less than 31 days after identification of the event.	The Balancing Authority reported an FME more than 30 days but less than 51 days after identification of the event.	The Balancing Authority reported an FME more than 50 days but less than 71 days after identification of the event.	The Balancing Authority reported an FME more than 70 days after identification of the event.
R2.	The Balancing Authority submitted a monthly report more than one month but less than 51 days after the end of the reporting month.	The Balancing Authority submitted a monthly report more than 50 days but less than 71 days after the end of the reporting month.	The Balancing Authority submitted a monthly report more than 70 days but less than 91 days after the end of the reporting month.	The Balancing Authority failed to submit a monthly report within 90 days after the end of the reporting month.
R3.	The Balancing Authority did not make the calculation and criteria for determination of the IMFR publicly available.	The Balancing Authority did not make the IMFR publicly available.	The Balancing Authority did not calculate the IMFR for the following year in December.	The Balancing Authority did not calculate the IMFR for a calendar year.
R4.	N/A	N/A	The Balancing Authority did not make public the six-FME rolling average Interconnection combined Frequency Response by the end of the following month.	The Balancing Authority did not calculate the six- FME rolling average Interconnection combined Frequency Response for any month in which an FME occurred.
R5.	N/A	N/A	N/A	The Balancing Authority did not take action to improve

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

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

D. Regional Variances

None

E. Associated Documents

Regional Standard BAL-001-TRE-2 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.

Standard Attachments

~~1. Attachment 1 – Implementation Plan.~~

1~~2~~. Attachment 1~~2~~ – 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~~2~~

Primary Frequency Response Reference Document

Texas Reliability Entity, Inc.
BAL-001-TRE-~~1~~2
Requirements R2, R9, and R10
Performance Metric Calculations

I. Introduction

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

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

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

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

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

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

[1] These spreadsheets are available at www.TexasRE.org.

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.

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

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

9.3. A generating unit/generating facility's initial Primary Frequency Response performance during an FME may be excluded by the Balancing Authority from the rolling average calculation 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 ~~Compliance Enforcement Authority~~Balancing Authority may request raw data from the Generator Owner as a substitute.

Initial Primary Frequency Response Performance Calculation Methodology

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

This process calculates the initial Per Unit Primary Frequency Response of a resource [$P.U.PFR_{Resource}$] as a ratio between the Adjusted Actual Primary Frequency Response ($APFR_{Adj}$),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 Primary Frequency Response [$P.U.PFR_{Resource}$] for any Frequency Measurable Event (FME).

Initial Primary Frequency Response performance requirement

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

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

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

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

The Adjusted Actual Primary Frequency Response (APFR$_{Adj}$) and the Final Expected Primary Frequency Response (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~~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

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

[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 Adjustment: The Actual Primary Frequency Response 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 = $(MW_{T-4} – MW_{T-60})*0.59$

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

Expected Primary Frequency Response (EPFR)

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

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

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

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

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

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

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

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

For each formula, when frequency is within the Governor deadband the appropriate EPFR value is zero. The $deadband_{max}$ and $droop_{max}$ 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 NDC (Net Dependable Capacity) 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 Capacity for wind-powered generators is the real time HSL of the wind plant at the time the FME occurred.

Power Augmentation: For Combined Cycle 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

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

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~~Where:

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

~~where~~Where:

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

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

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

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

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

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

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

~~where~~ 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. The 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.

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 by the Balancing Authority from the rolling average calculation 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 ~~Compliance Enforcement Authority~~ may request raw data from the Generator Owner as a substitute.

Sustained Primary Frequency Response Performance Calculation Methodology

This portion of this PFR Reference Document establishes the process used to calculate sustained Primary Frequency Response performance for each Frequency Measurable Event (FME), and then average the events over a 12-~~-~~month period (or 8-~~-~~event minimum) to establish whether a resource is compliant with Requirement R10.

This process calculates the Per Unit Sustained Primary Frequency Response of a resource [$P.U.SPFR_{Resource}$] as a ratio between the maximum actual unit response at any time during the period from T+46 to T+60, adjusted for the pre-event ramping of the unit, and the *Final* Expected Primary Frequency Response (EPFR) value at time T+46.[3]

This comparison of actual performance to a calculated target value establishes, for each type of resource, the Per Unit Sustained Primary Frequency Response [$P.U.SPFR_{Resource}$] for any Frequency Measurable Event (FME).

Sustained Primary Frequency Response performance requirement:

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

[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.

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

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

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

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

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

$P.U.SPFR_{Resource}$ is the per unit (P.U.) measure of the sustained Primary Frequency Response of a resource during identified Frequency Measurable Events. 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~~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~~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 Primary Frequency Response 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 ($MW_{T-4} - MW_{T-60}$) by a modifier. This extrapolates to an equivalent number of MWs the generator would have changed if it had been allowed to continue on its ramp to T+46 unencumbered by the FME. The modifier is $\frac{46 \text{ seconds}}{56 \text{ seconds}}$ or 0.821.

Expected Sustained Primary Frequency Response (*ESPFR*) Calculations

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

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

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

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

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

Capacity and Net Dependable Capability (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 capacity for wind-powered generators is the real-time HSL of the wind plant at the time the FME occurred. The $deadband_{max}$ and $droop_{max}$ quantities come from Requirement R6.

For Combined Cycle facilities, determination of Capacity includes subtracting Power Augmentation (PA) Capacity, if any, from the original 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 is required to provide the BA with documentation and identify conditions when this augmentation is in service.

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

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

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

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

~~where~~Where:

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

~~w~~Where:

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

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

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

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

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

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

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

If the generating unit/generating facility is operating within 2% of its (HSL – PA Capacity) or within 5 MW (whichever is greater) 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:

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

then Primary Frequency Response is not evaluated for this FME.

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

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

then Primary Frequency Response is not evaluated for this FME.

Final Expected Primary Frequency Response (EPFRfinal) is greater than Operating Margin: Caps and limits exist for resources operating with adequate reserve margin to be evaluated (at least 2% of (HSL less PA Capacity) or 5 MW), 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 Expected Primary Frequency Response$_{~~f~~Final}$ is greater than the generating unit/generating facility's available frequency responsive Capacity[4]; and
    c. The generating unit/generating facility's APFR$_{adj}$ response is in the correct direction.

2. When calculation of the P.U.PFR$_{Resource}$ uses the resource's (HSL less PA Capacity) 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 Primary Frequency Response measures.

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

Attachment A to

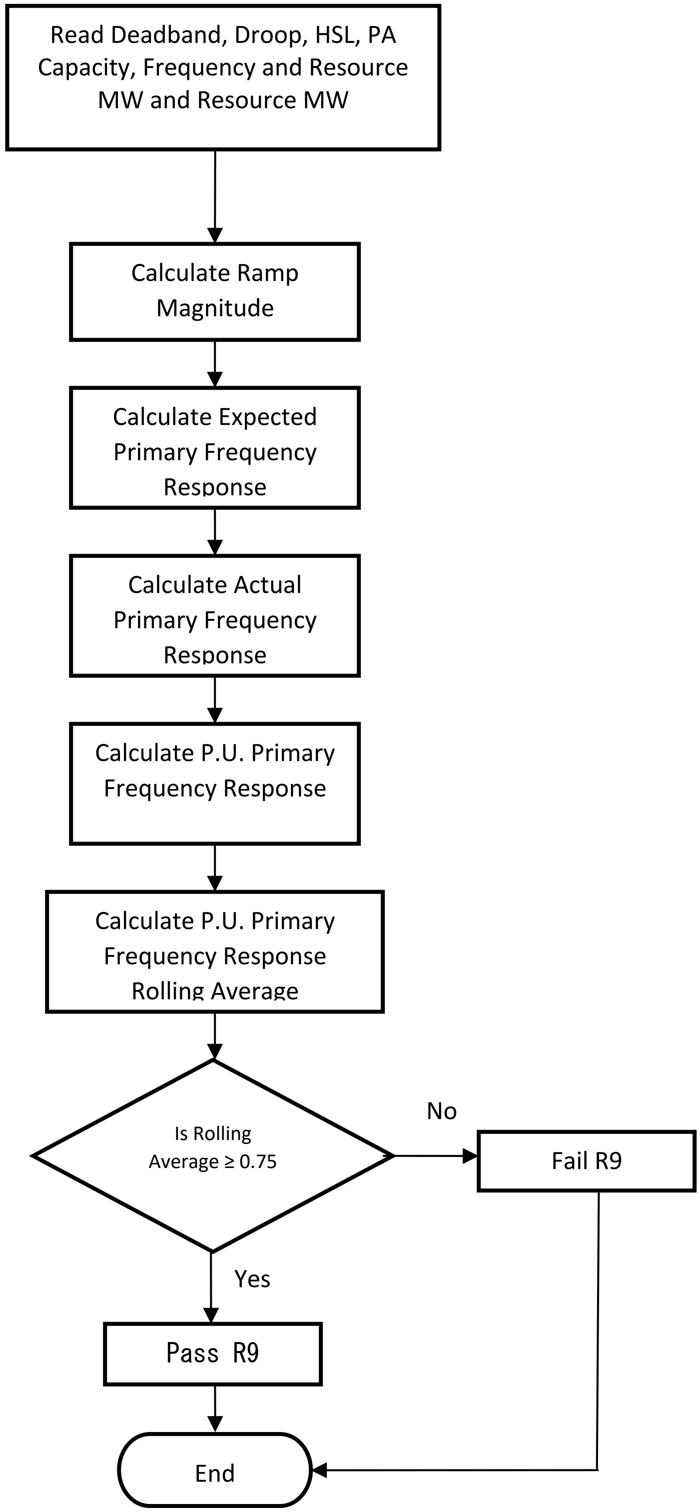
Primary Frequency Response Reference Document

