UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF PROPOSED RELIABILITY STANDARD TPL-008-1

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Pursuant to Section 215(d)(1) of the Federal Power Act ("FPA")[1] and Section 39.5 of the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"),[2] the North American Electric Reliability Corporation ("NERC")[3] hereby submits for Commission approval proposed Reliability Standard TPL-008-1 – Transmission System Planning Performance Requirements for Extreme Temperature Events. The proposed Reliability Standard[4] would advance the reliability of the Bulk-Power System by improving how the entities responsible for planning for the reliable operation of the North American interconnected transmission systems plan for the wide-area impacts of extreme heat and cold temperature events, particularly when their systems are facing unexpectedly high demand. These enhanced planning requirements are timely and necessary. Extreme temperature events have increased in frequency in recent years and are projected to increase further in the future,[5] and experience demonstrates these events can result in widespread and severe impacts on the reliability of the Bulk-Power System.

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1 16 U.S.C. § 824o.

2 18 C.F.R. § 39.5 (2024).

3 The Commission certified NERC as the electric reliability organization ("ERO") in accordance with Section 215 of the FPA. *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 (2006) [hereinafter ERO Certification Order].

4 Unless otherwise indicated, terms capitalized in this filing shall have the meaning provided in the *Glossary of Terms used in NERC Reliability Standards*, https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

5 *See, e.g.*, U.S. Environmental Protection Agency, Climate Change Indicators: Weather and Climate (2024) (EPA Climate Change Indicators), https://www.epa.gov/climate-indicators/weather-climate.

As explained more fully herein, proposed Reliability Standard TPL-008-1 is responsive to the Commission's directives in Order No. 896, in which the Commission directed NERC to submit new or revised standards that would address concerns pertaining to transmission system planning for extreme heat and cold weather events by December 23, 2024.[6]

NERC requests that the Commission approve the proposed Reliability Standard, provided in Exhibit A hereto, as just, reasonable, not unduly discriminatory or preferential, and in the public interest. NERC also requests approval of: (1) the associated Implementation Plan (Exhibit B); and the associated Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") for the proposed Reliability Standard (Exhibit F).

As required by Section 39.5(a) of the Commission's regulations,[7] this petition presents the technical basis and purpose of the proposed Reliability Standard, a summary of the development history, including the adoption of the proposed Reliability Standards by the NERC Board of Trustees on December 10, 2024 (Exhibit G), and a demonstration that the proposed Reliability Standard meets the criteria identified by the Commission in Order No. 672[8] (Exhibit C).

I. SUMMARY

Over the last several years, NERC has made the development of Reliability Standards addressing extreme weather conditions a high priority. Multiple events since 2011 have demonstrated the impacts extreme heat and extreme cold conditions can have on the reliability of the Bulk-Power System, underscoring the need to address the root causes and lessons learned as expeditiously as possible. From 2021 through the present, NERC has developed a series of

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[6] Order No. 896, *Transmission System Planning Performance Requirements for Extreme Weather*, 183 FERC ¶ 61,191 (2023) [hereinafter Order No. 896].

[7] 18 C.F.R. § 39.5(a).

[8] *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 262, 321-37 (2006) [hereinafter Order No. 672], *order on reh'g*, Order No. 672-A, 114 FERC 61,328 (2006).

Reliability Standards to address preparedness and operations during extreme cold weather conditions, as recommended in the reports of the joint inquiry teams examining grid operations during the 2018 and 2021 winter storm events affecting Texas and the South Central United States.[9] NERC has also initiated standard development projects to address energy assurance issues raised by extreme weather events concurrent with the growing reliance on generating units supported by natural gas infrastructure that may not be able to deliver fuel when impacted by extreme cold temperatures, and on weather-dependent (wind and solar) variable energy resources.[10]

Proposed Reliability Standard TPL-008-1 would build upon these efforts and advance the reliability of the Bulk-Power System by improving how entities plan for extreme heat and extreme cold weather events as part of long-term transmission system planning. By modeling and studying the potential impacts of widespread extreme heat and cold events on the reliable operation of the

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[9] To address the findings of these reports, NERC developed Reliability Standards EOP-011-2, IRO-010-4, and TOP-003-5 in 2021, Reliability Standards EOP-011-3 and EOP-012-1 in 2022; Reliability Standards TOP-002-5 and EOP-011-4 in 2023; and Reliability Standard EOP-012-2 in early 2024. As directed by the Commission, an additional project is underway to provide further clarification of the requirements of Reliability Standard EOP-012-2 addressing generator cold weather preparedness by March 2025.

For more information on the recommendations addressed in these projects, *see* 2019 FERC and NERC Staff Report: *The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018* (Jul. 2019), https://www.nerc.com/pa/rrm/ea/Documents/South_Central_Cold_Weather_Event_FERC-NERC-Report_20190718.pdf, and FERC, NERC, and Regional Entity Staff, *The February 2021 Cold Weather Outages in Texas and the South Central United States* (Nov. 2021), https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and. A third report, issued following a December 2022 event affecting the eastern United States, stressed the need for improvements to Cold Weather Reliability Standards consistent with the February 2021 Event Report findings, and recommended improvements for natural gas infrastructure in the United States. *See* FERC, NERC, and Regional Entity Staff, *Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliot* (Oct. 2023), https://www.ferc.gov/media/winter-storm-elliott-report-inquiry-bulk-power-system-operations-during-december-2022.

[10] For more information on these projects, *see* Project 2022-03 Energy Assurance with Energy Constrained Resources, https://www.nerc.com/pa/Stand/Pages/Project2022-03EnergyAssurancewithEnergy-ConstrainedResources.aspx (developing proposed Reliability Standards TOP-003-7 and BAL-007-1 addressing energy assurance issues in the operations horizon) and Project 2024-02 Planning Energy Assurance, https://www.nerc.com/pa/Stand/Pages/Project-2024-02-Planning-Energy-Assurance.aspx (addressing energy assurance issues in the planning horizon).

Bulk-Power System in advance, entities can develop Corrective Action Plans or evaluate other mitigating actions to avoid the worst of these impacts.

The proposed Reliability Standard consists of a framework, consisting of 11 requirements, for the performance of periodic studies assessing the wide-area impacts of extreme heat and extreme cold temperature events on the Bulk-Power System. These periodic studies are referred to as Extreme Temperature Assessments. Proposed Reliability Standard TPL-008-1 would require planning entities in a planning zone, defined in Attachment 1 of the standard, to coordinate with each other on the development of Extreme Temperature Assessments. The proposed standard contains requirements addressing wide-area coordination among planning entities, the identification of benchmark temperature events and the development of planning cases based on the benchmark temperature events, requirements for steady state and transient stability analyses including sensitivity cases, requirements for entities to develop Corrective Action Plans in specified instances where system performance requirements are not met, and requirements for the sharing of study information and any Corrective Action Plans developed to address system performance issues. Proposed Reliability Standard TPL-008-1 would require planning entities to complete an Extreme Temperature Assessment at least once every five years, with the first Extreme Temperature Assessment to be completed approximately five years following regulatory approval of the proposed standard.

As discussed more fully in this petition, the proposed Reliability Standard fully addresses the Commission's directives in Order No. 896 to develop a Reliability Standard that would improve transmission planning for extreme heat and cold temperature conditions.

For these reasons, which are summarized here and stated more fully below, NERC requests that the Commission approve proposed Reliability Standard TPL-008-1, provided in Exhibit A hereto, as just, reasonable, not unduly discriminatory or preferential, and in the public interest.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[11]

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III. REGULATORY BACKGROUND

A. Regulatory Framework

By enacting the Energy Policy Act of 2005,[12] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the Bulk-Power System, and with the duty of certifying an ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1) 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.[13] Section 215(d)(5) of the FPA authorizes

[11] 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.

[12] 16 U.S.C. § 824o.

[13] *Id.* § 824(b)(1).

the Commission to order the ERO to submit a new or modified Reliability Standard.[14] Section 39.5(a) of the Commission's regulations requires the ERO to file for Commission approval each Reliability Standard that the ERO proposes should become mandatory and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes to make effective.[15]

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. Pursuant to Section 215(d)(2) of the FPA and Section 39.5(c) 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.[16]

B. NERC Reliability Standards Development Procedure

The proposed Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[17] NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Standard Processes Manual.[18] In its ERO Certification Order, the Commission found that NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards and thus satisfies certain criteria for approving Reliability

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[14] *Id.* § 824o(d)(5).

[15] 18 C.F.R. § 39.5(a).

[16] 16 U.S.C. § 824o(d)(2); 18 C.F.R. § 39.5(c)(1).

[17] Order No. 672 at P 334.

[18] The NERC Rules of Procedure are available at https://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx. The NERC Standard Processes Manual is available at https://www.nerc.com/AboutNERC/RulesOfProcedure/Appendix_3A_SPM_Clean_Mar2019.pdf.

Standards.[19] The development process is open to any person or entity with a legitimate interest in the reliability of the Bulk-Power System. NERC considers the comments of all stakeholders. Further, a vote of stakeholders and adoption by the NERC Board of Trustees is required before NERC submits the Reliability Standard to the Commission for approval.

IV. THE NEED FOR ENHANCED TRANSMISSION PLANNING STANDARDS FOR EXTREME WEATHER CONDITIONS

Multiple events since 2011 have demonstrated the impacts extreme heat and extreme cold conditions can have on the reliability of the Bulk-Power System. Proposed Reliability Standard TPL-008-1 would improve how entities plan for extreme heat and extreme cold weather events as part of long-term transmission system planning. By modeling and studying the potential impacts of wide-area extreme heat and extreme cold events on the reliability of the Bulk-Power System in advance, entities would be able to take actions to avoid the worst of these impacts. The proposed Reliability Standard, developed in response to the Commission's directives in Order No. 896, would address a gap in the currently effective Transmission Planning (TPL) Reliability Standards relating to extreme temperature conditions.

This section provides background information regarding the need for a Reliability Standard addressing transmission planning for extreme temperature conditions. This section includes a discussion of the current NERC Transmission Planning (TPL) Reliability Standards framework, as well as a discussion of the considerations underlying Order No. 896, in which the Commission directed the development of new or revised Reliability Standards addressing transmission system planning for extreme heat and extreme cold conditions. This section also provides a summary of the Commission's directives from Order No. 896, each of which is addressed in proposed Reliability Standard TPL-008-1.

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[19] ERO Certification Order at P 250.

A. Overview of NERC Transmission Planning Reliability Standards

The Transmission Planning (TPL) Reliability Standards set forth requirements for Planning Authorities and Transmission Planners to develop studies of their portions of the Bulk-Power System. These Reliability Standards help improve the reliability of the Bulk-Power System by requiring planning entities to study how their system would perform under certain conditions, system events, and scenarios, and to take actions when studies indicate the system would not perform as required. There are currently two Transmission Planning (TPL) Reliability Standards in effect: Reliability Standard TPL-001-5.1 – Transmission System Planning Performance Requirements, and Reliability Standard TPL-007-4 – Transmission System Planned Performance for Geomagnetic Disturbance Events.

Reliability Standard TPL-001-5.1 – Transmission System Planning Performance Requirements requires each Planning Coordinator and Transmission Planner to perform an annual Planning Assessment[20] of its portion of the Bulk Electric System covering the System conditions and Contingencies described in the standard. Reliability Standard TPL-001-5.1 employs a risk-based approach to the study of Contingencies and the types of corrective action that are required if the planning entity's system cannot meet the performance requirements of the standard. For the scenarios considered to set the stage for the design basis of the desired system performance and are critical to ensure the reliable operation of the Bulk Power System ("planning events"), the planning entity must develop a Corrective Action Plan if it determines, through its studies, that its system would not meet the design basis laid out in the Reliability Standard. For the scenarios considered to be less likely but could result in potentially severe impacts ("extreme events"), the planning entity must conduct a comprehensive analysis to understand both the potential impacts

[20] "Planning Assessment" is defined in the NERC Glossary as a "documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies.

on its system and the types of actions that could reduce or mitigate those impacts. The standard requires Transmission Planners and Planning Coordinators to evaluate, as part of extreme event steady state analysis, wide-area events affecting the transmission system. These events may include loss of two generating stations resulting from conditions such as wildfires, extreme weather, or other events based on operating experience, that may result in wide-area disturbances. Entities, however, are not required to develop Corrective Action Plans to address any system performance issues identified through these extreme event studies.[21]

Reliability Standard TPL-007-4 – Transmission System Planned Performance for Geomagnetic Disturbance Events addresses transmission system planning for geomagnetic disturbance ("GMD") events. This standard requires each responsible Planning Authority and Transmission Planner to conduct a GMD Vulnerability Assessment at least once every sixty calendar months assessing the impact of both a "benchmark" 1-in-100 year GMD event and a "supplemental" GMD event reflecting a localized geoelectric field enhancement on its system. Where the results of the studies indicate that the system would not meet performance requirements (i.e. the system would experience voltage collapse, Cascading, or uncontrolled islanding), the planning entity must develop a Corrective Action Plan to address how the performance requirements would be met.

B. Order No. 896 Directs the Development of Reliability Standards Addressing Transmission Planning for Extreme Heat and Extreme Cold Events

On June 15, 2023, the Commission issued Order No. 896, a final rule directing NERC to develop a new Reliability Standard or modifications to Reliability Standard TPL-001-5.1 that would address concerns pertaining to transmission system planning for extreme heat and cold

[21] *See* Reliability Standard TPL-001-5.1 Table 1 – Steady State & Stability Performance Extreme Events.

weather events.[22] The Commission directed NERC to submit a responsive standard within 18 months of publication of the final rule in the *Federal Register*, or by December 23, 2024.[23]

In the order, the Commission noted that the country has experienced multiple major extreme heat and cold weather events since 2011; each of these events put stress on the Bulk-Power System and resulted in load shed, and some of these events nearly resulted in system collapse and uncontrolled blackouts which were avoided due to system operator actions.[24] The Commission further noted that the frequency and magnitude of wide-area extreme heat and cold weather events are expected to increase in future years.[25] The Commission continued: "Given the reliability risks associated with extreme heat and cold weather events, including the potential for widespread blackouts, maintaining the reliability of the Bulk-Power System requires transmission system planning to account for the potential impact of extreme heat and cold weather over wide geographical areas, and to consider the changing resource mix."[26]

While finding that the TPL-001 Reliability Standard includes provisions for Transmission Planners and Planning Coordinators to study system performance under extreme events based on their experience, the Commission found that the standard does not specifically require entities to conduct performance analysis for extreme heat and cold weather. The Commission thus found that there was a reliability gap in system planning.[27] To address this reliability gap, the Commission directed NERC to develop a new or revised Reliability Standard addressing transmission system planning for extreme heat and cold events, and to include the following in its proposed standard:

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22 Order No. 896, *Transmission System Planning Performance Requirements for Extreme Weather*, 183 FERC ¶ 61,191 (2023).

23 *Id.* at P 188.

24 Order No 896 at PP 4, 20.

25 *Id.* at P 21.

26 *Id.* at P 5; *see also id.* at P 22.

27 Order No. 896 at PP 5, 23.

1. The development of benchmark planning cases based on major prior extreme heat and cold weather events and/or meteorological projections;

2. Planning for extreme heat and cold weather events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios including the expected resource mix's availability during extreme heat and cold weather conditions, and including the wide-area impacts of extreme heat and cold weather; and

3. Development of corrective action plans that mitigate specified instances where performance requirements for extreme heat and cold weather events are not met.[28]

With respect to the first item above, the Commission directed NERC to: (1) develop extreme heat and cold weather benchmark events; and (2) require the development of benchmark planning cases based on identified benchmark events.[29] With respect to benchmark events, the Commission stated that NERC should consider approaches such as the use of projected frequency or probability distribution, or other approaches achieving the objectives of the final rule, in developing benchmark events.[30] The Commission further stated that all entities likely to be impacted by the same extreme weather events should use consistent benchmark events, so that they may coordinate their assumptions accordingly,[31] and that the benchmark events should "reflect regional differences in climate and weather patterns."[32] The Commission directed NERC to "ensure the reliability standard contains appropriate mechanisms for ensuring the benchmark event reflects up-to-date meteorological data."[33] The Commission further directed that NERC develop the benchmark events for extreme heat and cold weather events through the Reliability

[28] *Id.* at P 27.

[29] *Id.* at P 35.

[30] *Id.* at P 36.

[31] *Id.* at P 37.

[32] *Id.* at P 38.

[33] *Id.* at P 40.

Standards development process, along with the process for defining mechanisms to periodically update these events.[34]

With respect to benchmark planning cases, the Commission directed NERC to include "the framework and criteria that responsible entities shall use to develop from the relevant benchmark event planning cases to represent potential weather-related contingencies (e.g., concurrent/correlated generation and transmission outages, derates) and expected future conditions of the system such as changes in load, transfers, and generation resource mix, and impacts on generators sensitive to extreme heat or cold, due to the weather conditions indicated in the benchmark events."[35] The Commission stated that benchmark planning cases "should be developed by registered entities such as large planning coordinators, or groups of planning coordinators, with the capability of planning on a regional scope."[36]

With respect to the study of wide-area impacts of extreme heat and extreme cold weather, the Commission directed NERC to "clearly describe the process that an entity must use to define the wide-area boundaries," declining to endorse any one specific approach in the final rule.[37] The Commission directed NERC to require the study of concurrent/correlated generator and transmission outages due to the extreme heat or extreme cold benchmark events, with NERC to develop the framework and criteria for entities to use in representing potential weather-related contingencies in their planning cases.[38] The Commission directed NERC to require entities to perform both steady state and transient stability (dynamic) analyses in planning studies,[39] and to

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34 *Id.* at PP 58-59.

35 *Id.* at P 39.

36 *Id.* at P 60.

37 *Id.* at P 50.

38 *Id.* at PP 88, 91-92.

39 *Id.* at P 111.

define a set of contingencies that entities will be required to consider when conducting their studies.[40] The Commission directed that entities model load response in their planning area, and for NERC to determine whether additional steps are needed to ensure that the impacts of demand load response are accurately modeled.[41] The Commission directed NERC to require the use of sensitivity cases to demonstrate the impact of changes to the assumptions used in the benchmark planning case, which consideration to conditions that vary with temperature such as load, generation, and system transfers.[42] The Commission further directed NERC to require the use of planning methods that "ensure adequate consideration of the broad characteristics of extreme heat and cold weather conditions," and to consider whether probabilistic elements could be incorporated.[43]

The Commission directed NERC to ensure entities share information with the responsible planning entity as needed to develop benchmark planning cases and conduct wide-area studies, and for the planning entity to share the study results with affected Transmission Operators, Transmission Owners, Generator Owners, and other functional entities with a reliability need for the studies.[44]

With respect to corrective measures, the Commission directed NERC to require entities to develop Corrective Action Plans for specified instances when performance standards are not met – i.e., when studies show that an event would result in cascading outages, uncontrolled separation,

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40 *Id.* at P 112-113.

41 *Id.* at PP 116-117.

42 *Id.* at PP 124-125.

43 *Id.* at P 134. The Commission directed NERC to describe in its petition the barriers preventing implementation of probabilistic elements that were identified but determined to be infeasible for including in the proposed Reliability Standard at this time. *Id.* at P 138.

44 *Id.* at PP 72, 77.

or instability.[45] Noting jurisdictional and resource adequacy considerations, the Commission directed NERC to require entities to share their Corrective Action Plans with, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues; if such Corrective Action Plans include non-consequential load loss, the Corrective Action Plans should also identify corrective actions which, if approved and implemented, would avoid the use of load shedding.[46]

With respect to implementation, the Commission directed that NERC propose an implementation timeline for its proposed new or revised Reliability Standard that has implementation beginning no later than 12 months following the effective date of the Commission's order approving the standard.[47]

V. JUSTIFICATION FOR APPROVAL: PROPOSED RELIABILITY STANDARD TPL-008-1

Proposed Reliability Standard TPL-008-1 – Transmission System Planning Performance Requirements for Extreme Temperature Events is a new Reliability Standard, developed in response to Order No. 896, focused specifically on improving how Planning Coordinators and Transmission Planners plan for the potential impacts of extreme heat and extreme cold temperature events on the reliable operation of the Bulk-Power System. The proposed Reliability Standard consists of a framework, consisting of 11 requirements, for the performance of periodic studies assessing the wide-area impacts of extreme heat and extreme cold temperature events on the Bulk-Power System. These periodic studies are referred to as Extreme Temperature Assessments. Proposed Reliability Standard TPL-008-1 would require planning entities in a planning zone,

45 *Id.*at PP 152-153, 157.

46 *Id.* at P 165, 167.

47 *Id.* at P 188, 193.

defined in Attachment 1 to the standard, to coordinate with each other on the development of Extreme Temperature Assessments. The proposed standard contains requirements addressing coordination, requirements addressing the creation of benchmark temperature events and planning cases based on the benchmark temperature events, requirements for steady state and transient stability analyses including sensitivity cases, requirements for entities to develop Corrective Action Plans in specified instances where system performance requirements are not met, and requirements for the sharing of study information and any Corrective Action Plans developed to address system performance issues.

As discussed more fully below, proposed Reliability Standard TPL-008-1 addresses a reliability gap in the currently effective Transmission Planning Reliability Standards, is responsive to the Commission's directives in Order No. 896, and would advance the reliability of the Bulk-Power System by improving how entities plan for the impacts of extreme temperature events on their systems.

As explained in Exhibit G, NERC developed the proposed Reliability Standard using NERC's standard development process. This process included multiple public comment and ballot periods. The NERC Board of Trustees adopted the proposed Reliability Standard on December 10, 2024.

In this section, NERC provides an overview of proposed Reliability Standard TPL-008-1, including the proposed definition of Extreme Temperature Assessment, the title, purpose, and applicability of the proposed standard, and supporting justification for each of the proposed requirements. This section also describes the framework in the proposed standard for ensuring wide-area coordination for planning studies, consistent with Order No. 896. Additional information may be found in the Technical Rationale, included as Exhibit E to this filing, as well as the Summary of Development History and Complete Record of Development, included as Exhibit G.

A. Proposed *Glossary* Term: Extreme Temperature Assessment

Proposed Reliability Standard TPL-008-1 contains a new defined term, Extreme Temperature Assessment, to refer to the extreme heat and extreme cold planning studies required under the standard. The proposed definition of this term is as follows:

> **Extreme Temperature Assessment** – Documented evaluation of future Bulk Electric System performance for extreme heat and extreme cold benchmark temperature events.

The proposed definition is intended to make the requirements of the proposed standard easier to read and understand. NERC proposes to include this term in the *Glossary of Terms used in NERC Reliability Standards.*

B. Title, Purpose, and Applicability

The title of proposed Reliability Standard TPL-008-1 is Transmission System Planning Performance Requirements for Extreme Temperature Events. The stated purpose of the standard is: "Establish Transmission system planning performance requirements to develop a Bulk Power System (BPS) that will operate reliably during extreme heat and extreme cold temperature events." Proposed Reliability Standard TPL-008-1 is applicable to Transmission Planners and Planning Coordinators, consistent with the functional entity applicability of other Transmission Planning (TPL) Reliability Standards.

C. A New Framework for Wide-Area Coordination in the Performance of Extreme Temperature Assessments

Proposed Reliability Standard TPL-008-1 contains a framework unique among the transmission planning Reliability Standards for the regional coordination of transmission planning studies addressing extreme heat and extreme cold temperature events. In Order No. 896, the Commission directed NERC to develop a new or revised Reliability Standard "that addresses concerns pertaining to transmission system planning for extreme heat and cold weather events that impact the Reliable Operation of the Bulk-Power System."[48] Noting that the impacts of extreme heat and cold weather events can be widespread, causing loss of generation and transmission constraints within and across regions, the Commission directed that NERC consider these wide-area impacts in developing a responsive standard.[49] Further, the Commission directed NERC to ensure that studies would be undertaken by entities with the "capability of planning on a regional scope."[50] Proposed Reliability Standard TPL-008-1 addresses these directives through a framework by which Planning Coordinators in a predefined zone are required to coordinate on the identification of appropriate benchmark temperature events for the zone and the implementation of mutually agreeable processes for developing planning and sensitivity cases based on those benchmark temperature events.

Proposed Reliability Standard TPL-008-1 contains three requirements addressing wide-area coordination in the performance of the Extreme Temperature Assessment: proposed Requirement R2, addressing the identification of benchmark temperature events; proposed Requirement R3, addressing processes for developing benchmark planning cases based on the benchmark temperature events and sensitivity cases to demonstrate the impact of changes to the basic assumptions used in the benchmark planning cases; and proposed Requirement R4, addressing the development of benchmark planning cases using the coordinated processes. Attachment 1 to proposed Reliability Standard TPL-008-1 would define the zones, and thereby the Planning Coordinators, that must work with each other to select the appropriate benchmark events

48 Order No. 896 at P 1.

49 *See id.* at PP 41-50.

50 *Id.* at P 60.

and implement processes for coordinating the development of planning cases and sensitivity cases for the Extreme Temperature Assessment within that zone.

Collectively, proposed Reliability Standard TPL-008-1 Requirements R2-R4 and Attachment 1 are responsive to the Commission's directives in Order No. 896 relating to wide-area studies of extreme heat and extreme cold temperature events. In Order No. 896, the Commission directed NERC to require that transmission planning studies under the new or revised Reliability Standard consider the wide-area impacts of extreme heat and cold weather, with the standard describing the process to define the wide-area boundaries.[51] Proposed Reliability Standard TPL-008-1 Attachment 1 is responsive to these directives in that it defines the wide-area boundaries and helps to ensure that benchmark planning cases are developed on a regional scope, with consideration to the wide-area impacts of extreme heat and cold weather. Additional discussion of how the drafting team developed these zones is provided in Section V.E.2, below, and in the Technical Rationale, included as Exhibit E. While the zone boundaries defined in Attachment 1 would require some Planning Coordinators to coordinate with many other Planning Coordinators, the industry has demonstrated, through various working groups and organizations, that it is capable of cooperating to build models that represent large areas.

Proposed Reliability Standard TPL-008-1 Requirements R2-R4 and Attachment 1 are also responsive to the Commission's directive that benchmark planning cases be developed by entities capable of planning on a regional scope.[52] The Planning Coordinator, as "the responsible entity that coordinates and integrates transmission Facilities and service plans, resource plans, and Protection Systems," would coordinate with other Planning Coordinators in a zone to identify

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[51] *Id.* at P 50.

[52] *Id.* at P 60.

benchmark temperature events and implement a process for developing benchmark planning cases and sensitivity cases for the Extreme Temperature Assessment. The identification of joint and individual responsibilities in Requirement R1 provides a measure of flexibility for Planning Coordinators and Transmission Planners[53] to agree on a distribution of responsibilities. Thus, while Planning Coordinators are responsible for implementing the planning case development process in Requirement R3, Transmission Planners may be responsible for providing data and completing the case development according to that process under Requirement R4. Acting together, these functional entities would have a wide-area view of the Bulk-Power System and the ability to conduct long-term planning studies across a wide geographic area, consistent with paragraph 61 of Order No. 896. Further, these entities would have "the planning tools, expertise, processes, and procedures to develop benchmark planning cases and analyze extreme weather events in the long-term planning horizon."[54]

Additional discussion of the proposed requirements comprising this coordination framework is provided in the requirement-by-requirement discussion below.

D. Requirement R1

Proposed Reliability Standard TPL-008-1 Requirement R1 is a foundational requirement under which Planning Coordinators and Transmission Planners would identify which entity would be responsible for performing the tasks needed to complete the Extreme Temperature Assessment so that an Extreme Temperature Assessment is completed at least once every five years. Proposed Requirement R1 would provide as follows:

> **R1**. Each Planning Coordinator shall identify, in conjunction with its Transmission Planner(s), each entity's individual and joint responsibilities for completing the

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53 The NERC Glossary defines the Transmission Planner as "The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority [or Planning Coordinator] area."

54 Order No. 896 at P 61.

> Extreme Temperature Assessment, which shall include each of the responsibilities described in Requirements R2 through R11. Each responsible entity shall complete its responsibilities such that the Extreme Temperature Assessment is completed at least once every five calendar years.

Proposed Requirement R1 is similar to Reliability Standard TPL-001-5.1 Requirement R7 and TPL-007-4 Requirement R1, each of which address the Planning Coordinator working with its Transmission Planner(s) to identify individual and joint responsibilities for planning studies. As discussed more fully below, requirements for the selection of benchmark temperature events and processes for developing benchmark planning cases across a zone are the responsibility of the Planning Coordinators within that zone; however, Requirement R1 provides a measure of flexibility for Planning Coordinators and Transmission Planners to agree on a division of responsibilities for completing the remaining requirements.

In determining that the Extreme Temperature Assessment should be completed at least once every five calendar years, the drafting team considered the significant level of data collection and coordination that would be required between the Planning Coordinator(s) and Transmission Planner(s) to coordinate, prepare, perform, and document the study results and to develop any necessary Corrective Action Plans. A similar five-year timeframe is prescribed for the GMD Vulnerability Assessments required under Reliability Standard TPL-007-4. Planning entities may conduct more frequent Extreme Temperature Assessments; however, at least one Extreme Temperature Assessment must be completed at least once every five years.

E. Requirement R2

Proposed Reliability Standard TPL-008-1 Requirement R2 addresses the selection of benchmark temperature events to be used for completing the Extreme Temperature Assessment. Proposed Requirement R2 would provide as follows:

> **R2**. Each Planning Coordinator shall identify the zone(s) to which the Planning Coordinator belongs to under Attachment 1 and shall coordinate with all Planning

> Coordinators within each of its identified zone(s), to identify one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event for each of its identified zone(s) when completing the Extreme Temperature Assessment. The benchmark temperature events shall be obtained from the benchmark library maintained by the ERO or developed by the Planning Coordinators. Each benchmark temperature event identified by the Planning Coordinators shall:
>
> 2.1. Consider no less than a 40-year period of temperature data ending no more than five years prior to the time the benchmark temperature events are selected; and
>
> 2.2. Represent one of the 20 most extreme temperature conditions based on the three-day rolling average of daily maximum (heat) or daily minimum (cold) temperature across the zone.

Proposed Requirement R2 would require each Planning Coordinator to coordinate with other Planning Coordinators within the predefined planning zones specified in Attachment 1 in the selection of benchmark temperature events to be used for Extreme Temperature Assessments. These benchmark temperature events would be used for the creation of benchmark planning cases used to complete the Extreme Temperature Assessment. As explained below, the predefined zones in Attachment 1 were developed with a view toward studying the wide-area impacts of extreme weather, with consideration to regional differences in climate and weather patterns along with other relevant factors. Consistent with paragraphs 35-38 of Order No. 896, proposed Requirement R2 would ensure that all Planning Coordinators within a zone are using a consistent benchmark temperature event, that the benchmark temperature event would reflect regional differences in climate and weather patterns, and that the studied benchmark temperature events would be of an appropriate severity so that the Extreme Temperature Assessments may advance transmission system reliability during future extreme heat and extreme cold temperature conditions.

1. <u>Benchmark Temperature Event Criteria</u>

Extreme hot and cold temperatures experienced during benchmark temperature events are assumed to be outside the ranges used as the basis of planning cases studied under Reliability

Standard TPL-001-5.1. Since temperature levels and associated weather conditions affect load levels, generation performance, and transfer levels, the selection of benchmark temperature events is critical to ensuring the Extreme Temperature Assessment appropriately evaluates probable system conditions.

Since any region can experience temperatures that are higher or lower than normal, Planning Coordinators within the same zone must coordinate to select one common temperature event that includes hotter temperature assumptions and one common temperature event that includes colder temperature assumptions. While it is understood that, for example, one region may typically experience hotter summers and milder winters than another region, both a hotter than average summer and a colder than average winter could result in reliability concerns. Therefore, proposed Reliability Standard TPL-008-1 requires entities to study one common case specific to extreme heat conditions and one common case specific to extreme cold conditions for the Extreme Temperature Assessment. By selecting common events, Planning Coordinators would ensure that extreme temperatures are studied over the entire zone.

The drafting team determined that the extreme heat and extreme cold temperatures selected must have a verified statistical basis based on weather data from credible sources. In drafting this requirement, the drafting team considered the Commission's direction in paragraph 36 of Order No. 896 to consider approaches for developing benchmarks of an appropriate severity.[55] The drafting team has identified several key features that are used to determine when an extreme heat or extreme cold temperature event would constitute a valid benchmark temperature event for the purposes of the standard. Specifically, benchmark temperature events must: (1) consider no less

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[55] *See* Order No. 896 at P 36 ("As recommended by commenters, NERC should consider the examples of approaches for defining benchmark events identified in the NOPR (e.g., the use of projected frequency or probability distribution). NERC may also consider other approaches that achieve the objectives outlined in this final rule.").

than 40 years of temperature data; (2) use data ending no more than five years prior to the time benchmark temperature events are selected; and (3) represent one of the worst 20 extreme temperature conditions within the zone.

To support the identification of these criteria, NERC analyzed historical meteorological data over a 43-year period.[56] Over time, as tools and methods mature, NERC may expand its benchmark temperature event library or revise the TPL-008 benchmark temperature criteria to cover future meteorological projections or other factors that are identified that may advance accurate system planning.[57] However, historical event data analysis, focusing on historical extremes, represents an acceptable and technically justified basis for developing benchmark temperature events in proposed Reliability Standard TPL-008-1 in accordance with Order No. 896.

The requirement to consider no less than 40 years of temperature data was established based on the observation that many of the worst events identified in various regions of North America occurred in the 1980s and 1990s. For example, preliminary data indicated that the five worst extreme cold temperature events in the PJM region over the last 43 years occurred between 1983 and 1994. Similar results were seen in other regions for both extreme heat and extreme cold temperature events. Thus, the drafting team determined that a minimum of 40 years of temperature data should be used to ensure more extreme events would not be excluded by using a shorter duration of temperature data.

The requirement to use data that ends no more than five years prior ensures that the data would capture more recent extreme temperature events and would help ensure that the benchmark

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[56] For more information on this analysis, *see* draft ERO Enterprise Process for TPL-008-1 Benchmark Weather Event Development and Maintenance document, Exhibit G (Summary of Development History and Complete Record of Development) at item 82.

[57] For example, NERC's annual Long-Term Reliability Assessments may provide additional insights for more accurate modeling of future extreme weather conditions.

temperature events are updated over time. This requirement is responsive to paragraph 40 of Order No. 896, in which the Commission directed NERC to include mechanisms to periodically update benchmark temperature events.[58] To the extent future years bring more extreme temperature events, those events would be captured in the updated data.

The requirement to use one of the worst 20 temperature events within the zone is intended to ensure that entities have a sufficient collection of temperature events to review and identify for further studies. While extreme events have become more common in recent years, the historical data did not provide many extreme events over a three-day rolling average over 40 years. The drafting team determined that it is important for an entity to be able to evaluate events that happened over 40 years, as some of the events may not have been as extreme compared to other events, and that identifying a fewer number of events (e.g., 10 or fewer) may not provide a sufficiently complete picture of wide-area extreme conditions.[59]

Temperature events are ranked by computing the three-day rolling average of daily maximum temperatures (for extreme heat) or daily minimum temperatures (for extreme cold). Rather than isolating single hours of extreme weather, the rolling three-day average of minimum and maximum daily temperatures were chosen to represent prolonged periods of extreme weather. The three-day averaging period is centered on every day in the data and identifies the average minimum and maximum temperature from the day before, day of, and day after. The output of this process develops a dataset of multi-day minimum and maximum temperatures to filter out

[58] *See* Order No. 896 at P 40.

[59] Initially, the drafting team considered using a 95th percentile statistical basis for identifying extreme benchmark temperature events. Over a 40-year period, this would equate to 243 unique three-day periods, the majority of which would not reflect the most significant temperature events. Additionally, the worst case does not occur at the same time in each zone. Analysis of the data for the 40 coldest and 40 warmest maximum temperatures for each zone was performed; it was determined that, after refinement and elimination of duplicate or overlapping periods, a list of 20 events would capture the events that are the worst case for a region as well as those that had impacts across multiple regions simultaneously. The drafting team noted that, in some years, more than one extreme event occurred; therefore, the worst 20 events would not necessarily be the same as the worst event from 20 unique years.

individual days of extreme heat or cold under the assumption that the Bulk-Power System is more challenged by sustained periods of extreme heat or cold due to cumulative effects on increasing demand and generator outages.

NERC, as the Electric Reliability Organization, would maintain a library of benchmark temperature events to provide responsible entities with vetted events that meet the criteria of Requirement R2. The Draft ERO Enterprise Process for TPL-008-1 Benchmark Weather Event Development and Maintenance document describes how NERC would develop and maintain the benchmark temperature events in its library.[60] While selection of events from the ERO's library would assure Planning Coordinators they are selecting valid events, proposed Requirement R2 would allow Planning Coordinators flexibility to collect temperature data and identify benchmark temperature events through their own processes. Planning Coordinators that elect to develop their own benchmark temperature events would be responsible for ensuring the input temperature data and selected benchmark temperature events meet the criteria of proposed Requirement R2. Additionally, because proposed Requirement R2 would require Planning Coordinators within a zone to coordinate in the selection of the benchmark temperature events, the process used to identify these events must be agreeable to those Planning Coordinators. Thus, while proposed Requirement R2 would provide some flexibility in the selection of benchmark temperature events, it addresses fully the Commission's underlying concern in Order No. 896 that planning entities acting on a regional scope study consistent benchmark temperature events.[61]

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[60] S*ee* draft ERO Enterprise Process for TPL-008-1 Benchmark Weather Event Development and Maintenance document, Exhibit G (Summary of Development History and Complete Record of Development) at item 82.

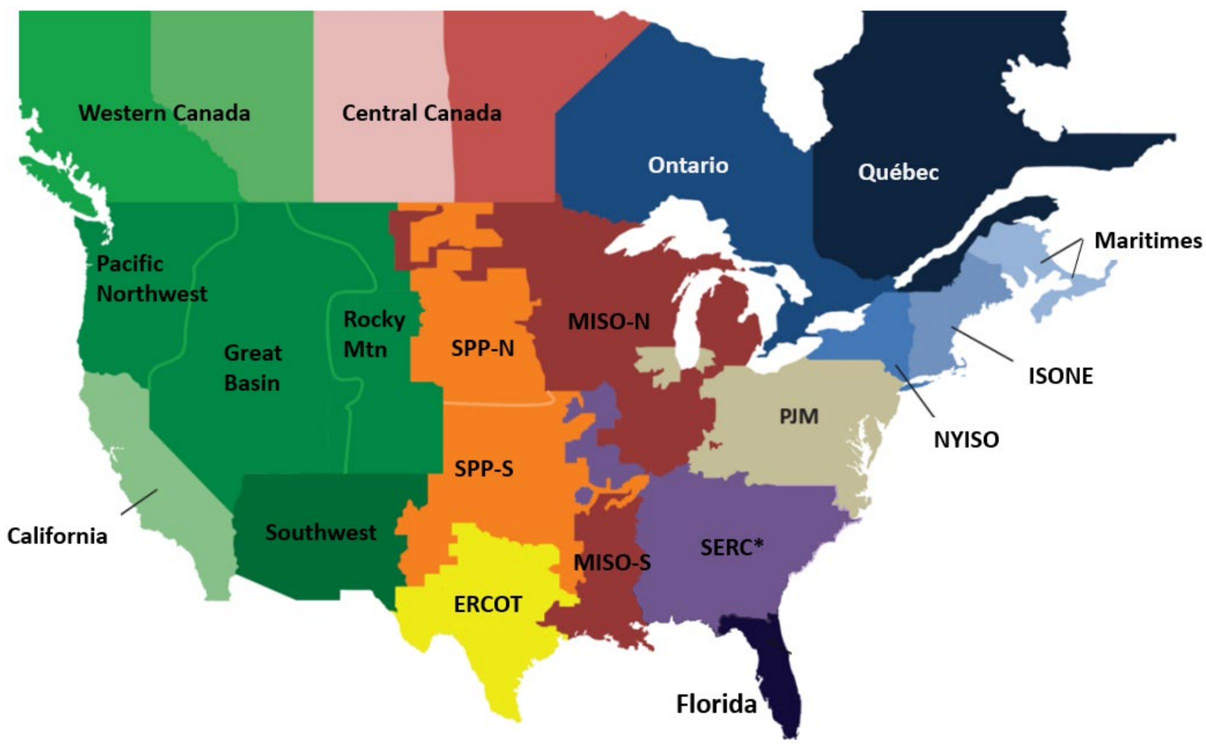
[61] *See* Order No. 896 at P 37 ("Because the impact of most extreme heat and cold events spans beyond the footprints of individual planning entities, it is important that all responsible entities likely to be impacted by the same extreme weather events use consistent benchmark events. Doing so is important to ensuring that neighboring planning regions are assuming similar weather conditions and are able to coordinate their assumptions accordingly. . .").