Initial Primary Frequency Response Methodology for

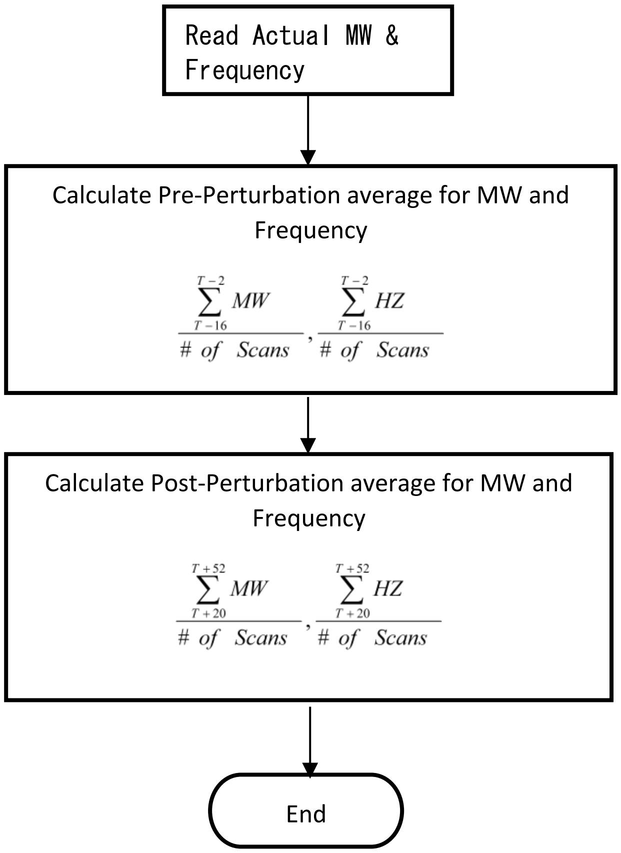
BAL-001-TRE-<ins>2</ins>~~1~~

Primary Frequency Response Measurement and Rolling Average Calculation – Initial Response

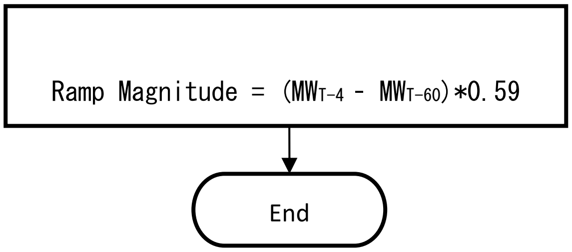
PA=Power Augmentation
HSL=High Sustained Limit



Pre/Post-Perturbation Average MW and Average Frequency Calculations

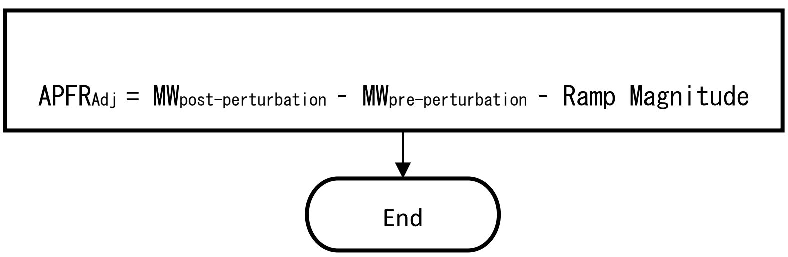


Ramp Magnitude Calculation



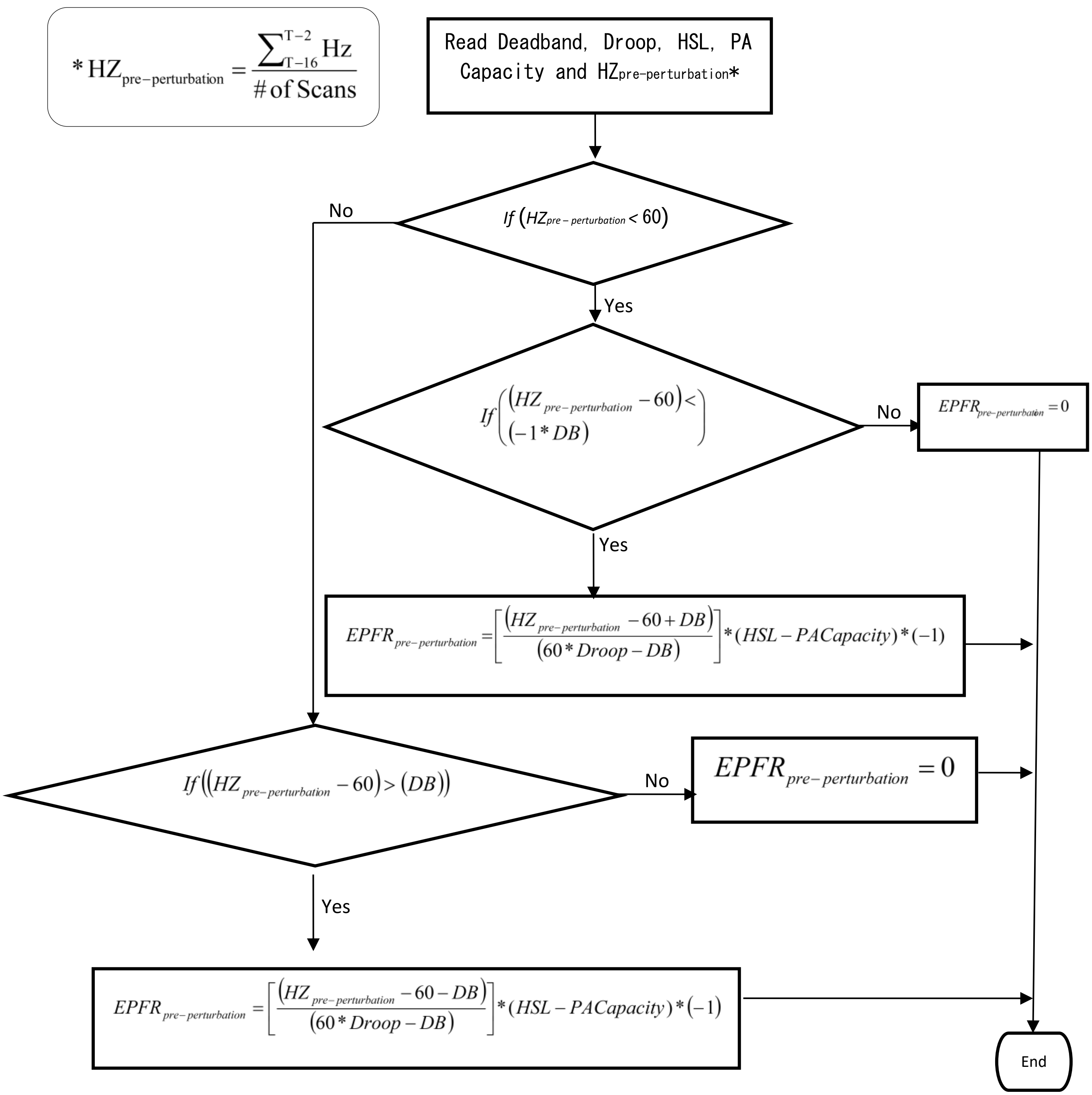
$(MW_{T-4} - MW_{T-60})$ represents the MW ramp of the generator resource/generator facility for a full minute prior to the event. The factor 0.59 adjusts this full minute ramp to represent the ramp that should have been achieved during the post-perturbation measurement period.