2. <u>Attachment 1: Extreme Temperature Assessment Zones</u>

Proposed Reliability Standard TPL-008-1 Attachment 1 defines twenty Extreme Temperature Assessment planning zones across the U.S. and Canada. As noted above, Planning Coordinators within each zone must coordinate with each other on selecting benchmark temperature events and performing other tasks to complete the Extreme Temperature Assessment.

The following map depicts the approximate boundaries of the Attachment 1 Extreme Temperature Assessment planning zones:

Figure 1: TPL-008-1 Attachment 1 Extreme Temperature Assessment Planning Zones



In defining the zones to be used for wide-area studies in the Extreme Temperature Assessment, the drafting team considered the Commission's directive in Order No. 896 that transmission planning studies consider the wide-area impacts of extreme heat and extreme cold weather. Proposed Reliability Standard TPL-008-1 Attachment 1 would split the North American Bulk-Power System into several distinct zones that have similar electric power system properties and similar weather or climatological patterns. In developing these zones, the drafting team considered Balancing Authority boundaries, the work of technical experts retained by NERC to analyze weather data and prepare benchmark temperature events for study, as well as comments submitted throughout the standard development process.

In proposed Attachment 1, Balancing Authorities with large areas of jurisdiction, exclusively Independent System Operators and Regional Transmission Organizations, would be assigned their own weather zones. In geographical areas comprised of multiple Balancing Authority Areas, generalized weather zones were created to best represent zonal weather patterns. The zones depicted in Attachment 1 are either aligned with existing Planning Coordinator boundaries or boundaries of a group of Planning Coordinators with similar weather patterns. Consistent with comments received during the standard development process, the drafting team considered the presence of transmission constraints (or the lack of transmission) between areas in developing the final zones, as well as other comments on the appropriateness of the defined zones for extreme weather planning studies.[62] Based on consideration of all relevant factors, the drafting team determined the zones depicted in Attachment 1 would represent reasonable boundaries that balance the need for studies to cover large regions with similar weather patterns with the need for a manageable level of coordination for the entities responsible for carrying out the studies.

For the reasons stated above, proposed Requirement R2 addresses Commission directives regarding the development of extreme heat and extreme cold benchmark temperature events in

[62] For example, stakeholder concerns on an earlier version of the proposed map included concerns that the map would have grouped regions that may have been too large to provide for meaningful analysis, would have grouped regions with different historical extreme weather patterns, or would have grouped regions that do not typically transfer significant power to each other during an extreme temperature event. *See* Draft 3 Comment Report (Oct. 2024), Exhibit G Summary of Development and Complete Record of Development, at item 51 (responses to Question 1).

Order No. 896. The Commission's directives regarding developing planning cases based on benchmark temperature events are addressed in proposed Requirement R3, as discussed below.

F. Requirement R3

Proposed Reliability Standard TPL-008-1 Requirement R3 establishes the framework and criteria for the development of benchmark planning cases for the Extreme Temperature Assessment. Proposed Requirement R3 would provide as follows:

> **R3.** Each Planning Coordinator shall coordinate with all Planning Coordinators within each of its zone(s) identified in Requirement R2, to implement a process for developing benchmark planning cases for the Extreme Temperature Assessment that represent the benchmark temperature events selected in Requirement R2 and sensitivity cases to demonstrate the impact of changes to the basic assumptions used in the benchmark planning cases. This process shall include the following:
>
> 3.1. Selection of System models within the Long-Term Transmission Planning Horizon to form the basis for the benchmark planning cases.
>
> 3.2. Forecasted seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers within the zone.
>
> 3.3. Assumed seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers in areas outside the zone, as needed.
>
> 3.4. Identification of changes to at least one of the following conditions for sensitivity cases: generation, real and reactive forecasted Load, or transfers.

Proposed Requirement R3 aligns with the Commission's directives in Order No. 896, emphasizing the importance of coordinating the development of benchmark planning cases and sensitivity cases amongst planning entities within a zone, where the scope of extreme temperature event studies will likely cover large geographical areas exceeding smaller individual planning areas.[63] Proposed Requirement R3 also addresses, in whole or in part, several other Commission directives related to coordination and the development of benchmark planning and sensitivity cases, as discussed more fully below.

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[63] *See, e.g.*, Order No. 896 at PP 60-62.

Recognizing that the scope of effective coordination may vary across the zones, proposed Requirement R3 would require each Planning Coordinator to coordinate with all Planning Coordinators within a zone to implement a process for the development of benchmark planning cases and sensitivity cases. Planning Coordinators within a zone must coordinate to implement a process that results in the development of benchmark planning cases that represent the benchmark temperature events selected in accordance with Requirement R2, and sensitivity cases that demonstrate the impact of changes to the basic assumptions used in the benchmark planning cases. This process requires several components, outlined in the sub-requirements of Requirement R3.

First, Requirement R3 Part 3.1 would require Planning Coordinators within a zone to select System models which form the basis for developing the benchmark planning cases. These models must represent one of the years in the Long-Term Transmission Planning Horizon.[64] Planning Coordinators would also need to ensure models include stability modeling data to provide for the performance of stability analysis later in the process. The drafting team anticipated that Planning Coordinators would likely use a summer peak model as the starting point for the extreme heat benchmark temperature event and a winter peak model as the starting point for the extreme cold benchmark temperature event.

Second, Requirement R3 Part 3.2 would require that Planning Coordinators within a zone provide forecasted data for their area within the zone that represents the benchmark temperature events selected in accordance with Requirement R2. Each Planning Coordinator must provide data for its area within the zone that represents seasonal and temperature adjustments for Load,

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[64] The NERC *Glossary* defines the Long-Term Transmission Planning Horizon as the "Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete."

generation, Transmission, and transfers. The provided data should be used to update the starting point models to reflect the selected benchmark temperature events.

Third, Requirement R3 Part 3.3 would allow Planning Coordinators to agree on assumptions for seasonal and temperature adjustments for Load, generation, Transmission, and transfers in areas outside of the zone. As a sub-requirement of Requirement R3, these assumptions must be coordinated among Planning Coordinators in the zone, as needed. As an example, Planning Coordinators within the zone may identify the need for imported power during a benchmark temperature event. The Planning Coordinators may evaluate historical import availability and assume imports from an area outside of the zone are reasonable and should be modeled.

Fourth, and lastly, Requirement R3 Part 3.4 would require Planning Coordinators to coordinate and identify changes to generation, real and reactive forecasted Load, or transfers that should be reflected in sensitivity cases. Sensitivity cases are intended to demonstrate the impact of changes to the basic assumptions used in the benchmark planning cases; Requirement R3 Part 3.4 would ensure Planning Coordinators are cooperating to identify changes that would sufficiently alter the assumptions reflected in the benchmark planning cases. For example, Planning Coordinators that identified an import external source to the zone for a benchmark planning case could elect to alter the source of that import in the sensitivity case.

Proposed Requirement R3 addresses in whole or in part several Commission directives from Order No. 896 related to the development of benchmark temperature event planning cases and sensitivity cases, as discussed below.

1. Consideration of Directive: Order No. 896 paragraph 39[65]

Proposed Requirement R3 addresses in part the Commission's directive in paragraph 39 to provide a "framework and criteria" for developing planning cases from the benchmark temperature events. Proposed Requirement R3 provides that Planning Coordinators shall develop benchmark planning cases from the selected benchmark temperature events to represent potential weather-related contingencies and expected future conditions of the system such as changes in load, transfers, and generation resource mix, and impacts on generators sensitive to extreme heat or cold.

Requirement R4, discussed in Section V.G below, also addresses this directive, by requiring the responsible entity to develop benchmark planning cases and sensitivity cases for performing the Extreme Temperature Assessment which reflects System conditions from the selected benchmark events.

2. Consideration of Directive: Order No. 896 paragraph 72[66]

Proposed Requirement R3 addresses in part the Commission's directive in paragraph 72 regarding sharing of information needed to complete studies. Under proposed Requirement R3, Planning Coordinators shall implement a process for developing benchmark planning and sensitivity cases that would by its nature require the responsible entities to share system information as needed to develop benchmark planning cases and conduct wide-area studies.

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[65] Order No. 896 at P 39 (directing NERC to "include in the Reliability Standard the framework and criteria that responsible entities shall use to develop from the relevant benchmark event planning cases to represent potential weather-related contingencies (e.g., concurrent/correlated generation and transmission outages, derates) and expected future conditions of the system such as changes in load, transfers, and generation resource mix, and impacts on generators sensitive to extreme heat or cold, due to the weather conditions indicated in the benchmark events. . ." *See also* general discussion, *id.* at P 35 ("[W]e direct NERC to: (1) develop extreme heat and cold weather benchmark events, and (2) require the development of benchmark planning cases based on identified benchmark events.").

[66] Order No. 896 at P 72 (directing NERC "to require functional entities to share with the entities responsible for developing benchmark planning cases and conducting wide-area studies the system information necessary to develop benchmark planning cases and conduct wide-area studies.").

Requirements R4 and R11, discussed in subsequent sections, also address parts of this directive related to data sharing among responsible entities and with reliability entities.

3. Consideration of Directive: Order No. 896 paragraph 76[67]

Proposed Requirement R3 addresses the Commission's directive in paragraph 76 regarding requirements for wide-area coordination in planning studies. Proposed Requirement R3 addresses requirements for wide-area coordination in the development of benchmark temperature event planning cases and sensitivity cases among planning Coordinators in each planning zone, with the zones defined in Attachment 1.

4. Consideration of Directives: Order No. 896 paragraphs 88 and 92[68]

Proposed Requirement R3 addresses the Commission's directives in paragraph 88 and 92 regarding the study of concurrent/correlated generator and transmission outages due to extreme heat and cold events. Proposed Requirement R3 would require the study of concurrent/correlated generator and transmission outages due to extreme heat and cold events in benchmark events, with contingencies identified based on similar contingencies that occurred in recent extreme weather events or expected in future events. Under proposed Requirement R3 Part 3.2, the benchmark planning case development process must include forecasted seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers within the zone. Requirement R4, discussed in Section V.G, also addresses this directive, by specifying the data necessary to build the benchmark planning cases must be provided via MOD-032, supplemented by other sources as

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67 Order No. 896 at P 76 ("[W]e…direct NERC to address the requirement for wide-area coordination through the standards development process, giving due consideration to relevant factors identified by commenters in this proceeding.").

68 *See id.* at P 88 ("[W]e direct NERC to require under the new or revised Reliability Standard the study of concurrent/correlated generator and transmission outages due to extreme heat and cold events in benchmark events as described in more detail below.") and P 92 ("These contingencies (i.e., correlated/concurrent, temperature sensitive outages, and derates) shall be identified based on similar contingencies that occurred in recent extreme weather events or expected to occur in future forecasted events.").

needed. Any concurrent/correlated generator and transmission outages due to extreme heat and cold events in benchmark temperature events should be reflected in the model data and thus represented in the initial conditions of the benchmark planning cases.

5. Consideration of Directives: Order No. 896 paragraphs 124 and 125[69]

Proposed Requirement R3 addresses the Commission's directives and guidance in paragraphs 124 and 125 requiring the use of sensitivity cases to demonstrate the impact of changes to the assumptions used in the benchmark planning case. Proposed Requirement R3 would require all Planning Coordinators within the same zone, defined in Attachment 1 to the proposed standard, to coordinate to implement a process for developing benchmark planning cases and sensitivity cases. Sensitivity cases are used to demonstrate the impact of changes to the basic assumptions used in the benchmark planning cases. Under Requirement R3 Part 3.4, Planning Coordinators must include provisions in the case development process to identify changes to generation, real and reactive forecasted Load, and/or transfers to develop sensitivity cases.

The identification of changes for sensitivity cases within the coordinated process of Requirement R3 addresses the Commission's direction in paragraph 125 that the proposed standard should preclude responsible entities from determining sensitivities alone. However, responsible entities would retain the flexibility to conduct additional sensitivity studies they would find relevant to their planning areas.

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69 Order No. 896 at P 124 (directing NERC to "to require the use of sensitivity cases to demonstrate the impact of changes to the assumptions used in the benchmark planning case" and "to define during the Reliability Standard development process a baseline set of sensitivities for the new or modified Reliability Standard. While we do not require the inclusion of any specific sensitivity in this final rule, NERC should consider including conditions that vary with temperature such as load, generation, and system transfers.").

Id. at P 125 (stating, "We do not agree ... that responsible entities alone should determine the sensitivity cases that must be considered in the responsible entity's study. … We…believe that responsible entities should be free to study additional sensitivities relevant to their planning areas…cooperation will be necessary between responsible entities conducting extreme heat and extreme cold weather studies and other registered entities within their extreme weather study footprints to ensure the selection of appropriate sensitivities.").

G. Requirement R4

Proposed Reliability Standard TPL-008-1 Requirement R4 establishes requirements for developing benchmark planning cases and sensitivity cases to include in the Extreme Temperature Assessment.

Proposed Requirement R4 would provide as follows:

> **R4**. Each responsible entity, as identified in Requirement R1, shall use the process developed in Requirement R3 and data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, to develop the following and establish category P0 as the normal System condition in Table 1:
>
> 4.1. One common extreme heat and one common extreme cold benchmark planning case.
>
> 4.2. One common extreme heat and one common extreme cold sensitivity case.

Proposed Requirement R4, like proposed Requirement R3 discussed in the previous section, aligns with the Commission's directives in Order No. 896 emphasizing the importance of coordinating the development of benchmark planning cases and sensitivity cases within a zone, where the scope of extreme temperature event studies will likely cover large geographical areas exceeding smaller individual planning areas.[70] Proposed Requirement R4 also addresses several other Commission directives related to coordination and the development of benchmark planning and sensitivity cases, as discussed more fully below and in the discussion of proposed Requirement R3 in the preceding section.

Proposed Requirement R4 would require the responsible entity, which may be the Planning Coordinator or Transmission Planner as identified in Requirement R1, to use the process implemented among the zone Planning Coordinators in Requirement R3 and data consistent with Reliability Standard MOD-032, supplemented by other sources as needed, for developing benchmark planning cases that represent System conditions based on selected benchmark

[70] *See, e.g.*, Order No. 896 at PP 60-62.

temperature events. Proposed Reliability Standard TPL-008-1 Requirement R4 is consistent with Reliability Standard TPL-001-5.1 in that it cross-references Reliability Standard MOD-032; Reliability Standard MOD-032 establishes consistent modeling data requirements and reporting procedures for the development of planning horizon cases necessary to support analysis of the reliability of the interconnected system. Proposed TPL-008-1 Requirement R4 is also consistent with Reliability Standard TPL-001-5.1 in acknowledging that data from other sources may be required to supplement the data collected through Reliability Standard MOD-032 procedures.

Proposed Requirement R4 would require entities to use the coordination process developed in accordance with proposed Requirement R3 to develop at a minimum the following four cases:

- One common extreme heat benchmark planning case (Requirement R4 Part 4.1),
- One common extreme cold benchmark planning case (Requirement R4 Part 4.1),
- One common extreme heat sensitivity case (Requirement R4 Part 4.2), and
- One common extreme cold sensitivity case (Requirement R4 Part 4.2).

At the completion of the case development process implemented in accordance with Requirement R3, and executed in Requirement R4, responsible entities would have at a minimum the four cases listed above. Category P0 would be established as the normal System condition in Table 1 for each case. As discussed in the previous section, proposed Requirement R3 would allow Planning Coordinators the flexibility to implement a process that would develop cases for multiple benchmark temperature events or to develop additional sensitivity cases. Moreover, planning entities may elect to develop additional cases for their internal use.

Proposed Requirement R4 addresses in whole or in part several Commission directives in Order No. 896 related to benchmark temperature event planning cases or sensitivity studies, as discussed below.

6. Consideration of Directive: Order No. 896 paragraph 39

As discussed in the previous section, proposed Requirement R3 addresses in part the Commission's directive in paragraph 39 to provide the framework and criteria that Planning Coordinators shall use to develop benchmark planning cases to represent potential weather-related contingencies and expected future conditions of the system such as changes in load, transfers, and generation resource mix, and impacts on generators sensitive to extreme heat or cold.

Proposed Requirement R4 also addresses this directive, by requiring the responsible entity to develop benchmark planning cases and sensitivity cases for performing the Extreme Temperature Assessment which reflects System conditions from the selected benchmark temperature events.

7. Consideration of Directive: Order No. 896 paragraph 72

As discussed in the previous section, proposed Requirement R3 addresses in part the Commission's directive in paragraph 72 regarding sharing of information needed to complete studies by specifying that Planning Coordinators shall implement a process for developing benchmark planning and sensitivity cases; this process would, by its nature, require Planning Coordinators to share system information as needed to develop benchmark planning cases and conduct wide-area studies. Proposed Requirement R4 builds on proposed Requirement R3 by requiring the responsible entities, as identified in Requirement R1, to use the coordination process implemented in accordance with Requirement R3 and data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, to develop benchmark planning cases and sensitivity cases.

8. Consideration of Directives: Order No. 896 paragraphs 88 and 92

As discussed in the previous section, proposed Requirement R3 addresses the Commission's directives in paragraph 88 and 92 regarding the study of concurrent/correlated generator and transmission outages due to extreme heat and cold events. Proposed Requirement R4 specifies the data necessary to build the benchmark planning cases must be provided via MOD-032, supplemented by other sources as needed. Any concurrent/correlated generator and transmission outages due to extreme heat and cold events in benchmark temperature events should be reflected in the model data and thus represented in the initial conditions of the benchmark planning cases.

9. Consideration of Directives: Order No. 896 paragraphs 116-117[71]

Proposed Requirement R4 addresses the Commission's directives and guidance in paragraphs 116 and 117 regarding the modeling of demand load response. Proposed Requirement R4 would require each responsible entity to develop benchmark planning cases and sensitivity cases using data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed. Attachment 1 of the MOD-032 standard requires responsible entities to provide information requested by the Planning Coordinator or Transmission Planner that is necessary for modeling purposes, to include demand response data. The drafting team determined that no further requirement specific to demand response was needed, as the modeling of demand load response can be implemented through the MOD-032 standard in which data needed for the base case development can be requested and obtained for development of the benchmark planning cases and sensitivity cases under proposed TPL-008-1.

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[71] *Order No.* 896 at P 116 ("We . . .direct NERC to require in the new or modified Reliability Standard that responsible entities model demand load response in their extreme weather event planning area.").

Id. at P 117 ("[I]n addressing this directive, we expect NERC to determine whether responsible entities will need to take additional steps to ensure that the impacts of demand load response are accurately modeled in extreme weather studies, such as by analyzing demand load response as a sensitivity, as is currently the case under Reliability Standard TPL-001-5.1.").

H. Requirement R5

Proposed Reliability Standard TPL-008-1 Requirement R5 would require each responsible entity to set the criteria needed for limits that will be used to evaluate System steady state voltage and post-Contingency voltage deviations for completing the Extreme Temperature Assessment. Proposed Requirement R5 would provide as follows:

> **R5**. Each responsible entity, as identified in Requirement R1, shall have criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations for completing the Extreme Temperature Assessment.

This requirement would allow for the comparison of the results of the Extreme Temperature Assessment with the established criteria. Similar requirements are found in other transmission planning Reliability Standards, including Reliability Standard TPL-001-5.1 (Requirement R5) and Reliability Standard TPL-007-4 (Requirement R3).

I. Requirement R6

Proposed Reliability Standard TPL-008-1 Requirement R6 would require each responsible entity to define and document the criteria or methodology used in evaluating the Extreme Temperature Assessment analysis to identify instability, uncontrolled separation, or Cascading within an Interconnection. Proposed Requirement R6 would provide as follows:

> **R6**. Each responsible entity, as identified in Requirement R1, shall define and document the criteria or methodology to be used in the Extreme Temperature Assessment to identify instability, uncontrolled separation, or Cascading within an Interconnection.

Adequate and thorough criteria should be built into the Extreme Temperature Assessment to help identify instability, uncontrolled separation, and Cascading conditions. The establishment of these criteria allows for comparison of the results of the Extreme Temperature Assessment with the established criteria. A similar requirement is found in Reliability Standard TPL-001-5.1 (Requirement R6). The inclusion of the phrase” within an Interconnection” is appropriate because

Planning Coordinators and Transmission Planners typically use Interconnection-wide starting cases prior to making further modifications to reflect the conditions of the benchmark temperature events and further modifications for the sensitivity cases for steady-state and transient stability analyses. Analyses that may result in instability, uncontrolled separation, or Cascading typically are confined within an Interconnection, where generation and transmission Facilities are interconnected. It is not expected that instability, uncontrolled separation, or Cascading that affect facilities within an Interconnection would impact other Interconnections, as these systems are asynchronous systems (i.e., not connecting synchronously).

J. Requirement R7

Proposed Reliability Standard TPL-008-1 Requirement R7 establishes requirements for identifying Contingencies for the Extreme Temperature Assessment. Proposed Requirement R7 would provide as follows:

> **R7**. Each responsible entity, as identified in Requirement R1, shall identify the Contingencies for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

Proposed Requirement R7 and the referenced Table 1 address the Commission's directives in paragraphs 112-113 of Order No. 896 to define a set of Contingencies that responsible entities would be required to consider when conducting wide-area studies of extreme heat and cold weather events.[72]

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[72] *Id.* at P 112 ("We . . . direct NERC to define a set of contingencies that responsible entities will be required to consider when conducting wide-area studies of extreme heat and cold weather events under the new or modified Reliability Standard. We believe that it is necessary to establish a set of common contingencies for all responsible entities to analyze. Required contingencies, such as those listed in Table 1 of Reliability Standard TPL-001-5.1 (i.e., category P1 through P7), establish common planning events that set the starting point for transmission system planning assessments.").

Id. at P 113 ("[T]he contingencies required in the new or revised Reliability Standards should reflect the complexities of transmission system planning studies for extreme heat and cold weather events.")

In defining the Contingencies to be considered for the Extreme Temperature Assessment, the drafting team considered that the Commission referred to the Contingencies used in Table 1 of Reliability Standard TPL-001-5.1 (category P0 through P7). The drafting team also considered the Commission's statement that it is "necessary to establish a set of common contingencies for all responsible entities to analyze."[73] Requiring the study of predefined Contingencies, such as those listed in Table 1 of the proposed standard, would ensure a level of uniformity across planning regions, considering that extreme heat and cold weather events often exceed the geographic boundaries of most existing planning footprints.

The drafting team determined to define the Contingencies in Table 1 of proposed Reliability Standard TPL-008-1 consistently with Table 1 of Reliability Standard TPL-001-5.1 to advance the goal of commonality. If feasible, all Contingencies listed in Table 1 should be considered for evaluation by the responsible entity; however, the language of proposed Requirement R7 affords flexibility to responsible entities in identifying the most appropriate Contingencies. The responsible entity should implement a method and establish sufficient supporting rationale to ensure Contingencies within each category of Table 1 that are expected to produce more severe System impacts within its planning area are adequately identified.

In developing proposed Reliability Standard TPL-008-1 Table 1, the drafting team included the categories P0 (No Contingency), P1 (Single Contingency), and P7 (Multiple Contingency, Common Structure) Contingencies from Reliability Standard TPL-001-5.1 Table 1, as the drafting team determined these events represent the more likely Contingencies to occur. The drafting team included the P7 Contingency category because common structure Contingencies are often evaluated after categories P0 and P1 as the most common minimum level of transmission

[73] *Id.* at P 112.

reliability assessment. In considering these events to have a higher likelihood of occurrence, the drafting team considered the following:

- Historical events that include simultaneous forced outages due to tripping of the double-circuit power lines due to electrical storms events;
- Environment-caused factors include pollution buildup, such as dust, that could cause a faulted condition that trips both transmission lines on a common tower;
- Avian-caused outages could impact both transmission lines on a common tower;
- Smoke from nearby wildfires could cause simultaneous tripping of both circuits on a common tower;
- Nearby wildfires could impact system operation, as system operators proactively de-energize both lines on a common tower to avoid further impact to the transmission grid in the event of a simultaneous tripping of both lines that may be carrying high power transfer between areas;
- Weather-related causes, such as lightning, flooding, wind, or icing, could cause tripping of both transmission lines on a common tower;
- A natural disaster, such as a winter storm, could cause a transmission tower to collapse, taking out both lines strung on the same tower;
- Other incidents, such as vehicle accidents, aircraft accidents, vandalism, or animal contact, could adversely impact both transmission lines on the common tower.

Additionally, loss of two circuits running in parallel simultaneously is likely to have a greater system impact versus loss of two unrelated or geographically separated circuits. Therefore, there is greater potential for reliability concerns, especially during heavy transfers that are likely during periods of extreme weather, due to loss of both circuits of a double-circuit line.

In developing the rationale for selected Contingencies, responsible entities should consider past studies, subject matter expert knowledge of the responsible entity's System (to be supplemented with data or analysis), historical data from past operating events, or other relevant considerations.

Since the benchmark planning cases are developed from the benchmark temperature events, they already represent extreme System conditions. Thus, not all Contingencies from Reliability Standard TPL-001-5.1 Table 1 are included in the TPL-008-1 Table 1 for assessment.

The drafting team determined to exclude the categories P2, P3, P4, P5, P6 Contingencies in Reliability Standard TPL-001-5.1 Table 1 in the proposed TPL-008-1 Table 1 for the reasons listed below.

The drafting team determined to exclude the category P2 (Single Contingency) and P4 (Multiple Contingency Fault plus stuck breaker) Contingencies due to the lower probability of occurrence than the P1 and P7 contingencies. Proposed Reliability Standard TPL-008-1 focuses on the single Contingencies (P1) or multiple Contingencies on common structure (P7) that are more likely to be monitored in operational scenarios. Category P2 Contingencies (e.g. Contingencies caused by internal breaker fault, bus section fault, opening line section without a fault), and category P4 Contingencies (e.g. Contingencies caused by stuck breaker), while plausible under extreme temperature conditions, occur with much less frequency than category P1 and P7 Contingencies.

The drafting team determined to exclude the category P3 (Multiple Contingency) and category P6 (Multiple Contingency Two Overlapping singles) Contingencies due to the complexity of those Contingencies, which involve multiple element outages triggered by multiple Contingencies, with System adjustments allowed between them. The drafting team determined that the likelihood of the P3 and P6 Contingencies occurring could be even lower compared to the category P1 and P7 Contingencies. Moreover, the drafting team determined that excluding the category P3 and P6 Contingencies would be justified, as generation and transmission derates or outages are already accounted for within the benchmark planning cases. In Order No. 896, the Commission emphasized the importance of incorporating derated generation, transmission capacity, and the availability of generation and transmission in the development of benchmark planning cases, which is reflected in proposed Requirements R3 and R4. As responsible entities must consider potential concurrent or correlated generation and transmission outages or derates within relevant benchmark planning cases, the benchmark planning case accurately reflects System conditions under extreme temperatures, with generation and transmission derates or outages already factored into the analysis.

The drafting team also determined to exclude the category P5 Contingency (Multiple Contingency - fault plus non-redundant component of a Protection System failure to operate) in proposed Reliability Standard TPL-008-1 Table 1. The drafting team determined to exclude the category P5 Contingency because studying this contingency would impose a significant burden while not providing commensurate benefits to reliability. Studying category P5 Contingency events often requires a significant level of engineering analysis (including protection or control analysis). These analyses are sensitive to the System topology and expected dispatch. As the benchmark temperature event planning cases that are developed for proposed Reliability Standard TPL-008-1 represent System conditions that are different than the typical summer or winter peak conditions, the drafting team determined that the development of category P5 Contingency events would be a significant burden. Further, evaluating this contingency would be unlikely to result in further insight beyond the general reliability improvements associated with eliminating and addressing the single point of failure included in the event definition.

In developing the BES voltage levels for the Contingencies in proposed Reliability Standard TPL-008-1 Table 1, the drafting team reviewed previous major wide-area events and found that the facilities that were out of service by these events have voltages that are 200 kV and above. Therefore, the drafting team established voltages of 200 kV and above for Contingencies in Table 1. The monitoring of potential impact is still applicable to Facilities with all BES voltage levels. However, the drafting team recognized that many Planning Coordinators and Transmission

Planners have Contingencies that include all BES levels. Responsible entities may elect to use the existing Contingencies that they already have and report the criteria violations for the categories in Table 1.

K. Requirement R8

Proposed Reliability Standard TPL-008-1 Requirement R8 establishes requirements for Extreme Temperature Assessment studies. Proposed Requirement R8 would provide as follows:

> **R8**. Each responsible entity, as identified in Requirement R1, shall complete steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, and shall document the assumptions and results. Steady state and transient stability analyses shall be performed for the following:
>
> 8.1. Benchmark planning cases developed in accordance with Requirement R4 Part 4.1.
>
> 8.2. Sensitivity cases developed in accordance with Requirement R4 Part 4.2.

Proposed Requirement R8 includes requirements for steady state and transient stability analyses, using the Contingencies identified in Requirement R7 (referencing Table 1), for the benchmark planning cases and sensitivity cases developed under Requirement R4. Proposed Requirement R8 addresses the Commission's directive in paragraph 111 of Order No. 896, in which the Commission directed NERC to require responsible entities to perform both steady state and transient stability (dynamic) analyses in extreme heat and extreme cold weather planning studies. As the Commission explained:

> In a steady state analysis, the system components are modeled as either in-service or out-of-service and the result is a single point-in-time snapshot of the system in a state of operating equilibrium. A transient stability (dynamic) analysis examines the system from the start to the end of a disturbance to determine if the system regains a state of operating equilibrium. Performing both analyses ensures that the system has been thoroughly assessed for instability, uncontrolled separation, and cascading failures in both the steady state and the transient stability realms.[74]

[74] Order No. 896 at P 111.

Proposed Requirement R8 addresses this directive by requiring both analyses for the benchmark planning cases and sensitivity cases, for a total of four required studies. Entities shall document the assumptions and results of these studies.

Along with proposed Requirement R3 discussed above, proposed Requirement R8 also addresses the Commission's Order No. 896 paragraph 124 directives relating to sensitivity cases. Specifically, proposed Requirement R8 would "require the use of sensitivity cases to demonstrate the impact of changes to the assumptions used in the benchmark planning case," and that sensitivity cases "should consider including conditions that vary with temperature such as load, generation, and system transfers." Since the benchmark planning case(s) already include System conditions under extreme heat or extreme cold events, the sensitivity analysis shall include changes to at least one of the following conditions: generation, real and reactive forecasted Load, or transfers. Under the proposed standard, Planning Coordinators or Transmission Planners would have the flexibility to include further sensitivity assessments to change more conditions should they wish to do so.

L. Requirement R9

Proposed Reliability Standard TPL-008-1 Requirement R9 establishes requirements for Corrective Action Plans when studies indicate the system will not perform in accordance with the standard. NERC defines a Corrective Action Plan as "a list of actions and associated timetable for implementation to remedy as specific problem." Proposed Requirement R9 would provide as follows:

> **R9**. Each responsible entity, as identified in Requirement R1, shall develop a Corrective Action Plan(s) when the analysis of a benchmark planning case, in accordance with Requirement R8 Part 8.1, indicates its portion of the Bulk Electric System is unable to meet performance requirements for category P0 or P1 in Table 1. For each Corrective Action Plan, the responsible entity shall:
>
> **9.1**. Document alternative(s) considered when Non-Consequential Load Loss is utilized as an element of a Corrective Action Plan for a Table 1 P1 Contingency.

9.2. Be permitted to utilize Non-Consequential Load Loss as an interim solution, which normally is not permitted for category P0 in Table 1, in situations that are beyond the control of the Planning Coordinator or Transmission Planner that prevent the implementation of a Corrective Action Plan in the required timeframe, provided that the responsible entity documents the situation causing the problem, alternatives evaluated, and takes actions to resolve the situation.

9.3. Make its Corrective Action Plan available to, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.

9.4. Be allowed to have revisions to the Corrective Action Plan in subsequent Extreme Temperature Assessments, provided that the planned Bulk Electric System shall continue to meet the performance requirements of Table 1.

Consistent with paragraphs 152 and 157 of Order No. 896, proposed Requirement R9 would require entities to develop a Corrective Action Plan for specified instances when performance standards are not met.[75] Under proposed Reliability Standard TPL-008-1, responsible entities would be required to develop Corrective Action Plans to address performance deficiencies for categories P0 and P1 in benchmark planning cases analyzed in the Extreme Temperature Assessment. The drafting team determined to require Corrective Action Plans for these deficiencies due to the higher likelihood of these events occurring. Furthermore, having a Corrective Action Plan requirement for categories P0 and P1 in benchmark planning cases helps to ensure resilience during future extreme cold and extreme heat temperature events. Proposed Requirement R10, discussed in the following section, addresses the actions responsible entities must take when potential system performance issues are identified for the remaining studies.

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[75] Order No. 896 at P 152 ("[W]e direct NERC to require in the new or modified Reliability Standard the development of extreme weather corrective action plans for specified instances when performance standards are not met.") *See also* Order No. 896 at P 157 ("[W]e direct NERC to require in the new or modified Reliability Standard the development of corrective action plans that include mitigation for specified instances where performance requirements for extreme heat and cold events are not met—i.e., when certain studies conducted under the Standard show that an extreme heat or cold event would result in cascading outages, uncontrolled separation, or instability") and P 158 ("[W]e give NERC in this final rule the flexibility to specify the circumstances that require the development of a corrective action plan.").

Proposed Requirement R9 addresses the issue of using Non-Consequential Load Loss as an element of a Corrective Action Plan to address identified deficiencies.[76] In some instances, load shed may be necessary to prevent system-wide failures and ensure the continued operation of essential services during extreme heat and cold temperature events. Given that the category P0 represents a continuous system condition without any system disturbances, the drafting team determined that Non-Consequential Load Loss should not be allowed as an element of Corrective Action Plan to address a performance deficiency identified through studies of the benchmark planning case. However, the drafting team has determined that Non-Consequential Load Loss may be considered as an element of a Corrective Action Plan to address a deficiency identified through studies of the category P1 Contingency.

Proposed Requirement R9 contains four sub-parts for required Corrective Action Plans. Under Requirement R9 Part 9.1, responsible entities would be required to document alternative(s) considered when Non-Consequential Load Loss is utilized as an element of a Corrective Action Plan for a Table 1 P1 Contingency. Under Requirement R9 Part 9.2, responsible entities would be able to use Non-Consequential Load Loss as an interim solution, which normally is not permitted for category P0 in Table 1, in situations that are beyond the control of the Planning Coordinator or Transmission Planner that prevent the implementation of a Corrective Action Plan in the required timeframe, provided that the responsible entity documents the situation causing the problem, alternatives evaluated, and takes actions to resolve the situation. This provision recognizes that

[76] The NERC Glossary defines Non-Consequential Load Loss as "Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end- user equipment." (The term Consequential Load Loss, used in this definition, is defined as "All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.")

certain circumstances may make Non-Consequential Load Loss unavoidable, at least on a temporary basis, and is similar to Reliability Standard TPL-001-5.1 Requirement R7 Part 2.7.3.

To provide visibility to the local authorities of matters relating to Corrective Action Plan implementation, proposed Requirement R9 Part 9.3 would require responsible entities to share their Corrective Action Plans with, and solicit feedback from, the applicable regulatory authorities or governing bodies responsible for retail electric service. This provision is responsive to the Commission's directive in paragraph 165 of Order No. 896, in which the Commission directed NERC to require that "responsible entities share their corrective action plans with, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues."[77] This provision, along with Requirements R9 Part 9.1 and 9.2 addressing the permitted uses of Non-Consequential Load Loss and alternative actions considered, would address the Commission's directive in paragraph 167 that responsible entities identify and share with these authorities alternatives to load shedding that would, if approved and implemented, avoid the use of load shedding.[78] Such alternatives could include, for example, building additional generation or transmission capacity, energy efficiency programs, and demand load response programs.

Proposed Requirement R9 Part 9.4 provides that the responsible entity may revise its Corrective Action Plan in subsequent Extreme Temperature Assessments, provided that the planned Bulk Electric System shall continue to meet the performance requirements of Table 1. This provision is consistent with similar language for Corrective Action Plans included in Reliability Standard TPL-001-5.1 (Requirement R7 Part 2.7). This provision would allow

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[77] Order No. 896 at P 165.

[78] Order No. 896 at P 167 ("Further, because an important goal of transmission planning is to avoid load shed, any responsible entity that includes non-consequential load loss in its corrective action plan should also identify and share with applicable regulatory authorities or governing bodies responsible for retail electric service alternative corrective actions that would, if approved and implemented, avoid the use of load shedding.").

responsible entities to incorporate approved mitigation measures from other planning assessments, such as an annual transmission reliability assessment performed under Reliability Standard TPL-001-5 or other planning assessments for policy-driven or economic needs.

M. Requirement R10

Proposed Reliability Standard TPL-008-1 Requirement R10 establishes requirements for entities to act when studies performed under the Extreme Temperature Assessment indicate that the occurrence of less likely Contingencies during a benchmark temperature event could have severe impacts on reliability. Proposed Requirement R10 would provide as follows:

> **R10**. Each responsible entity, as identified in Requirement R1, shall evaluate and document possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) if analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection, for the following:
>
> 10.1. Table 1 P7 Contingencies in benchmark planning cases analyzed in accordance with Requirement R8 Part 8.1.
>
> 10.2. Categories P0, P1, and P7 in Table 1 in sensitivity cases analyzed in accordance with Requirement R8 Part 8.2.

Proposed Requirement R10 carries forward the risk-based framework of Reliability Standard TPL-001-5.1, in which entities are required to develop Corrective Action Plans to address system performance issues for the more likely planning scenarios, and to evaluate and to consider potential actions to mitigate consequences for the less likely planning scenarios.

Under proposed Requirement R10 Part 10.1, responsible entities would be required to evaluate and document possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts when the study results in benchmark planning cases analyses conclude there could be instability, uncontrolled separation, or Cascading for category P7 Contingencies. Category P7 Contingencies involve multiple element outages resulting from a single event, making them relatively less likely to occur compared to categories P0 and P1;

however, they may cause more severe system impacts. Considering both the likelihood of these Contingencies, and the fact that the Extreme Temperature Assessment already addresses low probability system conditions, the drafting team determined that Corrective Action Plans should not be required for P7 Contingencies. However, due to the potential severity resulting from single-Contingency multiple element outages, the drafting team determined it would be appropriate for responsible entities to evaluate and document possible mitigation actions to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses conclude there could be instability, uncontrolled separation, or Cascading. The drafting team determined that requiring the evaluation and documentation of the possible mitigating actions would allow a responsible entity to see where major reliability concerns exist that may need to be addressed; if a sufficiently large number of reliability concerns are identified, it may encourage the responsible entity to consider and implement options for mitigating those concerns through transmission upgrades.

Similarly, proposed Requirement R10 Part 10.2 would require the responsible entity to document possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) if analyses conclude there could be instability, uncontrolled separation, or Cascading for the Categories P0, P1, and P7 sensitivity cases. In Order No. 896, the Commission directed NERC to require "the use of sensitivity cases to demonstrate the impact of changes to the assumptions used in the benchmark planning case."[79] The Commission deferred to NERC, however, to define the circumstances that would require the development of a Corrective Action Plan.[80] The drafting team determined that Corrective Action Plans should not be required

[79] Order No. 896 at P 124.