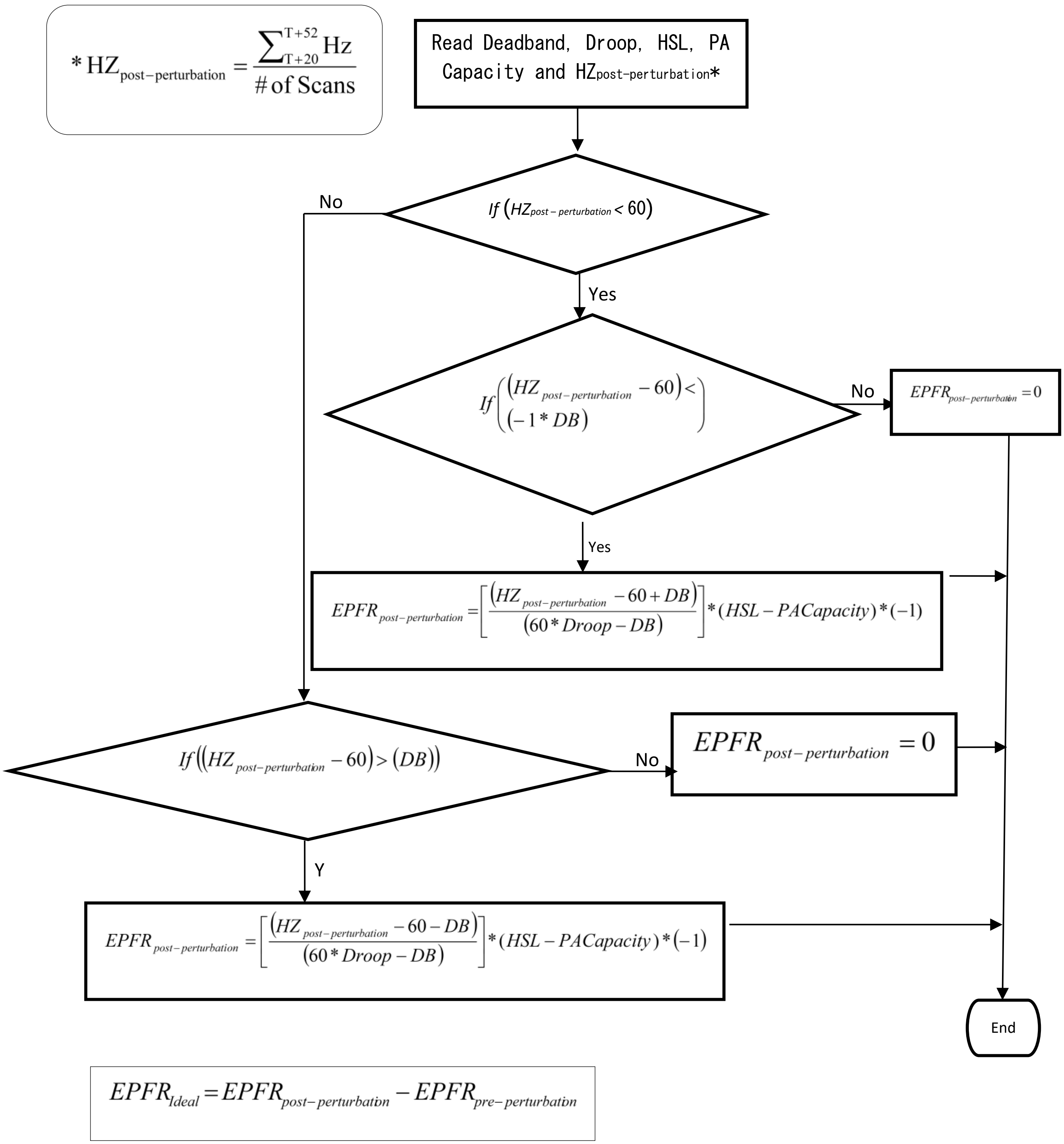
Actual Primary Frequency Response ($APFR_{Adj}$)



Expected Primary Frequency Response Calculation

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




$* HZ_{post-perturbation} = \frac{\sum_{T+20}^{T+52} Hz}{\# of Scans}$
Read Deadband, Droop, HSL, 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
$EPFR_{post-perturbation} = \left[\frac{(HZ_{post-perturbation} - 60 + DB)}{(60 * Droop - DB)}\right] * (HSL - PACapacity) * (-1)$
$If((HZ_{post-perturbation} - 60) > (DB))$
No
$EPFR_{post-perturbation} = 0$
Y
$EPFR_{post-perturbation} = \left[\frac{(HZ_{post-perturbation} - 60 - DB)}{(60 * Droop - DB)}\right] * (HSL - PACapacity) * (-1)$
End
$EPFR_{Ideal} = EPFR_{post-perturbation} - EPFR_{pre-perturbation}$