[80] *See* Order No. 896 at P 158 ("[W]e give NERC in this final rule the flexibility to specify the circumstances that require the development of a corrective action plan. For example, NERC should determine whether corrective

for sensitivity analysis for the following reasons. Sensitivity analysis is an important component of a robust transmission planning study. A requirement to develop and implement Corrective Action Plans for sensitivity cases may incentivize responsible entities to select fewer or less severe sensitivities. An incentive to select fewer sensitivities is undesirable, because sensitivity study results are used to identify constraints and initiate deeper analysis into the variables that impact those constraints. The study results of sensitivity cases are also important to inform the development of Corrective Action Plans in the benchmark planning cases. For these reasons, the drafting team determined that the proposed standard should require the responsible entity to evaluate and document possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses of sensitivity cases conclude there could be instability, uncontrolled separation, or Cascading for the categories P0, P1, and P7 analyses, but not require the entity to develop a Corrective Action Plan.

N. Requirement R11

Proposed Reliability Standard TPL-008-1 Requirement R11 establishes requirements for the sharing of Extreme Temperature Assessment results. Proposed Requirement R11 would provide as follows:

> **R11**. Each responsible entity, as identified in Requirement R1, shall provide its Extreme Temperature Assessment results within 60 calendar days of a request to any functional entity that has a reliability related need and submits a written request for the information.

Proposed Requirement R11 is responsive to that part of the Commission's directive in paragraph 72 of Order No. 896 directing NERC to require responsible entities to share the results

action plans should be required for single or multiple sensitivity cases, and whether corrective action plans should be developed if a contingency event that is not already included in benchmark planning case would result in cascading outages, uncontrolled separation, or instability.").

of Extreme Temperature Assessment studies with affected Transmission Operators, Transmission Owners, Generator Owners, and other functional entities with a reliability need for the studies.[81] Under proposed Requirement R11, a responsible entity must share Extreme Temperature Assessment results with any functional entity that has a reliability related need and submits a written request for the information within 60 calendar days of the request. This requirement, which is modeled on information sharing requirements in Reliability Standards TPL-001-5.1 and TPL-007-4 with modifications appropriate to the Extreme Temperature Assessment process, emphasizes coordination and sharing of study findings. It would help ensure collaboration among stakeholders and timely dissemination of critical information to entities with reliability-related needs, thereby fostering a collective understanding of reliability concerns identified in wide-area studies and enhancing overall grid reliability.

O. Consideration of Order No. 896 Directives Regarding Probabilistic Analysis and the MOD-032 Standard

In developing proposed Reliability Standard TPL-008-1, the drafting team considered additional directives from Order No. 896 not specifically addressed in the discussion above. These directives addressed: (1) consideration of probabilistic elements in the development of proposed Reliability Standard; and (2) consideration of whether the MOD-032 Reliability Standard should be revised to facilitate the exchange of information needed to complete Extreme Temperature Assessments. The drafting team's consideration of these directives is summarized below.

1. Paragraphs 134, 138 Directives for Consideration of Including Probabilistic Elements in Extreme Temperature Planning Studies

In paragraph 134 of Order No. 896, the Commission directed NERC "to determine during the standard development process whether probabilistic elements can be incorporated into the new

[81] Order No. 896 at P 72.

or modified Reliability Standard and implemented presently by responsible entities,"[82] and if such elements could be included, NERC should include them. Conversely, if NERC determined that probabilistic methods would improve upon existing practices but were deemed infeasible to include, NERC should explain in its petition "the barriers preventing the implementation" of those methods.[83]

In considering the use of probabilistic elements in accordance with paragraph 134, the drafting team determined that, while incorporating probabilistic analysis would be a good step forward, specific mandatory Reliability Standard requirements for probabilistic analysis would be better suited for the future as the methods, processes, tools, and data sets mature. The drafting team discussed requiring probabilistic assessment of generation and transmission facilities for the benchmark planning cases in developing proposed Reliability Standard TPL-008-1. As a practical matter, entities could incorporate probabilistic elements into their approach for meeting requirements in proposed Reliability Standard TPL-008-1. For example, when a benchmark temperature event is selected, the Planning Coordinator could include the use of probabilistic approaches for some elements of their process for developing the benchmark planning cases under proposed Requirement R3. Probabilistic tools are used for developing temperature dependent load forecasts and determining how the temperature would impact different types of generation (e.g., de-rates and outages). The tools make use of historical weather data and other sources for region and resource specific output. For example, gas plants may experience outages or de-rates due to pipeline disruptions, fuel prioritization, or freezing of mechanical components. The probability of any of those events occurring (and the relative impact) would be different depending on the region,

[82] Order No. 896 at P 134.

[83] Order No. 896 at P 138.

as well as the region in which the gas production is occurring. In complying with the proposed standard, entities are likely to use probabilistic tools in this way, but as discussed below, it is not required nor necessary to meet the reliability objectives of the proposed standard.

While probabilistic models and tools are capable and being used widely to perform resource adequacy studies, where generation capability can be factored in regionally and aggregated by fuel type, they are not in a mature state for transmission planning studies where models represent specific generation and transmission facilities. More mature methods, processes, and tools are needed for this granular modeling. The drafting team noted the limited data for specific generator and transmission facility outages from extreme weather events. In reviewing historical extreme heat and extreme cold temperature events,[84] the drafting team determined that outages for generation and transmission facilities were unique for each of these events. The impacts of extreme temperatures varied depending upon the nature of the event and the characteristics of the affected regions. Thus, the drafting team found it challenging to draw correlations for the outages that occurred for different extreme heat and cold events for different regions and different timeframes. In addition, the drafting team determined that the data available from these events was too limited to perform an adequate probabilistic assessment of generation and transmission facilities. Thus, the drafting team concluded that the available information did not support the development of specific probabilistic elements for inclusion in proposed Reliability

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[84] The drafting team reviewed reports analyzing the Winter Storm Uri and Winter Storm Elliot events, among others. For more information on the Winter Storm Uri and Winter Storm Elliott events, *see* FERC-NERC Regional Entity Staff Report: *The February 2021 Cold Weather Outages in Texas and the South Central United States* (Nov. 2021), available at https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and, and FERC, NERC, and Regional Entity Staff Report, *Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott* (Oct. 2023), available at https://www.ferc.gov/media/winter-storm-elliott-report-inquiry-bulk-power-system-operations-during-december-2022.

Standard TPL-008-1, and that specific requirements for probabilistic elements would not be effective at the current state of the art in transmission planning approaches.

For reasons explained in previous sections of this petition, proposed Reliability Standard TPL-008-1 represents a just, reasonable, and technically sound means of achieving the Commission's reliability objectives in Order No. 896. NERC, however, anticipates that there may be opportunities to improve the standard in the future, when additional data, as well as more mature methods, processes, and tools, could allow for the development of meaningful probabilistic elements for generation and transmission outages under extreme temperature conditions in transmission planning assessments. Any such effort must balance the benefits and drawbacks of probabilistic and deterministic approaches. While probabilistic approaches offer a more nuanced view of risk, their inherent complexity, potential for underestimating critical events, and alignment challenges with deterministic standards can pose significant drawbacks from a reliability perspective. Discussions of probabilistic planning often reference the probability of a particular BES element (e.g. generator, line, or transformer) experiencing an outage. Deterministic planning assumes the probability is equal. Probabilistic assessments are based on a wide range of uncertain variables (e.g., load forecasts, generation profiles, weather conditions, or equipment failures), and the approaches may underemphasize rare, catastrophic events such as widespread blackouts because such events have a low probability and may not significantly impact the overall risk metrics. Deterministic approaches, by contrast, would allow planning entities to be certain that the system is planned to a set of standardized criteria. Further development and maturation of probabilistic planning methods would allow NERC to consider how to best incorporate these methods to advance reliability in transmission planning studies in the future, such as through the development of hybrid approaches.

NERC notes that both NERC and the Commission have taken steps in recent years to improve transmission system planning, including the development and use of probabilistic elements in transmission planning studies. As noted in Order No. 896, the Commission convened a staff-led technical conference in June 2021 that focused on improving planning practices, including exploring best practices for developing probabilistic methods for estimating planning inputs.[85] NERC has explored through its reliability assessment work the development and incorporation of probabilistic approaches. NERC recently partnered with the National Academy of Engineering to provide recommendations on the evolution of resource and transmission adequacy planning criteria based on probabilistic methods. A joint report, published in July 2024, highlights the need for coordinated probabilistic generation and transmission studies to assess resource and transmission adequacy and makes recommendations to gain acceptance across the industry.[86]

As described in the draft ERO Enterprise Process for TPL-008-1 Benchmark Weather Event Development and Maintenance document,[87] NERC anticipates an ongoing review of relevant considerations and feedback when updating the ERO benchmark event library for subsequent Extreme Temperature Assessments. While NERC has not determined the precise forum for this review at this time, NERC notes that it has many tools available for seeking feedback, including public comment periods, the work of its technical committees, and technical conferences. To the extent that this review indicates there are opportunities to enhance the existing

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[85] *See Climate Change, Extreme Weather, and Electric System Reliability, Supplemental Notice of Technical Conference*, Docket No. AD21-13-000, at 4 (May 27, 2021).

[86] NERC and the National Academy of Engineering, Section 6, *Evolving Planning Criteria for a Sustainable Power Grid: A Workshop Report*, July 2024, available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Evolving_Planning_Criteria_for_a_Sustainable_Power_Grid.pdf.

[87] S*ee* draft ERO Enterprise Process for TPL-008-1 Benchmark Weather Event Development and Maintenance document, Exhibit G (Summary of Development History and Complete Record of Development) at item 82.

benchmark temperature event criteria or otherwise improve TPL-008 planning studies, NERC would consider these enhancements through its stakeholder processes and seek any necessary Commission approvals at the appropriate time.

2. Paragraph 73, Regarding Modifications to the MOD-032 Standard

In paragraph 73 of Order No. 896, the Commission noted that NERC may need to revise Reliability Standard MOD-032-1 Data for Power System Modeling and Analysis to ensure the entities responsible for developing benchmark planning cases and conducting wide-area extreme temperature studies will be able to request and receive the necessary data.[88] The drafting team determined that the entities responsible for completing the Extreme Temperature Assessment under proposed Reliability Standard TPL-008-1 would be able to obtain data through the MOD-032 standard, and that no revisions were needed at this time.

In considering this directive, the drafting team determined that Reliability Standard MOD-032-1 ensures an adequate means of data collection for transmission planning and requires applicable registered entities to provide steady-state, dynamic, and short circuit modeling data to their Transmission Planners and Planning Coordinators. As provided in Reliability Standard MOD-032-1 Requirement R1 and Attachment 1, the standard provides for the collection of various data, such as in-service status and capability associated with demand, generation, and transmission associated with various case types, scenarios, system operating states, or conditions for the long-term planning horizon. Reliability Standard MOD-032-1 also requires applicable registered entities to provide "other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes." Because Planning Coordinators and Transmission Planners would be the entities responsible for performing tasks needed to complete the Extreme

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[88] Order No. 896 at P 73.

Temperature Assessment, these entities would be able to request and receive the necessary data under Reliability Standard MOD-032-1. Therefore, the drafting team concluded that there was no need to revise Reliability Standard MOD-032-1 at this time.

VI. ENFORCEABILITY OF PROPOSED RELIABILITY STANDARDS

Proposed Reliability Standard TPL-008-1 includes measures that support each requirement by clearly identifying what is required and how the ERO will enforce the requirement. These measures help ensure that the requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.[89] Additionally, proposed Reliability Standard TPL-008-1 includes VRFs and VSLs. The VRFs and VSLs provide guidance on the way that NERC will enforce the requirements of the proposed Reliability Standard. The VRFs and VSLs for the proposed Reliability Standard comport with NERC and Commission guidelines related to their assignment. Exhibit G provides a detailed review of the VRFs and VSLs, and the analysis of how the VRFs and VSLs were determined using these guidelines.

VII. EFFECTIVE DATE OF THE PROPOSED RELIABILITY STANDARDS

NERC respectfully requests that the Commission approve proposed Reliability Standard TPL-008-1 to become effective as set forth in the proposed implementation plan, provided in Exhibit B hereto. Proposed Reliability Standard TPL-008-1 would require the performance of an Extreme Temperature Assessment at least once every five calendar years (Requirement R1). The proposed implementation plan would provide a staggered approach over five years for the performance of the first Extreme Temperature Assessment. Consistent with Order No. 896, the phased-in compliance dates would begin 12 months from the effective date of regulatory approval of proposed Reliability Standard TPL-007-1.

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[89] Order No. 672 at P 327.

The proposed implementation plan provides that proposed Reliability Standard TPL-008-1 and the definition of Extreme Temperature Assessment would become effective on the first day of the first calendar quarter that is 12 months after the effective date of the Commission's order approving the proposed Reliability Standard. Entities would be required to comply with Requirement R1 pertaining to the identification of individual and joint responsibilities for completing the Extreme Temperature Assessment, by this date. Entities would have an additional 24 months past the effective date to comply with Requirements R2, R3, R4, R5, and R6, and an additional 48 months past the effective date to comply with Requirements R7, R8, R9, R10, and R11.

In developing the proposed implementation timeframe, the drafting team considered the Commission's directive in paragraph 188 of Order No. 896, in which the Commission directed NERC to propose an implementation timeline for its proposed Reliability Standard with implementation beginning no later than 12 months after the effective date of a Commission order approving the standard.[90] Under the proposed implementation plan, responsible entities would need to comply with Requirement R1 within 12 months. In establishing the remaining compliance dates, the drafting team considered the scope of coordination that will be required to perform Extreme Temperature Assessments under the proposed standard, including completing each of the discrete tasks identified in Requirements R2 through R11 for the first time. The drafting team determined that five years represented a reasonable period to complete this work; further, the five year implementation timeframe reflects the five-year periodicity for Extreme Temperature Assessments in proposed Reliability Standard TPL-008-1. The proposed implementation plan balances the urgency in the need to implement the proposed Reliability Standard against the

[90] Order No. 896 at P 188.

reasonableness of the time allowed for those who must comply to develop the necessary processes and capabilities to perform these new wide-area extreme temperature studies. The proposed implementation plan for proposed Reliability Standard TPL-008-1 is therefore just and reasonable, consistent with Commission guidance in Order No. 672, and responsive to the Commission's guidance for the implementation of this standard in Order No. 896. NERC respectfully requests approval of the proposed implementation plan as submitted by NERC.

VIII. CONCLUSION

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

- proposed Reliability Standard TPL-008-1, including the definition of Extreme Temperature Assessment, and the associated elements included in Exhibit A, effective as proposed herein; and
- the proposed Implementation Plan included in Exhibit B.

Respectfully submitted,

/s/ Lauren A. Perotti

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Date: December 17, 2024

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit A

Proposed Reliability Standard TPL-008-1

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the final draft of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	July 19, 2023
SAR posted for comment	August 8–September 27, 2023
45-day formal comment period with initial ballot	March 20–May 3, 2024
38-day formal comment period with additional ballot	July 16–August 22, 2024
15-day formal comment period with additional ballot	October 7–21, 2024
15-day formal comment period with additional ballot	November 7–21, 2024

Anticipated Actions	Date
5-day final ballot	December 2–6, 2024
Board adoption	December 10, 2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

Extreme Temperature Assessment – Documented evaluation of future Bulk Electric System performance for extreme heat and extreme cold benchmark temperature events.

A. Introduction

1. **Title:** Transmission System Planning Performance Requirements for Extreme Temperature Events
2. **Number:** TPL-008-1
3. **Purpose:** Establish Transmission system planning performance requirements to develop a Bulk Power System (BPS) that will operate reliably during extreme heat and extreme cold temperature events.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Transmission Planner
     - **4.1.2.** Planning Coordinator
5. **Effective Date:** See Implementation Plan for Project 2023-07.

B. Requirements and Measures

R1. Each Planning Coordinator shall identify, in conjunction with its Transmission Planner(s), each entity's individual and joint responsibilities for completing the Extreme Temperature Assessment, which shall include each of the responsibilities described in Requirements R2 through R11. Each responsible entity shall complete its responsibilities such that the Extreme Temperature Assessment is completed at least once every five calendar years. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M1. Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall provide dated documentation of each entity's individual and joint responsibilities, such as meeting minutes, agreements, copies of procedures, or protocols in effect between entities or between departments of a vertically integrated system, or email correspondence that identifies an agreement has been reached on individual and joint responsibilities for completing the Extreme Temperature Assessment, and that these responsibilities were completed such that the Extreme Temperature Assessment was completed once every five calendar years.

R2. Each Planning Coordinator shall identify the zone(s) to which the Planning Coordinator belongs to under Attachment 1 and shall coordinate with all Planning Coordinators within each of its identified zone(s), to identify one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event for each of its identified zone(s) when completing the Extreme Temperature Assessment. The benchmark temperature events shall be obtained from the benchmark library maintained by the ERO or developed by the Planning Coordinators. Each benchmark temperature event identified by the Planning Coordinators shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. Consider no less than a 40-year period of temperature data ending no more than five years prior to the time the benchmark temperature events are selected; and

2.2. Represent one of the 20 most extreme temperature conditions based on the three-day rolling average of daily maximum (heat) or daily minimum (cold) temperature across the zone.

M2. Each Planning Coordinator shall have evidence in either electronic or hard copy format that it identified the zone(s) to which it belongs to, under Attachment 1, and that it coordinated with all other Planning Coordinators within each of its identified zone(s) to identify one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event meeting the criteria of Requirement R2 for each of their identified zone(s) when completing the Extreme Temperature Assessment.

R3. Each Planning Coordinator shall coordinate with all Planning Coordinators within each of its zone(s) identified in Requirement R2, to implement a process for developing

benchmark planning cases for the Extreme Temperature Assessment that represent the benchmark temperature events selected in Requirement R2 and sensitivity cases to demonstrate the impact of changes to the basic assumptions used in the benchmark planning cases. This process shall include the following: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Selection of System models within the Long-Term Transmission Planning Horizon to form the basis for the benchmark planning cases.

3.2. Forecasted seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers within the zone.

3.3. Assumed seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers in areas outside the zone, as needed.

3.4. Identification of changes to at least one of the following conditions for sensitivity cases: generation, real and reactive forecasted Load, or transfers.

M3. Each Planning Coordinator shall have dated evidence that it implemented a process for coordinating the development of benchmark planning cases and sensitivity cases for the Extreme Temperature Assessment as specified in Requirement R3.

R4. Each responsible entity, as identified in Requirement R1, shall use the process developed in Requirement R3 and data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, to develop the following and establish category P0 as the normal System condition in Table 1: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

4.1. One common extreme heat and one common extreme cold benchmark planning case.

4.2. One common extreme heat and one common extreme cold sensitivity case.

M4. Each responsible entity, as identified in Requirement R1, shall have dated evidence in either electronic or hard copy format that it developed benchmark planning cases and sensitivity cases in accordance with Requirement R4.

R5. Each responsible entity, as identified in Requirement R1, shall have criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations for completing the Extreme Temperature Assessment. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M5. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of the documentation, specifying the criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations for completing the Extreme Temperature Assessment.

R6. Each responsible entity, as identified in Requirement R1, shall define and document the criteria or methodology to be used in the Extreme Temperature Assessment to

identify instability, uncontrolled separation, or Cascading within an Interconnection. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M6. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of documentation, specifying the criteria or methodology to be used in the Extreme Temperature Assessment to identify instability, uncontrolled separation, or Cascading within an Interconnection in accordance with Requirement R6.

R7. Each responsible entity, as identified in Requirement R1, shall identify the Contingencies for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System. The rationale for those Contingencies selected for evaluation shall be available as supporting information. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M7. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of documentation, of the Contingencies for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System along with supporting rationale.

R8. Each responsible entity, as identified in Requirement R1, shall complete steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, and shall document the assumptions and results. Steady state and transient stability analyses shall be performed for the following: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

8.1. Benchmark planning cases developed in accordance with Requirement R4 Part 4.1.

8.2. Sensitivity cases developed in accordance with Requirement R4 Part 4.2.

M8. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of documentation, of the assumptions and results of the steady state and transient stability analyses completed in the Extreme Temperature Assessment.

R9. Each responsible entity, as identified in Requirement R1, shall develop a Corrective Action Plan(s) when the analysis of a benchmark planning case, in accordance with Requirement R8 Part 8.1, indicates its portion of the Bulk Electric System is unable to meet performance requirements for category P0 or P1 in Table 1. For each Corrective Action Plan, the responsible entity shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

9.1. Document alternative(s) considered when Non-Consequential Load Loss is utilized as an element of a Corrective Action Plan for a Table 1 P1 Contingency.

9.2. Be permitted to utilize Non-Consequential Load Loss as an interim solution, which normally is not permitted for category P0 in Table 1 for situations that are

beyond the control of the Planning Coordinator or Transmission Planner that prevent the implementation of a Corrective Action Plan in the required timeframe, provided that the responsible entity documents the situation causing the problem, alternatives evaluated, and takes actions to resolve the situation.

9.3. Make its Corrective Action Plan available to, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.

9.4. Be permitted to have revisions to the Corrective Action Plan in subsequent Extreme Temperature Assessments, provided that the planned Bulk Electric System shall continue to meet the performance requirements of Table 1.

M9. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of documentation, of each Corrective Action Plan developed in accordance with Requirement R9 when the analysis of a benchmark planning case indicates its portion of the Bulk Electric System is unable to meet performance requirements for category P0 or P1 in Table 1. Evidence shall include documentation of correspondence with applicable regulatory authorities or governing bodies responsible for retail electric service issues and any revision history.

R10. Each responsible entity, as identified in Requirement R1, shall evaluate and document possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) if analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection, for the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

10.1. Table 1 P7 Contingencies in benchmark planning cases analyzed in accordance with Requirement R8 Part 8.1.

10.2. Categories P0, P1, and P7 in Table 1 in sensitivity cases analyzed in accordance with Requirement R8 Part 8.2.

M10. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of documentation that it evaluated and documented possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts when the analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection for Table 1 P7 Contingencies in benchmark planning cases or categories P0, P1, or P7 in Table 1 in sensitivity cases.

R11. Each responsible entity, as identified in Requirement R1, shall provide its Extreme Temperature Assessment results within 60 calendar days of a request to any functional entity that has a reliability related need and submits a written request for the information. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M11. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as email notices, documentation of updated web pages, or postal receipts showing recipient, that it provided its Extreme Temperature Assessment to any

functional entity who has a reliability need within 60 calendar days of a written request.

C. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. 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.

- Each responsible entity shall retain evidence of compliance with each requirement in this standard for five calendar years or one complete Extreme Temperature Assessment cycle, whichever is longer.

1.3. Compliance Monitoring and Enforcement Program: "Compliance Monitoring Enforcement Program" or "CMEP" means, depending on the context (1) the NERC Compliance Monitoring and Enforcement Program (Appendix 4C to the NERC Rules of Procedure) or the Commission-approved program of a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that is responsible for performing compliance monitoring and enforcement activities with respect to Registered Entities' compliance with Reliability Standards.

Table 1 – Steady State & Stability Performance Events
Steady State & Stability: a. Instability, uncontrolled separation, or Cascading within an Interconnection, defined in accordance with Requirement R6, shall not occur. b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0. c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event. d. Simulate Normal Clearing unless otherwise specified. e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings. **Steady State Only:** f. Applicable Facility Ratings shall not be exceeded. g. System steady state voltages and post-Contingency voltage deviations shall meet the criteria identified in Requirement R5.

<table>
<tr><th colspan="8">Table 1 – Steady State & Stability Performance Events</th></tr>
<tr><th rowspan="2">Category</th><th rowspan="2">Initial Condition</th><th rowspan="2">Event[1]</th><th rowspan="2">Fault Type[3]</th><th rowspan="2">Contingency BES Level</th><th rowspan="2">Interruption of Firm Transmission Service Allowed</th><th colspan="2">Non-Consequential Load Loss Allowed</th></tr>
<tr><th>Benchmark Planning Cases</th><th>Sensitivity Cases</th></tr>
<tr><td>P0
No Contingency</td><td>Normal System</td><td>None</td><td>N/A</td><td>N/A</td><td>Yes</td><td>No[6]</td><td>Yes</td></tr>
<tr><td rowspan="2">P1
Single Contingency</td><td rowspan="2">Normal System</td><td>Loss of one of the following:
1. Generator
2. Transmission Circuit
3. Transformer[2]
4. Shunt Device[4]</td><td>3Ø</td><td rowspan="2">≥ 200 kV</td><td rowspan="2">Yes</td><td rowspan="2">Yes[6]</td><td rowspan="2">Yes</td></tr>
<tr><td>5. Single Pole of a DC line</td><td>SLG</td></tr>
<tr><td>P7
Multiple Contingency
(Common Structure)</td><td>Normal System</td><td>The loss of:
1. Any two adjacent (vertically or horizontally) circuits on common structure[5]
2. Loss of a bipolar DC line</td><td>SLG</td><td>≥ 200 kV</td><td>Yes</td><td>Yes</td><td>Yes</td></tr>
</table>

Table 1 – Steady State & Stability Performance Events
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the BES level of the event. For P7 events, the BES level of the event is the highest System voltage level of the element(s) removed for the analyzed event.
2. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
3. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
4. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
5. Excludes circuits that share a common structure for 1 mile or less.
6. Benchmark planning cases require the development of a Corrective Action Plan when the responsible entity's portion of the BES is unable to meet the performance requirements for categories P0 or P1. Additionally, in benchmark planning cases, Non-Consequential Load Loss is not permitted for category P0 except where permitted as an interim solution in a Corrective Action Plan in accordance with Requirement R9 Part 9.2.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed less than or equal to six months late.	The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed more than six months but less than or equal to 12 months late.	The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed more than 12 months but less than or equal to 18 months late.	The Planning Coordinator, in conjunction with its Transmission Planner(s), failed to identify individual and joint responsibilities for completing the Extreme Temperature Assessment. OR The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed more than 18 months late.
R2.	N/A	N/A	The Planning Coordinator coordinated with all Planning Coordinators within each identified zone to identify one common extreme heat and one common extreme cold benchmark temperature event for completing the Extreme Temperature Assessment, but one of the identified events	The Planning Coordinator coordinated with all Planning Coordinators within each identified zone to identify one common extreme heat and one common extreme cold benchmark temperature event for completing the Extreme Temperature Assessment, but both of the identified events

			failed to meet all the criteria of Requirement R2.	failed to meet all of the criteria of Requirement R2. OR The Planning Coordinator failed to coordinate with all Planning Coordinators within each identified zone to identify one common extreme heat and one common extreme cold benchmark temperature event for completing the Extreme Temperature Assessment.
R3.	N/A	N/A	N/A	The Planning Coordinator did not coordinate with all Planning Coordinators within each of its identified zone(s) to implement a process for developing benchmark planning cases. OR The Planning Coordinator coordinated with all Planning Coordinators within each of its identified zone(s) to implement a process for developing benchmark planning cases, but the process did not include all of the required elements.

R4.	N/A	N/A	N/A	The responsible entity, as identified in Requirement R1, did not use the process developed in Requirement R3 to develop benchmark planning cases or sensitivity cases. OR The responsible entity, as identified in Requirement R1, used the process developed in Requirement R3 to develop benchmark planning cases and sensitivity cases, but did not use data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, for one or more of the required cases. OR The responsible entity, as identified in Requirement R1, used the process developed in Requirement R3 and data consistent with that provided in accordance with the MOD-032 standard, supplemented as needed, but failed to develop one or more of the required planning or sensitivity cases.

R5.	N/A	N/A	N/A	The responsible entity, as identified in Requirement R1, did not have criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations for completing the Extreme Temperature Assessment.
R6.	N/A	N/A	N/A	The responsible entity, as identified in Requirement R1, failed to define or document the criteria or methodology to be used in the Extreme Temperature Assessment to identify instability, uncontrolled separation, or Cascading within an Interconnection.
R7.	N/A	N/A	The responsible entity, as identified in Requirement R1, identified Contingencies for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System, but did not include the rationale for those Contingencies selected for evaluation as supporting information.	The responsible entity, as identified in Requirement R1, did not identify Contingencies for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System.

R8.	The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to document the assumptions for one or more sensitivity cases in accordance with Requirement R8.	The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to document the assumptions for one or more benchmark planning cases in accordance with Requirement R8.	The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to document results for one or more of the sensitivity cases in accordance with Requirement R8.	The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to document results for one or more of the benchmark planning cases in accordance with Requirement R8. OR The responsible entity, as identified in Requirement R1, failed to complete steady state or transient stability analyses and document results in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, in accordance with Requirement R8.
R9.	N/A	N/A	The responsible entity, as identified in Requirement R1, developed a Corrective Action Plan in accordance with Requirement R9, but failed to make its Corrective Action Plan available to, or solicit feedback from, applicable	The responsible entity, as identified in Requirement R1, failed to develop a Corrective Action Plan when the benchmark planning case study results indicate the System is unable to meet performance requirements for

			regulatory authorities or governing bodies responsible for retail electric service issues.	the Table 1 P0 or P1 Contingencies. OR The responsible entity, as identified in Requirement R1, developed a Corrective Action Plan, but it was missing one or more of the elements of Requirement R9 Part 9.1, 9.3 and 9.4 (as applicable).
R10.	N/A	N/A	The responsible entity, as identified in Requirement R1, evaluated and documented possible actions to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection where required under Requirement R10 Part 10.1, but failed to evaluate and document possible actions where required under Requirement R10 Part 10.2.	The responsible entity, as identified in Requirement R1, evaluated and documented possible actions to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection where required under Requirement R10 Part 10.2, but failed to evaluate and document possible actions where required under Requirement R10 Part 10.1. OR The responsible entity, as identified in Requirement R1, failed to evaluate and document possible actions to

				reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection where required under Requirement R10 Parts 10.1 and 10.2.
R11.	The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 60 days but less than or equal to 80 days following the request.	The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 80 days but less than or equal to 100 days following the request.	The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 100 days but less than or equal to 120 days following the request.	The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 120 days following the request. OR The responsible entity, as identified in Requirement R1, did not provide its Extreme Temperature Assessment results to functional entities having a reliability related need who submitted a written request for the information.

D. Regional Variances

None.

E. Associated Documents

- Implementation Plan for Project 2023-07
- Technical Rationale Document
- Consideration of Issues and Directives for FERC Order 896.
- ERO Benchmark Event Library
- TPL-008 Data Library Read Me

Version History

Version	Date	Action	Change Tracking
1	TBD	Addressing FERC Order 896	New Standard

Attachment 1: Extreme Temperature Assessment Zones

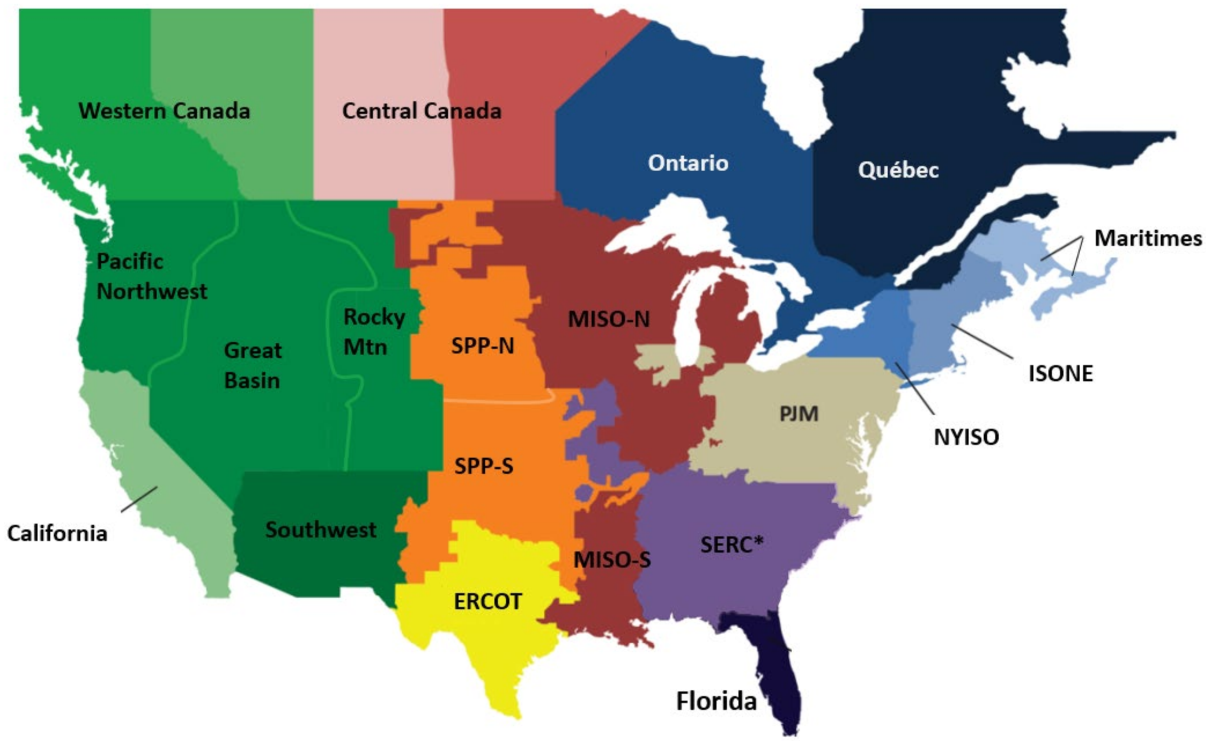
The table below lists the zones to be used in the Extreme Temperature Assessment and identifies the Planning Coordinators that belong to each zone. In accordance with Requirement R2, each Planning Coordinator is required to identify the zone(s) to which it belongs. Planning Coordinators, in different zones within a broader planning region, may use the same benchmark temperature events for their respective benchmark planning cases, provided the benchmark temperature events meet the criteria of Requirement R2 for each zone.

Zone	Planning Coordinators
Eastern Interconnection	
MISO North	Planning Coordinator(s) in MISO that serve portions of MISO in Montana, North Dakota, South Dakota, Minnesota, Iowa, Wisconsin, Michigan, Indiana, Illinois, Missouri, and Kentucky
MISO South	Planning Coordinator(s) in MISO that serve portions of Arkansas, Mississippi, Louisiana, and Texas
SPP North	Planning Coordinator(s) in portions of SPP that serve Iowa, Montana, Nebraska, North Dakota, and South Dakota.
SPP South	Planning Coordinator(s) in portions of SPP that serve Arkansas, Kansas, Louisiana, Missouri, New Mexico, Oklahoma, and Texas.
PJM	Planning Coordinator(s) that serves PJM
New England	Planning Coordinator(s) in NPCC that serve the six New England States
New York	Planning Coordinator(s) in NPCC that serve New York
SERC	Planning Coordinator(s) in SERC, excluding those that serve Florida and those in MISO, SPP, and PJM
Florida	Planning Coordinator(s) in SERC that serve Florida
Central Canada	Planning Coordinator(s) that serve Saskatchewan and Manitoba region of MRO
Ontario	Planning Coordinator(s) in NPCC that serve Ontario
Maritimes	Planning Coordinator(s) in NPCC that primarily serve New Brunswick, Nova Scotia, Prince Edward Island, and Northern Maine
Western Interconnection	
Southwest	Planning Coordinator(s) in the Southwest region of WECC, including El Paso in West Texas
Pacific Northwest	Planning Coordinator(s) in the Pacific Northwest region of WECC

Zone	Planning Coordinators
Great Basin	Planning Coordinator(s) in the Great Basin region of WECC
Rocky Mountain	Planning Coordinator(s) in the Rocky Mountain region of WECC
California/Mexico	Planning Coordinator(s) in the California/Mexico region of WECC
Western Canada	Planning Coordinator(s) that primarily serve British Columbia and Alberta region of WECC
ERCOT Interconnection	
ERCOT	Planning Coordinator(s) in Texas that are part of the ERCOT Interconnection
Quebec Interconnection	
Quebec	Planning Coordinator(s) that serve Quebec in the NPCC Region.

The map below depicts an approximation of the zones to be used in the Extreme Temperature Assessment and is provided as a visual aid; to the extent that there is a conflict between the map and the table, the table controls. This map is not to be used for compliance purposes.

TPL-008-1 Weather Zones Map



NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit B

Implementation Plan

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Implementation Plan

Project 2023-07 Transmission System Planning Performance Requirements for Extreme Weather
Reliability Standard TPL-008-1

Applicable Standard

- TPL-008-1 – Transmission System Planning Performance Requirements for Extreme Temperature Events

Requested Retirement

- Not applicable

Prerequisite Standard

- Not applicable

Applicable Entities

- Planning Coordinators
- Transmission Planners

New Term in the NERC Glossary of Terms

This section includes all newly defined, revised, or retired terms used or eliminated in the NERC Reliability Standard. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

- **Extreme Temperature Assessment** – Documented evaluation of future Bulk Electric System performance for extreme heat and extreme cold benchmark temperature events.

Background

On June 15, 2023, the U.S. Federal Energy Regulatory Commission ("FERC") issued Order No. 896, a final rule directing NERC to develop a new or modified Reliability Standard to address the lack of a long-term planning requirement(s) for extreme heat and cold weather events.[1] Specifically, FERC directed NERC to develop modifications to Reliability Standard TPL-001-5.1 or develop a new Reliability Standard that requires the following: (1) development of benchmark planning cases based on major prior extreme heat and cold weather events and/or meteorological projections; (2) planning for extreme heat and cold weather

[1] *Transmission System Planning Requirements for Extreme* Weather, Order No. 896, 183 FERC ¶ 61,191 (2023).

events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios including the expected resource mix's availability during extreme heat and cold weather conditions, and including the wide-area impacts of extreme heat and cold weather; and (3) development of Corrective Action Plans that mitigate any instances where performance requirements for extreme heat and cold weather events are not met. FERC further directed NERC to ensure that the proposed new or modified Reliability Standard becomes mandatory and enforceable beginning no later than 12 months from the effective date of FERC approval.

General Considerations

Proposed Reliability Standard TPL-008-1 would require the performance of an Extreme Temperature Assessment at least once every five calendar years (Requirement R1). This implementation plan provides a staggered approach for the performance of the first Extreme Temperature Assessment, with phased-in compliance dates beginning 12 months from the effective date of regulatory approval consistent with Order No. 896. For subsequent Extreme Temperature Assessments, entities may establish timeframes appropriate to their facts and circumstances for carrying out their responsibilities under the standard, provided that the Extreme Temperature Assessment is completed no later than five calendar years following the previous Extreme Temperature Assessment.

Effective Date

The effective date for the proposed Reliability Standard is provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of the proposed Reliability Standard (e.g., an entire Requirement or a portion thereof), the additional time for compliance with that section is specified below. These phased-in compliance dates represent the dates that entities must begin to comply with that particular section of the Reliability Standard, even where the Reliability Standard goes into effect at an earlier date.

TPL-008-1 and Definition

Where approval by an applicable governmental authority is required, the standard and definition of Extreme Temperature Assessment shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard and definition of Extreme Temperature Assessment is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Phased-In Compliance Dates

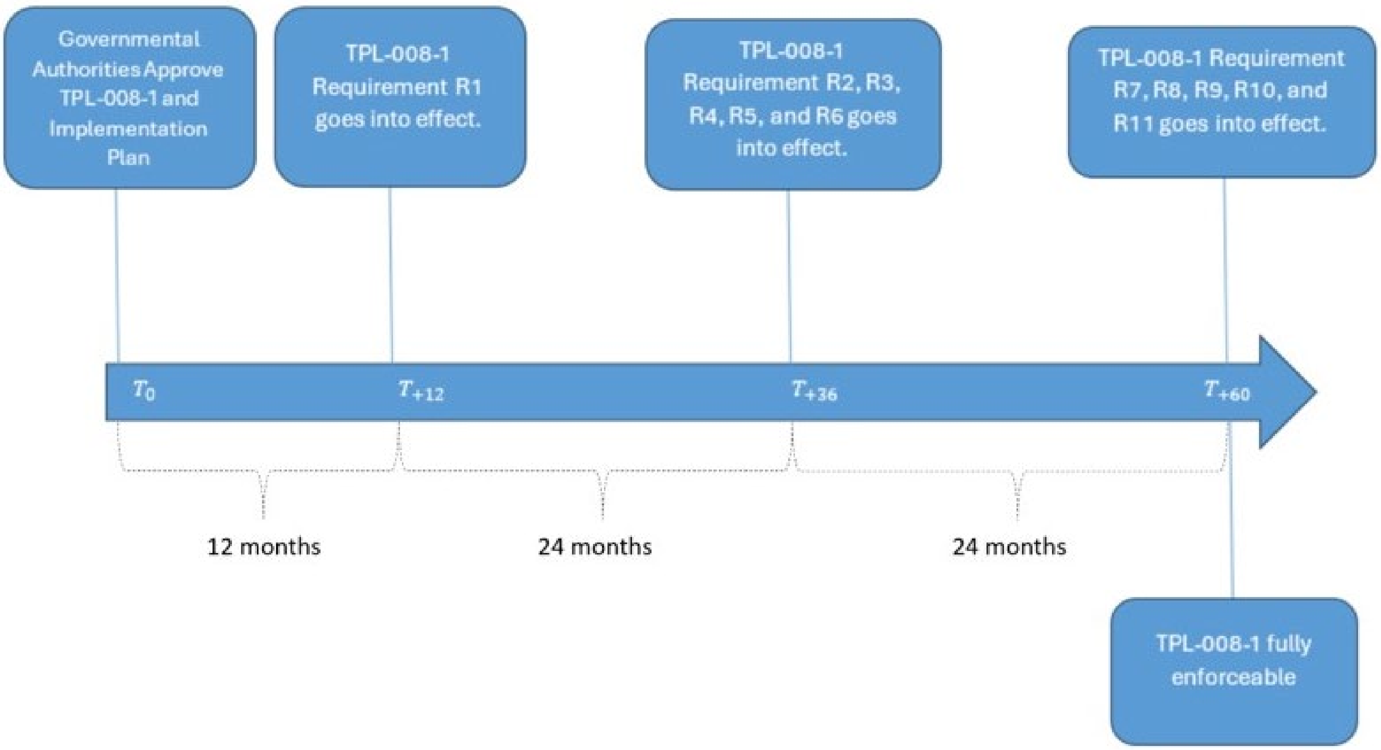
Compliance Date for TPL-008-1 Requirement R1

Entities shall be required to comply with Requirement R1, pertaining to the identification of individual and joint responsibilities for completing the Extreme Temperature Assessment, upon the effective date of Reliability Standard TPL-008-1.

Compliance Date for TPL-008-1 Requirements R2, R3, R4, R5, R6
Entities shall not be required to comply with Requirements R2, R3, R4, R5, and R6 until twenty-four (24) months after the effective date of Reliability Standard TPL-008-1.

Compliance Date for TPL-008-1 Requirements R7, R8, R9, R10, R11
Entities shall not be required to comply with Requirements R7, R8, R9, R10, and R11 until forty-eight (48) months after the effective date of Reliability Standard TPL-008-1.

Figure 1: Implementation Plan, Demonstrating Effective Date and Phased-in Compliance Dates from the effective date of the governmental authority's order approving this standard



Initial Performance of Periodic Requirements

Entities shall complete the Extreme Temperature Assessment no later than forty-eight (48) months after the effective date of Reliability Standard TPL-008-1. Subsequent Extreme Temperature Assessments shall be completed by no later than five calendar years following the completion of the previous Extreme Temperature Assessment.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit C

Order No. 672 Criteria

EXHIBIT C

Order No. 672 Criteria

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 proposed Reliability Standard TPL-008-1 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]

Proposed Reliability Standard TPL-008-1 – Transmission System Planning Performance Requirements for Extreme Temperature Events is a new Reliability Standard, developed in response to Order No. 896,[3] focused specifically on improving how Planning Coordinators and Transmission Planners plan for the potential impacts of extreme heat and extreme cold temperature events on the reliable operation of the Bulk-Power System. The proposed Reliability Standard

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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, *supra* note 1, 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, *supra* note 1, 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.").

[3] Order No. 896, *Transmission System Planning Performance Requirements for Extreme Weather*, 183 FERC ¶ 61,191 (2023) [hereinafter Order No. 896].

consists of a framework, consisting of 11 requirements, for the performance of periodic studies assessing the wide-area impacts of extreme heat and extreme cold temperature events on the Bulk-Power System. These periodic studies are referred to as Extreme Temperature Assessments. Proposed Reliability Standard TPL-008-1 would require planning entities in a planning zone, defined in Attachment 1 to the standard, to coordinate with each other on the development of Extreme Temperature Assessments. The proposed standard contains requirements addressing coordination, requirements addressing the creation of benchmark temperature events (based on analysis of historical weather data), requirements addressing the creation of planning cases based on the benchmark temperature events, requirements for steady state and transient stability analyses including sensitivity cases, requirements for entities to develop Corrective Action Plans in specified instances where system performance requirements are not met, and requirements for the sharing of study information and any Corrective Action Plans developed to address system performance issues.

Proposed Reliability Standard TPL-008-1 is thus designed to achieve a specific reliability goal and contains a technically sound means to achieve that goal.

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.[4]

Proposed Reliability Standard TPL-008-1 is clear and unambiguous as to what is required and who is required to comply, in accordance with Order No. 672. The proposed standard is applicable to Planning Coordinators and Transmission Planners, the functional entities who

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[4] *See* Order No. 672, *supra* note 1, 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, *supra* note 1, 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.").

perform tasks related to planning the Bulk-Power System. As discussed further in the main petition, the proposed standard clearly articulates the actions that applicable entities must take to comply with the standard.

3. A proposed Reliability Standard must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation.[5]

The Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") for proposed Reliability Standard TPL-008-1 comport with NERC and Commission guidelines related to their assignment, as discussed further in **Exhibit F**. 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 Reliability Standard includes clear and understandable consequences in accordance with Order No. 672.

4. A proposed Reliability Standard must identify clear and objective criteria or measures for compliance, so that it can be enforced in a consistent and non-preferential manner.[6]

Proposed Reliability Standard TPL-008-1 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 would be enforced and help ensure that the requirements would be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.

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[5] *See* Order No. 672, *supra* note 1, 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.").

[6] *See* Order No. 672, *supra* note 1, 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.").

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.[7]

Proposed Reliability Standard TPL-008-1 achieves the reliability goal of improving how entities plan for the wide area impacts of extreme heat and extreme cold temperature events on the Bulk-Power System effectively and efficiently in accordance with Order No. 672. By design, proposed Reliability Standard TPL-008-1 accounts for regional differences across North America: the proposed benchmark temperature event criteria, developed following an analysis of historical North American weather data, account for climate differences across regions, and the planning zones reflect areas that have similar electric system properties and similar weather or climatological patterns. While planning entities within a given zone retain flexibility to select the appropriate benchmark events for study within the zone, the standard helps ensure that entities are working together to select a sufficiently severe benchmark temperature event for study. In determining the Contingencies that must be studied and the circumstances under which an entity must develop a Corrective Action Plan to address system performance issues, the drafting team carefully considered all relevant considerations, including the risks, benefits, and implementation concerns associated with different approaches. The result is a proposed standard that achieves its reliability goal effectively and efficiently.

6. Proposed Reliability Standards cannot be "lowest common denominator," i.e., cannot reflect a compromise that does not adequately protect Bulk-Power System reliability. Proposed Reliability Standards can consider costs to implement for smaller entities,

[7] *See* Order No. 672, *supra* note 1, 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.").

but not at consequences of less than excellence in operating system reliability.[8]

Proposed Reliability Standard TPL-008-1 does not reflect a "lowest common denominator" approach. In accordance with the Commission's direction in Order No. 896, the proposed standard contains requirements that would advance the goal of improving how entities plan for the wide area impacts of extreme heat and extreme cold temperature events while balancing the need for manageable coordination among the entities responsible for carrying out the required studies. The proposed requirements are intended to focus studies (and any necessary corrective actions identified through these studies) on the scenarios most likely to occur during an extreme temperature event.

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.[9]

The proposed Reliability Standard would apply consistently throughout North America and does not favor one geographic area or regional model. By design, the proposed standard considers regional variations in climate and electric system properties.

8. Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid beyond any restriction necessary for reliability.[10]

Proposed Reliability Standard TPL-008-1 would have no undue negative effect on competition and would not unreasonably restrict the available transmission capacity or limit the use of the BPS in a preferential manner. The reliability need for improved transmission system planning requirements for extreme temperature events is well documented, as highlighted in Order No. 896.

9. The implementation time for the proposed Reliability Standard is reasonable.[11]

The implementation plan for proposed Reliability Standard TPL-008-1 is just and reasonable and appropriately balances the urgency in the need to implement the standard against the reasonableness of the time allowed for those who must comply to develop necessary procedures or other relevant capability.

The proposed implementation plan, included as **Exhibit B** to this filing, provides that proposed Reliability Standard TPL-008-1 and the definition of Extreme Temperature Assessment would become effective on the first day of the first calendar quarter that is 12 months after the effective date of the Commission's order approving the proposed Reliability Standard. Entities would be required to comply with Requirement R1 pertaining to the identification of individual

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8 *See* Order No. 672, *supra* note 1, 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, *supra* note 1, 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.").

9 *See* Order No. 672, *supra* note 1, 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.").

10 *See* Order No. 672, *supra* note 1, at P 332 ("As directed by section 215 of the FPA, the Commission 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.").

11 *See* Order No. 672, *supra* note 1, 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.").

and joint responsibilities for completing the Extreme Temperature Assessment, by this date. Entities would have an additional 24 months past the effective date to comply with Requirements R2, R3, R4, R5, and R6, and an additional 48 months past the effective date to comply with Requirements R7, R8, R9, R10, and R11.

In developing the proposed implementation timeframe, the drafting team considered the Commission's directive in paragraph 188 of Order No. 896, in which the Commission directed NERC to propose an implementation timeline for its proposed Reliability Standard with implementation beginning no later than 12 months after the effective date of a Commission order approving the standard.[12] Under the proposed implementation plan, responsible entities would need to comply with Requirement R1 within 12 months. In establishing the remaining compliance dates, the drafting team considered the scope of coordination that will be required to perform Extreme Temperature Assessments under the proposed standard, including completing each of the discrete tasks identified in Requirements R2 through R11 for the first time. The drafting team determined that five years represented a reasonable period to complete this new work; further, the five year implementation timeframe reflects the five-year periodicity for Extreme Temperature Assessments in proposed Reliability Standard TPL-008-1. The proposed implementation plan for proposed Reliability Standard TPL-008-1 is therefore just and reasonable, consistent with Commission guidance in Order No. 672, and responsive to the Commission's guidance for the implementation of this standard in Order No. 896.

[12] Order No. 896 at P 188.

10. The Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[13]

Proposed Reliability Standard TPL-008-1 was developed in accordance with NERC's Commission-approved processes for developing and approving Reliability Standards. **Exhibit G** includes a summary of the development proceedings for the proposed standard, and details the processes followed to develop the proposed standard. These processes included, among other things, public comment and ballot periods. Additionally, all meetings of the 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.[14]

NERC has identified no competing public interests regarding the proposed standard. No comments were received that indicated that the proposed standard conflicts with other vital public interests. Consistent with Order No. 896, the proposed standard would require each entity developing a Corrective Action Plan to address system performance issues to share that plan with, and solicit feedback from, the regulatory authority responsible for retail electric service issues in the jurisdiction.

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[13] *See* Order No. 672, *supra* note 1, 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.").

[14] *See* Order No. 672, *supra* note 1, 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.").

12. Proposed Reliability Standards must consider any other appropriate factors.[15]

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

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[15] *See* Order No. 672, *supra* note 1, 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.").

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Exhibit D

Consideration of Order No. 896 Directives

Consideration of FERC Order 896 Directives

Project 2023-07 Transmission System Planning Performance Requirements for Extreme Weather
December 2024

On June 15, 2023, FERC issued a Final Rule, Order No. 896, directing NERC to develop a new or modified Reliability Standard to address a lack of a long-term planning requirement(s) for extreme heat and cold weather events. Specifically, FERC directed NERC to develop modifications to Reliability Standard TPL-001-5.1 or to develop a new Reliability Standard to require the following: (1) development of benchmark planning cases based on major prior extreme heat and cold weather events and/or meteorological projections; (2) planning for extreme heat and cold weather events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios including the expected resource mix's availability during extreme heat and cold weather conditions, and including the wide-area impacts of extreme heat and cold weather; and (3) development of corrective action plans that mitigate any instances where performance requirements for extreme heat and cold weather events are not met. FERC directed NERC to submit a new or revised standard within 18 months, or by December 2024. The below provides the directives from FERC Order 896 along with the drafting team's consideration of the directives.

FERC Order 896 Directives	
Directive Language	**Consideration of Directives**
P35. "[W]e direct NERC to: (1) develop extreme heat and cold weather benchmark events, and (2) require the development of benchmark planning cases based on identified benchmark events." **P36**: "…As recommended by commenters, NERC should consider the examples of approaches for defining benchmark events identified in the NOPR (e.g., the use of projected frequency or probability distribution). NERC may also consider other approaches that achieve the objectives outlined in this final rule."	The ERO has worked with respective subject matter experts, including climate experts, the six regions, etc., to explore extreme heat and extreme cold benchmark temperature events. NERC, in consultation with climate data subject matter expert consultants on the benchmark events, utilized publicly available modeled data to address the requirements of TPL-008-1 that define extreme heat and extreme cold benchmark temperature events. Specifically, based on the available data, the drafting team determined that extreme benchmark temperature events must: 1) consider no less than forty years of historical temperature data, 2) include recent temperature

FERC Order 896 Directives	
Directive Language	**Consideration of Directives**
	data due to ongoing climate changes, and 3) represent one of the twenty worst extreme temperature conditions over the forty year period, based on a 3-day rolling average of daily maximum (heat) or minimum (cold) temperatures. The ERO will maintain a library of benchmark temperature events that meet these requirements. Responsible entities will be able to review and select benchmark temperature events from this library to assist with the development of benchmark planning cases. However, responsible entities may also identify benchmark temperature events via their own processes, provided that the event meets the criteria of Requirement R2 and is agreed upon by all PCs within the zone. Should the extreme heat and cold weather benchmark events provided not suffice for the entities zone, the Planning Coordinator (PC) in coordination with all PCs within its zone, may develop a common extreme heat and extreme cold weather benchmark event to use for the TPL-008-1 Standard. The drafting team developed requirements within TPL-008-1 to require PCs within zones to select one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event (Requirement R2). After selecting its benchmark events, the responsible entity is required to implement a process for coordinating the development of benchmark planning cases and sensitivity cases among the responsible entities (Requirement R3) and to develop benchmark planning cases and sensitivity cases (Requirement R4).

FERC Order 896 Directives	
Directive Language	**Consideration of Directives**
P37. "Because the impact of most extreme heat and cold events spans beyond the footprints of individual planning entities, it is important that all responsible entities likely to be impacted by the same extreme weather events use consistent benchmark events. Doing so is important to ensuring that neighboring planning regions are assuming similar weather conditions and are able to coordinate their assumptions accordingly. As a result, defining the benchmark event in a manner that provides responsible entities significant discretion to determine the applicable meteorological conditions would not meet the objectives of this final rule."	NERC, in consultation with climate data subject matter expert consultants on benchmark events, developed subregions or "zones" of North America that are likely to experience similar weather conditions. These zones also consider practical concerns with coordination such as the boundaries of Interconnections and Balancing Authority Areas. The drafting team developed Requirement R2 such that PCs within the same zone are required to select one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event. This process balances the opportunity to provide input with the need for common events to be modeled over wide areas.
P38. "[I]n developing extreme heat and cold benchmark events, NERC shall ensure that benchmark events reflect regional differences in climate and weather patterns."	NERC, in consultation with climate data subject matter expert consultants on benchmark events, has utilized publicly available modeled data in the last forty-three years (1980-2022), as well as more than eighty years of projected hourly meteorology data from PNNL to ensure regional differences in climate and weather patterns are reflected in the zones depicted in Attachment 1 of TPL-008-1. A Map has been added to the TPL-008-1 Standard showing the zones split throughout the US and Canada. These are to be considered wide area, and regional differences went into consideration when developing the data based on extreme historical events over the past 40 years.
P39. "We also direct NERC to include in the Reliability Standard the framework and criteria that responsible entities shall use to develop from the relevant benchmark event planning cases to represent potential weather-related contingencies (e.g., concurrent/correlated generation and transmission outages, derates) and expected future conditions of the system such as changes in load, transfers, and generation resource mix, and impacts on generators sensitive to extreme heat or cold, due to the weather conditions indicated in the benchmark events. Developing such a	The directive is addressed in Requirements R3 and R4 of the proposed TPL-008-1 standard. Requirement R3 obligates the PC to implement a process to coordinate the development of the benchmark planning cases and sensitivity cases. This process shall include: 1) the selection of System models within the Long-Term Transmission Planning Horizon to serve as a starting point for the benchmark planning cases, 2) forecasted seasonal and temperature

FERC Order 896 Directives	
Directive Language	**Consideration of Directives**
framework would provide a common design basis for responsible entities to follow when creating benchmark planning cases. This would not only help establish a clear set of expectations for responsible entities to follow when developing benchmark planning events, but also facilitate auditing and enforcement of the Standard.”	dependent adjustments for Load, generation, Transmission, and transfers within the zone to represent the selected benchmark temperature events, 3) assumed seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers outside of the zone as needed, and 4) the identification of changes to at least one of generation, real and reactive forecasted load, or transfers to serve as a sensitivity case. Requirement R4 obligates the responsible entity to develop benchmark planning cases and sensitivity cases for performing the Extreme Temperature Assessment which reflects System conditions from the selected benchmark events. Requirement R4 also references the NERC MOD-032 Reliability Standard that provides PCs and Transmission Planners a mechanism for obtaining the data needed to develop the benchmark planning cases.
P40. “We also direct NERC to ensure the reliability standard contains appropriate mechanisms for ensuring the benchmark event reflects up-to-date meteorological data.”	Requirement R2 Part 2.1 requires that the temperature data collected to identify benchmark temperature events includes 40 years of data “ending no more than 5 years prior to the time the benchmark temperature events are selected”. This requirement ensures that the window of time considered for benchmark temperature events reflects up-to-date data. The up-to five-year gap was included due to potential lags in data sources.
P50. “[W]e…direct NERC to require that transmission planning studies under the new or revised Reliability Standard consider the wide-area impacts of extreme heat and cold weather. We direct NERC to clearly describe the process that an entity must use to define the wide-area boundaries. While commenters provide various views in favor of both a geographical approach and electrical approach to defining wide-area boundaries, we do not adopt any one approach in this final rule…NERC should consider the comments in this proceeding when developing a new or modified reliability standard that considers the broad area impacts of extreme heat and cold weather.”	To understand the complexities of defining wide-area boundaries, the drafting team reviewed the extreme weather events mentioned within FERC Order No. 896, as well as the comments received during the FERC Order proceeding. In addition, NERC consulted with climate data subject matter experts who evaluated publicly available modeled data in the last forty-three years (1980-2022) and more than eighty years of projected hourly meteorology data from PNNL. The drafting team struck a balance between a geographical approach and an electrical approach by dividing North America into zones that are likely to experience similar weather conditions but also consider practical

FERC Order 896 Directives	
Directive Language	**Consideration of Directives**
	concerns with coordination such as the boundaries of Interconnections and Balancing Authority Areas. These zones are depicted in Attachment 1 of TPL-008-1, and PCs will be required to coordinate with all PCs in the zone(s) they belong to.
P58. "[W]e…direct NERC to develop benchmark events for extreme heat and cold weather events through the Reliability Standards development process. We agree … that the development of adequate benchmark events is critical and should be committed to the subject matter experts on the standards drafting team. " **P59.** Further, requiring NERC to develop the new or modified Reliability Standard's benchmark events is consistent with the approach the Commission took in Order No. 779, when the Commission directed NERC to develop benchmark events for geomagnetic disturbance analyses.1 For the same reasons, we also conclude that NERC is best positioned to define mechanisms to periodically update extreme heat and cold weather benchmark events, as discussed above.	The drafting team considered various approaches to developing benchmark temperature events. With assistance from NERC's subject matter expert consultants, the drafting team identified the key components of temperature events that are necessary for the event to constitute an adequate benchmark temperature event. These components were included in Requirement R2. Specifically, based on the available data, the drafting team determined that extreme benchmark temperature events must: 1) consider no less than forty years of historical temperature data, 2) include recent temperature data due to ongoing climate changes, and 3) represent one of the twenty worst extreme temperature conditions over the forty year period based on a 3-day rolling average of daily maximum (heat) or minimum (cold) temperatures. The ERO will maintain a library of benchmark temperature events that meet these requirements. Responsible entities will be able to review and select benchmark temperature events from this library to assist with the development of benchmark planning cases. However, responsible entities may also identify benchmark temperature events via their own processes provided that the event meets the criteria of Requirement R2 and is agreed upon by all PCs within the zone.

FERC Order 896 Directives	
Directive Language	**Consideration of Directives**
	In addition to describing the minimum requirements of a benchmark temperature event, Requirement R2 obligates PCs within the same zone to coordinate in selecting one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event for completing the Extreme Temperature Assessment. This coordination is required to ensure the benchmark temperature event is reflected over a wide-area.
P60. "[W]e…direct NERC to designate the type(s) of entities responsible for developing benchmark planning cases and conducting wide-area studies under the new or modified Reliability Standard…benchmark planning cases should be developed by registered entities such as large planning coordinators, or groups of planning coordinators, with the capability of planning on a regional scope." **P61**: "We believe the designated responsible entities should have certain characteristics, including having a wide-area view of the Bulk-Power System and the ability to conduct long-term planning studies across a wide geographic area. The responsible entities should also have the planning tools, expertise, processes, and procedures to develop benchmark planning cases and analyze extreme weather events in the long-term planning horizon." **P62**: "To comply with this directive, NERC may designate the tasks of developing benchmark planning cases and conducting wide-area studies to an existing functional entity or a group of functional entities (e.g., a group of planning coordinators). NERC may also establish a new functional entity registration to undertake these tasks. In the petition accompanying the proposed Reliability Standard NERC should explain how the applicable registered entity or entities meet the objectives outlined above."	The drafting team discussed that the Transmission Planner (TP) and/or Planning Coordinator (PC) would be the responsible entities to address TPL-008-1 Requirements. Requirement R1 obligates both the TP and PC to identify their individual and joint responsibilities. Requirement R3 obligates each PC to implement a process for coordinating the development of benchmark planning cases and sensitivity cases, using the selected benchmark temperature events identified in Requirement R2. This process must be implemented in coordination with all PCs within the same zone. Requirement R4 obligates each responsible entity, as identified in Requirement R1, to use the coordination process developed in accordance with Requirement R3 and data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, to develop benchmark planning cases and sensitivity cases. The identification of joint and individual responsibilities in Requirement R1 provides a measure of flexibility for PCs and TPs to agree on a distribution of responsibilities. Thus, while PCs are responsible for implementing the case development process in Requirement R3, TPs may be responsible for providing data and completing the case development according to that process.

FERC Order 896 Directives	
Directive Language	**Consideration of Directives**
	The development of benchmark planning cases and sensitivity cases will require cooperation amongst many PCs and TPs. By requiring participation from all entities within a zone, TPL-008-1 ensures that the group of functional entities have a sufficient wide-area view of the Bulk Power System and the planning tools, expertise, processes and procedures necessary for developing benchmark planning cases and sensitivity cases.
P72. "[W]e direct NERC to require functional entities to share with the entities responsible for developing benchmark planning cases and conducting wide-area studies the system information necessary to develop benchmark planning cases and conduct wide-area studies. Further, responsible entities must share the study results with affected transmission operators, transmission owners, generator owners, and other functional entities with a reliability need for the studies."	The directive is addressed in proposed TPL-008-1 in Requirements R3, R4 and R11. Requirement R3 obligates each PC to implement a process for coordinating the development of benchmark planning cases, using the selected benchmark temperature events identified in Requirement R2, among all Planning Coordinators within a zone. Requirement R4 obligates each responsible entity, as identified in Requirement R1, to use the coordination process implemented in accordance with Requirement R3 and data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, to develop benchmark planning cases and sensitivity cases. Requirement R11 obligates each responsible entity, as identified in Requirement R1, to provide its Extreme Temperature Assessment results within 60 calendar days of a request to any functional entity that has a reliability related need and submits a written request for the information.
P73. "Because in this final rule we direct NERC to determine the responsible entities that will be developing benchmark planning cases and conducting wide-area studies, it is possible that the selected responsible entities under the new or modified Reliability Standard will not be able to request and receive needed data pursuant to MOD-032-1, absent modification to that Standard."	The drafting team discussed and determined that data needed to address the Extreme Temperature Assessment would still be appropriate to receive through MOD-032. MOD-032 ensures an adequate means of data collection for transmission planning and requires applicable registered entities to provide steady-state, dynamic, and short circuit modeling data to their Transmission Planner(s) and Planning Coordinator(s). As outlined in Requirement R1 and Attachment 1 of MOD-032, MOD-032 allows various

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Directive Language	**Consideration of Directives**
	data collection such as in-service status and capability associated with demand, generation, and transmission associated with various case types, scenarios, system operating states, or conditions for the long-term planning horizon. MOD-032 also requires applicable registered entities to provide “other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes” for each of the three types of data required. Because the drafting team determined the responsible entities that will be developing benchmark planning cases are limited to Planning Coordinators and Transmission Planners, they will be able to request and receive needed data pursuant to MOD-032. Thus, the drafting team believes that there is no need to update MOD-032.
P76: “[W]e…direct NERC to address the requirement for wide-area coordination through the standards development process, giving due consideration to relevant factors identified by commenters in this proceeding.”	The drafting team reviewed all the extreme weather events mentioned within the FERC Order 896. For this project, the drafting team focused the scope of Requirement R3 to require each PC to implement a process for coordinating the development of benchmark planning cases and sensitivity cases, using the selected benchmark temperature events identified in Requirement R2, among all PCs within a zone.
P77. “[W]e direct NERC to require in the new or modified Reliability Standard that responsible entities share the results of their wide-area studies with other registered entities such as transmission operators, transmission owners, and generator owners that have a reliability related need for the studies.”	This directive is addressed in proposed TPL-008-1 Requirement R11. Requirement R11 obligates each responsible entity to provide the wide-area study results within 60 calendar days of a request to any functional entity that has a reliability related need and has submitted a written request for the information.
P88. “[W]e direct NERC to require under the new or revised Reliability Standard the study of concurrent/correlated generator and transmission outages due to extreme heat and cold events in benchmark events as described in more detail below.” **P92.** “These contingencies (i.e., correlated/concurrent, temperature sensitive outages, and derates) shall be identified based on similar	This directive is addressed in proposed TPL-008-1 through Requirements R3 and R4. Per Requirement R3 Part 3.2, the benchmark planning case development process must include forecasted seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers within the zone. Per Requirement R4, the data necessary to build the benchmark planning cases must be provided via MOD-032, supplemented by other sources as needed. Any concurrent/correlated generator and transmission outages due to extreme heat and cold events in benchmark

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Directive Language	**Consideration of Directives**
contingencies that occurred in recent extreme weather events or expected to occur in future forecasted events."	temperature events should be reflected in the model data and thus represented in the initial conditions of the benchmark planning cases.
P111. "[W]e direct NERC to require in the proposed new or modified Reliability Standard that responsible entities perform both steady state and transient stability (dynamic) analyses in the extreme heat and cold weather planning studies. In a steady state analysis, the system components are modeled as either in-service or out-of-service and the result is a single point-in-time snapshot of the system in a state of operating equilibrium. A transient stability (dynamic) analysis examines the system from the start to the end of a disturbance to determine if the system regains a state of operating equilibrium. Performing both analyses ensures that the system has been thoroughly assessed for instability, uncontrolled separation, and cascading failures in both the steady state and the transient stability realms." (internal citations omitted).	This directive is addressed in proposed TPL-008-1 through Requirement R8 and Table 1. Requirement R8 requires the responsible entity to complete both steady state and transient stability analyses and document the assumptions and results. Table 1 obligates each responsible entity to perform both steady state and transient stability analyses and compare the study results against steady state and stability performance requirements.
P112. "[W]e direct NERC to define a set of contingencies that responsible entities will be required to consider when conducting wide-area studies of extreme heat and cold weather events under the new or modified Reliability Standard. We believe that it is necessary to establish a set of common contingencies for all responsible entities to analyze. Required contingencies, such as those listed in Table 1 of Reliability Standard TPL-001-5.1 (i.e., category P1 through P7), establish common planning events that set the starting point for transmission system planning assessments. Requiring the study of predefined contingencies will ensure a level of uniformity across planning regions—a feature that will be necessary in the new or revised Reliability Standard considering that extreme heat and cold weather events often exceed the geographic boundaries of most existing planning footprints."	This directive is addressed in proposed TPL-008-1 through Requirement R7 and Table 1. Requirement R7 requires the responsible entity to identify Contingencies for completing the Extreme Temperature Assessment. The rationale, for those Contingencies selected for evaluation, shall be available as supporting information. The Contingencies for each category in Table 1 of TPL-008-1 correspond to the well-established Contingencies defined in Reliability Standard TPL-001-5.1. Utilizing these well-established Contingencies will ensure a level of uniformity across planning regions.

FERC Order 896 Directives	
Directive Language	**Consideration of Directives**
P113: "[T]he contingencies required in the new or revised Reliability Standards should reflect the complexities of transmission system planning studies for extreme heat and cold weather events."	
P116. "[W]e direct NERC to require in the new or modified Reliability Standard that responsible entities model demand load response in their extreme weather event planning area. As indicated by several commenters, because demand load response is generally a mitigating action that involves reducing distribution load during periods of stress to stabilize the Bulk-Power System, its effect during an extreme weather event should be modeled." **P 117:** "[I]n addressing this directive, we expect NERC to determine whether responsible entities will need to take additional steps to ensure that the impacts of demand load response are accurately modeled in extreme weather studies, such as by analyzing demand load response as a sensitivity, as is currently the case under Reliability Standard TPL-001-5.1."	TPL-008-1 Requirement R4 meets this directive by requiring each responsible entity to develop benchmark planning cases using data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed. Specifically, Attachment 1 of MOD-032 requires information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes.
P124. "[W]e direct NERC to require the use of sensitivity cases to demonstrate the impact of changes to the assumptions used in the benchmark planning case. Sensitivity analyses help a transmission planner to determine if the results of the base case are sensitive to changes in the inputs. The use of sensitivity analyses is particularly necessary when studying extreme heat and cold events because some of the assumptions made when developing a base case may change if temperatures change – for example, during extreme cold events, load may increase as temperatures decrease, while a decrease in temperature may result in a decrease in generation. We… direct NERC to define during the Reliability Standard development process a baseline set of sensitivities for the new or modified Reliability Standard. While we do not require the inclusion of any specific sensitivity in this final rule, NERC should consider including conditions that vary with temperature such as load, generation, and system transfers."	This directive is addressed in proposed TPL-008-1 in Requirement R3, which requires all PCs within the same zone to coordinate to implement a process for developing benchmark planning cases and sensitivity cases. Sensitivity cases are used to demonstrate the impact of changes to the basic assumptions used in the benchmark planning cases. Per Requirement R3 Part 3.4, PCs must include provisions in the case development process to identify changes to generation, real and reactive forecasted Load, and/or transfers to develop sensitivity cases. The identification of changes for sensitivity cases within the coordinated process of Requirement R3 addresses the directive that precludes responsible entities from determining sensitivities alone. However, nothing prevents responsible entities from conducting additional sensitivity studies they find relevant to their planning areas.

FERC Order 896 Directives	
Directive Language	**Consideration of Directives**
P125. "We do not agree ... that responsible entities alone should determine the sensitivity cases that must be considered in the responsible entity's study. … We…believe that responsible entities should be free to study additional sensitivities relevant to their planning areas…cooperation will be necessary between responsible entities conducting extreme heat and extreme cold weather studies and other registered entities within their extreme weather study footprints to ensure the selection of appropriate sensitivities."	
P134. "[W]e directs NERC to require in the new or modified Reliability Standard the use of planning methods that ensure adequate consideration of the broad characteristics of extreme heat and cold weather conditions. We further direct NERC to determine during the standard development process whether probabilistic elements can be incorporated into the new or modified Reliability Standard and implemented presently by responsible entities. If NERC identifies probabilistic elements which responsible entities can feasibly implement and that would improve upon existing planning practices, we expect the inclusion of those methods in the proposed Reliability Standard." **P138.** "[W]e direct NERC to identify during the standard development process any probabilistic planning methods that would improve upon existing planning practices, but that NERC deems infeasible to include in the proposed Reliability Standard at this time. If any such methods are identified, NERC shall describe in its petition for approval of the proposed Reliability Standard the barriers preventing the implementation of those probabilistic elements. We intend to use this information to determine whether and what next steps may be warranted to facilitate the use of probabilistic methods in transmission system planning practices."	The drafting team discussed probabilistic elements and determined while probabilistic analysis would be a good step forward, it would be better suited for the future as the methodology, process, and tools mature. Probabilistic assessment of generation and transmission facilities for the benchmark planning cases was discussed during the process of drafting the TPL-008-1 standard. However, based on the actual extreme heat and extreme cold events that have occurred, outages for generation and transmission facilities were unique for each of these events. Thus, it was challenging to draw correlation for the outages that occurred for different extreme heat and cold events for different regions and different timeframes. In addition, the data, available from these events, was limited to perform an adequate probabilistic assessment. Due to these reasons, the drafting team has decided not to pursue any probabilistic assessment for the current TPL-008-1 standard. This, however, does not preclude future development of probabilistic assessment when having additional data, as well as mature methodology, process and tools that can provide meaningful probabilistic assessment for generation and transmission outages under extreme temperature conditions.
P152. "[W]e direct NERC to require in the new or modified Reliability Standard the development of extreme weather corrective action plans for	The directive is addressed in the proposed TPL-008-1 Requirement R9.

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Directive Language	**Consideration of Directives**
specified instances when performance standards are not met. In addition, as explained below, we direct NERC to develop certain processes to facilitate interaction and coordination with applicable regulatory authorities or governing bodies responsible for retail electric service as appropriate in implementing a corrective action plan." **P155**: "[T]he Commission is not directing any specific result or content of the corrective action plan."	When the benchmark planning case study results indicate the System is unable to meet performance requirements for P0 and P1 Contingencies, Corrective Action Plans (CAPs) must be developed. Additionally, in accordance with Requirement R9 Part 9.1, responsible entities shall make their CAP available to, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.
P157. "[W]e direct NERC to require in the new or modified Reliability Standard the development of corrective action plans that include mitigation for specified instances where performance requirements for extreme heat and cold events are not met—i.e., when certain studies conducted under the Standard show that an extreme heat or cold event would result in cascading outages, uncontrolled separation, or instability." **P158**: "[W]e give NERC in this final rule the flexibility to specify the circumstances that require the development of a corrective action plan."	The directive is addressed in the proposed TPL-008-1 Requirement R9. When the benchmark planning case study results indicate the system is unable to meet performance requirements for P0 and P1 Contingencies, Corrective Action Plans must be developed.
P165. "[w]e direct NERC to require in the new or modified Reliability Standard that responsible entities share their corrective action plans with, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues."	The directive is addressed in the proposed TPL-008-1 Requirement R9. Requirement R9.1 requires the responsible entities to make their CAP available and solicit feedback from applicable regulatory authorities or governing bodies responsible for retail electric service issues.
P167. "Further, because an important goal of transmission planning is to avoid load shed, any responsible entity that includes non-consequential load loss in its corrective action plan should also identify and share with applicable regulatory authorities or governing bodies responsible for retail electric service alternative corrective actions that would, if approved and implemented, avoid the use of load shedding."	This directive is addressed in proposed TPL-008-1 Requirement R9. As stipulated in Requirement R9 Part 9.2, when Non-Consequential Load Loss is utilized as an element of a CAP for a Table 1 P1 Contingency, the responsible entity must document the alternative(s) considered, and notify the applicable regulatory authorities or governing bodies responsible for retail electric service issues.

FERC Order 896 Directives	
Directive Language	**Consideration of Directives**
P188. "[W]e direct NERC to submit a new or modified Reliability Standard within 18 months of the date of publication of this final rule in the Federal Register. Further, we direct NERC to propose an implementation timeline for the new or modified Reliability Standard, with implementation beginning no later than 12 months after the effective date of a Commission order approving the proposed Reliability Standard."	The directive is addressed with the publication of TPL-008-1 and will be filed with the regulatory government no later than December 23, 2024, within 18 months of the date Order No. 896 was published in the *Federal Register*. The implementation plan addresses Requirement R1 becoming effective 12 months from the effective date of the Commission order approving the TPL-008-1. In addition, phased-in approaches have been provided for other Requirements needing additional time. See the TPL-008-1 Implementation Plan.
P193. "[W]e direct NERC to establish an implementation timeline for the proposed Reliability Standard. In complying with this directive, NERC will have discretion to develop a phased-in implementation timeline for the different requirements of the proposed Reliability Standard (i.e., developing benchmark cases, conducting studies, developing corrective action plans). However, this phased-in implementation must begin within 12 months of the effective date of a Commission order approving the proposed Reliability Standard and must include a clear deadline for implementation of all requirements."	The implementation plan addresses Requirement R1 becoming effective 12 months from the effective date of the Commission order approving the TPL-008-1. In addition, phased-in approaches have been provided for other Requirements needing additional time. See the TPL-008-1 Implementation Plan.