Adjustment for Steam Turbine

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

↓

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

↓

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

↓

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

↓

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

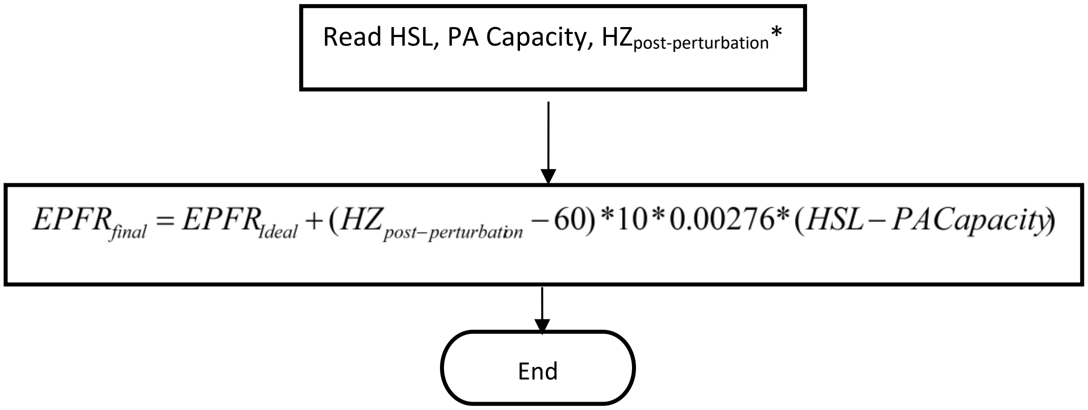
↓

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

↓

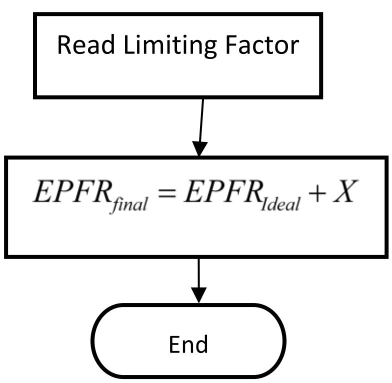
End

Adjustment for Combustion Turbines and Combined Cycle Facilities



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

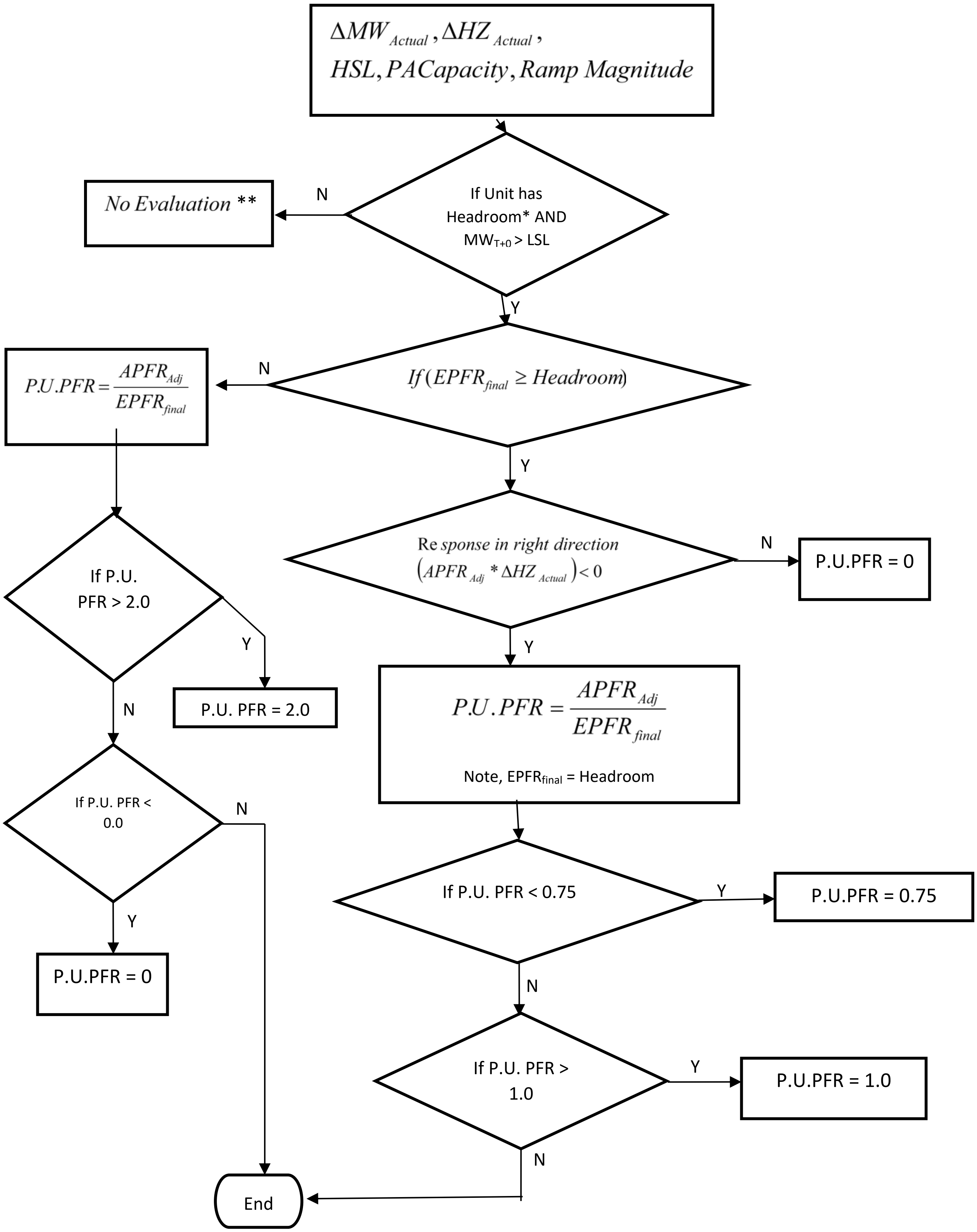
Adjustment for Other Units



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

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



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

*Check for adequate up headroom, low frequency events. Headroom must be greater than either 5MW or 2% of (HSL less PA Capacity), whichever is larger. If a unit does not have adequate up headroom, the unit is considered operating at full capacity and will not be evaluated for low frequency events.

Check for adequate down headroom, high frequency events. Headroom must be greater than either 5MW or 2% of (HSL less PA Capacity), whichever is larger. If a unit does not have adequate down headroom, the unit is considered operating at low capacity and will not be evaluated for high frequency events.

For low frequency events:

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

For high frequency events:

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

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

T = Time in Seconds

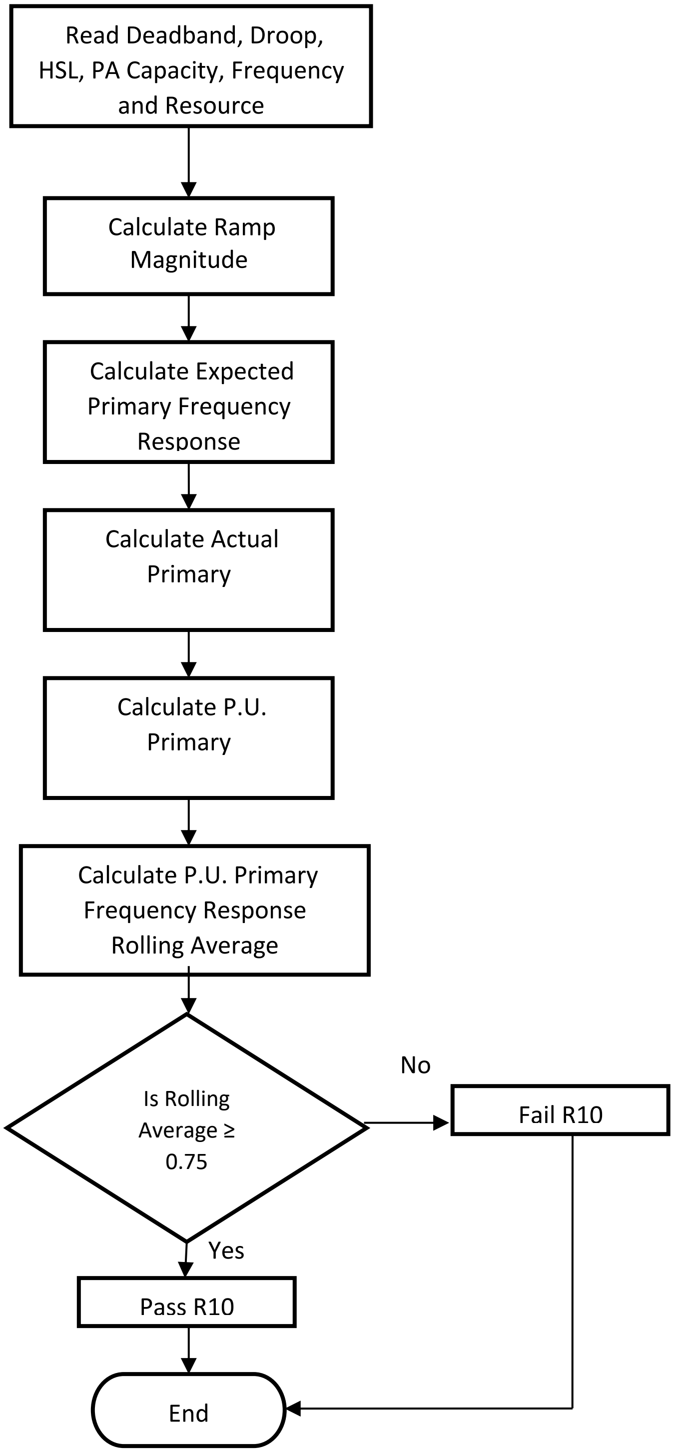
Attachment B to

Primary Frequency Response Reference Document

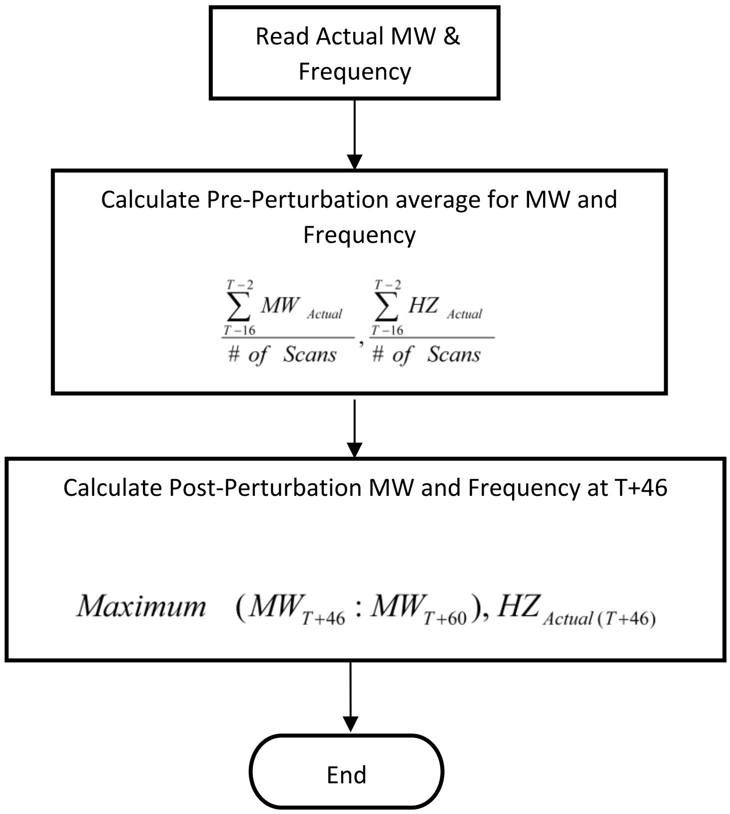
Sustained Primary Frequency Response Methodology for

BAL-001-TRE-2~~1~~

Primary Frequency Response Measurement and Rolling Average Calculation–Sustained Response



Pre/Post-Perturbation Average MW and Average Frequency Calculations



Ramp Magnitude Calculation - Sustained

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

↓

End

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

Actual Sustained Primary Frequency Response (ASPFRa~~A~~dj)

For low frequency events:

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

↓

End

For high frequency events:

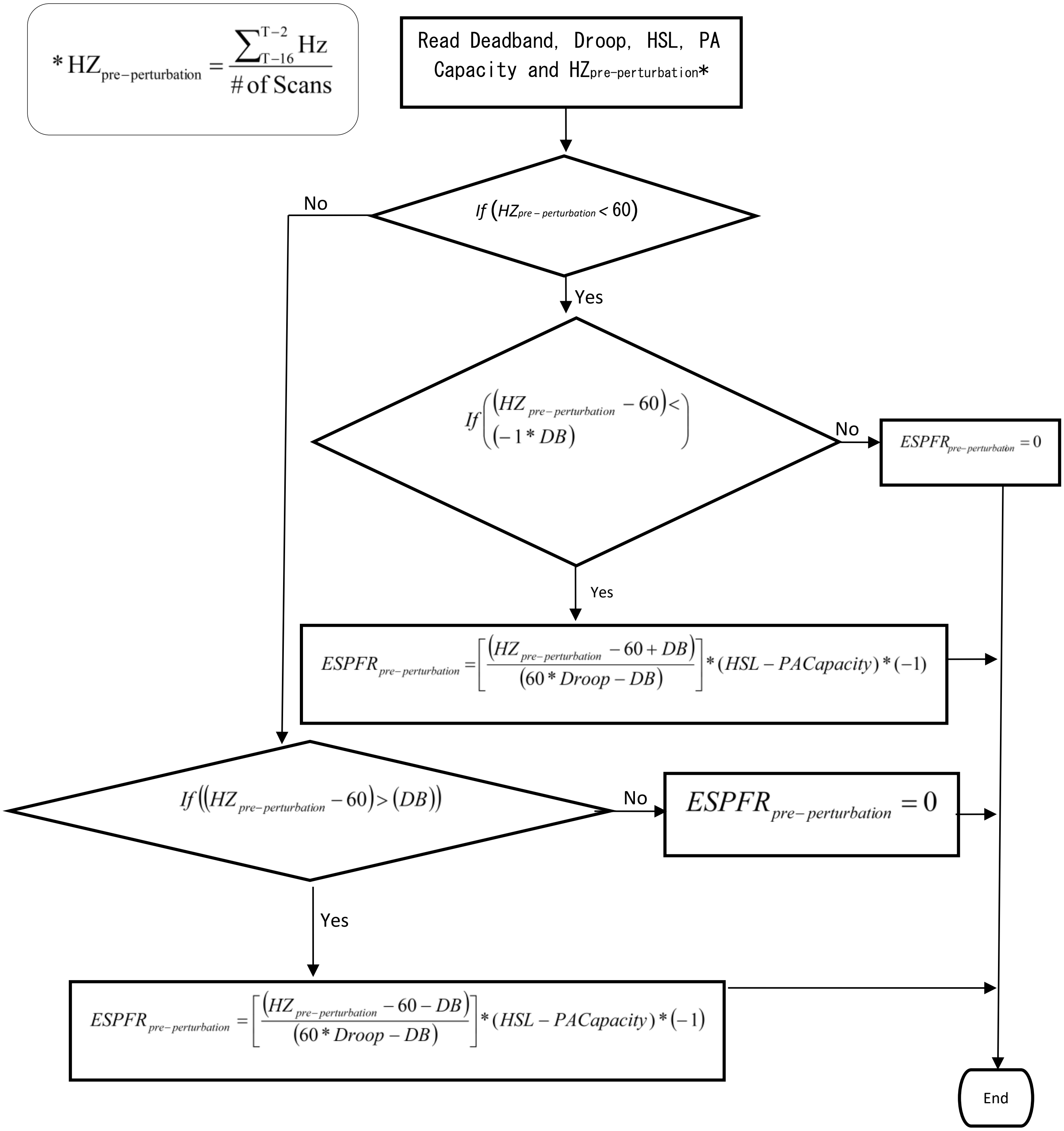
$$ASPFR_{Adj} = Minimum(MW_{T+46} : MW_{T+60}) - MW_{pre\text{-perturbation}} - Ramp\ Magnitude_{Sustained}$$