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Exhibit E

Technical Rationale

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Technical Rationale and Justification for TPL-008-1

Project 2023-07 Transmission Planning Performance Requirements for Extreme Weather

December 2024

RELIABILITY | RESILIENCE | SECURITY




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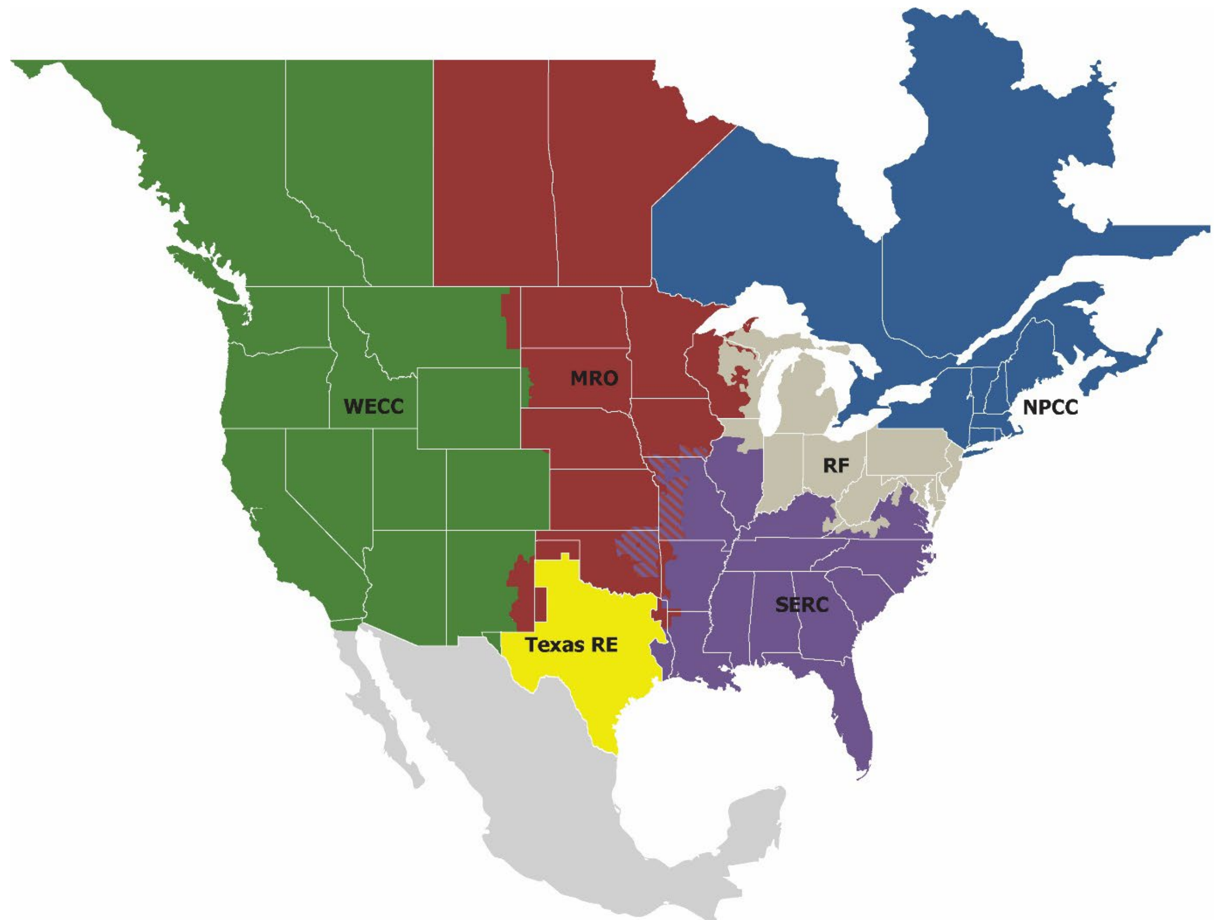
Preface

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

Reliability | Resilience | Security

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

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



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

Introduction

This document explains the technical rationale and justification for the proposed Reliability Standard TPL-008-1. It provides stakeholders and the ERO Enterprise with an understanding of the technology and technical requirements in the Reliability Standard. This Technical Rationale and Justification for TPL-008-1 is not a Reliability Standard and should not be considered mandatory and enforceable.

Background

On June 15, 2023, FERC issued FERC Order No. 896 that acknowledges the "challenges associated with planning for extreme heat and cold weather events, particularly those that occur during periods when the Bulk-Power System must meet unexpectedly high demand. Extreme heat and cold weather events have occurred with greater frequency in recent years and are projected to occur with even greater frequency in the future. These events have shown that load shed during extreme temperatures result in unacceptable risk to life and have extreme economic impact. As such, the impact of concurrent failures of Bulk-Power System (BPS) generation and transmission equipment and the potential for cascading outages that may be caused by extreme heat and cold weather events should be studied and corrective actions should be identified and implemented."[1]

Therefore, the Commission directed in FERC Order No. 896 to develop a new or modified Reliability Standard to address a lack of long-term planning requirement(s) for extreme heat and cold weather events. Specifically, FERC directed NERC to develop modifications to Reliability Standard TPL-001-5.1 or a new Reliability Standard, to require the following: (1) development of benchmark planning cases based on major prior extreme heat and cold weather events and/or meteorological projections; (2) planning for extreme heat and cold weather events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios including the expected resource mix's availability during extreme heat and cold weather conditions, and including the wide-area impacts of extreme heat and cold weather; and (3) development of corrective action plans that mitigate any instances where performance requirements for extreme heat and cold weather events are not met.

[1] N. Am. Elec. Reliability Corp., 183 FERC ¶ 61,191 (2023) (FERC Order), Final Rule. [eLibrary | File List (ferc.gov)]

Defined Terms

The Drafting Team (DT) defined one term to be added to the NERC Glossary of Terms to make the requirements easier to read and understand.

Extreme Temperature Assessment
Documented evaluation of future Bulk Electric System performance for extreme heat and extreme cold benchmark temperature events.

The definition of Extreme Temperature Assessment was developed by the DT to limit wordiness throughout the requirements.

TPL-008-1 Standard

The FERC Order No. 896 directed NERC to submit a new Reliability Standard or modifications to Reliability Standard TPL-001-5.1 to address the concerns pertaining to transmission system planning for extreme heat and cold weather events that impact the Reliable Operation of the Bulk-Power System.

The SDT determined that a new Reliability Standard was the cleanest way to address FERC's directives versus modifying Reliability Standard TPL-001-5.1. While the TPL-008-1 standard uses similar requirements, this allows industry to have one standard that focuses on extreme heat and extreme cold benchmark temperature events.

The purpose of TPL-008-1 is to "Establish Transmission system planning performance requirements to develop a Bulk Power System (BPS) that will operate reliably during extreme heat and extreme cold temperature events." The directives in FERC Order No. 896 pertain to the reliable operation of the BPS, and the requirements of TPL-008-1 support that by ensuring Planning Coordinators and Transmission Planners are planning their portions of the Bulk Electric System (BES) to meet performance requirements in extreme heat and extreme cold benchmark temperature events.

Requirement R1

Requirement R1 requires each Planning Coordinator (PC) and the Transmission Planner(s) (TP) within the PC's footprint to identify each entity's individual and joint responsibilities when completing the Extreme Temperature Assessment at least once every five calendar years. Due to significant level of data collection and coordination between the Planning Coordinator(s) and Transmission Planner(s) for the potential wide-area extreme heat and extreme cold benchmark events, as well as the need to document the assumptions and study results, the drafting team opined that completing the Extreme Temperature Assessment once every five calendar years is a reasonable timeframe to allow responsible entities to coordinate, prepare, perform, and document the study results. To the extent that responsible entities want to complete more than one set of the Extreme Temperature Assessment for an extreme heat and extreme cold benchmark event, they can do so, but the minimum requirement is once every five calendar years to complete one set of the Extreme Temperature Assessment.

The purpose of this requirement is to have the PC and its TP(s) identify their individual and joint responsibilities for the following activities:

- Identifying the PC's zone(s) and coordinating with all PCs in each of its identified zone(s) to select one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event (Requirement R2),
- Implementing a process for developing benchmark planning cases and sensitivity cases (Requirement R3),
- Developing benchmark planning cases and sensitivity cases (Requirement R4),
- Having acceptable criteria (Requirements R5 and R6),
- Identifying Contingencies for evaluation (Requirement R7),
- Performing steady state and transient stability analyses (Requirement R8),
- Developing Corrective Action Plans when required (Requirement R9),
- Evaluating and documenting possible actions for performance deficiencies that do not require Corrective Action Plans (Requirement R10), and
- Providing study results to any functional entity that has a reliability related need (Requirement R11).

The responsibilities described in Requirements R2 and R3 are explicitly assigned to the PC. The responsibilities described in Requirements R4 through R11 may be completed by either the PC or one or more of its TPs. Requirement R1 requires that an agreement is reached on the individual and joint responsibilities for completing the Extreme Temperature Assessment between the PC and its TPs.

Requirement R2

Requirement R2 requires each Planning Coordinator (PC) to identify the zone(s) it will participate in for the components of the Extreme Temperature Assessment that require coordination. PCs in the same zone are required to coordinate to:

- Select one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event (Requirement R2), and
- Implement a process for developing benchmark planning cases and sensitivity cases (Requirement R3).

FERC Order No. 896 directed NERC to require that transmission planning studies under the new or revised Reliability Standard consider the wide-area impacts of extreme heat and cold weather. Considering this directive, the SDT identified the zones depicted in Attachment 1 as reasonable boundaries that balance the need for studies to cover large regions with similar weather patterns with the need for a manageable level of coordination. An earlier proposal to limit coordination to only adjacent PCs was not adequate for meeting FERC's directives. While the zones depicted in Attachment 1 will require some PCs to coordinate with many other PCs, the industry has demonstrated, through various working groups and organizations, that it is capable of cooperating to build models that represent larger areas. The zones depicted in Attachment 1 are either aligned with existing PC boundaries or boundaries of a group of PCs with similar weather patterns.

Requirement R2 describes the need to select extreme benchmark temperature events necessary for the creation of benchmark planning cases. Specifically, extreme hot and cold temperatures experienced during benchmark events are assumed to be outside the ranges used as the basis of planning cases studied under Reliability Standard TPL-001-5.1. Since temperature levels and associated weather conditions affect load levels, generation performance, and transfer levels, the selection of benchmark events is critical to ensuring the Extreme Temperature Assessment appropriately evaluates probable System conditions.

Since any region can experience temperatures that are higher or lower than normal, PCs within the same zone must coordinate to select one common temperature event that includes hotter temperature assumptions and one common temperature event that includes colder temperature assumptions. While it is understood that, for example, one region may typically experience hotter summers and milder winters than another region, both a hotter than average summer and a colder than average winter could result in reliability concerns. Therefore, the requirement is for one common case specific to extreme heat and one common case specific to extreme cold conditions to be studied for the Extreme Temperature Assessment. By selecting the same, common events, PCs ensure that extreme temperatures are studied over the entire zone. The evaluation of a common event taking place over a wide area is foundational to FERC Order No. 896. Furthermore, selecting the same, common events reasonably limits coordination requirements. PCs are required to participate in the selection of events for their zone(s), but have no responsibilities for the selection of events in other zones.

The SDT determined that the extreme heat and extreme cold temperatures selected must have a verified statistical basis based on weather data from credible sources. The SDT has identified several key features that are used to determine when a temperature event will constitute a valid extreme benchmark temperature event for the purposes of completing the Extreme Temperature Assessment. Specifically, extreme benchmark temperature events must:

- Consider no less than 40 years of temperature data,
- Utilize data ending no more than five years prior to the time benchmark temperature events are selected, and
- Represent one of the worst 20 extreme temperature conditions within the zone.

Temperature events are ranked by computing the 3-day rolling average of daily maximum temperatures (for extreme heat) or daily minimum temperatures (for extreme cold). The 3-day rolling average temperatures are calculated for both extreme heat and extreme cold to identify multi-day periods of extreme heat or extreme cold temperature events. The ERO will maintain a library of benchmark events to provide responsible entities access to vetted benchmark temperature events that meet the criteria of Requirement R2. While selection of events from the ERO's provided library assures entities they are selecting valid events, Requirement R2 does not preclude entities from collecting temperature data and identifying benchmark temperature events through their own process. Entities that elect to develop their own benchmark temperature events are responsible for ensuring the input temperature data and selected benchmark temperature events meet the criteria of Requirement R2. Additionally, because Requirement R2 requires PCs within a zone to coordinate in the selection of the benchmark temperature events, the process used to identify these events must be agreeable to those PCs.

The requirement to consider no less than 40 years of temperature data was established based on the observation that many of the worst events identified in various regions of North America occurred in the 1980s and 1990s. For example, preliminary data indicated that the five worst extreme cold temperature events in the PJM region over the last 43 years occurred between 1983 and 1994. Similar results were seen in other regions for both extreme heat and extreme cold temperature events. Thus, the SDT determined that a minimum of 40 years of temperature data should be used to ensure more extreme events weren't excluded by using a shorter duration of temperature data.

Requirement R3

Requirement R3 aligns with directives in FERC Order No. 896, emphasizing the importance of coordinating the development of benchmark planning cases and sensitivity cases amongst PCs within a zone, where the scope of extreme temperature event studies will likely cover large geographical areas exceeding smaller individual planning areas. The SDT considered comments from the industry expressing concerns regarding the necessity to coordinate among all impacted PCs in developing benchmark planning cases and sensitivity cases for various extreme benchmark temperature events. Recognizing that coordination among all impacted PCs may not be necessary to ensure reliability within an individual planning area, the SDT drafted Requirement R3 to require each PC to coordinate with all PCs within a zone to implement a process for the development of benchmark planning cases and sensitivity cases. The SDT believes this change balances the need to ensure the planning cases capture impacts to/from entities affected by the same benchmark temperature event, while recognizing that reliability will be less impacted by system changes far removed from the zone.

PCs within a zone must coordinate to implement a process that results in the development of benchmark planning cases that represent the benchmark temperature events selected in accordance with Requirement R2, and sensitivity cases that demonstrate the impact of changes to the basic assumptions used in the benchmark planning cases. This process requires several components, outlined in the sub-requirements of Requirement R3.

First, Requirement R3 Part 3.1 requires PCs within a zone to identify System models form the basis for developing the benchmark planning cases. These models must represent one of the years in the Long-Term Transmission Planning Horizon. PCs will also need to ensure models include stability modeling data to provide for the performance of stability analysis later in the process. It is reasonably anticipated that PCs will likely utilize a summer peak model as the starting point for the extreme heat benchmark temperature event and a winter peak model as the starting point for the extreme cold benchmark temperature event.

Secondly, Requirement R3 Part 3.2 requires that PCs within a zone provide forecasted data for their area within the zone that represents the benchmark temperature events selected in accordance with Requirement R2. Each PC must provide data for their area within the zone that represents seasonal and temperature adjustments for Load, generation, Transmission, and transfers. The provided data should be used to update the starting point models to reflect the selected benchmark temperature events.

Thirdly, Requirement R3 Part 3.3 allows PCs to agree on assumptions for seasonal and temperature adjustments for Load, generation, Transmission, and transfers in areas *outside* of the zone. As a sub-requirement of Requirement R3, these assumptions must be coordinated among PCs in the zone, as needed. As an example, PCs within the zone may identify the need for imported power during a benchmark event. The PCs may evaluate historical import availability and assume an import from an area outside of the zone is reasonable and should be modeled.

Finally, Requirement R3 Part 3.4 requires PCs to coordinate and identify changes to generation, real and reactive forecasted Load, or transfers that should be reflected in sensitivity cases. Sensitivity cases are intended to demonstrate the impact of changes to the basic assumptions used in the benchmark planning cases, and Requirement R3 Part 3.4 ensures PCs are cooperating to identify changes that sufficiently alter the assumptions reflected in the benchmark planning cases. For example, PCs that identified an import external source to the zone for a benchmark planning case may elect to alter the source of that import in the sensitivity case.

Requirement R4

The SDT drafted Requirement R4 to require the responsible entity to use data consistent with Reliability Standard MOD-032, supplemented by other sources as needed, for developing benchmark planning cases that represent System conditions based on selected benchmark temperature events. This aligns with directives in FERC Order No. 896, paragraph 30, emphasizing the requirement of developing both benchmark planning cases and sensitivity study cases. Requirement R4 is consistent with Reliability Standard TPL-001-5.1 in cross-referencing Reliability Standard MOD-032, which establishes consistent modeling data requirements and reporting procedures for the development of planning horizon cases necessary to support analysis of the reliability of the interconnected System. It is also consistent with Reliability Standard TPL-001-5.1 in acknowledging that data from other sources may be required to supplement the data collected through Reliability Standard MOD-032 procedures.

FERC Order No. 896, paragraph 116, directs NERC "to require in the new or modified Reliability Standard that responsible entities model demand load response in their extreme weather event planning area". This requirement can be met via the use of data consistent with Reliability Standard MO-032, as included in the TPL-008-1 standard's Requirement R4. The modeling of the demand load response can be implemented through the use of MOD-032 in which data needed for study base case development can be requested and obtained for development of the benchmark planning cases and sensitivity cases.

Requirement R4 requires entities to use the coordination process developed in accordance with Requirement R3 to develop the following four cases:

- One common extreme heat benchmark planning case (Requirement R4 Part 4.1),
- One common extreme cold benchmark planning case (Requirement R4 Part 4.1),
- One common extreme heat sensitivity case (Requirement R4 Part 4.2), and
- One common extreme cold sensitivity case (Requirement R4 Part 4.2).

At the completion of the case development process, implemented in accordance with Requirement R3, and executed in Requirement R4, responsible entities will have the four cases listed above. This establishes category P0 as the normal System condition in Table 1 for each case. Requirement R3 does not preclude PCs from implementing a process that develops cases for multiple benchmark temperature events or additional sensitivity cases. Moreover, entities may elect to develop additional cases for their internal use.

As per FERC Order No. 896, paragraph 94, it is clarified that resource adequacy benchmarks are not within the scope of TPL-008-1. The intent of the standard is to evaluate benchmark events where sufficient generation is available to supply load. However, under an extreme heat or extreme cold temperature condition, there may be instances where the benchmark planning cases and/or sensitivity cases may not have sufficient available generation to supply the load. In these scenarios, it may be acceptable for the responsible entity to revise the model to reduce the forecasted Load, or include forecasted generation, to achieve a solution for the benchmark planning cases and/or sensitivity cases and evaluate future Bulk Electric System performance for extreme temperature events. Each responsible entity, as identified in Requirement R1, shall have dated evidence in either electronic or hard copy format that it developed benchmark planning cases and sensitivity cases in accordance with Requirement R4.

Requirement R5

Requirement R5 was drafted to require each responsible entity to set the criteria needed for limits that will be used to evaluate System steady state voltage and post-Contingency voltage deviations for completing the Extreme Temperature Assessment. The establishment of these criteria allows auditors to compare the results of the Extreme Temperature Assessment with the established criteria.

Requirement R6

Requirement R6 was drafted to require the responsible entity to define and document the criteria or methodology used in evaluating the Extreme Temperature Assessment analysis to identify instability, uncontrolled separation, or Cascading within an Interconnection. In developing planning benchmark as well as sensitivity cases for steady-state and transient stability analyses, the Planning Coordinators and Transmission Planners typically use Interconnection-wide starting cases prior to further modifications to reflect the conditions of the benchmark events as well as modifications for sensitivity cases. Analyses that may result in instability, uncontrolled separation, or Cascading typically are confined within an Interconnection where generation and transmission Facilities are interconnected. It is not expected that instability, uncontrolled separation, or Cascading that affect Facilities within an Interconnection would impact other Interconnection(s) as these systems are asynchronous systems (i.e., not connecting synchronously). Adequate and thorough criteria should be built into the Extreme Temperature Assessment to help identify instability, uncontrolled separation, and Cascading conditions. The establishment of these criteria allows auditors to compare the results of the Extreme Temperature Assessment with the established criteria.

Requirement R7

This requirement addresses directives in FERC Order No. 896 to define a set of Contingencies that responsible entities will be required to consider when conducting wide-area studies of extreme heat and cold weather events. FERC's preference to rely on established Contingency definitions, "[w]e believe that it is necessary to establish a set of common contingencies for all responsible entities to analyze. Required contingencies, such as those listed in Table 1 of Reliability Standard TPL-001-5.1 (i.e., category P1 through P7), establish common planning events that set the starting point for transmission system planning assessments," was also considered by the SDT. It is necessary to establish a set of common Contingencies for all responsible entities to analyze. Requiring the study of predefined Contingencies, such as those listed in Table 1, will ensure a level of uniformity across planning regions, considering that extreme heat and cold weather events often exceed the geographic boundaries of most existing planning footprints. Defining the Contingencies in Table 1 consistently with Table 1 of Reliability Standard TPL-001-5.1 meets FERC's preference for commonality.

If feasible, all Contingencies listed in Table 1 should be considered for evaluation by the responsible entity; however, the language affords flexibility in identifying the most appropriate Contingencies. As such, the responsible entity should implement a method and establish sufficient supporting rationale to ensure Contingencies within each category of Table 1, that are expected to produce more severe System impacts within its planning area, are adequately identified. It is noted that since the benchmark planning cases are developed from the extreme temperature benchmark events, they already represent extreme System conditions and thus not all Contingencies from Reliability Standard TPL-001-5.1 Table 1 are included in the TPL-008-1 Table 1 for assessment. The Events included in TPL-008-1 Table 1 represent the more likely Contingencies to occur.

The SDT included categories P0, P1, and P7 in Table 1 of TPL-008-1. The SDT finds it reasonable to exclude P2, P3, P4, P5 and P6 Contingencies from the Extreme Temperature Assessment. Studying categories P0, P1 and P7 is the minimum requirement of TPL-008-1. The standard does not preclude entities from studying additional Contingencies if desired. The following discusses the rationale for excluding P2 through P6 Contingencies for TPL-008-1:

1. Excluding P2 and P4 Contingencies:

   After consideration of comments received from the industry, the SDT removed P2 and P4 Contingencies due to lower probability of occurrence than P1 and P7 Contingencies. TPL-008 now focuses on the single Contingencies (P1) or multiple Contingencies on common structure (P7) that are more likely to be monitored in operational scenarios. P2 Contingencies (e.g. Contingencies caused by internal breaker fault, bus section fault, opening line section without a fault), and P4 Contingencies (e.g., Contingencies caused by stuck breaker), while plausible under extreme temperature conditions, occur in much less frequency when compared to P1 and P7 Contingencies. The standard establishes minimum requirement for Contingencies with higher probability of occurrence. To the extent that the responsible entity determines the need for studying beyond the minimum requirements, the standard does not preclude the entity from doing so.

2. Excluding P3 and P6 Contingencies:

   Part of the decision stems from the complexity of P3 and P6 Contingencies, which involve multiple element outages triggered by multiple Contingencies, with System adjustments allowed between them. Consequently, the occurrence likelihood of P3 and P6 Contingencies could be even lower compared to P1 and P7 Contingencies. Moreover, aligning with the directives set forth in FERC Order 896, which emphasizes the importance of incorporating derated generation, transmission capacity, and the availability of generation and transmission in the development of benchmark planning cases, it becomes imperative for responsible entities to consider potential concurrent or correlated generation and transmission outages and/or derates within relevant benchmark planning cases. This ensures that the benchmark planning case accurately reflects System conditions under extreme temperatures, with generation and transmission derates and/or outages already factored. Therefore, the SDT believes excluding P3 and P6 is justified, as generation and transmission derates and/or outages are already accounted for within the benchmark planning cases.

3. Excluding P5 Contingencies:

   After consideration of comments received from the industry, the SDT removed P5 Contingency (Delayed Fault Clearing due to failure of non-redundant component of a Protection System). This is because while some categories of Contingencies may be assessed in a straightforward approach, category P5 Contingency events often require a significant level of engineering analysis (including protection and/or control analysis). These analyses are sensitive to the System topology and expected dispatch. As the planning benchmark cases are developed for TPL-008-1 that represent System conditions that are different than the typical summer or winter peak conditions, the development of category P5 Contingency events is expected to be a significant burden. Since these events only require evaluations of possible mitigations (and not Corrective Action Plans), violations resulting from these events are unlikely to result in significant transmission System investment. Furthermore, any violations resulting from category P5 events may be mitigated by eliminating and addressing the single point of failure included in the event definition. Thus, the evaluation of possible actions is unlikely to result in further insight beyond the general reliability improvements associated with eliminating single points of failure.

The SDT discussed and decided to keep the P7 Contingency category because common structure Contingencies are often evaluated after categories P0 and P1 as the most common minimum level of transmission reliability assessment. These events have a high likelihood of occurrence due to the following reasons:

- Historical events that include simultaneous forced outage due to tripping of the double-circuit power lines due to electrical storm events;
- Environment-caused factors include pollution buildup, such as dust, that could cause faulted condition that trips both transmission lines on a common tower;
- Avian-caused outages that impact both transmission lines on a common tower;
- Smoke from nearby wildfires can cause simultaneous tripping of both circuits on a common tower;
- Nearby wildfires can impact System Operation as System Operators proactively de-energize both lines on a common tower to avoid further impact to the transmission grid in the event of a simultaneous tripping of both lines that may be carrying high power transfer between areas;
- Weather-related causes such as lightning, flooding, wind, or icing can cause tripping of both transmission lines on a common tower;
- Natural disaster such as winter storm can cause transmission tower to collapse, taking out both lines strung on the same tower;
- Other incidents such as vehicle accident, aircraft accident, vandalism, or animal contact that can adversely impact both transmission lines on the common tower.

Loss of two circuits running in parallel, simultaneously, is likely to have a greater system impact versus loss of two unrelated or geographically separated circuits. Therefore, there is greater potential for reliability concerns, especially during heavy transfers that are likely during periods of extreme weather, due to loss of both circuits of a double-circuit line. Due to the reasons above, Contingencies that involve double-line circuits on a common tower are included in the critical multiple Contingency list in either transmission planning or System Operations reliability assessment.

Some, but not all, items to consider when developing the rationale for selecting Contingencies are:

- Past studies,
- Subject matter expert knowledge of the responsible entity's System (to be supplemented with data or analysis), and
- Historical data from past operating events.

Lastly, regarding the Bulk Electric System (BES) voltage levels for the Contingencies, the SDT reviewed previous major wide-area benchmark events and found that the Facilities that were out of service by these events have voltages that are 200 kV and above. Thus, it is the reason for establishing voltages of 200 kV and above for Contingencies in Table 1 of TPL-008-1. The monitoring of potential impact is still applicable to Facilities with all BES voltage levels. However, with that said, the SDT recognized that many PCs and TPs have Contingencies that include all BES levels. Responsible entities may elect to use the existing Contingencies that they already have and report the criteria violations for the categories in TPL-008-1 Table 1.

Requirement R8

Requirement R8 was drafted to provide clarity on the following:

1. What planning study cases are required?

   The Requirement R8 includes the following number of assessments to complete the Extreme Temperature Assessment and address FERC Order No. 896 directives per paragraph 111 that "direct NERC to require in the proposed new or modified Reliability Standard that responsible entities perform both steady state and transient stability (dynamic) analyses in the extreme heat and cold weather planning studies". In addition, Requirement R8 also addresses FERC Order No. 896 directives per paragraph 124 that "require the use of sensitivity cases to demonstrate the impact of changes to the assumptions used in the benchmark planning case". Requirement R8 also addresses FERC Order No. 896 directives per paragraph 124 that sensitivity cases "should consider including conditions that vary with temperature such as load, generation, and system transfers." Since the benchmark planning case(s) already include System conditions under extreme heat or extreme cold events, the sensitivity analysis is to include changes to at least one of the following conditions: generation, real and reactive forecasted Load, or transfers. Since the minimum requirement includes changes to one of these conditions, the PCs and the TPs can include further sensitivity assessments to change more conditions if they choose to do so.

   The following provides the number of assessments required for the benchmark planning and sensitivity cases to complete the Extreme Temperature Assessment.

Type of Extreme Temperature Assessment	Extreme Cold Temperature Event	Extreme Heat Temperature Event	Total
Benchmark Planning Case Analysis	One extreme cold benchmark planning case assessment	One extreme heat benchmark planning case assessment	Two benchmark planning case assessments
Sensitivity Case Analysis	One sensitivity case with changes to at least one of the following conditions: generation, real and reactive forecasted Load, or transfers	One sensitivity case with changes to at least one of the following conditions: generation, real and reactive forecasted Load, or transfers	Two sensitivity case assessments
Total			A total of four assessments to complete the Extreme Temperature Assessment

2. What are the types of analyses required?

   There are two types of analyses required: steady-state and transient stability. Each type of analysis must be completed for each of the four cases described in the table above. This requirement is to satisfy FERC Order No. 896 directive paragraph 111.

Requirement R9

FERC Order No. 896 identifies a deficiency in the existing Reliability Standard TPL-001-5.1 where "planning coordinators and transmission planners are required to evaluate possible actions to reduce the likelihood or mitigate the consequences of extreme temperature events but are not obligated to develop corrective action plans" (¶139).

Given potential severe consequences of extreme cold and extreme heat events, FERC Order No. 896 raises the bar and "directs NERC to require in the new or modified Reliability Standard the development of extreme weather corrective action plans for specified instances when performance standards are not met" (¶152).

Due to higher likelihood of categories P0 and P1, these categories are held to a higher performance requirement in benchmark planning cases. Corrective Action Plans are required to address performance deficiencies for categories P0 and P1 in benchmark planning cases analyzed in the Extreme Temperature Assessment.

Furthermore, having a Corrective Action Plan requirement for categories P0 and P1 in benchmark planning cases ensures resilience during future extreme cold and extreme heat temperature events, when the transmission System is required to be P1 Contingency-secure (for steady-state and transient stability).

Given that a category P0 represents a continuous System condition without any system disturbances, the SDT determined that load shedding should not be considered as a Corrective Action Plan. However, the SDT has determined that load curtailment may be considered for a P1 Contingency as a Corrective Action Plan where load shed is allowed to prevent system-wide failures and ensuring the continued operation of essential services under a critical P1 Contingency in the extreme heat and cold temperature events. The SDT also emphasizes that alternative solutions, other than firm load curtailment, are evaluated in higher priorities. Non-Consequential Load Loss is permitted as an interim solution in situations that are beyond the control of the Planning Coordinator or Transmission Planner that prevent the implementation of a Corrective Action Plan in the required timeframe; however, the responsible entity must document the situation causing the problem, alternatives evaluated, and take actions to resolve the situation. Future revisions to the Corrective Action Plan are allowed, provided that the planned Bulk Electric System continues to meet the performance requirements of Table 1.

FERC Order No. 896 also directs NERC "to develop certain processes to facilitate interaction and coordination with applicable regulatory authorities or governing bodies responsible for retail electric service as appropriate in implementing a corrective action plan" (¶152). In the event that Non-Consequential Load Loss is included in the Corrective Action Plan for a P1 Contingency, the responsible entity shall document alternative(s) considered, make the Corrective Action Plan available to, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.

Lastly, the standard also permits the responsible entities to revise or update the Corrective Action Plan that was considered and approved in the previous Extreme Temperature Assessment. This allows responsible entities to incorporate approved mitigation measures from other planning assessments, such as annual transmission reliability assessment under TPL-001-5 or subsequent related planning standard, or from other planning assessments for policy-driven or economic needs. The revised or updated Corrective Action Plan associated with TPL-008-1 can be documented as an addendum to the previous Extreme Temperature Assessment's Corrective Action Plan.

Requirement R10

The requirement for responsible entities to evaluate and document possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts when the study results in the benchmark planning cases analyses conclude there could be instability, uncontrolled separation, or Cascading for P7 Contingencies is in response to directives outlined in FERC Order No. 896.

P7 Contingencies involve multiple element outages resulting from a single event, making them relatively less likely to occur, compared to categories P0 and P1, but potentially causing more severe system impacts. Considering both the likelihood of these Contingencies, and the fact that the Extreme Temperature Assessment already addresses low-probability System conditions, the SDT determined that Corrective Action Plans should not be required for P7 Contingencies. However, due to the potential severity resulting from single-Contingency multiple element outages, the SDT believes it is appropriate for responsible entities to at least evaluate and document possible mitigation actions to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses conclude there could be instability, uncontrolled separation, or Cascading. The biggest benefit from the evaluation and documentation of the possible mitigating actions is it allows a responsible entity to see where major reliability concerns exist that may need to be addressed; and, if a sufficiently large number of reliability concerns are identified, it may encourage transmission upgrade mitigation option(s) to be considered and implemented without it being strictly called for in the standard. Not requiring Corrective Action Plans for these Contingencies, but requiring the evaluation, is a compromise from having Corrective Action Plans for all studied Contingencies.

Furthermore, FERC Order No. 896 requires “the use of sensitivity cases to demonstrate the impact of changes to the assumptions used in the benchmark planning case” (¶124). FERC Order No. 896 also states: “NERC should determine whether corrective action plans should be required for single or multiple sensitivity cases, and whether corrective action plans should be developed if a contingency event that is not already included in benchmark planning case would result in cascading outages, uncontrolled separation, or instability” (¶158). The SDT acknowledges that sensitivity analysis is an important component of a robust transmission planning study. A requirement to develop and implement Corrective Action Plans for sensitivity cases may incentivize responsible entities to select fewer or less severe sensitivities. An incentive to select fewer sensitivities is undesirable because sensitivity study results are used to identify constraints and initiate deeper analysis into the variables that impact those constraints. The study results of sensitivity cases are also important to inform the development of Corrective Action Plans in the benchmark planning cases. Therefore, the SDT determined the responsible entity must evaluate and document possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses of sensitivity cases conclude there could be instability, uncontrolled separation, or Cascading for categories P0, P1, and P7. Finally, TPL-008-1 does not preclude the responsible entity from developing Corrective Action Plans for sensitivity cases beyond what is required in the standard.

Requirement R11

The requirement for responsible entities to share Extreme Temperature Assessment results aligns with directives in FERC Order No. 896, emphasizing coordination and sharing of study findings. It ensures collaboration among stakeholders and timely dissemination of critical information to entities with reliability-related needs. This fosters a collective understanding of reliability concerns identified in wide-area studies, thereby enhancing overall grid reliability.

Attachment 1: Extreme Temperature Assessment Zones

The map depicts an approximation of the zones to be used in the Extreme Temperature Assessment and is provided as a visual aid for each Planning Coordinator to identify the zone(s) to which the Planning Coordinator belongs to under Attachment 1. The zone topology is a function of balancing authority jurisdiction and general knowledge of zonal weather patterns, or in some cases, are limited by transmission constraints, or lack of transmission thereof, between zones. The goal of the topology was to split the North American System into several distinct zones that have similar electric power system properties (i.e., balancing authority and interconnections) and similar weather or climatological patterns. Balancing authorities with large areas of jurisdiction, exclusively ISOs and RTOs, are assigned their own weather zone. In geographical areas comprised of multiple balancing authorities, generalized weather zones are created to best represent zonal weather patterns.

The NPCC region of the Eastern Interconnection was divided into New England, New York, Quebec Interconnection, Ontario, and Maritimes. The Planning Coordinators for the NPCC region of the Eastern Interconnection are listed below:

- New England: Planning Coordinators in NPCC that primarily serve the six New England States.
- New York: Planning Coordinators in NPCC that primarily serve New York.
- Quebec: Planning Coordinators that primarily serve Quebec in the NPCC Region.
- Ontario: Planning Coordinators in NPCC that primarily serve Ontario.
- Maritimes: Planning Coordinators in NPCC that primarily serve New Brunswick, Nova Scotia, Prince Edward Island, and the Northern Maine Independent System Administrator (NMISA). The NMISA is responsible for the administration of the northern Maine transmission system and electric power markets in Aroostook and Washington counties, with the load served radially from New Brunswick. It was not included in the New England division since there are no physical transmission ties between NMISA and ISO-NE which is the Planning Coordinator serving the remainder of the six New England States.

Additionally, SERC combined NERC Assessment areas of SERC-East, SERC-Central, and SERC-Southeast into a single zone based on climate similarities. Northwest Regions, WECC-SW, SERC, and SERC-FP were based on balancing authority PNNL data. SPP-N, SPP-S, MISO-N, and MISO-S were aggregated based on county-level PNNL data.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit F

Analysis of Violation Risk Factors and Violation Severity Levels

Violation Risk Factor and Violation Severity Level Justifications

Project 2023-07 Transmission System Planning Performance Requirements for Extreme Weather

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Project 2023-07 Transmission System Planning Performance Requirements for Extreme Weather. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for TPL-008-1, Requirement R1	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to the fact that the Planning Coordinators, in conjunction with its Transmission Planner(s) will determine joint responsibilities for requirements throughout TPL-008-1.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed less than or equal to six months late.	The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed more than six months but less than or equal to 12 months late.	The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed more than 12 months but less than or equal to 18 months late.	The Planning Coordinator, in conjunction with its Transmission Planner(s), failed to identify individual and joint responsibilities for completing the Extreme Temperature Assessment. OR The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed more than 18 months late.

VSL Justifications for TPL-008-1, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL has been assigned as a binary due to the Planning Coordinator and Transmission Planner to determine who completes the responsibilities throughout TPL-008-1. The responsibilities documentation will either be developed or not.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R2	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of high is appropriate due to the fact that selecting a benchmark event to perform an extreme temperature assessment can affect the grid based on planning analysis for future events.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Planning Coordinator coordinated with all Planning Coordinators within each identified zone to identify one common extreme heat and one common extreme cold benchmark temperature event for completing the Extreme Temperature Assessment, but one of the identified events failed to meet all the criteria of Requirement R2.	The Planning Coordinator coordinated with all Planning Coordinators within each identified zone to identify one common extreme heat and one common extreme cold benchmark temperature event for completing the Extreme Temperature Assessment, but both of the identified events failed to meet all of the criteria of Requirement R2. OR The Planning Coordinator failed to coordinate with all Planning Coordinators within each identified zone to identify one common extreme heat and one common extreme cold benchmark temperature event for completing the Extreme Temperature Assessment.

VSL Justifications for TPL-008-1, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	This VSL has been assigned as a binary due to the benchmark event needing to be selected for benchmark planning cases to be completed. You either select a benchmark event or not.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R3	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of medium is appropriate due to the fact that it is important to develop and maintain System models within an entity's planning area for performing Extreme Temperature Assessments. Connecting to MOD-032 to provide important data needed to assist entities with System models is also important for accurate information to be used.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Planning Coordinator did not coordinate with all Planning Coordinators within each of its identified zone(s) to implement a process for developing benchmark planning cases. OR The Planning Coordinator coordinated with all Planning Coordinators within each of its identified zone(s) to implement a process for developing benchmark planning cases, but the process did not include all of the required elements.

VSL Justifications for TPL-008-1, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL has been assigned as a binary due to the responsible entity either develops and maintains the System models within its planning area or it does not develop and maintain the System models within its planning area.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R4	
Proposed VRF	**High**
NERC VRF Discussion	The VRF of High is appropriate because it could directly affect the electrical state or capability of the BPS if coordination is not completed for benchmark planning cases and sensitivity cases for the Extreme Temperature Assessment results.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity, as identified in Requirement R1, did not use the process developed in Requirement R3 to develop benchmark planning cases or sensitivity cases. OR The responsible entity, as identified in Requirement R1, used the process developed in Requirement R3 to develop benchmark planning cases and sensitivity cases, but did not use data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, for one or more of the required cases. OR The responsible entity, as identified in Requirement R1, used the process developed in Requirement R3 and data consistent with that provided in accordance with the MOD-032 standard, supplemented as needed, but failed to develop one or more of the required planning or sensitivity cases.

VSL Justifications for TPL-008-1, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL has been assigned as a binary due to the Planning Coordinator to develop and implement a process for coordinating the development of benchmark planning cases. The benchmark planning cases will either be developed and implemented or not.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R5	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of medium is appropriate due to the importance of having criteria for acceptable System steady state voltage limits of post-Contingency voltage deviations for performing Extreme Temperature Assessments.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity, as identified in Requirement R1, did not have criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations for completing the Extreme Temperature Assessment.

VSL Justifications for TPL-008-1, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL has been assigned as a binary due to the responsible entity either having acceptable criteria for System steady state voltage limits and post-contingency voltage deviations or not.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R6	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate due to the importance of defining and documenting the criteria or methodology for System instability, uncontrolled separation, or Cascading.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity, as identified in Requirement R1, failed to define or document the criteria or methodology to be used in the Extreme Temperature Assessment to identify instability, uncontrolled separation, or Cascading within an Interconnection.

VSL Justifications for TPL-008-1, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R7	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of medium is appropriate for this requirement. Identifying Contingencies for performing Extreme Temperature Assessments for each of the event categories in Table 1 can indirectly impact the BES.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The responsible entity, as identified in Requirement R1, identified Contingencies for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System, but did not include the rationale for those Contingencies selected for evaluation as supporting information.	The responsible entity, as identified in Requirement R1, did not identify Contingencies for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System.

VSL Justifications for TPL-008-1, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R8	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate due to the importance of performing an Extreme Temperature Assessment every 5 years.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to document the assumptions for one or more sensitivity cases in accordance with Requirement R8.	The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to document the assumptions for one or more benchmark planning cases in accordance with Requirement R8.	The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to document results for one or more of the sensitivity cases in accordance with Requirement R8.	The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to document results for one or more of the benchmark planning cases in accordance with Requirement R8. OR The responsible entity, as identified in Requirement R1, failed to complete steady state or transient stability analyses and document results in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, in accordance with Requirement R8.

VSL Justifications for TPL-008-1, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R9	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate for this requirement. Developing a Corrective Action Plan is important to the BES as it assists entities when Systems are unable to meet performance requirements.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R9			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The responsible entity, as identified in Requirement R1, developed a Corrective Action Plan in accordance with Requirement R9, but failed to make its Corrective Action Plan available to, or solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.	The responsible entity, as identified in Requirement R1, failed to develop a Corrective Action Plan when the benchmark planning case study results indicate the System is unable to meet performance requirements for the Table 1 P0 or P1 Contingencies. OR The responsible entity, as identified in Requirement R1, developed a Corrective Action Plan, but it was missing one or more of the elements of Requirement R9 Part 9.1, 9.3 and 9.4 (as applicable).

VSL Justifications for TPL-008-1, Requirement R9	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL has been assigned as a binary due to the responsible entity either having acceptable criteria for System steady state voltage limits and post-contingency voltage deviations or not.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R10	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of lower has been assigned to Requirement R10. Documenting possible actions to reduce the likelihood or mitigate the consequences and adverse impacts are administrative in nature.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R10			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The responsible entity, as identified in Requirement R1, evaluated and documented possible actions to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection where required under Requirement R10 Part 10.1, but failed to evaluate and document possible actions where required under Requirement R10 Part 10.2.	The responsible entity, as identified in Requirement R1, evaluated and documented possible actions to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection where required under Requirement R10 Part 10.2, but failed to evaluate and document possible actions where required under Requirement R10 Part 10.1. OR The responsible entity, as identified in Requirement R1, failed to evaluate and document possible actions to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection where required under Requirement R10 Parts 10.1 and 10.2.

VSL Justifications for TPL-008-1, Requirement R10	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL has been assigned as a binary due to the fact that the responsible entity will have evaluated and documented possible actions to mitigate adverse impacts.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R11	
Proposed VRF	**Medium**
NERC VRF Discussion	The VRF of Medium is appropriate because it could directly affect the electrical state or capability of the BES if entities are not aware of the results from its Extreme Temperature Assessment results.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R11			
Lower	**Moderate**	**High**	**Severe**
The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 60 days but less than or equal to 80 days following the request.	The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 80 days but less than or equal to 100 days following the request.	The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 100 days but less than or equal to 120 days following the request.	The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 120 days following the request. OR The responsible entity, as identified in Requirement R1, did not provide its Extreme Temperature Assessment results to functional entities having a reliability related need who submitted a written request for the information.

VSL Justifications for TPL-008-1, Requirement R11	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

Exhibit G

Summary of Development History and Complete Record of Development

Summary of Development History

The following is a summary of the development record for proposed Reliability Standard TPL-008-1.

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 in accordance with Section 4.3 of the NERC Standard Processes Manual.[2] For this project, the SDT consisted of industry experts, all with a diverse set of experiences. A roster of the Project 2023-07 SDT members is included in **Exhibit H**.

II. Standard Development History

A. Project 2023-07 Transmission System Planning Performance Requirements for Extreme Weather

On June 15, 2023, the Commission issued Order No. 896[3] directing NERC to develop modifications to Reliability Standard TPL-001-5.1 or a new Reliability Standard to address a need for long-term planning requirements for extreme heat and cold weather events. Accordingly, proposed Reliability Standard TPL-008-1 was developed to comply with associated regulatory directives from Order No. 896.

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

2 The NERC *Standard Processes Manual* is available at https://www.nerc.com/FilingsOrders/us/RuleOfProcedureDL/SPM_Clean_Mar2019.pdf.

3 Order No. 896, *Transmission System Planning Performance Requirements for Extreme Weather*, 183 FERC ¶ 61,191 (2023).

B. Standard Authorization Request Development

On July 19, 2023, the Standards Committee accepted the Project 2023-07 Standards Authorization Request ("SAR") and authorized posting the SAR for a 30-day informal comment period and the solicitation of drafting team members.[4]

C. Standards Committee Authorizes Procedural Waiver

On December 13, 2023, the Standards Committee authorized a waiver of Sections 4.9 and 4.12 of the Standard Processes Manual to meet the FERC deadlines for this project. The waiver authorized NERC to reduce the initial formal comment and ballot periods for Project 2023-07 from 45 days to as little as 25 days, with ballot pools formed in the first 10 days and initial ballot and non-binding polls conducted during the last 10 days of the comment period. Additional formal comment and ballot periods were reduced from 45 days to as few as 15 days with ballots conducted during the last 5 days of the comment period. The final ballot was reduced from 10 days to as little as 5 days.[5]

D. First Posting – Comment Period, Initial Ballot, and Non-binding Poll

On March 20, 2024, the Standards Committee authorized the initial posting of proposed Reliability Standard TPL-008-1 and associated Implementation Plan and other associated documents for a 45-day formal comment period.[6] The initial posting took place from March 20, 2024 through May 3, 2024, with a parallel initial ballot and non-binding poll on the Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") held during the last 10 days of the

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4 NERC, *Meeting Minutes – Standards Committee Meeting* (July 19, 2023), https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/July%20Meeting%20Minutes%20-%20Approved%20August%2023,%202023.pdf.

5 NERC, *Meeting Minutes – Standards Committee Meeting* (Dec. 13, 2023), https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/SC%20December%20Minutes%20-%20Approved%20January%2017,%202024.pdf.

6 NERC, *Meeting Minutes – Standards Committee Meeting* (Mar. 20, 2024), https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/SC_Meeting_Minutes-March_2024.pdf.

comment period from April 24, 2024 through May 3, 2024.[7] The initial ballot for proposed Reliability Standard TPL-008-1 received 18.69 percent approval, reaching quorum at 88.22 percent of the ballot pool, and the initial ballot for the associated Implementation Plan received 30.03 percent approval with 87.9 percent quorum.[8] The non-binding poll for the associated VRFs and VSLs received 16.67 percent supportive opinions, reaching quorum at 88.22 percent of the ballot pool.[9] There were 78 sets of responses, including comments from approximately 179 different individuals and approximately 99 companies, representing all 10 industry segments.[10]

E. Second Posting – Comment Period, Additional Ballot, and Non-binding Poll

The second draft of proposed Reliability Standard TPL-008-1, the associated Implementation Plan, and other associated documents were posted for a 38-day formal comment period from July 16, 2024 through August 22, 2024, with a parallel additional ballot and non-binding poll held from August 13, 2024 through August 22, 2024.[11] The additional ballot for proposed Reliability Standard TPL-008-1 received 18.17 percent approval, reaching quorum at 87.9 percent of the ballot pool, and the additional ballot for the associated Implementation Plan received 31.97 percent approval with 87.58 percent quorum.[12] The non-binding poll for the associated VRFs and VSLs received 20.71 percent supportive opinions, reaching quorum at 86.87 percent of the ballot pool.[13] There were 74 sets of responses, including comments from approximately 191 different individuals and approximately 118 companies, representing all 10 industry segments.[14]

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7 *See* exhibit G, Complete Record of Development, at items 16, 19.
8 *Id.* at items 21, 22.
9 *Id.* at item 23.
10 *Id.* at item 18.
11 *Id.* at items 33, 36.
12 *Id.* at items 38, 39.
13 *Id.* at item 40.
14 *Id.* at item 35.

F. Third Posting - Comment Period, Initial Ballot, and Non-binding Poll

The third draft of proposed Reliability Standard TPL-008-1, the associated Implementation Plan, and other associated documents were posted for a 15-day formal comment period from October 7, 2024 through October 21, 2024, with a parallel additional ballot and non-binding poll held from October 11, 2024 through October 21, 2024.[15] The additional ballot for proposed Reliability Standard TPL-008-1 received 51.9 percent approval, reaching quorum at 84.39 percent of the ballot pool, and the additional ballot for the associated Implementation Plan received 63.34 percent approval with 84.08 percent quorum.[16] The non-binding poll for the associated VRFs and VSLs received 55.19 percent supportive opinions, reaching quorum at 83.84 percent of the ballot pool.[17] There were 66 sets of responses, including comments from approximately 156 different individuals and approximately 101 companies, representing all 10 industry segments.[18]

G. Fourth Posting- Comment Period, Initial Ballot, and Non-binding Poll

The fourth draft of proposed Reliability Standard TPL-008-1, the associated Implementation Plan, and other associated documents were posted for a 15-day formal comment period from November 7, 2024 through November 21, 2024, with a parallel additional ballot and non-binding poll held from November 12, 2024 through November 21, 2024.[19] The additional ballot for proposed Reliability Standard TPL-008-1 received 73.71 percent approval, reaching quorum at 83.12 percent of the ballot pool, and the additional ballot for the associated Implementation Plan received 77.72 percent approval with 83.12 percent quorum.[20] The non-binding poll for the associated VRFs and VSLs received 73.4 percent supportive opinions,

[15] *Id*. at items 50, 54.
[16] *Id*. at items 55, 56.
[17] *Id*. at item 57.
[18] *Id*. at item 52.
[19] *Id*. at items 68,71.
[20] *Id*. at items 73,74.

reaching quorum at 84.18 percent of the ballot pool.[21] There were 50 sets of responses, including comments from approximately 140 different individuals and approximately 89 companies, representing all 10 industry segments.[22]

H. Final Ballot

The final draft of proposed Reliability Standard TPL-008-1 was posted for a 5-day final ballot period from December 2, 2024 through December 6, 2024.[23] The final ballot for proposed Reliability Standard TPL-008-1 reached quorum at 84.08 percent of the ballot pool, receiving support from 75.43 percent of the voters.[24] The ballot for the Implementation Plan reached quorum at 84.08 percent of the ballot pool, receiving support from 79.38 percent of the voters.[25]

I. Board of Trustees Adoption

The NERC Board of Trustees adopted proposed Reliability Standard TPL-008-1 on December 10, 2024.[26]

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21 *Id*. at item 75.
22 *Id*. at item 70.
23 *Id*. at item 87.
24 *Id*. at item 88.
25 *Id*. at item 89.
26 NERC, *Board of Trustees Agenda Package Dec. 2024*, Agenda Item 3b (Project 2023-07 – Transmission System Planning Performance Requirements for Extreme Weather), https://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Board_Open_Meeting%20Agenda%20Package%20-%20December%202024%20-%20ATT.pdf.

Complete Record of Development

Project 2023-07 Transmission System Planning Performance Requirements for Extreme Weather

Related Files

Status

The final ballots for **TPL-008-1 – Transmission System Planning Performance Requirements for Extreme Temperature Events** and its implementation plan concluded **8 p.m. Eastern, Friday, December 6, 2024**. The voting results can be accessed via the links below. The standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

The Standards Committee approved waivers to the Standards Process Manual at their December 2023 meeting. These waivers were sought by NERC Standards for reduced formal comment and ballot periods to assist the drafting teams in expediting the standards development process due to firm timeline expectations set by FERC Order 896.

Background

On June 15, 2023, FERC issued a Final Rulemaking to direct NERC to develop a new or modified Reliability Standard to address a lack of a long-term planning requirement(s) for extreme heat and cold weather events. Specifically, FERC directed NERC to develop modifications to Reliability Standard TPL-001-5.1 or a new Reliability Standard, to require the following: (1) development of benchmark planning cases based on major prior extreme heat and cold weather events and/or meteorological projections; (2) planning for extreme heat and cold weather events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios including the expected resource mix's availability during extreme heat and cold weather conditions, and including the wide-area impacts of extreme heat and cold weather; and (3) development of corrective action plans that mitigate any instances where performance requirements for extreme heat and cold weather events are not met. In addition, FERC directed "NERC to submit a new or modified Reliability Standard within 18 months of the date of publication of this final rule in the Federal Register," which equates to December 15, 2024.

Standard Affected: TPL-001-5.1

Purpose/Industry Need

Consistent with FERC Order No. 896, the purpose of this project is to address the reliability gap pertaining to the consideration of extreme heat and cold weather events that exist in current transmission planning standards (e.g., NERC Reliability Standard TPL-001-5.1 – Transmission System Planning Performance Requirements).

Recent extreme weather events have shown the risk that such events can pose to the reliable operation of the BPS, and have highlighted the high risk to life and extreme economic impacts that can result from unplanned load shed during such conditions. The impact of concurrent failures of BPS generation and transmission equipment and the potential for cascading outages that may be caused by extreme heat and cold weather events should be studied and corrective actions should be identified and implemented.

Subscribe to this project's observer mailing list

Select "NERC Email Distribution Lists" from the "Service" drop-down menu and specify "Project 2023-07 Transmission System Planning Performance Requirements for Extreme Weather Observer List" in the Description Box.

Draft	Actions	Dates	Results	Consideration of Comments
Final Ballots **TPL-008-1** (76) Clean | (77) Redline to Last Posted (78) Implementation Plan **Supporting Materials** (79) Technical Rationale (80) VRF/VSL Justifications (81) Consideration of FERC Order 896 Directives **Informational Materials** (82) TPL-008-1 ERO Benchmark Weather Event Development and Maintenance Process*updated (83) Benchmark Event Data (84) TPL-008 Data Library Read Me (85) Extreme Temperature Assessment (New Definition) (86) RSAW	Final Ballots (87) Info Vote	12/02/24 - 12/06/24	Ballot Results (88) TPL-008-1 (89) Implementation Plan	
Draft 4 **TPL-008-1** (58) Clean | (59) Redline to Last Posted (60) Implementation Plan **Supporting Materials** (61) Technical Rationale (62) Unofficial Comment Form (63) VRF/VSL Justifications (64) Consideration of FERC Order 896 Directives **Informational Materials** (65) TPL-008-1 ERO Benchmark Weather Event Development and Maintenance Process DRAFT (66) Benchmark Event Data (67) TPL-008 Data Library Read Me	Additional Ballot (71) Ballot Open Reminder (72) Info Vote	11/12/24 - 11/21/24	Ballot Results (73) TPL-008-1 (74) Implementation Plan (75) Non-binding Poll Results	(70) Consideration of Comments
	Comment Period (68) Info Submit Comments	11/07/24 - 11/21/24	(69) Comments Received	
Draft 3 **TPL-008-1** (41) Clean | (42) Redline to Last Posted (43) Implementation Plan **Supporting Materials** (44) Technical Rationale (45) Unofficial Comment Form (46) VRF/VSL Justifications (47) Consideration of FERC Order 896 Directives **Informational Materials**	Additional Ballot (53) Ballot Open Reminder (54) Info Vote	10/11/24 - 10/21/24	Ballot Results (55) TPL-008-1 (56) Implementation Plan (57) Non-binding Poll Results	

(48) TPL-008-1 ERO Benchmark Weather Event Development and Maintenance Process DRAFT 2 **(49)** Benchmark Event Data	Comment Period **(50)** Info Submit Comments	10/07/24 - 10/21/24	**(51)** Comments Received	**(52)** Consideration of Comments
Draft 2 **TPL-008-1** **(24)** Clean | **(25)** Redline to Last Posted **(26)** Implementation Plan **Supporting Materials** **(27)** Technical Rationale **(28)** Unofficial Comment Form **(29)** VRF/VSL Justifications **(30)** Consideration of FERC Order 896 Directives **Informational Materials** Note: NERC is committed to providing additional information regarding the criteria used in the development of benchmark events. As a reminder, the items being balloted are the TPL-008-1 Reliability Standard and the Implementation Plan. See FERC Order 896 Paragraph 35 regarding the directive for creation of benchmark events. **(31)** TPL-008-1 ERO Benchmark Weather Event Development and Maintenance Process DRAFT **(32)** Benchmark Event Example	Additional Ballot **(36)** Ballot Open Reminder **(37)** Info Vote	8/13/24 - 8/22/24	Ballot Results **(38)** TPL-008-1 **(39)** Implementation Plan **(40)** Non-binding Poll Results	**(35)** Consideration of Comments
	Comment Period **(33)** Info Submit Comments	7/16/24 - 8/22/24	**(34)** Comments Received	
Draft 1 **(10) TPL-008-1** **(11)** Implementation Plan **Supporting Materials** **(12)** Technical Rationale **(13)** Unofficial Comment Form **(14)** VRF/VSL Justifications **(15)** Consideration of FERC Order 896 Directives	Initial Ballot **(19)** Ballot Open Reminder **(20)** Info Vote	4/24/24 - 5/3/24	Ballot Results **(21)** TPL-008-1 **(22)** Implementation Plan **(23)** Non-binding Poll Results	**(18)** Consideration of Comments
	Join Ballot Pools	3/20/24 - 4/18/24		
	Comment Period **(16)** Info Submit Comments	3/20/24 - 5/3/24	**(17)** Comments Received	
(9)**Waiver**	The Standards Committee accepted the waiver on December 13, 2023.			
(8)SAR	The Standards Committee accepted the SAR on July 19, 2023.			
(3) Standard Authorization Request Supporting Materials **(4)** Unofficial Comment Form (Word)	Comment Period **(5)** Info Submit Comments	8/29/23 – 9/27/23	(6)Comments Received	**(7)**Consideration of Comments
Drafting Team Nominations **Supporting Materials** **(1)** Unofficial Nomination Form (Word)	Nomination Period **(2)** Info Submit Nominations	8/29/23 – 9/27/23		

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Do not use this form for submitting nominations

Unofficial Nomination Form

Project 2023-07 Modifications to TPL-001-5.1 Transmission System Planning Performance Requirements for Extreme Weather Drafting Team

General Information

Additional information is available on the project page. If you have questions, contact Manager of Standards Development, Jamie Calderon (via email), or at 404-960-0568.

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in face-to-face meetings and conference calls. Previous drafting or quality review team experience is beneficial, but not required.

Project Information

Project Purpose

On June 15, 2023, FERC issued a Final Rulemaking to direct NERC to develop a new or modified Reliability Standard to address a lack of a long-term planning requirement(s) for extreme heat and cold weather events. Specifically, FERC directed NERC to develop modifications to Reliability Standard TPL-001-5.1 or a new Reliability Standard, to require the following: (1) development of benchmark planning cases based on major prior extreme heat and cold weather events and/or meteorological projections; (2) planning for extreme heat and cold weather events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios including the expected resource mix's availability during extreme heat and cold weather conditions, and including the wide-area impacts of extreme heat and cold weather; and (3) development of corrective action plans that mitigate any instances where performance requirements for extreme heat and cold weather events are not met.

Standard(s) Affected

TPL-001-5.1

Nominee Expertise Requested

For this project, NERC is seeking individuals who possess experience in one or more of the following areas:

- Transmission planning assessments;
- Steady state and dynamic stability analyses;
- Sensitivity analysis;
- Developing benchmark events and Interconnection wide planning cases.

Time Commitment Expectations

Time commitments for most projects include up to two face-to-face meetings per quarter (on average two full working days each meeting) with conference calls scheduled as needed. Team members may agree to individual or subgroup assignments, to work in separate meetings and present to the larger team for discussion and review. Another important component of quality reviews and drafting team efforts is outreach. Members of the team will be expected to conduct industry outreach during the development process to support a successful project outcome.

Project Priority

Each project will be developed according to that project's priority status. While each standard project addresses particular industry needs, some projects will be identified as a higher priority project. A higher priority project may initially include a strict timeline, which may be needed to effectively respond to a FERC Directive or as determined by the NERC Board of Trustees. A higher priority project may also need to increase the frequency of meetings at any time throughout the development process to account for project timeline needs. Similarly, other priority projects may adjust to a lower frequency of meetings throughout the development process to reallocate resources to high priority projects.

This project has been identified as higher priority at this time. The project has a FERC deadline of December 2024. To meet this deadline, the team will meet regularly, up to three times a week on conference calls, with face-to-face meetings scheduled as the members' schedule allows, up to once a quarter.

Submitting Nominations

Do not use this form for submitting nominations. Use the electronic form to submit nominations for **Project 2023-07 Modifications to TPL-001-5.1 Transmission System Planning Performance Requirements for Extreme Weather** drafting team members by **8 p.m. Eastern, Wednesday, September 27, 2023.** This unofficial version is provided to assist nominees in compiling the information necessary to submit the electronic form.

Name:	
Organization:	
Address:	

Telephone:	
E-mail:	

Please briefly describe your experience and qualifications to serve on the requested Standard Drafting Team (Bio):

If you are currently a member of any NERC drafting team, please list each team here:

☐ Not currently on any active SAR or standard drafting team.

☐ Currently a member of the following SAR or standard drafting team(s):

If you previously worked on any NERC drafting team please identify the team(s):

☐ No prior NERC SAR or standard drafting team.

☐ Prior experience on the following team(s):

Acknowledgement that the nominee has read and understands both the *NERC Participant Conduct Policy* and the *Standard Drafting Team Scope* documents, available on NERC Standards Resources.

☐ Yes, the nominee has read and understands these documents.

Select each NERC Region in which you have experience relevant to the Project for which you are volunteering:

☐ MRO ☐ NPCC ☐ RF	☐ SERC ☐ Texas RE ☐ WECC	☐ NA – Not Applicable

Select each Industry Segment that you represent:	
☐	1 — Transmission Owners
☐	2 — RTOs, ISOs
☐	3 — Load-serving Entities
☐	4 — Transmission-dependent Utilities
☐	5 — Electric Generators
☐	6 — Electricity Brokers, Aggregators, and Marketers
☐	7 — Large Electricity End Users
☐	8 — Small Electricity End Users
☐	9 — Federal, State, and Provincial Regulatory or other Government Entities
☐	10 — Regional Reliability Organizations and Regional Entities
☐	NA – Not Applicable

Select each Function in which you have current or prior expertise:	
☐ Balancing Authority	☐ Transmission Operator
☐ Compliance Enforcement Authority	☐ Transmission Owner
☐ Distribution Provider	☐ Transmission Planner
☐ Generator Operator	☐ Transmission Service Provider
☐ Generator Owner	☐ Purchasing-selling Entity
☐ Interchange Authority	☐ Reliability Coordinator
☐ Load-serving Entity	☐ Reliability Assurer
☐ Market Operator	☐ Resource Planner
☐ Planning Coordinator	

Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group:			
Name:		Telephone:	
Organization:		E-mail:	
Name:		Telephone:	
Organization:		E-mail:	
Provide the name and contact information of your immediate supervisor or a member of your management who can confirm your organization's willingness to support your active participation.			
Name:		Telephone:	
Title:		Email:	

NERC
NORTH AMERICAN ELECTRIC
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Standards Announcement

Project 2023-07 Modifications to TPL-001-5.1 Transmission System Planning Performance Requirements for Extreme Weather

Drafting Team Nomination Period Open through September 27, 2023

Now Available

Nominations are being sought for drafting team members through **8 p.m. Eastern, Wednesday, September 27, 2023**.

Use the electronic form to submit a nomination. Contact Cindy Jackson regarding issues using the electronic form. An unofficial Word version of the nomination form is posted on the Standard Drafting Team Vacancies page and the project page.

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in face-to-face meetings and conference calls.

Time commitments for most projects include up to two face-to-face meetings per quarter (on average two full working days each meeting) with conference calls scheduled as needed. Team members may agree to individual or subgroup assignments, to work in separate meetings and present to the larger team for discussion and review. Another important component of quality reviews and drafting team efforts is outreach. Members of the team will be expected to conduct industry outreach during the development process to support a successful project outcome.

This project has been identified as higher priority at this time. The project has a FERC deadline of December 2024. To meet this deadline, the team will meet regularly, up to three times a week on conference calls, with face-to-face meetings scheduled as the members' schedule allows, up to once a quarter.

Previous drafting or quality review team experience is beneficial but not required. See the project page and nomination form for additional information.

Next Steps

The Standards Committee is expected to appoint members to the Drafting Team in October 2023. Nominees will be notified shortly after they have been appointed.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Manager of Standards Development, Jamie Calderon (via email), or at 404-960-0568. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify "Project 2023-07 Modifications to TPL-001-5.1 Transmission System Planning Performance Requirements for Extreme Weather" in the Description Box.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standard Authorization Request (SAR)

Complete and submit this form, with attachment(s) to the NERC Help Desk. Upon entering the Captcha, please type in your contact information, and attach the SAR to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	Transmission System Planning Performance Requirements for Extreme Weather		
Date Submitted:	July 5, 2023		
SAR Requester			
Name:	Mohammed Osman, Lead Engineer of System Analysis, Power System Analysis William Lamanna, Senior Engineer – Reliability Assessments Scott Barfield-McGinnis, Principal Technical Advisor, Power Risk Issues and Strategic Management		
Organization:	NERC		
Telephone:	Mohamed: 404-446-9634 Scott: 404-446-9689 William: 404-446-2568	Email:	Mohamed.Osman@nerc.net Scott.Barfield@nerc.net William.Lamanna@nerc.net
SAR Type (Check as many as apply)			
☒ New Standard ☒ Revision to Existing Standard ☒ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☒ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☐ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☐ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
The current transmission planning Reliability Standard TPL-001-5.1 – Transmission System Planning Performance Requirements[1] does not expressly require transmission planners and planning coordinators to consider extreme hot and cold weather in their transmission planning assessments. In particular, Reliability Standard TPL–001–5.1, Table 1, provisions 2.f (stability) and 3.b (steady state)			

[1] TPL-001-5.1 at https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-5.1.pdf.

Requested information
require stability and steady state analyses, respectively, to be performed for certain traditional extreme events, but does not expressly require them for extreme heat and cold conditions. Extreme weather-related events that have spanned the continent in recent years demonstrate the challenges associated with planning for extreme heat and cold weather events, particularly those events that affect a wide area or that occur during periods when the Bulk-Power System (BPS) must meet unexpected high demand. Extreme heat and cold weather events have occurred with greater frequency in recent years, and are projected to occur with even greater frequency in the future. At the same time, the changing resource mix has resulted in a grid that is increasingly more susceptible to the impacts of extreme heat and cold weather events. Recent extreme weather events have shown the risk that such events can pose to the reliable operation of the BPS, and have highlighted the high risk to life and extreme economic impacts that can result from unplanned load shed during such conditions. Long-term transmission planning, along with other measures, can play an important role in identifying and helping to minimize these risks. Accordingly, this project will revise the NERC transmission planning Reliability Standards, consistent with FERC Order No. 896,[2] to address the study of extreme heat and cold conditions. The impact of concurrent failures of BPS generation and transmission equipment and the potential for cascading outages that may be caused by extreme heat and cold weather events should be studied and corrective actions should be identified and implemented. These standard(s) should use benchmark extreme heat and cold weather events for the required studies, and require the development of planning cases with appropriate sensitivities over a wide-area. The standard should also require the identification and implementation of corrective actions where system performance requirements are not met, including appropriate coordination and communication of studies.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
Consistent with FERC Order No. 896, this purpose of this project is to address the reliability gap pertaining to the consideration of extreme heat and cold weather events that exist in current transmission planning standards (e.g., NERC Reliability Standard TPL-001-5.1 – Transmission System Planning Performance Requirements). In Order No. 896, NERC was directed to develop a new or modified Reliability Standard (“Standard”) that requires the following: (1) the development of benchmark planning cases based on information such as major prior extreme heat and cold weather events and/or future meteorological projections; (2) planning for extreme heat and cold weather events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios, including expected availability of the resource mix during extreme heat and cold weather conditions, and including the broad area impacts of extreme

[2] Order No. 896, *Transmission System Planning Performance Requirements for Extreme Weather*, 183 FERC ¶ 61,191 (2023), available at https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20230615-3100&optimized=false.

Requested information
heat and cold weather; and (3) the development of corrective action plans that mitigate specified instances where performance requirements during extreme heat and cold weather events are not met.
Project Scope (Define the parameters of the proposed project):
The scope of the proposed project is to develop a new transmission planning Standard, or modify an existing Standard, to address the directives from FERC Order No. 896 pertaining to the study of extreme heat and cold events. New or revised definitions may be required. This project may also need to revise Standard MOD-032-1 – Data for Power System Modeling and Analysis[3] for data sharing.
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[4] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
The drafting team is responsible for the development of new Standard or the revision of Standard TPL-001-5.1 that shall achieve the actions listed below related to addressing concerns pertaining to transmission system planning for extreme heat and cold weather events outlined in the Order that impact the Reliable Operation of the Bulk-Power System. The technical justification of the reliability-related benefits of developing a new Standard, modified Standard, or industry definition were addressed in the NOPR[5] and Order. The following actions have been listed in a sequence consistent with the directives in the Order. **A. Develop New or Modified Standard** Develop a new or modified Standard[6] to require the following:[7] 1. Development of benchmark planning cases based on major prior extreme heat and cold weather events and/or meteorological projections; 2. Planning for extreme heat and cold weather events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios including the expected resource mix's availability during extreme heat and cold weather conditions, and including the wide-area impacts of extreme heat and cold weather; and

[3] See MOD-032-1 at https://www.nerc.com/pa/Stand/Reliability%20Standards/MOD-032-1.pdf.
[4] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.
[5] See Docket RM22-10-000, NOPR 179 FERC ¶ 61,195, document number 2022-13471 at https://www.federalregister.gov/documents/2022/06/27/2022-13471/transmission-system-planning-performance-requirements-for-extreme-weather.
[6] Order at P25.
[7] Order at P27.

Requested information
3. Development of corrective action plans that mitigate specified instances where performance requirements for extreme heat and cold weather events are not met.[8] Also, identify the responsible entities for developing benchmark planning cases and conducting wide-area studies. **B. Develop Benchmark Events and Planning Cases Based on Major Prior Extreme Heat and Cold Weather Events and/or Meteorological Projections** The drafting team must consider approaches that would provide a uniform framework for developing benchmark events while still recognizing regional differences. For example, consider defining benchmark events around: • a projected frequency (e.g., 1-in-50-year event); or • a probability distribution (95th percentile event). Although the NOPR did not specify how these benchmark events should be developed, the NOPR provided two examples: (1) the drafting team could develop the benchmark event or events during the standard development process; or (2) the drafting team could include in the new or modified Standard a framework establishing a common design basis for the development of benchmark events. In developing a new of modified Standard, responsible entities are to be required to:[57] 1. Develop extreme heat and cold weather benchmark events;[9] 2. Develop benchmark planning cases based on identified benchmark events; and 3. Describe/define the types of heat and cold scenarios/events that responsible entities must study.[10] For instance, a benchmark event could be constructed based on data from a major prior extreme heat or cold event, with adjustments if necessary to account for the fact that future meteorological projections may estimate that similar events in the future are likely to be more extreme.[11] The drafting must consider the examples of approaches for defining benchmark events identified in the NOPR (e.g., the use of projected frequency or probability distribution).[12] The drafting must ensure that benchmark events that all responsible entities likely to be impacted by the same extreme weather events use consistent benchmark events. Doing so is important to ensuring that neighboring planning regions are assuming similar weather conditions and are able to coordinate

[8] NOPR, 179 FERC ¶ 61,195 at P 51.
[9] Benchmark events will form the basis for a planner's benchmark planning case— i.e., the base case representing system conditions under the relevant benchmark event—that will be used to study the potential wide-area impacts of anticipated extreme heat and cold weather events.
[10] Order at P35.
[11] NOPR, 179 FERC ¶ 61,195 at P47.
[12] Order at P36.

Requested information
their assumptions accordingly. Allowing responsible entities significant discretion to determine the applicable meteorological conditions would not meet the objectives of the Order.[13] Extreme heat and cold benchmark events must reflect regional differences in climate and weather patterns.[14] The drafting team may and is encouraged to engage the national labs, RTOs, NOAA, and other agencies and organizations in developing benchmark events.[15] To provide for a common design basis for responsible entities to follow when creating benchmark planning cases, case are to represent:[16] 1. Potential weather-related contingencies (*e.g.,* concurrent/correlated generation and transmission outages, derates) and expected future conditions of the system such as changes in load: 2. Transfers; 3. Generation resource mix; and 4. Impacts on generators sensitive to extreme heat or cold (due to the weather conditions indicated in the benchmark events). The drafting team must ensure the new or modified Standard contains appropriate mechanisms for ensuring the benchmark event reflects up-to-date meteorological data. A mechanism to update the benchmark event at least every five years would strike a reasonable balance between the benefits of using the most up-to-date meteorological data and administrative the burdens of collecting and analyzing such data.[17] **C. Defining "Wide-Area"** The drafting team in developing a new or modified Standard must include that transmission planning studies consider the wide-area impacts of extreme heat and cold weather.[18] The drafting team should consider approaches in defining "wide-area" over a geographical area consistent with weather and electrically, and how these two approaches correlate.[19] The drafting team must clearly describe the process that a responsible entity must use to define the wide-area boundaries.[20]

[13] Order at P37.
[14] Order at P38.
[15] Order at P37.
[16] Order at P39.
[17] Order at P40.
[18] Order at P41.
[19] Order at P47.
[20] Order at P50.

D. Entities Responsible for Developing Benchmark Events and Planning Cases, and for Conducting Transmission Planning Studies of Wide-Area Events

a. Entity Responsible for Establishing Benchmark Events

The Order directed NERC to develop requirements that address the types of extreme heat and cold weather scenarios responsible entities are required to study, including the development of benchmark events and benchmark planning cases.

The drafting team shall develop the new or modified Standard consistent with the approach the Commission took in Order No. 779 (i.e., TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events). Also, define mechanisms to periodically update extreme heat and cold weather benchmark events.[21]

The drafting team may use an existing functional entity or a group of functional entities (e.g., a group of planning coordinators) to designate the tasks of developing benchmark planning cases and conducting wide-area studies.[22]

b. Entities Responsible for Development of Planning Cases and Conducting Transmission Planning Studies of Wide-Area Events

The drafting team is to (1) designate the responsible entities responsible for developing benchmark planning cases, and (2) specify which responsible entities have an obligation to conduct wide-area studies under the new or modified Standard.[23]

The drafting team may designate the tasks of developing benchmark planning cases and conducting wide-area studies to an existing functional entity or a group of functional entities (*e.g.,* a group of planning coordinators). If needed, the drafting team may propose to establish a new functional entity registration to undertake these tasks by working with NERC registration and legal staffs. The drafting team, if considering such an approach, will need to consider that a new functional registration will require a modification to the NERC Rules of Procedure, which can take additional time to complete.[24]

E. Coordination Among Registered Entities and Sharing of Data and Study

In determining the responsible entities that will be developing benchmark planning cases and conducting wide-area studies, the drafting team must ensure there is a mechanism is place to ensure the sharing of data and studies. For example, it is possible that the selected responsible entities under the new or modified Standard will not be able to request and receive needed data pursuant to MOD–032–1, absent modification to that Standard.[25]

The drafting team must require system information and study results sharing and coordination among planning coordinators and transmission planners with transmission operators, transmission owners, and generator owners for extreme heat and cold weather events.[26]

The drafting team must address wide-area coordination among giving due consideration to relevant factors identified by commenters in the Order and NOPR[27,28] At a minimum, the drafting team must require responsible entities to share the results of their wide-area studies with other registered entities

Requested information
consistent with TPL-00-1-5.1 (e.g., transmission operators, transmission owners, and generator owners that have a reliability related need for the studies).[29] **F. Concurrent/Correlated Generator and Transmission Outages** The drafting team must require the study of concurrent/correlated generator and transmission outages due to extreme heat and cold events in benchmark events as described in more detail below. Previous extreme weather events have demonstrated that there is a high correlation between generator outages and cold temperatures, indicating that as temperatures decrease, unplanned generator outages and derates increase. Because of this correlation, it is necessary that responsible entities evaluate the risk of correlated or concurrent outages and derates of all types of generation resources and transmission facilities as a result of extreme heat and cold events. Some generators may be unavailable under extreme heat or cold conditions and thus their potential outages must be considered in extreme heat and cold weather planning scenarios. The drafting team may strike a balance between allowing responsible entities discretion to ensure the study incorporates their operating experience and the need to create a robust framework that ensures extreme heat and cold events are adequately studied.[30] **G. Conduct Transmission System Planning Studies for Extreme Heat and Cold Weather Events** **1. Steady State and Transient Stability Analyses** In a steady state analysis, the system components are modeled as either in-service or out-of-service and the result is a single point-in-time snapshot of the system in a state of operating equilibrium. A transient stability (dynamic) analysis examines the system from the start to the end of a disturbance to determine if the system regains a state of operating equilibrium. Performing both analyses ensures that the system has been thoroughly assessed for instability, uncontrolled separation, and cascading failures in both the steady state and the transient stability realms. The drafting team must require that responsible entities: 1. Perform both steady state and transient stability (dynamic) analyses in the extreme heat and cold weather planning studies (in the long-term planning horizon[31]);

[21] Order at P59. See also Order No. 779 at https://www.federalregister.gov/documents/2016/09/30/2016-23441/reliability-standard-for-transmission-system-planned-performance-for-geomagnetic-disturbance-events.
[22] Order at P62.
[23] Order at P60.
[24] Order at P62.
[25] Order at P73.
[26] Order at P65.
[27] See Appendix A, P81 and P82 for additional information.
[28] See Appendix B, P57, P64, and P70.
[29] Order at P77.
[30] Order at P88 through P91.
[31] Order at P95.

Requested information
2. Define a set of contingencies that responsible entities will be required to consider when conducting wide-area studies of extreme heat and cold weather events under the new or modified Standard; 3. Develop specific criteria for determining which outages should be considered in the benchmark planning case; and 4. Model demand load response in their extreme weather event planning area.[32] **2. Sensitivity Analysis** Sensitivity analyses help a transmission planner to determine if the results of the base case are sensitive to changes in the inputs. The use of sensitivity analyses is particularly necessary when studying extreme heat and cold events because some of the assumptions made when developing a base case may change if temperatures change. For example, during extreme cold events, load may increase as temperatures decrease, while a decrease in temperature may result in a decrease in generation.[33] In developing sensitivities the drafting must: 1. Require the use of sensitivity cases to demonstrate the impact of changes to the assumptions used in the benchmark planning case; and 2. Establish a baseline set of sensitivities for the new or modified Standard. FERC stated that while it would not require the inclusion of any specific sensitivity in Order No. 896, NERC should consider including conditions that vary with temperature such as load, generation, and system transfers.[34] **3. Modifications to the Traditional Planning Approach** The drafting team must require the use of planning methods that ensure adequate consideration of the broad characteristics of extreme heat and cold weather conditions that also address: 1. Whether probabilistic elements can be incorporated into the new or modified Standard and implemented presently by responsible entities, and 2. Identify any probabilistic planning methods that would improve upon existing planning practices, but are infeasible to include in a new or modified Standard at this time.[35] **H. Implement a Corrective Action Plan if Performance Standards Are Not Met** The Order specifies that NERC must develop standards that require Corrective Action Plans that include mitigation for any instances where performance requirements for extreme heat and cold events are not

[32] Order at P111 through P116.
[33] Order at P124 and also at P126.
[34] Order at P124.
[35] Order at P134, P138, and P158.

met; therefore, the drafting must require the development of extreme weather corrective action plans that:

1. Identify specified instances when performance standards are not met;
2. Require certain processes to facilitate interaction and coordination with applicable regulatory authorities or governing bodies responsible for retail electric service as appropriate in implementing a corrective action plan;
3. Require mitigation for specified instances where performance requirements for extreme heat and cold events are not met (*i.e.,* when certain studies conducted under the Standard show that an extreme heat or cold event would result in cascading outages, uncontrolled separation, or instability);
4. Determine whether corrective action plans should be required for single or multiple sensitivity cases;
5. Determine whether corrective action plans should be developed if a contingency event that is not already included in benchmark planning case would result in cascading outages, uncontrolled separation, or instability;
6. Establish required study contingencies and baseline sensitivities for which a corrective action plan is required; and
7. Require that responsible entities share their corrective action plans with, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.[36]

I. Other Extreme Weather-Related Events and Issues

Reliability Standard Implementation Timeline

NERC must submit a responsive Reliability Standard to FERC by December 23, 2024.