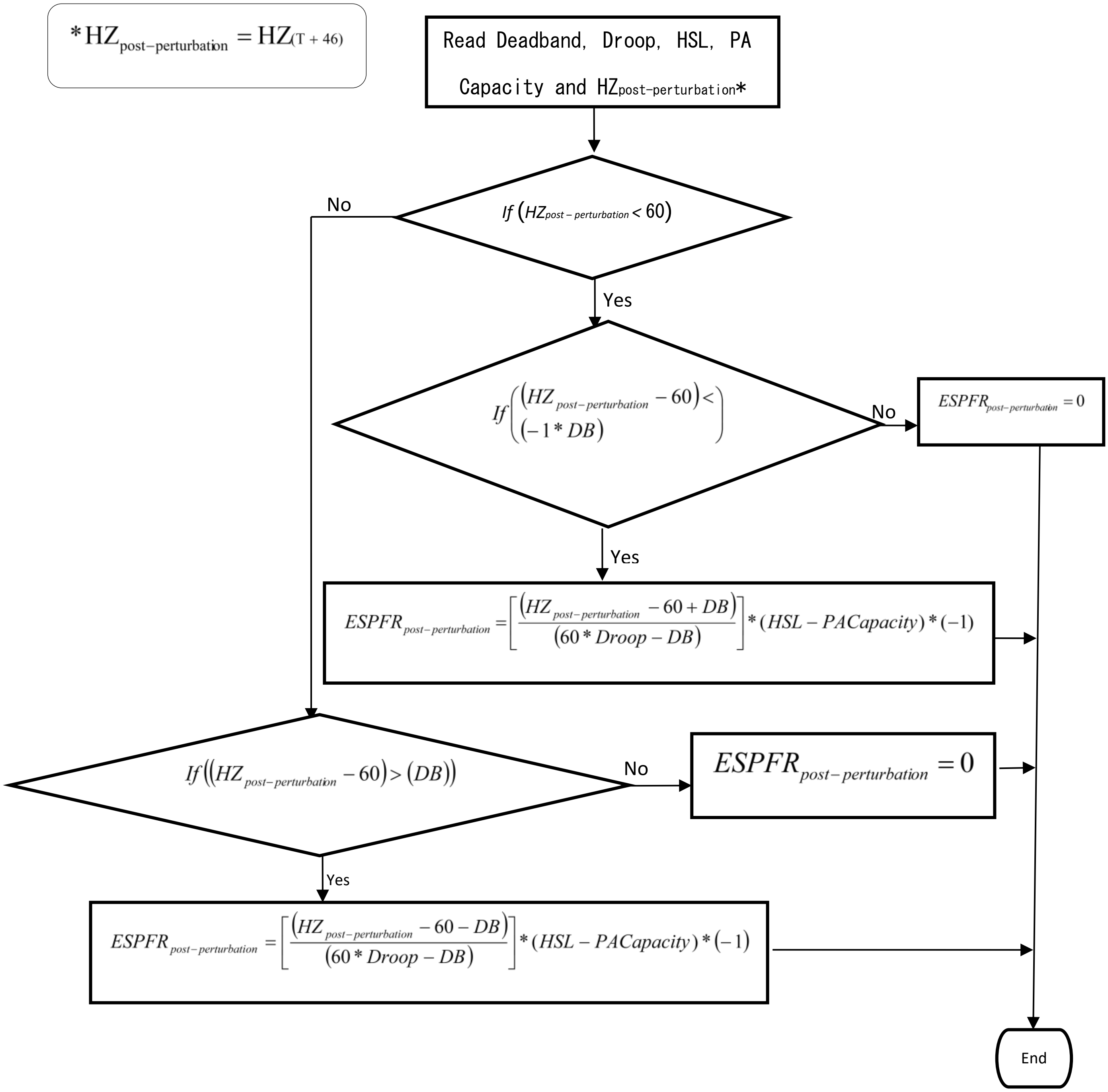
↓

End

Expected Sustained Primary Frequency Response Calculation

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





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

Adjustment for Steam Turbine

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

↓

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

↓

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

↓

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

↓

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

↓

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

↓

End

$MW_{post-perturbation}$ = 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 HSL, PA Capacity, $HZ_{post\text{-}perturbation}$*

↓

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

↓

End

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

Adjustment for Other Units

Read Limiting Factor

↓

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

↓

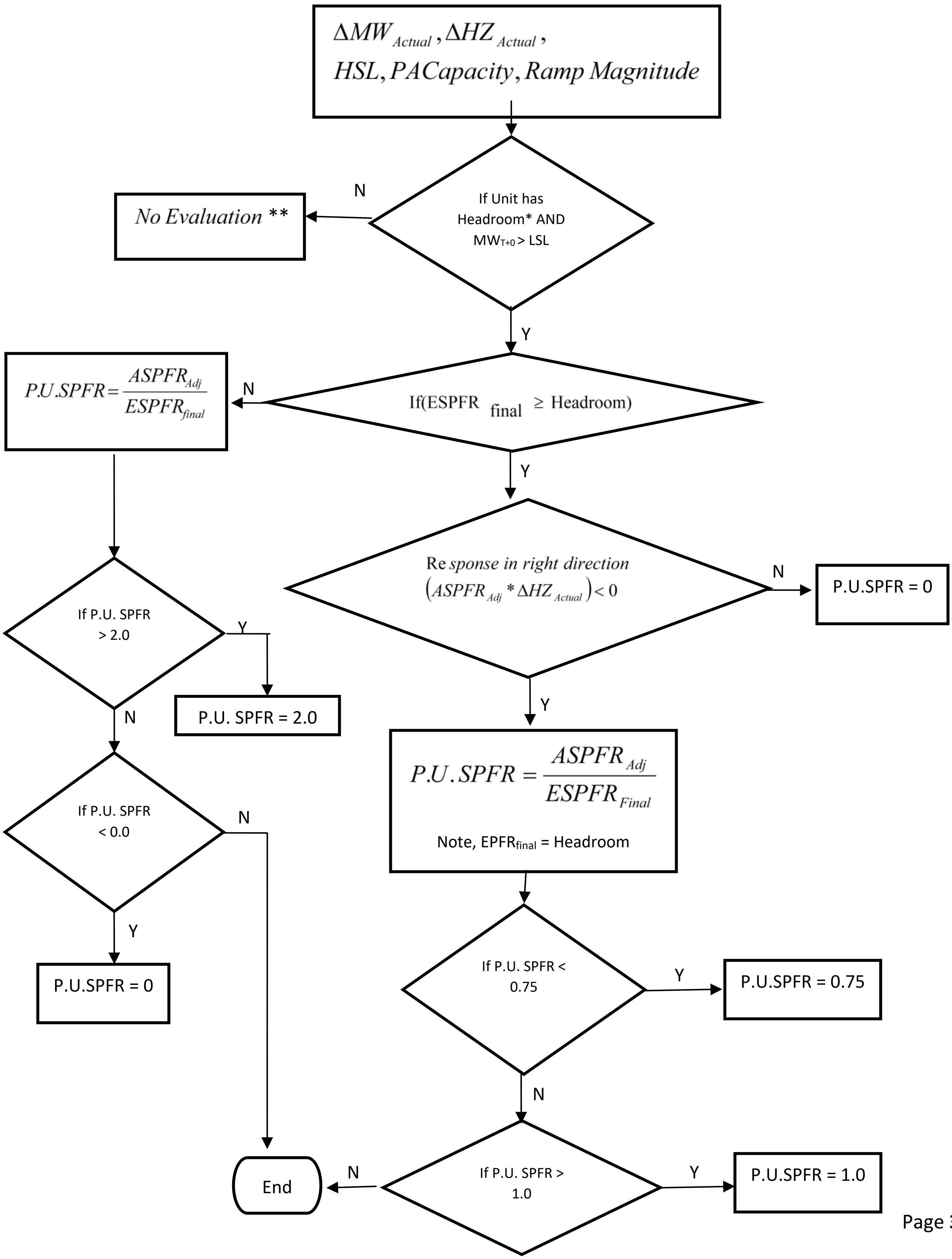
End

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

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

P.U. Sustained Primary Frequency Response Calculation

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


$\Delta MW_{Actual}, \Delta HZ_{Actual},$
$HSL, PACapacity, Ramp\ Magnitude$
If Unit has Headroom* AND MW_{T+0} > LSL
N
No Evaluation **
Y
If(ESPFR final ≥ Headroom)
N
$P.U.SPFR = \frac{ASPFR_{Adj}}{ESPFR_{final}}$
Y
$Re\,sponse\ in\ right\ direction$
$(ASPFR_{Adj} * \Delta HZ_{Actual}) < 0$
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 5MW or 2% of (HSL less PA Capacity), whichever is larger. If a unit does not have adequate up headroom, the unit is considered operating at full capacity and will not be evaluated for low frequency events.

Check for adequate down headroom, high frequency events. Headroom must be greater than either 5MW or 2% of (HSL less PA Capacity), whichever is larger. If a unit does not have adequate down headroom, the unit is considered operating at low capacity and will not be evaluated for high frequency events.

For low frequency events:

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

For high frequency events:

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

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

T = Time in Seconds

Revision History

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

Implementation Plan

Project SAR-011 Revisions to BAL-001-TRE
BAL-001-TRE-2

Requested Approval
BAL-001-TRE-2 – Primary Frequency Response in the ERCOT Region

Requested Retirement
BAL-001-TRE-1 – Primary Frequency Response in the ERCOT Region

Approvals Required
None.

Prerequisite Approvals
None.

Revisions to Glossary Terms
None.

Applicable Entities

- Balancing Authority (BA)
- Generator Owners (GO)
- Generator Operators (GOP)
- Exemptions:
  - o Existing generating facilities regulated by the U.S. Nuclear Regulatory Commission are exempt from Standard BAL-001-TRE-2.
  - o Generating units/generating facilities while operating in synchronous condenser mode are exempt from Standard BAL-001-TRE-2.

o Any generators that are not required by the BA to provide primary frequency response are exempt from this standard.

Effective Date
The 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.

Standard for Retirement
Regional Standard BAL-001-TRE-1 shall be retired immediately prior to the Effective Date of BAL-001-TRE-2.