The proposed implementation timeline for a new or modified Reliability Standard must have an implementation beginning no later than 12 months after the effective date of a Commission order approving the proposed new or modified Reliability Standard.[37]

The drafting team in developing the standard has the discretion to develop a phased-in implementation timeline for the different requirements of the proposed Reliability Standard (*i.e.,* developing benchmark cases, conducting studies, developing corrective action plans, etc.). However, this phased-in implementation must begin within 12 months of the effective date of a Commission order approving the proposed Reliability Standard and must include a clear deadline for implementation of all requirements.[38]

Other

There is a concern that there is limited modeling of protection systems in dynamic assessments currently, and any dynamic simulation of extreme events would require significant modeling of protection systems to provide for convergence of the numerical simulation. The drafting team in developing the planning requirements for extreme heat and cold weather must take into account any

Requested information
deficiencies in dynamic modeling of protection systems. The dynamics databases used for transient stability simulations by various interconnections typically do not include comprehensive dynamic models of relays installed in the interconnection. The drafting team should consider wide-area applications by various interconnections that may not typically include comprehensive dynamic models of relays installed in the interconnection.[39] The drafting team should consider the cost impacts to responsible entities.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
The cost impact is unknown and will be considered during drafting team meetings. However, The SAR proposes to either create a new Standard or modify an existing Standard(s) that would require responsible entities to create Corrective Action Plans to address risks related to transmission system planning performance for extreme weather directed in the Order. The costs associated are anticipated to be comparable to those associated with a responsible entity's performance of TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
BES facilities may be uniquely impacted by the results of improved studies that incorporate enhanced extreme heat and cold weather scenarios and sensitivity analyses performed by the transmission planners. Mitigating and corrective actions may require transmission system topology changes, including but not limited to re-evaluating load shedding plans as a safety net in response to high demand in extreme heat and cold weather over a wide-area. For example, if studies reveal thermal violations that could be anticipated during extreme weather, transmission facilities may need to be upgraded. Generation facilities may be impacted by having to change the way concurrent or coincident generator outages are managed and planned to reduce the likelihood of not meeting high demands over a wide-area. For example, if multiple generators are disrupted due to pipeline issues and don't have dual fuel capability.
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.*, Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
The development of a new or modified Standard should consider drafting team individuals from the following functional entities: Balancing Authority, Generator Owner, Planning Coordinator, Reliability Coordinator, Transmission Owner, and Transmission Planner.

[36] Order at P152 through P158, and P165.
[37] Order at P188.
[38] Order at P193.
[39] Order at P68 and P74.

Requested information
Do you know of any consensus building activities[40] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
In Order No. 896, FERC highlighted that industry experts agreed that extreme weather events are likely to become more severe and frequent in the future and there is a need to address them in the long-term planning horizon.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so, which standard(s) or project number(s)?
TPL-001-5.1a and MOD-032-1.
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
None.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those 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.

Market Interface Principles	
Does the proposed standard development project comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes

[40] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Market Interface Principles	
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
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

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
e.g., NPCC	No needed Regional or Interconnection variances were identified. The Order did acknowledge that the drafting team consider approaches that would provide a uniform framework for developing benchmark events while still recognizing regional differences in climate and weather patterns, among other considerations; therefore, the use of region is considered to be the common geographical understanding and not NERC Regional Entity footprints. The Commission disagreed that Regional Entities and reliability coordinators should not lead the development of benchmark events and that the drafting team should.[41]

For Use by NERC Only

SAR Status Tracking (Check off as appropriate).	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised

[41] Order at P58.

2	June 28, 2017	Standards Information Staff	Updated template
3	February 22, 2019	Standards Information Staff	Added instructions to submit via Help Desk
4	February 25, 2020	Standards Information Staff	Updated template footer

Appendix A

Excerpts from NOPR, 179 FERC ¶ 61,195

P51. February 2011 Southwest Cold Weather Event and January 2014 Polar Vortex Cold Weather Event

81. While balancing authorities and other entities must share system information and study results with their transmission and planning coordinator pursuant to Reliability Standards MOD-032-1 and TPL-001-5.1 as described above, there is no required sharing of such information—**or required coordination**—among planning coordinators and transmission planners with transmission operators, transmission owners, and generator owners, thus limiting the benefits of additional modeling. Sharing system information and study results and **enhancing coordination** among these entities for extreme heat and cold weather events could result in more representative planning models by better:

> (1) integrating and including operations concerns (e.g., lessons learned from past issues including corrective actions and projected outcomes from these actions, evolving issues concerning extreme heat/cold) in planning models; and
>
> (2) conveying reliability concerns from planning studies (e.g., potential widespread cascading, islanding, significant loss of load, blackout, etc.) as they pertain to extreme heat or cold.

82. Therefore, as part of its revisions, NERC should require system information and study results sharing, and **coordination** among planning coordinators and transmission planners with transmission operators, transmission owners, and generator owners for extreme heat and cold weather events. To better understand the benefits of the suggested actions, we are inviting comments on:

> (1) the parameters and timing of coordination and sharing;
>
> (2) specific protocols that may need to be established for efficient coordination practices; and
>
> (3) potential impediments to the proposed coordination efforts.

Appendix B

Excerpts from Order No. 896
57. Environmental Defense Fund (EDF), Tri-State, and Eversource Energy Service Company (Eversource) propose that reliability coordinators should have the responsibility to perform wide-area planning and coordination in collaboration with other impacted reliability coordinators

64. there is no required sharing of such information related to extreme heat or cold weather events—or required coordination—among planning coordinators and transmission planners with transmission operators, transmission owners, and generator owners. Sharing system information and study results and enhancing coordination among these entities for extreme heat and cold weather events could result in more representative planning models by better integrating and including operations concerns (*e.g.,* lessons learned from past issues including corrective actions and projected outcomes from these actions, evolving issues concerning extreme heat/cold) in planning models; and conveying reliability concerns from planning studies (*e.g.,* potential widespread cascading, islanding, significant loss of load, blackout, etc.) as they pertain to extreme heat or cold.[42]

70. Tri-State suggests that the balancing authority should address the results of the studies and how they should communicate those results among the transmission planners. Tri-State also asserts that the balancing authority is responsible for resource adequacy and should communicate resource needs for the area with the responsible transmission planners who can evaluate system needs and "provide access to remove" resource needs.

[42] NOPR at P81.

Unofficial Comment Form

Project 2023-07 Modifications to TPL-001-5.1 Transmission System Planning Performance Requirements for Extreme Weather

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on **Project 2023-07 Modifications to TPL-001-5.1 Transmission System Planning Performance Requirements for Extreme Weather Standard Authorization Request (SAR)** by **8 p.m. Eastern, Wednesday, September 27, 2023.**

Additional information is available on the project page. If you have questions, contact Manager of Standards Development, Jamie Calderon (via email), or at 404-960-0568.

Background Information

On June 15, 2023, FERC issued a Final Rulemaking to direct NERC to develop a new or modified Reliability Standard to address a lack of a long-term planning requirement(s) for extreme heat and cold weather events. Specifically, FERC directed NERC to develop modifications to Reliability Standard TPL-001-5.1 or a new Reliability Standard, to require the following: (1) development of benchmark planning cases based on major prior extreme heat and cold weather events and/or meteorological projections; (2) planning for extreme heat and cold weather events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios including the expected resource mix's availability during extreme heat and cold weather conditions, and including the wide-area impacts of extreme heat and cold weather; and (3) development of corrective action plans that mitigate any instances where performance requirements for extreme heat and cold weather events are not met.

Questions

1. What technical considerations should the drafting team consider to assist with the development of benchmark planning cases per the Order?

   Comments:

2. What Contingencies and scenarios should the drafting team consider to represent extreme weather events per the Order?

   Comments:

3. What potential variants for extreme heat and cold weather events should the drafting team consider that are 1) representative of different planning areas, and 2) assure reasonable consistency between planning areas?

   Comments:

4. Provide any additional comments for the SAR drafting team to consider, if desired.

   Comments:

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2023-07 Modifications to TPL-001-5.1 Transmission System Planning Performance Requirements for Extreme Weather
Standard Authorization Request

Informal Comment Period Open through September 27, 2023

Now Available

A 30-day informal comment period for the **Project 2023-07 Modifications to TPL-001-5.1 Transmission System Planning Performance Requirements for Extreme Weather** Standard Authorization Request (SAR), is open through **8 p.m. Eastern, Wednesday, September 27, 2023**.

Commenting
Use the Standards Balloting and Commenting System (SBS) to submit comments. An unofficial Word version of the comment form is posted on the project page.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps
The drafting team will review all responses received during the comment period and determine the next steps of the project.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Manager of Standards Development, Jamie Calderon (via email), or at 404-960-0568. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2023-07 Modifications to TPL-001-5.1 Transmission System Planning Performance Requirements for Extreme Weather observer list” in the Description Box.

RELIABILITY CORPORATION

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comment Report

Project Name:	2023-07 Modifications to TPL-001-5.1 Transmission System Planning Performance Requirements for Extreme Weather | SAR
Comment Period Start Date:	8/29/2023
Comment Period End Date:	9/27/2023
Associated Ballots:	

There were 31 sets of responses, including comments from approximately 93 different people from approximately 81 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. What technical considerations should the drafting team consider to assist with the development of benchmark planning cases per the Order?

2. What Contingencies and scenarios should the drafting team consider to represent extreme weather events per the Order?

3. What potential variants for extreme heat and cold weather events should the drafting team consider that are 1) representative of different planning areas, and 2) assure reasonable consistency between planning areas?

4. Provide any additional comments for the SAR drafting team to consider, if desired.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Midcontinent ISO, Inc.	Bobbi Welch	2	MRO,RF,SERC	ISO/RTO Council Standards Review Committee Project 2023-07 Modifications to TPL-001-5.1	Ali Miremadi	CAISO	2	WECC
					Kennedy Meier	Electric Reliability Council of Texas, Inc.	2	Texas RE
					Helen Lainis	IESO	2	NPCC
					Bobbi Welch	MISO	2	RF
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Elizabeth Davis	PJM	2	RF
					Charles Yeung	SPP	2	MRO
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,RF,SERC,Texas RE,WECC	ACES Collaborators	Bob Soloman	Hoosier Energy Electric Cooperative	1	RF
					Kris Carper	Arizona Electric Power Cooperative, Inc.	1	WECC
					Bill Pezalla	Old Dominion Electric Cooperative	3,4	SERC
MRO	Kendra Buesgens	1,2,3,4,5,6	MRO	MRO NSRF	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Christopher Bills	City of Independence Power & Light	3,5	MRO
					Fred Meyer	Algonquin Power Co.	3	MRO
					Jamie Monette	Allete - Minnesota Power, Inc.	1	MRO
					Larry Heckert	Alliant Energy Corporation Services, Inc.	4	MRO
					Marc Gomez	Southwestern Power Administration	1	MRO

					Matthew Harward	Southwest Power Pool, Inc.	2	MRO
					Bryan Sherrow	Kansas City Board Of Public Utilities	1	MRO
					Terry Harbour	MidAmerican Energy	1,3	MRO
					Jamison Cawley	Nebraska Public Power	1,3,5	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Shonda McCain	Omaha Public Power District	6	MRO
					George Brown	Acciona Energy North America	5	MRO
					Jaimin Patel	Saskatchewan Power Corporation	1	MRO
					Kimberly Bentley	Western Area Power Administration	1,6	MRO
					Jay Sethi	Manitoba Hydro	1,3,5,6	MRO
					Michael Ayotte	ITC Holdings	1	MRO
FirstEnergy - FirstEnergy Corporation	Mark Garza	1,3,4,5,6		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	RF
Southern Company -	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company -	1	SERC

Southern Company Services, Inc.						Southern Company Services, Inc.		
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
					Leslie Burke	Southern Company - Southern Company Generation	5	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Alain Mukama	Hydro One Networks, Inc.	1	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
					Randy Buswell	Vermont Electric Power Company	1	NPCC
					James Grant	NYISO	2	NPCC
					John Pearson	ISO New England, Inc.	2	NPCC
					Harishkumar Subramani Vijay Kumar	Independent Electricity System Operator	2	NPCC

					Randy MacDonald	New Brunswick Power Corporation	2	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					David Burke	Orange and Rockland	3	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
					David Kwan	Ontario Power Generation	4	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Sean Cavote	PSEG	4	NPCC
					Jason Chandler	Con Edison	5	NPCC
					Tracy MacNicoll	Utility Services	5	NPCC
					Shivaz Chopra	New York Power Authority	6	NPCC
					Vijay Puran	New York State Department of Public Service	6	NPCC
					ALAN ADAMSON	New York State Reliability Council	10	NPCC
					David Kiguel	Independent	7	NPCC

					Joel Charlebois	AESI	7	NPCC
					Joshua London	Eversource Energy	1	NPCC

1. What technical considerations should the drafting team consider to assist with the development of benchmark planning cases per the Order?

Ben Hammer - Western Area Power Administration - 1,6	
Answer	
Document Name	
Comment	
Modifying TPL-001-5.1 Table 1 - Steady State & Stability Performance Extreme Events consistent with the FERC directives in Order No. 896 is straightforward. The formulation of benchmark planning cases should remain subject to the cognizance of the Planning Coordinator and Transmission Planner, avoiding one-size-fits-all extreme hear or cold weather conditions.	
Likes 0	
Dislikes 0	
Response	
Lenise Kimes - City and County of San Francisco - 1 - WECC	
Answer	
Document Name	
Comment	
Comments below for your consideration.	
Likes 0	
Dislikes 0	
Response	
Kacie Fischer - Oncor Electric Delivery - 1 - Texas RE	
Answer	
Document Name	
Comment	
From Oncor's perspective, Planning Coordinators would be able to provide more accurate insights into the development of benchmark planning cases because they have a broader view of the bulk electric system and would be able to more accurately adjust generation dispatch in the base cases to reflect real-world events.	

The drafting team should consider whether it would be more effective in addressing extreme weather conditions in each geographical region if the planning requirements were developed in a manner that allows each Planning Coordinator and corresponding Transmission Planners to determine relevant planning case assumptions.

When developing extreme weather benchmark planning cases, Oncor believes the generation dispatch levels need to be more realistic to aid in anticipating extreme weather conditions. For example, an unrealistic amount of projected load growth may lead to an unrealistic level of generation dispatch, which may not be available during extreme weather conditions. This is true for both peak load and off-peak load planning cases.

Likes 0	
Dislikes 0	

Response

Srikanth Chennupati - Entergy - 1,3,5,7 - SERC

Answer	
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter

Answer	
Document Name	

Comment

FirstEnergy asks the Drafting Team to provide guidance of meaning extreme and cold weather events that would also include the duration of the event as well as the frequency of events mentioned in the SAR.

Likes 0	
Dislikes 0	

Response

Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2

Answer	
Document Name	

Comment	
To satisfy the requirement for a wide are view the drafting team should propose specific criteria as to what constitutes extreme weather demand, for example, demand expected at a 90-10 weather scenario, or a once in 31-year weather, or a 3 standard deviation weather temperature. This is not to advocate for any one scenario, but the standard should be specific so that wide areas can be modelled in a consistent manner.	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 3,5,6	
Answer	
Document Name	
Comment	
Historic events can be used as examples and references, however forward-looking planning cases should not be limited only to specific recent events. If history alone were sufficient, these assumptions would not need to be revisited. AEP recommends that the drafting team focus on analyzing the assumptions used in current planning practices, in contrast to observed extremes, to develop scenarios that capture a broader range of potential conditions. While these cases will appropriately differ by region, the drafting team should focus on establishing a framework that will ensure a consistent methodology across all regions. Historic events may be beneficial in helping to define “wide area”, as has been observed by industry in reviewing recent events affecting multiple regions. It will be important however for neighboring regions to share assumptions and run studies that consider concurrent events. It may also be appropriate to review historical events to determine the potential impacts of extreme weather on demand, load, and generation types. For example, residential demand may be affected differently than industrial or commercial.	
Likes 0	
Dislikes 0	
Response	

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
NERC’s should not seek to address these issues through their wholesale inclusion in the TPL-001 standard. There may be some aspects that may be appropriate for inclusion in TPL-001 but overall the scope of additions is too large. TPL-001 is presently the baseline standard for design of the transmission system that is sufficiently robust enough to be operated reliably most of the time, including consideration of the impact of more extreme events.	

The extreme weather scenarios NERC is now seeking to address go beyond TPL-001 and involve very abnormal conditions that mostly involve wide areas of the interconnections. Separate standards, industry studies or guidance would be a better means to address these scenarios and should be performed by entities with a wide area perspective.

Scenario development requires cooperation of neighboring area/regions and requires input and cooperation from other subject matters experts both internal and external to the electric industry. NERC standards cannot guarantee such cooperation.

Extreme Weather Events require extensive analysis and should not be performed annually.

Evaluation of benchmark extreme weather events are not unlike previous efforts to prepare models for Y2k or to evaluate wide scale events on the interconnection. NERC's efforts to evaluate Minimum Interregional Transfer Capability may serve as a template for how NERC can approach studies of extreme weather scenarios on an ongoing basis. These efforts require collaborative efforts of multiple PC's in order to develop the models. Similarly, it will require collaborative efforts to establish assumptions on expected reduction in generation or increased load levels, as well as any sensitivities that may be desirable to study.

Consider establishment of a NERC committee/working group to develop the plan and scenarios for regions' study of extreme events in each interconnection. Collaboration and cooperation on these studies will lead to greater likelihood of corrective actions being accepted and sharing of cost/benefits is appropriate.

Likes 0	
Dislikes 0	

Response

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators

Answer	
Document Name	

Comment

We do not currently have any additional technical considerations for the drafting team to consider.

Likes 0	
Dislikes 0	

Response

Israel Perez - Salt River Project - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

Technical considerations should include but not be limited to: Consideration of regional differences for benchmarked planning cases, coordination of studies among interconnected TPs in similar geographical location and biomes and the availability of regionally coordinated cases for extreme weather scenarios.	
Likes 0	
Dislikes 0	
Response	
Randall Buswell - VELCO -Vermont Electric Power Company, Inc. - 1	
Answer	
Document Name	
Comment	
Define extreme heat and extreme cold by region. Considerations are temperature levels, wet bulb, wind speed, humidity, and hourly data over a certain number of days. The definition has to be detailed enough to allow a load forecaster to produce load values to be modeled. Our engineering team will need to produce transmission equipment ratings for the conditions under study. The reliability regions will need to figure out how various types of generators will be affected by the weather events. We are assuming that NERC will need to analyze historical data to capture events in the tails of the probabilistic distribution. However, historical events may not be a sufficient dataset to define events that have not yet occurred.	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	
Document Name	
Comment	
No Comment	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	

Comment	
The NSRF would request that the drafting team review and include realistic natural gas assumptions within the planning requirements.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1,3	
Answer	
Document Name	
Comment	
Exelon suggests the drafting team review the methods, terminology, and timeframes in the new EOP-012 standard and consider alignment between generation and transmission were appropriate.	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	
Document Name	
Comment	
ATC believes the SAR and SDT should ensure the feasibility of assumptions made in the benchmark cases and scenarios. For example, how can we ensure assumed natural gas needs can be served with exiting natural gas infrastructure under extreme cold-weather conditions (and particularly if solar and/ or wind resources generation is affected/ reduced)? o ATC does not believe the Transmission Planner has the wide-area view to coordinate with natural gas providers. Probabilistic analysis of the likelihood of these events is not in the SAR, especially to justify projects/costs to mitigate. Probability distribution was mentioned in the development of benchmark cases.	
Likes 0	
Dislikes 0	
Response	

Allie Gavin - International Transmission Company Holdings Corporation - 1 - MRO,RF	
Answer	
Document Name	
Comment	
ITC believes that the model used for this study should encompass a large geographic area typically that analyzed by an RTO/ISO. See concerns about the need for the study in question 4 below.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	
Document Name	
Comment	
We recommend the drafting team consider a 1 in 10 load scenario.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE appreciates the drafting team's efforts to be responsive to FERC Order No. 896 to make the transmission system more reliable in extreme heat and cold events. Texas RE recommends creating a new standard to address extreme weather events. While the current version of the standard, TPL-001-5.1, requires assessment of peak load conditions and sensitivity analysis based on system variations, the new standard should consider the TPs and PCs for study extreme cold and hot weather peak load conditions regardless of the entity's historical peak load seasons as the system issues encountered during extreme hot and cold weather conditions can vary greatly. In the extreme heat conditions, the TP/PC should consider wide area wildfire, low wind conditions, extreme drought conditions, facility rating reductions due to high temperatures (if the ambient temperatures are higher the value assumed in the design parameters). In the extreme cold conditions, the TP/PC should consider wide area icing conditions, higher heat pump loads, resource capacity reductions due to ice builds, gas curtailments to resources, etc.	

The benchmark cases should consider at minimum, the worst system conditions experienced in the last 25 years and extrapolate those conditions to update the current model (load, resource mix, etc.)	
Likes 0	
Dislikes 0	
Response	

Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee Project 2023-07 Modifications to TPL-001-5.1	
Answer	
Document Name	
Comment	

To satisfy wide-area view requirement, the **ISO/RTO Council Standards Review Committee (SRC)** [1] suggests the Standard Drafting Team (SDT) consider the following parameters to assist the Planning Coordinators in working with their respective Transmission Planners in the development of region-specific, extreme weather benchmark planning cases per the Order:

Define what attributes are needed to represent extreme weather events:

- **Attributes** should **be specific for different regions** (i.e., the Northeast, Northwest, West, Southwest, the South, Midwest, etc.) but **common for entities within that region**.
- To **ensure the wide-area view is modeled in a consistent manner**, the standard should provide a framework that must be **applied consistently across a region**. For example, demand expected in a 90-10 weather scenario, once in 31-year weather, or a 3-standard deviation in weather temperature. This is not to advocate for any one scenario; however, it is **important for entities within a region to use a consistent approach.**

Note that while the FERC Order described a "benchmark event," as noted in the SAR, "Benchmark events will form the basis for a planner's benchmark planning case— i.e., the base case representing system conditions under the relevant benchmark event". Describing these as the base case planning case in the SAR and from here on would be beneficial in clarifying this term then a footnote could be used to tie the new term back to the wording in the FERC Order.

It would be beneficial for the National Laboratories (or other recognized research entity) to research historical events that occurred and ***recommend*** (not dictate) key attributes for each region (or Planning Coordinator) to consider in developing their benchmark planning cases. These attributes could also be included in the guidelines for NERC planning standards.

- If the above recommendation is adopted, the attributes should be updated by the National Laboratories on a periodic basis (i.e., once every 5 or 10 years) depending on the frequency of the extreme events that are anticipated in the future.

[1] For purposes of these comments, the IRC SRC includes the following entities: CAISO, ERCOT (with the exception of our response to question 1), IESO, MISO, NYISO, PJM and SPP.

Likes 0	
Dislikes 0	
Response	

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	

BPA recommends that the scope of the extreme weather events should be confined to the area that would be experiencing the extreme weather. For example, extreme heat or cold weather events tend to move across a broader geographic area rather than impacting the entire widespread area simultaneously. So, the weather events in the benchmark cases should be confined to a reasonable area of impact – i.e. Pacific Northwest heat wave or cold snap rather than simultaneous WECC-wide impact.

Also, BPA recommends that extreme heat/cold weather should be referred to as extreme **conditions** rather than extreme **events**, which implies extreme *contingencies* in the context of the TPL-001-5 Standard.

Likes 0	
Dislikes 0	
Response	

Darcy O'Connell - California ISO - 2	
Answer	
Document Name	
Comment	

The California ISO supports comments submitted by the ISO/RTO Council Standards Review Committee (SRC).

Likes 0	
Dislikes 0	
Response	

John Pearson - ISO New England, Inc. - 2	
Answer	
Document Name	
Comment	

To satisfy wide-area view requirement, ISO New England suggests that the Standard Drafting Team (SDT) consider the following parameters to assist the Planning Coordinators and Transmission Planners with the development of benchmark planning cases per the Order:

Define what attributes are needed to represent extreme weather events

Attributes should **be specific for different regions** (i.e., the Northeast, Northwest, West, Southwest, the South, Midwest, etc.) but common for entities within that region.

To **ensure the wide-area view is modeled in a consistent manner**, the standard should provide a framework that must be **applied consistently across a region**. For example, demand expected in a 90-10 weather scenario, once in 31-year weather, or a 3-standard deviation in weather temperature. This is not to advocate for any one scenario; however, it is **important for entities within a region to use a consistent approach**.

It would be helpful if the National Laboratories (or other recognized research entity) would research historical events and recommend (not dictate) specific attributes for each Region's entities to consider and implement in the development of benchmark planning cases. These attributes should be included in the NERC planning standards or technical rationale as guidelines for the PCs and TPs to follow.

If the above recommendation is adopted, the attributes should be updated by the National Laboratories on a periodic basis (i.e., once every 5 or 10 years) depending on the frequency of the extreme events that are anticipated in the future.

Note that while the FERC Order described a "benchmark event", as noted in the SAR, "Benchmark events will form the basis for a planner's benchmark planning case— i.e., the base case representing system conditions under the relevant benchmark event". Describing these as the base planning case in the SAR and from here on would be beneficial in clarifying this term along with a footnote to tie the new term back to the language in the FERC Order.

Likes 0	
Dislikes 0	

Response

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2

Answer	
Document Name	

Comment

When addressing the wide-area view requirement of the FERC order, ERCOT recommends that the Standard Drafting Team define what attributes are needed to represent extreme weather events. This will assist Planning Coordinators in working with their respective Transmission Planners in the development of region-specific, extreme weather benchmark planning cases.

- Different regions (i.e., the Northeast, Northwest, West, Southwest, the South, Midwest, etc.) should have different attributes, but attributes should be common for entities within a given region.
- To ensure the wide-area view is modeled in a consistent manner, the standard should provide a framework that must be applied consistently across a region. For example, demand expected during a 90-10 weather scenario, or during once in 31-year weather, or during weather that exceeds 3 standard deviations in temperature. ERCOT is not advocating for any particular scenario; ERCOT merely seeks to emphasize that it is important for entities within a region to use a consistent approach.

Additionally, ERCOT notes that the SAR (e.g., in footnote 9) uses the term "benchmark event," which is described in the FERC Order. Defining a benchmark event as the base case planning case in the SAR would be beneficial in clarifying this term; a footnote could be used to establish the link back to the wording in the FERC Order.

Likes 0	
Dislikes 0	
Response	

2. What Contingencies and scenarios should the drafting team consider to represent extreme weather events per the Order?

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	
ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) for this question and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2	
Answer	
Document Name	
Comment	
ISO New England recommends the Standard Drafting Team (SDT) consider scenarios on a regional basis, including: Ratings - generation (e.g., output derates) and transmission (e.g., ambient adjusted ratings) related to extreme events Potential concurrent events - e.g., such as fires and corresponding Public Safety Power Shutoffs, impact of weather on fuel availability (unavailability, wellhead production freeze-offs, lack of wind, too much wind that requires turbine shutdown, etc.) and loss of a supply source (e.g., pipeline, railroad service, etc.) Scenarios should consider the maximum transfers that can reasonably be expected from an external area that is experiencing similar weather. Finally, the SDT must consider the risk of piling on too many coincident improbable contingencies in an extreme weather event scenario as it will not provide useful planning results.	
Likes 0	
Dislikes 0	
Response	
Darcy O'Connell - California ISO - 2	
Answer	

Document Name	
Comment	

The California ISO supports comments submitted by the ISO/RTO Council Standards Review Committee (SRC).

Likes 0	
Dislikes 0	

Response

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

BPA recommends that a limited set of contingencies should be included for extreme heat and cold weather events. Since the additional scenarios of extreme heat and cold already significantly expand the scope of required studies compared with the present TPL-001-5 Standard, the contingency list should be limited to the most impactful. BPA recommends that an entity should only consider single contingency (P1 events) for the EHV (300 kV and greater) system, or loss of a single transmission element in combination with loss of a single generator. Transmission Planners may elect to run additional contingencies, if needed, based upon their Planning experience.

Likes 0	
Dislikes 0	

Response

Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee Project 2023-07 Modifications to TPL-001-5.1

Answer	
Document Name	

Comment

The SRC recommends the Standard Drafting Team (SDT) consider contingencies and scenarios on a regional basis, including:

- Outages - for generation and transmission correlated to extreme events
- Ratings - generation (e.g., output derates) and transmission (e.g., ambient adjusted ratings) related to extreme events
- Potential concurrent events - e.g., such as fires and corresponding Public Safety Power Shutoffs, impact of weather on fuel scarcity (lack of availability, wellhead production freeze-offs, lack of wind, too much wind, etc.) and loss of a supply source (e.g., pipeline, railroad service, etc.)
- Extreme (Hot & Cold) weather impacts - in applicable regions, consider generation outages due to unavailability of gas or extreme high winds impacting wind generation resources
- In each region, PCs and TPs should gather input from transmission and generator owners and operators to identify additional types of contingencies, beyond normal planning contingencies, that have an increased probability of occurring due to extreme temperatures, particularly as they affect fuel supplies, hydroelectric capability, and wind turbine operation as they are in the best position to provide this information.

- Scenarios should consider the maximum transfers that can reasonably be expected from an external area that is experiencing similar weather.

Finally, the SDT must consider the risk of piling on too many coincident improbable contingencies in an extreme weather event scenario as it will not provide useful planning results. In each region, Planning Coordinators in conjunction with their Transmission Planners, should assess the risk of possible contingencies and apply those that are most probable under suitable scenarios.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE recommends the standard specify the model scenarios with generation dispatch conditions and facility ratings (if applicable) that represent the extreme weather conditions that need to be studied. In addition to the existing contingencies listed under the current TPL-001-5.1 standard, Texas RE recommends the drafting team consider contingencies due to a wide area wildfire that could impact multiple PC/TP areas, extreme load levels (which should also include capacities of the distribution connected resources that are embedded in the current load forecast, higher heat pump loads or cooling loads), wide area gas curtailment conditions, sudden loss of wind, and solar resources due to atmospheric variations, etc.

Likes 0	
Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	
Document Name	

Comment

The drafting team should define the benchmark case conditions before determining what contingencies are required. The more severe the benchmark case is, the less severe the contingencies should be. Additionally, requiring CAP items for severe system conditions and contingencies that are less likely (by suggestion of the SAR a 1 in 50-year event), will likely result in CAP items that are not needed which would represent a burden to ratepayers.

Likes 0	
Dislikes 0	

Response

David Jendras Sr - Ameren - Ameren Services - 1,3,6

Answer	
Document Name	
Comment	
Contingencies: Loss of an entire windfarm or gas pipeline, all wind or solar at 100%. Scenarios: Extreme winter cases, modeling transfers across the system.	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - International Transmission Company Holdings Corporation - 1 - MRO,RF	
Answer	
Document Name	
Comment	
ITC believes that a review of work being proposed within other current NERC SDT should be performed to identify what gaps might exist post the completion of those projects. The scope of this project should be revised following that review.	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	

Document Name	
Comment	
No comment	
Likes 0	
Dislikes 0	
Response	
Randall Buswell - VELCO -Vermont Electric Power Company, Inc. - 1	
Answer	
Document Name	
Comment	
All contingencies except for extreme contingencies, such as loss of ROW or loss of substations. Known generator limitations would not be contingencies, and would be part of the initial conditions. For scenarios, the standard may want to consider extreme weather events in the context of extended weather events, as opposed to a single day of extreme weather. For example, long periods of heat tend to increase load more than a single day of heat. Long periods of cold may stress natural gas reserves in some areas more than a single very cold day.	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
P0- P7 contingencies should be sufficient Scenarios should include limitations on import or export capabilities within subregional areas.	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	

Answer	
Document Name	
Comment	

We do not have any addtiional specific Contingencies or scenarios that the drafting team should consider at this time.

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	
Document Name	
Comment	

Establishing the contingencies and scenarios in the standard would reduce the flexibility to study future postulated events as experience is gained through both performance of studies and operating experience under future extreme weather conditions.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 3,5,6

Answer	
Document Name	
Comment	

The future drafting team will need to consider the potential impact of extreme weather on both demand (i.e. load) and generation, as well as impacts to transmission. For example, high demand can be anticipated in high heat scenarios, but high heat may also be associated with lower wind output or higher solar output. There are many potential scenarios and while the team may not need to define them all, they can use appropriate agencies (perhaps National Laboratories) to assist in defining the most likely scenarios that might occur. In addition, transmission ratings may be higher or lower depending on the ambient temperature assumptions, and the team may need to consider how the weather assumptions impact *all* of the variables in a planning case and if the impact is determined to be severe enough to warrant consideration.

From a contingency perspective, outages or de-rates of similar generation types across a region (as opposed to a unit-by-unit outage) will need to be incorporated into the analysis. Transmission outages could continue to be deterministic as currently prescribed in the current TPL standard, however additional analyses should be performed to determine if transmission performance has been significantly different during recent periods of extreme weather.

Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	
Document Name	
Comment	
The drafting team should get significant input from transmission and generation owners and operators to identify those types of contingencies, beyond the normal planning contingencies, that have an increased probability of occurring due to extreme temperatures, particularly as they affect fuel supplies, hydroelectric capability, and wind turbine operation. They should address the maximum transfers that can reasonably be expected from an external area that is experiencing similar weather. They must also be aware of the risk of piling on too many coincident improbable contingencies will not provide useful planning results.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter	
Answer	
Document Name	
Comment	
FE feels the current TPL-001 standard captures the intent of extreme weather events.	
Likes 0	
Dislikes 0	
Response	
Srikanth Chennupati - Entergy - 1,3,5,7 - SERC	
Answer	
Document Name	
Comment	

None

Likes 0	
Dislikes 0	

Response

Kacie Fischer - Oncor Electric Delivery - 1 - Texas RE

Answer	
Document Name	

Comment

Oncor would like to echo our previous comment that the Planning Coordinator would have the best insight into region-specific issues. If the planning requirements were developed to allow each Planning Coordinator and corresponding Transmission Planners to determine relevant planning contingencies and scenarios, it may be more effective in addressing extreme weather conditions that are unique to each geographical region.

Based on the extreme weather events Oncor has experienced in our portion of the system, we would recommend the drafting team consider the following contingencies/ scenarios when planning for extreme weather:

- Generation dispatch scenarios that are more aligned with real-time operations conditions.
  - This summer we still had 100-degree days well into September, but since the days were shorter, there was less solar generation assistance. Compound that with low wind, and we quickly had low reserve issues.
  - Shorter days towards Fall or days with cloud cover, combined with low wind and an extended heatwave.
  - During severe winter storms, we saw the outage of gas units (due to low pressure) and freezing wind turbines.
- Extreme weather events, such as tornados and hurricanes, should include the outage of a double circuit, other circuits in the same right of way, and multiple autos because those scenarios would be reflective of real-world events. Extreme events should also include consideration of extended outages due to limited or no access to utility facilities without extraordinary construction efforts. We have also seen congestion issues arise due to multiple clustered outages.
- During a few heatwaves, Oncor noticed that some approved transmission outages were not canceled during the onset of the inclement weather. Thus, the drafting committee should consider the potential impact of scheduled outages.

Likes 0	
Dislikes 0	

Response

Lenise Kimes - City and County of San Francisco - 1 - WECC

Answer	
Document Name	

Comment

At the cost of being repetitive, scenarios where the weather has been proven to cause a problem such as fire in SW California or tornados in Midwest should be considered.

Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1,6	
Answer	
Document Name	
Comment	
The framework of the existing TPL-001-5.1 Table 1 - Steady State & Stability Performance Extreme Events should define the Contingencies assessed under extreme weather events. Similar to the case representations selected, the event causality and scenarios should be solely the cognizance of the Planning Coordinator and Transmission Planner.	
Likes 0	
Dislikes 0	
Response	
Michael Goggin - Grid Strategies - 6 - NA - Not Applicable	
Answer	
Document Name	contingencies.docx
Comment	
Likes 0	
Dislikes 0	
Response	

3. What potential variants for extreme heat and cold weather events should the drafting team consider that are 1) representative of different planning areas, and 2) assure reasonable consistency between planning areas?

Ben Hammer - Western Area Power Administration - 1,6	
Answer	
Document Name	
Comment	

Attempting to craft “variants”, “conditions”, or “scenarios” during the drafting of the TPL-001 modifications will be very difficult and is likely to fail. Instead, the well-understood principle of specifying that the Planning Coordinator and Transmission Planner formulate appropriate System condition representative cases and assess extreme weather Contingency events subject to clear, deterministic System performance criteria will succeed in meeting the FERC directive.

Likes 0	
Dislikes 0	
Response	

Lenise Kimes - City and County of San Francisco - 1 - WECC	
Answer	
Document Name	
Comment	

Some type of variants built in, like TPL-007 when considering latitude/longitude, where physical locations are affected more by that extreme event should be considered. For instance, in the WECC area, the NW gets colder than mid CA and the SW gets hotter than mid CA.

Likes 0	
Dislikes 0	
Response	

Kacie Fischer - Oncor Electric Delivery - 1 - Texas RE	
Answer	
Document Name	
Comment	

Oncor would like to echo our previous comments that the Planning Coordinator would have the best insight into region-specific issues. Oncor would recommend that generation dispatch levels within the model be consistent with real-world generation levels during extreme summer and winter events.

Likes 0	

Dislikes 0	
Response	
Srikanth Chennupati - Entergy - 1,3,5,7 - SERC	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter	
Answer	
Document Name	
Comment	
FirstEnergy asks the Drafting Team to provide guidance for response and coordination between planning areas.	
Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	
Document Name	
Comment	
The drafting team should recognize the likely combinations of high heat and humidity, and low temperatures and high wind on increasing demand, while also recognizing their effects on generation.	
Likes 0	

Dislikes 0	
Response	
Thomas Foltz - AEP - 3,5,6	
Answer	
Document Name	
Comment	
The potential variants will appropriately differ by region, but a common framework will help establish consistency in methodology. Reliability entities should not make differing assumptions, for example on *how* weather events affect the same type of resource, however the scenarios developed may be much different depending on the geography, weather, and resource mix of the region in question.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	
Document Name	
Comment	
We suggest that the drafting team consider regional impacts of extreme heat and cold weather events by taking into account local climate information and historical data. To accomplish this task, we recommend considering the climate/weather zones identified by various governmental agencies. For example, the USDA identifies a “Plant Hardiness Zone” for each location in the country. While this data only identifies the average annual minimum winter temperature divided into 10 degF zones, it serves as a good indicator of areas that have similar climates and weather events. Another example of such data is the IECC 2021 Climate zone data provided by the US Department of Energy. This data is intended to be utilized for identify Energy	

Efficiency gains in buildings; however, like the aforementioned example from the USDA, we believe it serves as a good indicator of areas with similar weather patterns and climates. We believe this type of approach will allow each planning area authority to plan for realistic impacts to the BES in its specific planning area while also providing for a consistent approach across planning areas.	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
Variants should include the loss of resources dependent on favorable environmental conditions.	
Likes 0	
Dislikes 0	
Response	
Randall Buswell - VELCO -Vermont Electric Power Company, Inc. - 1	
Answer	
Document Name	
Comment	
This is one area where regional differences are necessary. The ranges of possible weather will be different. Consistency is desirable. To the extent consistency is critical, perhaps we can express weather severity in terms of percent over normal. For example, extreme temperature is defined as 10% over the five-year average of high temperatures.	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	
Document Name	

Comment	
AZPS suggests that the drafting team ensure there is flexibility for regional variance as different regions will have unique weather conditions.	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	
Document Name	
Comment	
ATC believes that extreme weather coordination and model benchmarking should be handled at the Planning Coordinator level, similar to the approach for TPL-007 (as indicated in page 6 of the SAR)	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - International Transmission Company Holdings Corporation - 1 - MRO,RF	
Answer	
Document Name	
Comment	

ITC believes that a review of work being proposed within other current NERC SDT should be performed to identify what gaps might exist post the completion of those projects. The scope of this project should be revised following that review. The size of the planning areas should encompass a large geographic area similar to the large geographic areas within an RTO/ISO.

Likes 0	
Dislikes 0	

Response

David Jendras Sr - Ameren - Ameren Services - 1,3,6

Answer	
Document Name	

Comment

We ask that the drafting team allow the regions to develop additional criteria after a definition for extreme weather is final.

Likes 0	
Dislikes 0	

Response

Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee Project 2023-07 Modifications to TPL-001-5.1

Answer	
Document Name	

Comment

The SDT should recognize the likely combinations of high heat and humidity, and low temperatures and high/low renewable output on increasing demand, while also recognizing their effects on generation in addition to those items mentioned in our response to Questions #1 and 2 above.