TEXAS RE
Ensuring electric reliability for Texans

Summary of Changes

SAR-011 Revisions to Regional Standard BAL-001-TRE-1

Draft Standard

Section	Proposed Change	Rationale
Format	Updated to NERC's most recent Results-based template.	This is at the request of NERC standards staff.
Format	Changed all of the abbreviations of the functions to the written function.	This is at the request of NERC standards staff.
Header	Changed from BAL-001-TRE-1 to BAL-001-TRE-2	The version of the standard is changing.
Standard Version	Changed from BAL-001-TRE-1 to BAL-001-TRE-2	The version of the standard is changing.
Background	Changed "Section 5.9" to Section 8.5".	This information moved to a different section in the Protocols.
Background	Added (FME) after Frequency Measurable Event	This change shows that the rest of the document will use the acronym FME.
Background	Capitalized "regional standard".	The term "Regional Standard" is defined in the Texas RE Standard Development Process document.
Background	Added (PFR) after Primary Frequency Response.	This change shows that the rest of the document will use the acronym PFR.
Effective Date	Changed to "See implementation plan"	This is consistent with the national standards. There is a separate implementation plan document.
Requirement 6.2 Table	Remove Nuclear, Coal and Lignite, from the table	These are fuel types. Plants with these fuel types operate as steam turbines.
Requirement 6.2 Table	Removed Wind Powered Generator from the table	Wind Powered Generator is included in Variable Renewable (Non-Hydro)
Requirement 6.2 Table	Changed "Steam Turbine (Simple Cycle)" to "Steam Turbine"	The original BAL-001-TRE drafting team accounted for the lack of Primary Frequency Response (PFR) from the steam turbines in a combined cycle resource train by requiring an overall 5.78% PFR performance for the entire

Section	Proposed Change	Rationale
		train. This change aligns the standard's requirements with current operational practices. As the Balancing Authority for the ERCOT Region, ERCOT has already used its directive authority under R6 of the standard to explicitly exempt Generator Operators with steam turbines in combined-cycle trains from the droop and deadband settings in R6.1 and R6.2, pending a clarification to the standard. See ERCOT Market Notice W-C050418-01 (May 4, 2018).
Requirement 6.2 Table	Removed "Steam Turbine (Combined Cycle)"	The original BAL-001-TRE drafting team accounted for the lack of Primary Frequency Response (PFR) from the steam turbines in a combined cycle resource train by requiring an overall 5.78% PFR performance for the entire train. This change aligns the standard's requirements with current operational practices. As the Balancing Authority for the ERCOT Region, ERCOT has already used its directive authority under R6 of the standard to explicitly exempt Generator Operators with steam turbines in combined-cycle trains from the droop and deadband settings in R6.1 and R6.2, pending a clarification to the standard. See ERCOT Market Notice W-C050418-01 (May 4, 2018).
Requirement 6.2 Table	Revised "Renewable (Non-Hydro)" to "Variable Renewable (Non-Hydro)"	This change indicates that all non-hydro renewable resources, including wind, are included.
Requirement 6.2 asterisk	Revised the asterisk from "Steam Turbines of combined cycle resources are required to comply with Requirements R6.1, R6.2, and R6.3. Compliance with Requirements R9 and R10 will be determined through	The original BAL-001-TRE drafting team accounted for the lack of Primary Frequency Response (PFR) from the steam turbines in a combined cycle resource train by requiring an overall 5.78% PFR performance for the entire

Section	Proposed Change	Rationale
	evaluation of the combined cycle facility using an expected performance droop of 5.78%." to "Requirements R6.1, R6.2, and R6.3 are not applicable to steam turbine(s) of a combined cycle resource."	train. This change aligns the standard's requirements with current operational practices. As the Balancing Authority for the ERCOT Region, ERCOT has already used its directive authority under R6 of the standard to explicitly exempt Generator Operators with steam turbines in combined-cycle trains from the droop and deadband settings in R6.1 and R6.2, pending a clarification to the standard. See ERCOT Market Notice W-C050418-01 (May 4, 2018).
Requirement R6.2 asterisk	Removed this from the asterisk: "Compliance with Requirements R9 and R10 will be determined through evaluation of the combined cycle facility using an expected performance droop of 5.78%."	This exists in Section B.R2.1. The intent is to indicate the BA will evaluate performance according to a certain value, which is stated in Section B.R2.1.
M6	Revised "governer" to "governor".	This change corrects the spelling.
Requirement R9.3	Added "by the Balancing Authority"	This change specifies that the BA is the entity responsible for review and approval of exclusion requests for a generating unit/generating facility's initial Primary Frequency Response performance during an FME.
Requirement R9.3	Added "but are not limited to"	There are several legitimate operating conditions that may support exclusion aside from the 2 examples.
Requirement R9.3, second bullet	Changed Compliance Enforcement Authority to Balancing Authority	This change reflects current processes. The BA is the entity that may request raw data from the GO.
M9	Changed "should be excluded" to "was excluded".	This indicates the performance was already excluded from the rolling average calculation.
Requirement R10.3	Added "by the Balancing Authority"	This change specifies that the BA is the entity responsible for review and approval of exclusion requests for a

Section	Proposed Change	Rationale
		generating unit/generating facility's initial Primary Frequency Response performance during an FME.
Requirement R10.3	Added "but are not limited to"	There are several legitimate operating conditions that may support exclusion aside from the 2 examples.
Requirement R10.3, second bullet	Changed Compliance Enforcement Authority to Balancing Authority	This change reflects current processes. The BA is the entity that may request raw data from the GO.
M10	Changed "should be excluded" to "was excluded".	This indicates the performance was already excluded from the rolling average calculation.
C. 1 1.2	Added (s) after corrective action.	There could be more than one corrective action to meet requirements R9 and R10.
C. 1 1.3, First Bullet	Changed Frequency Measurable Event to FME.	It was established during the Background section that FME is the acronym for Frequency Measurable Event.
C. 1 1.3 Fourth Bullet	Changed "The BA shall retain all data and calculations relating to the Interconnection's Frequency Response, and all evidence of actions taken to increase the Interconnection's Frequency Response, since its last compliance audit for Requirements R4 and R5, Measures M4 and M5." To "The BA 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."	This indicates the evidence for the performance of Frequency Response.

Section	Proposed Change	Rationale
Standard Attachments	Removed "1. Attachment 1 – Implementation Plan"	This was the implementation plan for BAL-001-TRE-1. It is no longer relevant.
Standard Attachments	Changed "2. Attachment 2 – Primary Frequency Response Reference Document, including Flow Charts A and B" to "1. Attachment 1 – Primary Frequency Response Reference Document, including Flow Charts A and B"	Moved the reference document up to account for the removal of the implementation plan.
Version History	Added 2 with the changes being proposed.	This shows the changes being made at this time.

<u>Primary Frequency Response Reference Document</u>

Attachment 1	Changed from Attachment 2 to Attachment 1.	This change is in accordance with the change to Section E of the standard.
Attachment 1 Title	Changed from BAL-001-TRE-1 to BAL-001-TRE-2	The version of the standard is changing.
Attachment 1 Header	Changed from BAL-001-TRE-1 to BAL-001-TRE-2	The version of the standard is changing.
I. Introduction	Changed "will be" to "is". Removed the second "will be" and made modifications plural.	This document is currently being used so changed the tense to present.
Requirement R9.3	Added "by the BA"	This reflects the changes made to the standard requirement language.
Requirement R9.3	Added "but are not limited to"	This reflects the changes made to the standard requirement language.
Requirement R9.3	Changed Compliance Enforcement Authority to BA	This reflects the changes made to the standard requirement language.
Initial Frequency Response Performance	Hyphenated 12-month and 8-event	Compound adjectives that precede a noun should be hyphenated.

Calculation Methodology		
Initial Frequency Response performance requirement	Capitalized “Where”	Where should be capitalized because it is at the beginning of the line.
Initial Frequency Response performance requirement	Changed P.U.PFRResource to $P.U.PFR_{Resource}$	Resource should be a subscript. This is consistent with the formula.
Actual Primary Frequency Response ($APFR_{adj}$)	Capitalized “Where”	Where should be capitalized because it is at the beginning of the line.
$EPFR_{final}$ for Steam Turbine	Capitalized “Where”	Where should be capitalized because it is at the beginning of the line.
$EPFR_{final}$ for Other Generating Units/Generating Facilities	Capitalized “Where”	Where should be capitalized because it is at the beginning of the line.
Requirement R10.3	Added “by the BA”	This reflects the changes made to the standard requirement language.
Requirement R10.3	Added “but are not limited to”	This reflects the changes made to the standard requirement language.
Requirement R10.3	Changed Compliance Enforcement Authority to BA	This reflects the changes made to the standard requirement language.
Sustained Primary Frequency Response Performance Calculation Methodology	Hyphenated 12-month and 8-event	Compound adjectives that precede a noun should be hyphenated.
Actual Sustained Primary Frequency	Capitalized “Where” and “And”	Where and And should be capitalized because they are at the beginning of the line.

Response (ASPFR) Calculations		
$EPFR_{final}$ for Steam Turbine	Capitalized "Where" and "And"	Where and And should be capitalized because they are at the beginning of the line.
$EPFR_{final}$ for Other Generating Units/Generating Facilities	Capitalized "Where"	Where should be capitalized because it is at the beginning of the line.

SAR-011 Revisions to Regional Standard BAL-001-TRE-1 Non-binding Poll Results

				Standards Development Sectors					
Name	Entity	Non-binding Poll - violation risk factors	Non-binding poll - Violation Severity Levels	System Coordination and Planning	Transmission	Cooperative or Utility	Municipal Utility	Generation	Load-Serving and Marketing
Thomas Foltz	American Electric Power	No Opinion	No Opinion		x				
Leanna Lamatrice	American Electric Power	No Opinion	No Opinion						x
Matt Mereness	ERCOT	Positive Opinion	Positive Opinion	x					
James Rappach	American Electric Power	No Opinion	No Opinion					x	
Teresa Cantwell	LCRA	Positive Opinion	Positive Opinion					x	
Gladys DeLaO	CPS Energy	Positive Opinion	Positive Opinion		x				
Robert Stevens	CPS Energy	Positive Opinion	Positive Opinion					x	
Dwayne Preston	Austin Energy	Positive Opinion	Positive Opinion				x		
Lee D. Maurer	Oncor Electric Delivery – NCR04109	Positive Opinion	Positive Opinion		x				

SAR 011 Revisions to Regional Standard BAL-001-TRE-1 Ballot Pool							
		Standards Development Sectors					
Name	Entity	System Coordination and Planning	Transmission	Cooperative or Utility	Municipal Utility	Generation	Load-Serving and Marketing
Thomas Foltz	American Electric Power		x				
Leanna Lamatrice	American Electric Power						x
Matt Mereness	ERCOT	x					
James Rappach	American Electric Power					x	
Teresa Cantwell	LCRA					x	
James Grimshaw	CPS Energy				x		
Darin Ferguson	Cross Texas Transmission, LLC		x				
Shari Heino	Brazos Electric Power Cooperative, Inc.			x			
Deb Reichard Steitz	Buffalo Gap Wind Farm, LLC [NCR04025]					x	
Gladys DeLaO	CPS Energy		x				
Robert Stevens	CPS Energy					x	
Minh Ngo	City of Garland		x				
Dwayne Preston	Austin Energy				x		
Daniela Hammons	CenterPoint Energy Houston Electric, LLC		x				
Lee D. Maurer	Oncor Electric Delivery – NCR04109		x				
Trey Melcher	Lower Colorado River Authority		x				

SAR 011 Revisions to Regional Standard BAL-001-TRE-1 Ballot Results								
			Standards Development Sectors					
Name	**Entity**	**Ballot**	**System Coordination and Planning**	**Transmission**	**Cooperative or Utility**	**Municipal Utility**	**Generation**	**Load-Serving and Marketing**
Thomas Foltz	American Electric Power	Affirmative		x				
Leanna Lamatrice	American Electric Power	Affirmative						x
Matt Mereness	ERCOT	Affirmative	x					
James Rappach	American Electric Power	Affirmative					x	
Teresa Cantwell	LCRA	Affirmative					x	
Shari Heino	Brazos Electric Power Cooperative, Inc.	Affirmative			x			
Deb Reichard Steitz	Buffalo Gap Wind Farm, LLC [NCR04025]	Affirmative					x	
Gladys DeLaO	CPS Energy	Affirmative		x				
Robert Stevens	CPS Energy	Affirmative					x	
Dwayne Preston	Austin Energy	Affirmative				x		
Daniela Hammons	CenterPoint Energy Houston Electric, LLC	Affirmative		x				
Lee D. Maurer	Oncor Electric Delivery – NCR04109	Affirmative		x				

Proposed Standard Drafting Team Roster
Project SAR-011 Revisions to BAL-001-TRE-1
BAL-001-TRE-2

Name	**Experience and Qualifications to serve on the SDT**	**Development Sector(s)**
James R. Fletcher*, AEP	Member ERCOT PDCWG,Member PJM PFRSTF,Member BAL-003 Revisions SDT, Member SPP PFRTF, 42 years power generation engineering experience	Transmission, Cooperative or Utility, Generation, Load-Serving and Marketing
Presilo A Galliguez, Brazos Electric Power Cooperative, Inc.	As a member of PDCWG for nearly 10 years and 2 years as chair of the PDCWG, I have been involved in the discussions at PDCWG regarding BAL-001-TRE-01 from it's beginnings as well as participated in pre-trial testing as a generation resource owner for Brazos Electric Power Cooperative(BEPC) of a few Combined Cycle Power plants. As a PDCWG member, each member has participated in the review and discussion of the primary frequency response performance of all generation resources in accordance to BAL-001-TRE-01, namely, R9 and R10. These discussions at PDCWG are geared to each generation resource in helping a resource owner to identify the possible causes in deficiencies that limit a resource's ability to provide primary frequency response so that the overall ERCOT Interconnection Frequency Response Obligation can be maintained. In addition, as an EMS Engineer and member of the BEPC EMS Support staff, I prepare and analyze the BAL-001-TRE-01 spreadsheet for each of our generation resources and provide a summary to each generation plant on it's governor response performance for each possible system frequency disturbance which may become a Frequency Measurable Event.	Transmission, Cooperative or Utility, Generation
Jay Langley*, Talen Energy - Barney M. Davis LP, Barney M. Davis Unit 1, Laredo WLE LP, Laredo WLE LP (Laredo Energy Center), Nueces Bay WLE LP	Twenty years of operational experience with combine cycle technology. 9 years of compliance experience meeting ERCOT protocol requirements for governor response for combine cycle technology. Also, currently ensure compliance of the Talen ERCOT fleet that includes two combined cycle plants, one simple cycle facility and a traditional boiler facility further strengthen my technology experience.	Generation
Bracy Nesbit, LCRA	Over 30 years experience in the power generation industry. Professional Engineer in Texas and Oklahoma. IEEE Member for 32 years.	Generation
Joseph Bezzam, ERCOT	Joseph has been with ERCOT for 11 years and is a Senior Reliability and Compliance Engineer. He supports and analyzes NERC and Protocol compliance for ERCOT and	System Coordination and Planning

	its Market Participants. Joseph was very involved in implementing the BAL-001-TRE processes for ERCOT and has worked closely with the ERCOT Performance, Disturbance, Compliance Working Group (PDCWG) in the compliance metrics as they relate to BAL-001-TRE for individual and overall frequency performance at ERCOT.	
Arthur L. Mayclin, Calpine	My background starts in plant operation, moving to plant level IC&E support, and eventually moving into engineering. I hold a BSEE degree and currently manage the EI&C Engineering group at Calpine. However, fundamentally I am a controls engineer with over 20 years experience with turbine control systems, including governor operation. My group currently supports over 190 turbine control system in the Calpine fleet. I designed the AGC Bias logic for Calpine and managed the implementation throughout ERCOT and other regions (I also manage Calpine's field services group that implements logic changes). I currently attend PDCWG meetings and provide support services for Calpine with regard to primary frequency response analysis for the ERCOT region. My group supports MOD testing as well, including MOD-027. I am a registered engineer in both Electrical Engineering and Control System Engineering	Generation
Chad Mulholland, NRG	I am the Vice-Chair of the PDCWG. I work regularly with BAL-001-TRE-1 compliance in both my regular role with the NRG QSE, and with the PDCWG.	Generation

*James R. Fletcher and Jay Langley withdrew from the standard drafting team during the project.