Likes 0	
Dislikes 0	

Response

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

BPA interprets 'variants' to mean sensitivities. BPA recommends only including sensitivities for the most limiting seasonal conditions for specific load areas. For example, most load areas in the BPA footprint have higher-peaking loads in either the winter or summer season which creates the most severe impacts for the load area. The season which is most impactful for that area is the one that should be selected for additional sensitivities to the extreme weather scenario. Potential variants or sensitivities could include: change in generation patterns, change in path flows, variation in the degree of "extreme" weather (i.e., 1 in 10 year expected probability, 1 in 15 year, 1 in 20 year, etc.)

Likes 0	
Dislikes 0	

Response

Darcy O'Connell - California ISO - 2

Answer	
Document Name	

Comment

The California ISO supports comments submitted by the ISO/RTO Council Standards Review Committee (SRC).

Likes 0	
Dislikes 0	

Response

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2

Answer	
Document Name	

Comment

ERCOT joins the comments submitted by the IRC SRC for this question and adopts them as its own.

Likes 0	
Dislikes 0	

Response

Michael Goggin - Grid Strategies - 6 - NA - Not Applicable

Answer	
Document Name	

Comment

The TPL-001 Standard should be revised to require each Regional Entity to develop the benchmark severe weather events that will be evaluated by all Transmission Planners and Planning Coordinators in that region. The Regional Entities cover large regions but are often subject to the sale type of extreme weather events, so they are well positioned to determine the benchmark for their regions. We recognize that some weather events cross multiple Regional Entities – such as Winter Storms Uri and Elliott that traversed the seams among TRE, MRO, RFC, and SERC. To account for this, the Regional Entities should be required to use the same event when the worst event (after accounting for loss of imports from the other Regional Entities) across the Regional Entities is the same. For those extreme weather events that occur wholly within a sub-region of a Regional Entity, the revised Reliability Standard can allow a Regional Entity to specify different events for parts of their footprint if they can demonstrate events typically affect subregions differently. For example, SERC may need a benchmark hurricane scenario that affects the coastal areas but does not apply to the rest of its footprint. Another option would be to have NERC approve the benchmarks proposed by each Regional Entity for those events that affect either only part of the Regional Entity or cross multiple Regional Entities.

These benchmark events should be based on the best available data concerning the recent historical severe heat, cold, and drought events during which generating supply was most at risk of falling short of demand in that region. For example, FERC could specify that Regional Entities select the events during which operating reserves for the Balancing Authorities (BAs) in that region fell to their lowest levels, or in which spot electricity prices were at a high level for multiple hours. However, simply using historical data, even recent historical data, is not sufficient. As FERC explained in Order 896, extreme weather events “are occurring with greater frequency, and are projected to occur with even greater frequency in the future.” Thus, FERC must also specify that TPL-001 should require the reliability analyses of these benchmark events account for how climate change is increasing their frequency and magnitude.

The use of a common set of events will ensure consistent and comparable results among transmission planning conducted by neighboring BAs, which is essential for evaluating solutions that affect the entire region, like increases in interregional transfer capacity. As FERC explained in Order 896, “Because the impact of most extreme heat and cold events spans beyond the footprints of individual planning entities, it is important that all responsible entities likely to be impacted by the same extreme weather events use consistent benchmark events.”

Likes 0	
Dislikes 0	

Response

4. Provide any additional comments for the SAR drafting team to consider, if desired.

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	

ERCOT joins the comments submitted by the IRC SRC for this question and adopts them as its own.

In addition, ERCOT notes that extreme weather events should be treated as extreme events or sensitivity scenarios rather than as TPL-001 base case studies.

Likes 0	
Dislikes 0	
Response	

John Pearson - ISO New England, Inc. - 2	
Answer	
Document Name	
Comment	

The SAR should expand its focus to consider the design of BES facilities (including the expansion of IBR registration criteria and definition of BES facilities, particularly for smaller-sized generators and DER if these types of resources will be a significant portion of supply). It is misguided to create mandatory requirements to “plan” a system to withstand extreme supply shortages or equipment outages resulting from extreme weather (Item F in the SAR description) if all elements are not required to meet the same standards.

Planners should be able to expect that transmission facilities and generation resources are designed to be available and function during reasonably expected extreme weather conditions for an area. While there may be some value in performing system studies of extreme weather scenarios to determine their impact on load level, the value is limited if transmission elements and generation resources are not designed to operate under the same extreme weather conditions since there is no benefit in upgrading transmission systems to deliver power during extreme conditions if distribution systems, DER, and other generation (and fuel supply systems) are not designed to deliver under those same conditions.

Consider developing a new standard modeled after TPL-007. If adopted, this option should:

Clearly articulate how the new standard differs from the existing sensitivity scenario analysis requirements in TPL-001-5.1, parts 2.1.3 and 2.4.3.

Specify which future year or years are intended to be the primary focus on the study.

Provide clear criteria to determine when mitigating action should be taken.

The SAR states “The costs associated are anticipated to be comparable to those associated with a responsible entity’s performance of TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events”. What is the basis for this statement? We suggest deleting this sentence.

Revise the sentence stating “In determining the responsible entities that will be developing benchmark planning cases and conducting wide-area studies, the drafting team must ensure there is a mechanism is place to ensure the sharing of data and studies.” to “In determining the responsible entities that will be developing benchmark planning cases and conducting wide-area studies, the drafting team must ensure there is a mechanism in place to ensure the sharing of data and studies.”

To the extent Planning Coordinators and/or Transmission Planners require additional data to study the benchmarking cases, the SAR should allow the standard to require the provision of that data from relevant entities to the PC/TP.

Likes 0	
Dislikes 0	

Response

Darcy O'Connell - California ISO - 2

Answer	
Document Name	

Comment

The California ISO supports comments submitted by the ISO/RTO Council Standards Review Committee (SRC) and offers the following supplemental suggestions.

- Extreme weather events should be considered as sensitivity scenarios rather than a TPL-001 base case. This would be more of a long-term planning effort, led by the PC, to develop a matrix of extreme weather event scenarios with studies to be performed at a set frequency. CAISO suggests a frequency of every 5 years with more frequent assessment as needed.
- Attention should be given to jurisdictional concerns related to resource planning in regards to state regulatory authority.

Likes 0	
Dislikes 0	

Response

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

BPA believes the goal of the new or modified Standard should be to maintain reliability of the backbone EHV transmission system (300 kV and above). For the underlying (below 300 kV) network, load serving entities can shift loads between substations or sectionalize their systems during extreme weather events. Investments for corrective actions, such as transmission reinforcements, would provide the best value if they improve the resilience of the EHV system to withstand extreme heat or cold weather events.

Because extreme weather is considered a sensitivity case, BPA believes the new or modified standard should not require a CAP for one specific single contingency for an Extreme weather Event since the likelihood of one specific element outage occurring is low. The focus should be on fixing an issue that can occur during the extreme weather event for several independent single contingency events.

The existing TPL-001-5 Standard does not require corrective action plans for problems flagged in a single sensitivity; therefore it is not reasonable to require corrective actions for a single sensitivity when we are already studying events that are extreme.

There also appears to be inconsistency in the SAR regarding when Corrective Actions would be required. At one point, the SAR suggests corrective actions would only be required if studies indicate there is potential for cascading. However, later in the SAR, there is an example of proposing corrective actions to prevent thermal overloads. With the existing TPL-001-5 Standard, corrective actions for Extreme Events are intended to reduce the potential for cascading. Requiring corrective actions for thermal or voltage issues is not consistent with how the TPL Standard for Extreme Events is structured.

The SAR mentions the need to identify the responsible entities for developing the extreme weather cases and performing the studies. The following statement was copied from the SAR: *"The drafting team is to (1) designate the responsible entities responsible for developing benchmark planning cases, and (2) specify which responsible entities have an obligation to conduct wide-area studies under the new or modified Standard."*

Given the emphasis on a "wide area approach" to these studies, it is suggested that in the west, WECC may be in a better position to be the responsible entity to develop these cases and perform the studies rather than individual TP's or PC's which have more limited geographical areas.

BPA recommends that extreme heat/cold weather should be referred to as extreme **conditions** rather than extreme **events**, which implies extreme contingencies in the context of the TPL-001-5 Standard.

Likes 0	
Dislikes 0	

Response

Stephen Stafford - Georgia Transmission Corporation - 1 - SERC

Answer	
Document Name	

Comment

The proposed requirements should not be added to TPL-001; they should instead be added to a new standard with a less frequent periodicity of study than TPL-001.

When considering the requirement of corrective action plans (CAP) to mitigate specified instances where performance requirements during extreme heat and cold weather events are not met, the drafting team should consider the following:

- Performance requirements should be reasonable relative to the extremity and probability of the case/scenario compounded by the extremity and probability of the required contingencies. In short, the set of system performance requirements for the new standard might be less stringent than that of TPL-001.
- The requirement of a CAP should also be reasonable relative to the probability of occurrence of the causal severe system conditions & extreme contingency combination. The requirement should not result in expensive corrective actions to resolve issues with a very low probability of occurrence and/or a moderate consequence.
- In the Southeastern Region of SERC, the impacts of extreme weather events have primarily been related to resource adequacy issues, not transmission issues. This might prove to the be the case in other regions as well. Transmission projects may not the best solution to resource adequacy problems. As such, the CAP requirements should include limited load shedding options.

Likes 0	
Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	
Document Name	

Comment

The drafting team should consider making this its own TPL standard and not placing it in TPL-001. By doing this, the analysis could be performed on a different frequency (e.g., every five years instead of annually) criteria. This is consistent with how TPL-007 was handled.

Performance requirements should be reasonable relative to the extremity and probability of the case/scenario compounded by the extremity and probability of the required contingencies. In short, the set of system performance requirements for the new standard would be appropriately established.

The drafting team should leverage the Eastern Interconnection Planning Collaborative (EIPC) to assist with the identification and development of any benchmark planning cases that are to be created and assign the EIPC full responsibility for wide-area studies from an Eastern Interconnection perspective under any new or modified standard. The EIPC is comprised of registered Planning Coordinators who represent the majority of transmission planning for the Eastern Interconnection and are uniquely situated to perform such studies.

In the Southeastern Region of SERC, the impacts of extreme weather events have primarily been related to resource adequacy issues, not transmission issues. This might prove to the be the case in other regions as well. Transmission projects may not the best solution to resource adequacy problems. As such, the CAP requirements should include the option of limited load shedding.

Likes 0	
Dislikes 0	

Response

Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee Project 2023-07 Modifications to TPL-001-5.1

Answer	
Document Name	2023-07_Unofficial_Comment_Form_SRC_09-27-23_final.docx

Comment

The SRC makes the following recommendations:

1. The SAR should expand its focus to consider the design of BES facilities (including the expansion of IBR registration criteria and definition of BES facilities, particularly for smaller-sized generators and DER if these types of resources will be a significant portion of supply). It is misguided to create mandatory requirements to "plan" a system to withstand extreme supply shortages or equipment outages resulting from extreme weather (Item F in the SAR description) if all elements are not required to meet the same standards.

Planners should be able to expect that transmission facilities and generation resources are designed to be available and function during reasonably expected extreme weather conditions for an area. While there may be some value in performing system studies of extreme weather scenarios to determine their impact on load level, the value is limited if transmission elements and generation resources are not designed to operate under the same extreme weather conditions since there is no benefit in upgrading transmission systems to deliver power during extreme conditions if distribution systems, DER, and other generation (and fuel supply systems) are not designed to deliver under those same conditions.

2. Consider developing a new standard modeled after TPL-007. Whether or not this option is adopted, ***the standard should***:

- Clearly articulate how the new standard differs from the existing sensitivity scenario analysis requirements in TPL-001-5.1, parts 2.1.3 and 2.4.3.
- Be led by the PC, working in conjunction with its TPs, to develop a matrix of extreme weather event scenarios with studies to be performed periodically. (Periodicity to be defined in the standard development process.)
- For outages, suggest identifying a subset of contingencies for extreme weather events such as P0, P1, and P7 rather than the whole set of contingencies outlined in TPL-001 standard.
- Specify the time domains to be addressed. There is no single time snap scenario that works. Most of the events needing study are not just "extreme" in temperature for example, but are also generally long in duration (wildfires, hurricanes, winter storms, heat waves, etc.). This means the scenarios need to cover various time periods within the event – not just during summer or winter peak.
- Specify which future year or years are intended to be the primary focus on the study.
- If an extreme event affects multiple regions, the standard should provide a mechanism to coordinate inter-regional benchmark planning cases.

3. The results of the study need to be actionable. To ensure this, there must be clear criteria to determine when mitigating action is to be taken. Corrective Action Plans that result from the studies should address credible potential problems and scenarios; layering too many extreme situations on top of each other (which is a particular concern here, since extreme weather scenarios already have extreme situations built in to a certain degree) could result in resources being allocated disproportionately towards addressing low probability events.

4. The SAR states "The costs associated are anticipated to be comparable to those associated with a responsible entity's performance of TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events". What is the basis for this statement? We suggest deleting this sentence.

5. Revise the following sentence:

"In determining the responsible entities that will be developing benchmark planning cases and conducting wide-area studies, the drafting team must ensure there is a mechanism ***in*** place to ensure the sharing of data and studies."

6. To the extent probabilistic approaches are incorporated, the implementation plan for the standard should allow for modeling changes.[1]

7. Likewise, to the extent Planning Coordinators and/or Transmission Planners require additional data; e.g. generator availability and operability, to study the benchmarking cases, the SAR should allow the standard to require the provision of that data from relevant entities to the PC/TP.

8. To properly build and dispatch models, we will need clarity on generator availability and operability. Knowing the generators that will be available on extreme conditions will be challenging. The chart provided in the attachment illustrates if you push temperatures to either extreme, eventually generators are not able to operate in those extreme cold or heat due to either environmental, equipment, or fuel supply limitations as observed in the polar vortex and in Winter Storm Elliott. Similarly, time of day matters, we may have plenty of generation on a sunny, extreme heat afternoon that dramatically reduces as the sun goes down; units that generally would be relied on to pick up load as the sun goes down may encounter extreme heat limitations (cooling water discharge limits, GSU max temp limits, etc.). Thus, an extreme summer peak afternoon case may not provide the dispatch of concern for an extreme heat weather scenario. On the other extreme, as extreme freezing temperatures are experienced, units relying on water cooling

will eventually struggle. Add in heavy snow or freezing rain and other operating challenges are introduced. Then consider fuel delivery issues. To properly build and dispatch models, we will need clarity on generation availability issues also in these scenarios and inputs.

[1] We…direct NERC to determine during the standard development process whether probabilistic elements can be incorporated into the new or modified Reliability Standard and implemented presently by responsible entities. If NERC identifies probabilistic elements which responsible entities can feasibly implement and that would improve upon existing planning practices, we expect the inclusion of those methods in the proposed Reliability Standard. (Paragraph 134)

Likes 0	
Dislikes 0	

Response

David Jendras Sr - Ameren - Ameren Services - 1,3,6

Answer	
Document Name	

Comment

We recommend that the SDT consider utilizing the IEEE standards for equipment operating temperature. In addition, we believe a definition of what extreme heat and cold weather events are needs to address all the regions separately because they are each vastly different. Finally, we are concerned that to benchmark planning cases would be a burden because they change every year as the resource mix is constantly changing.

Likes 0	
Dislikes 0	

Response

Allie Gavin - International Transmission Company Holdings Corporation - 1 - MRO,RF

Answer	
Document Name	

Comment

ITC supports the EEI comments to question 4 with the addition that ITC believes the studies should be performed at the macro level covered by typically RTO/ISOs.

Likes 0	
Dislikes 0	

Response

LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	
Document Name	
Comment	

ATC believes that extreme weather coordination and model benchmarking should be handled at the Planning Coordinator level, similar to the approach for TPL-007 (as indicated in page 6 of the SAR).

ATC believes that updating the benchmark cases every five years is reasonable, similar to the approach for TPL-007. These studies would be too onerous to conduct annually.

· A five-year timeline would be better supported under a new Reliability Standard.

ATC cautions that scenarios should be reasonable to avoid requiring Corrective Action Plans that could be prohibitively expensive and labor-intensive.

Concerns on building for low-probably events; what if state does not agree? Events should be actionable and address events that are probable.

· There seems to be a directive of mitigations but not a directive of the review of associated potential projects (mitigations) with a cost- benefit analysis.

If the SDT creates a definition for “wide-area,” ATC cautions that this term is used in other NERC Reliability Standards.

Bulk power systems (BPS) should be replaced with Bulk Electric Systems (BES) throughout the SAR and any developed new or modified standard. BPS is not clearly defined in the NERC glossary of terms whereas BES is clearly defined. BPS seems to leave open the potential for NERC over-reach into <100 kV systems.

Probabilistic analysis of the likelihood of these events is not in the SAR, especially to justify projects/costs to mitigate. Probability distribution was mentioned in the development of benchmark cases.

Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1,3	
Answer	
Document Name	
Comment	

Exelon supports the comments to Question #4 submitted by the EEI.

Likes 0	
Dislikes 0	

Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	
NERC should work with industry to ensure NERC standards do not put industry in a position where federal standards mandate construction for low probability or forecasted events and states could disagree. The NERC SDT must strike an appropriate balance between reliability, affordability and impacts on rate payers. Hardening the system against all potential weather contingencies may not be possible, could be cost prohibitive or deemed not prudently incurred and thus not recoverable. Corrective Actions Plans developed pursuant to this project must be not only be actionable but address those outcomes that are probable. Additionally, there are multiple projects currently that may have cross over with each other. NSRF would recommend that NERC review open projects and coordinate amongst drafting teams and consolidate where appropriate to promote efficiency in managing standard projects (e.g., Project 2022-03).	
Likes 0	
Dislikes 0	
Response	
Junji Yamaguchi - Hydro-Quebec (HQ) - 1,5	
Answer	
Document Name	
Comment	
While we recognize that the normal and extreme natural events in the Transmission Planning Energy Scenario SAR does not include extreme heat and cold as addressed in the FERC Order 896, consideration should be taken to combine these two SARs.	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	
Document Name	
Comment	
• Given the large scope of the existing TPL-001 standard, AZPS recommends that a New Reliability Standard be created to address the directed scope as defined by FERC Order 896.	

- AZPS considers the planning obligations, as defined in this SAR, to be too excessive to be reasonably conducted on an annual basis. For this reason, AZPS recommends that the planning studies described in Order 896, and this SAR, be conducted on a planning cycle of 3 to 5 calendar years.
- AZPS also recommends that mitigations directed by FERC Order 896, be limited to those events that are reasonably likely to happen in order to limit significant financial impacts that do not improve reliability.

Likes 0	
Dislikes 0	

Response

Nicolas Turcotte - Hydro-Quebec (HQ) - 1,5

Answer	
Document Name	

Comment

While we recognize that the normal and extreme natural events in the Transmission Planning Energy Scenario SAR do not include extreme heat and cold as addressed in the FERC Order 896, consideration should be taken to combine these two SARs.

Likes 0	
Dislikes 0	

Response

Randall Buswell - VELCO -Vermont Electric Power Company, Inc. - 1

Answer	
Document Name	

Comment

TPL-001 focuses on transmission capacity under various system conditions. Resource adequacy should also be part of the discussion, and in some parts of the country energy adequacy may be a concern. (i.e. In the northeast, an extreme weather event could be an extended cold snap that stresses natural gas reserves and therefor resource adequacy.) As see in previous extreme weather events. The availability of the generation resources could be compromised due to extreme temperature conditions. Situations such as the downgrade of available solar PV capacity due to extreme heat or unavailability of gas powered resources due to extreme cold.

Secondly, the revised standard needs to be clear whether the performance requirements are the same under normal and extreme weather conditions. And if different, the expectations need to be clear. For example, the standard could state the amount of load and generation that can trip during extreme events, how much support should be relied upon from neighboring control areas, what operational actions are acceptable, and what corrective actions are appropriate.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	

EEI offers the following suggested comments for SDT consideration:

1. Given the intended scope of this SAR and the technical differences with TPL-001-5.1, EEI suggests that a new Reliability Standard be created to address the directed scope as defined within FERC Order No. 896.
2. While EEI does not oppose the proposed scope set forth in this SAR, the planning obligations, as defined in this SAR, are too onerous to be reasonably conducted on an annual basis. For this reason, we ask that the planning studies mandated by Order No. 896, and this SAR, be conducted on a planning cycle of 3 calendar years or greater.
3. EEI is additionally concerned that mitigations directed under FERC Order No. 896, if not limited in scope, could have significant financial impacts on companies. Reliability and affordability must be considered.

Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	
Document Name	
Comment	

While we recognize that the normal and extreme natural events in the Transmission Planning Energy Scenario SAR do not include extreme heat and cold as addressed in the FERC Order 896, consideration should be taken to combine these two SARs.

Likes 0	
Dislikes 0	
Response	

Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	

The best outcomes will be derived from regional or sub regional efforts.

Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	
Document Name	
Comment	

We believe the appropriate approach for developing benchmark events is to use a probability distribution.

Thanks you for the opportunity to comment.

Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	

The SAR should further elaborate on the “The drafting team should consider the cost impacts to responsible entities.” comment in Section I (Other Extreme Weather-Related Events and Issues). Specifically, what cost impacts are being referred to – the cost of performing the analysis or something else such as cost of corrective actions?

To the extent that extreme weather leads to lost generation resources, it is unclear how corrective action plans in transmission space can address that loss. Although additional resources may seem to be the solution, resource adequacy has typically been a state jurisdictional issue. Project 2022-03 (Energy Assurance with Energy Constrained Resources) will require entities to perform energy reliability assessments to evaluate energy assurance and develop Corrective Action Plan(s) to address identified risks. That project will be looking at both near term and long-term planning. Assessment of Operating Reserves and Planning Margins will most likely be discussed in that project.

Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 3,5,6	
Answer	
Document Name	
Comment	

AEP requests that the drafting team provide clarity regarding the establishment of a minimum performance criteria. While AEP believes that the performance criteria could be the same as in the current TPL standard, the scenarios studied will likely need to consider different load/generation scenarios involving a wider variety of multi-contingency events (e.g., multiple generator outages coupled with transmission outages). The SDT will need to consider both the similarities and differences between the current performance criteria, and the criteria necessary for more extreme scenarios. In addition, the SDT will need to consider the frequency of these studies as well as their impact on the resources required to perform them. While the studies currently in the TPL-001 standard are performed on an annual basis, such periodicity may not be necessary for new studies involving more extreme scenarios.

Responsible entities will need the flexibility to use sound engineering judgement in these plans, rather than be obligated to take prescriptive measures that may not be the best for every situation. As one example, while Corrective Action Plans would be a key component in this proposed SAR, care should be taken so that load shed is not relied upon as a sole mitigating measure.

Likes 0	
Dislikes 0	
Response	

Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	
Document Name	
Comment	

The current standard applies to Planning Coordinators and their respective areas. To cover a much wider view as required in the FERC order, the standard should be instructive as to the minimum expectation to accomplish a wide area coverage, for example, a study led by one planning coordinator must include a view of all adjacent (or two adjacent over) planning coordinators.

The drafting team should work to adopt a wide area co-operation and involvement requirement, if at all possible, rather than introducing a new responsible entity.

Likes 0	
Dislikes 0	
Response	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter	
Answer	

Document Name	
Comment	

FirstEnergy supports EEI's comments which state:

EEI offers the following suggested comments for SDT consideration:

1. Given the intended scope of this SAR and the technical differences with TPL-001-5.1, we suggest that a new Reliability Standard be created to address the directed scope as defined within FERC Order 896.

2. While EEI does not oppose the proposed scope as defined in this SAR, the planning obligations, as defined in this SAR, are too onerous to be reasonable conducted on an annual basis. For this reason, we ask that the planning studies as envisioned in Order 896, and this SAR, be conducted on a planning cycle of 3 calendar years or greater.

3. EEI is additionally concerned that mitigations directed under FERC Order 896, if not limited in scope, could have significant financial impacts on companies. Reliability and affordability must be considered.

Likes 0	
Dislikes 0	
Response	

Srikanth Chennupati - Entergy - 1,3,5,7 - SERC

Answer	
Document Name	
Comment	

1. Entergy recommends SDT to create a separate new standard and not simply a revision to TPL-001-5.1.
2. The standard should specifically address the Generator Owner (GO) role in study and corrective action plan.
3. Sensitivities should not simply be "worse than base case "instead they should focus on how load and generation availability vary within parts of study region due to variation in temperatures across the study region.

Likes 0	
Dislikes 0	
Response	

Kacie Fischer - Oncor Electric Delivery - 1 - Texas RE

Answer	
Document Name	
Comment	

Could the SAR committee provide further insight into how corrective action plans from Transmission Providers might significantly mitigate violations that occur during extreme weather events? From our experiences, the lack of dispatchable generation during extreme weather has been the main hindrance to reliability.

Likes 0	
Dislikes 0	

Response

Lenise Kimes - City and County of San Francisco - 1 - WECC

Answer	
Document Name	

Comment

1. This is sounding a lot like a whole new TPL standard. As a small entity, it is increasingly harder to add another study. For instance, TPL-001 and TPL-007 had requirements that needed to be adhered to in 2023. TPL-007 had requirements to be implemented in January. TPL-001 had requirements to be implemented a few months later but to be compliant there were 2 options: the first was to have the 2022 planning assessment compliant before December 31 or run a whole other planning assessment mid-year 2023. HHWP chose the first option, so this caused us to have to perform 2 lengthy studies before December 31 of 2022. In a nutshell… consider the little "guys".

2. It is suggested that there be consideration for hydro units (or any generating unit) that may never experience mechanical or design complications due to hot or cold weather. For instance, HHWP hydro units are in a temperature-controlled environment and will likely never experience a weather event that will shut them down. Maybe there can be a question in the standard that determines if a study would even need to be done at all.

3. Additionally, it is suggested that there be a customer load capacity (MW) to determine if a study needs to be performed. HHWP's maximum load is 10MW with loads separated by a large distance. There wouldn't be a huge impact to any NERC entity if any one load were lost due to extreme weather.

Likes 0	
Dislikes 0	

Response

Alan Kloster - Evergy - 1,3,5,6 - MRO

Answer	
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute for question #4.

Likes 0	
Dislikes 0	

Response

Ben Hammer - Western Area Power Administration - 1,6	
Answer	
Document Name	
Comment	
The Project 2022-02 (Modifications to TPL-001 and MOD-032) drafting team is already underway to modify TPL-001. It would be more consistent with prior TPL-001 modifications practices and better leverage resources to modify the Project 2022-02 SAR with desired parts of the "Modifications to TPL-001-5.1 Transmission System Planning Performance Requirements for Extreme Weather" SAR and allow the existing TPL-001-5.1 SDT guide the draft modifications.	
Likes 0	
Dislikes 0	
Response	

Michael Goggin - Grid Strategies - 6 - NA - Not Applicable	
Answer	
Document Name	GETs.docx
Comment	
Likes 0	
Dislikes 0	
Response	

Summary Response to SAR Comments

NERC Project 2023-07 Transmission System Planning Performance Requirements for Extreme Weather
October 2023

Comments Received Summary

There were 31 sets of responses, including comments from approximately 93 different people from approximately 81 companies representing 10 of the Industry Segments as shown in the table on the following pages.

A summary of comments submitted can be reviewed on the project page. If you have an interest in joining the distribution list for this project, please reach out to standards developer, Jordan Mallory.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact Director of Standards Latrice Harkness (via email) or at (404) 446-9728.

Consideration of Comments

The NERC Project 2023-07 thanks all of industry for your time and comments. The standard drafting team (SDT) feels that many great points have been provided for the SDT to consider during the drafting phase of this project. High level themes received from industry are located below (bolded is the high-level theme followed by the SDT's response).

Addressed in TPL-001-5.1

FERC Order 896 Paragraph 5 states: "...Reliability Standard TPL-001-5.1 was developed to establish transmission system planning performance requirements that ensure that the Bulk-Power System operates reliably over a broad spectrum of system conditions and following a wide range of probable contingencies. Both it and its successor, TPL-001-5.1, include provisions for transmission planners and planning coordinators to study system performance under extreme events based on their experience; however, neither standard specifically requires entities to conduct performance analysis for extreme heat and cold weather, despite the fact that such conditions have clearly demonstrated a risk to the Reliable Operation of the Bulk-Power System, thus leaving a reliability gap in system planning." To address the reliability gap, FERC has directed NERC to modify an existing or create a new Reliability Standard by December 2024.

Confine scope of project where extreme weather will be experienced and consider regional variances.

Paragraph 3 of FERC Order 896, which states: "…planners cannot simply project historical weather patterns forward to effectively forecast the future, since climate change has made the use of historical weather observations no longer representative of future conditions. For example, extreme summer heat in regions like the Pacific Northwest and extreme winter cold in regions like Texas have increased demand for electricity at times when historically demand has been low. As events such as these will likely continue to present challenges in the future, transmission planners and planning coordinators must account for this new reality in their planning processes." The SAR has been drafted at an appropriate level to ensure all regions are prepared for continued future climate change and/or the SDT has the flexibility to draft regional variances should the team decide this route is needed.

Guidance on extreme heat and cold weather events

The SDT will focus on extreme heat and extreme cold weather conditions during this project. Please see FERC Order 896 for additional details regarding examples and further details on extreme heat and extreme cold weather. Order No. 896, Transmission System Planning Performance Requirements for Extreme Weather, 183 FERC ¶ 61,191 (2023), available at FERC Order 896 (link).

Specifically, Paragraph 2: "We take this action to address challenges associated with planning for extreme heat and cold weather events, particularly those that occur during periods when the Bulk-Power System must meet unexpectedly high demand. Extreme heat and cold weather events have occurred with greater frequency in recent years and are projected to occur with even greater frequency in the future. These events have shown that load shed during extreme temperature results in unacceptable risk to life and have extreme economic impact. As such, the impact of concurrent failures of Bulk-Power System generation and transmission equipment and the potential for cascading outages that may be caused by extreme heat and cold weather events should be studied and corrective actions should be identified and implemented." The SDT will take your comment into consideration during the drafting phase of this project."

In addition, paragraphs 20–24 in FERC Order 896 provide examples of the major extreme heat and extreme cold weather.

> "Extreme weather-related events that spread across large portions of the country over the past decade demonstrate the challenges to transmission planning from extreme heat and cold weather patterns. The NOPR discussed seven major extreme heat and cold weather events that had occurred since 2011. Of these, four (2011, 2013, 2018, and 2021) were extreme cold weather events that nearly caused system collapse if the operators had not acted to shed load. The remaining three events (2014, 2020, and 2021) were extreme heat weather events that resulted in generation losses and varying degrees of load shedding. Since the issuance of the NOPR, another extreme cold weather event indicated reliability challenges faced by the Bulk-Power System. In December 2022, Winter Storm Elliott caused extreme cold conditions that significantly stressed the Bulk-Power System, forcing some utilities to deploy rolling blackouts to preserve Bulk-Power System reliability. These extreme heat and cold events demonstrate a risk to Reliable Operation of the Bulk-Power System. These conditions have created an urgency to address the negative impact of extreme weather on the reliability of the Bulk-Power System. To that end, the directives to NERC in this final rule aim to improve system planning specifically for extreme heat and cold weather events. The potential impact of widespread extreme heat and cold events on the reliability of the Bulk-Power System can be modeled and studied in advance as part of near-term and long-term transmission system planning. Responsible entities could then use the studies to develop transmission system operational strategies or corrective action plans with mitigations that could be deployed in preparation for extreme heat and cold events. The current transmission planning Reliability Standards, however, do not obligate transmission planners and planning coordinators to consider

extreme hot and cold weather in their transmission assessments. In particular, Reliability Standard TPL-001-5.1 requires steady state and stability analyses to be performed for certain extreme events but does not require steady state and stability analyses for extreme heat and cold conditions. Likewise, while Reliability Standard TPL-001-5.1 Table 1, provisions 2.f (stability) and 3.b (steady state), requires responsible entities to study events based on operating experience that may result in a wide-area disturbance, the Standard does not specify the study of extreme heat or cold conditions. While wide-area extreme heat and cold weather events may not occur every year, their frequency and magnitude are expected to increase. The National Oceanic and Atmospheric Administration's (NOAA) data and analyses show an increasing trend in extreme heat and cold weather events, and the U.S. Environmental Protection Agency climate change indicators also show upward trends in heatwave frequency, duration, and intensity. NOAA states that climate change is also driving more compound events, i.e., multiple extreme events occurring simultaneously or successively, such as concurrent heat waves and droughts, and more extreme heat conditions in cities."

Narrow scope to focus on extreme cold weather and lesser extend heat

NERC was directed to address extreme cold and extreme heat weather events. Based on the events stated in the FERC Order, the SDT determined that the SAR is drafted at the appropriate level regarding the extent of extreme heat events to be addressed during the drafting phase of this project. See FERC Order 896 Paragraph 20:

> "…The remaining three events (2014, 2020, and 2021) were extreme heat weather events that resulted in generation losses and varying degrees of load shedding."

Consider a new standard.

The team will consider all possible paths during the drafting phase of this project. A new standard will be a part of that consideration.

Revise TPL-001

The team will consider all possible paths during the drafting phase of this project. Revisions to TPL-001 will be part of that consideration.

Consider how GMD (TPL-007) was drafted for the layout of this standard.

The team will consider all possible paths during the drafting phase of this project and will take a look at how TPL-007 was drafted as guidance.

Use FERC/NERC reports and regional analysis.

The SDT will use the FERC/NERC report and other analysis/reports to assist with data gathering and determination of drafting requirements and/or determining benchmarks.

Consider alignment methods, terminology, and timeframes in EOP-012 standard.

The SDT will consider methods, terminology, and timeframes in EOP-012 standard during the drafting phase of this project.

Avoid one size fits all standard.

The SDT acknowledges that a one size fits all may be complicated when it comes to weather condition assessments and will consider this during the drafting phase of this project.

Frequency of event (1 in 25-year event)

Duration of frequency will be discussed and determined by the SDT during the drafting phase of this project.

Reach out to RTO/ISO, National Laboratories, NOAA, and other agencies.

The SDT plans to involve the respective agencies to assist in discussion around meteorological projections and/or other respective areas when it comes to developing suggested benchmarks for this project.

Use extreme heat or cold weather conditions rather than extreme events.

The SDT will consider usage of terms during the drafting phase of this project.

Consider realistic schedules for data preparation and performing of the scenario planning study.

The SDT will consider preparation and performing schedules during the drafting phase of this project.

Various recommendations on 1 in 10 load scenario, specific criteria as to what constitutes extreme weather demand (example, demand expected at a 90-10 weather scenario, or a once in 31-year weather, or a 3 standard deviation weather temperature or demand expected in a 90-10 weather scenario, once in 31-year weather, or a 3-standard deviation in weather temperature), etc.

The SDT will consider all these recommendations during the drafting phase of this project.

Define "benchmark event" and/or "wide area"

Possible NERC glossary of terms like "benchmark event" or "wide area," etc. will be discussed and determined by the SDT during the drafting phase of this project.

Other extreme weather events (i.e., wind, wildfire, hurricanes, humidity, etc.)

Due to the tight turnaround of this project, this SDT will keep its focus on extreme heat and extreme cold weather. Notes will be taken regarding other extreme weather discussed during this project. Additional considerations outside of this scope can be considered for a later drafting team. Lastly, there is nothing that precludes an entity from studying extreme events that would pose a risk to the BPS.

Narrow scope to BES instead of BPS

The SDT determined to keep the scope of extreme heat and extreme cold weather events to what FERC Order 896 focuses on, which is the BPS. See Paragraph 1 of FERC Order 896.

> "…the Commission directs the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO), to submit a new Reliability Standard or modifications to Reliability Standard TPL-001-5.1 that addresses concerns pertaining to transmission

system planning for extreme heat and cold weather events that impact the Reliable Operation[1] of the Bulk-Power System.[2]"

Overlap with other TPL SDT

Each SDT has been provided with a scope of work, which does not overlap with one another. This team will focus on drafting requirements that focus on benchmarking planning for extreme heat and extreme cold events. The Standards Developers are in close coordination with one another as modifications are made to the TPL standards.

Lead by PCs with input from TPs. Avoid piling on too many coincident improbable contingencies which would not produce useful results.

The SDT will take this into consideration during the drafting phase of this project.

TOs and GOs input to contingency development.

The SDT will take this into consideration during the drafting phase of this project.

Standard should specify scenarios.

The SDT will take this into consideration during the drafting phase of this project.

Limit sensitivity to the most impactful scenarios within the planning region.

Consistent with your comment, in FERC Order 896, the Commission states: "We also direct NERC to include in the Reliability Standard the framework and criteria that responsible entities shall use to develop from the relevant benchmark event planning cases to represent potential weather-related contingencies (e.g., concurrent/correlated generation and transmission outages, derates) and expected future conditions of the system such as changes in load, transfers, and generation resource mix, and impacts on generators sensitive to extreme heat or cold, due to the weather conditions indicated in the benchmark events."

Limiting considerations to specific seasonal conditions conflicts with the directive that both extreme heat and cold weather events should be considered. The SDT will consider these variants (sensitivities) into account during the drafting phase of this project.

Extreme weather variant definition flexibility needed to allow PC and TP to utilize judgment.

The SDT will take this into consideration during the drafting phase of this project.

Consider CAPs for 300 kV and above.

The SDT will take this into consideration during the drafting phase of this project.

CAPs should be for several independent contingencies, rather than one specific contingency.

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[1] The FPA defines "Reliable Operation" as "operating the elements of the Bulk-Power System within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements." 16 U.S.C. 824o(a)(4).

[2] The Bulk-Power System is defined in the FPA as "facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof), and electric energy from generating facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy." *Id.* 824o(a)(1).

The SDT will take this into consideration during the drafting phase of this project.

Inconsistency with SAR - identifies CAPs are required to prevent cascading and thermal overloads. Cascading is consistent with TPL-001, but thermal overloads are not.

The SDT sought clarification from the folks who drafted this project's SAR. This project is to focus on events that could trigger cascading conditions.

Expand on "cost impacts" in SAR - performing analysis or CAPs. Per SAR, cost is unknown and will be considered by SDT.

The SDT will take this into consideration during the drafting phase of this project.

Standard Authorization Request (SAR)

Complete and submit this form, with attachment(s) to the NERC Help Desk. Upon entering the Captcha, please type in your contact information, and attach the SAR to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	Transmission System Planning Performance Requirements for Extreme Weather		
Date Submitted:	July 5, 2023		
SAR Requester			
Name:	Mohammed Osman, Lead Engineer of System Analysis, Power System Analysis William Lamanna, Senior Engineer – Reliability Assessments Scott Barfield-McGinnis, Principal Technical Advisor, Power Risk Issues and Strategic Management		
Organization:	NERC		
Telephone:	Mohamed: 404-446-9634 Scott: 404-446-9689 William: 404-446-2568	Email:	Mohamed.Osman@nerc.net Scott.Barfield@nerc.net William.Lamanna@nerc.net
SAR Type (Check as many as apply)			
☒ New Standard ☒ Revision to Existing Standard ☒ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☒ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☐ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☐ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
The current transmission planning Reliability Standard TPL-001-5.1 – Transmission System Planning Performance Requirements[1] does not expressly require transmission planners and planning coordinators to consider extreme hot and cold weather in their transmission planning assessments. In particular, Reliability Standard TPL–001–5.1, Table 1, provisions 2.f (stability) and 3.b (steady state)			

[1] TPL-001-5.1 at https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-5.1.pdf.

Requested information
require stability and steady state analyses, respectively, to be performed for certain traditional extreme events, but does not expressly require them for extreme heat and cold conditions. Extreme weather-related events that have spanned the continent in recent years demonstrate the challenges associated with planning for extreme heat and cold weather events, particularly those events that affect a wide area or that occur during periods when the Bulk-Power System (BPS) must meet unexpected high demand. Extreme heat and cold weather events have occurred with greater frequency in recent years, and are projected to occur with even greater frequency in the future. At the same time, the changing resource mix has resulted in a grid that is increasingly more susceptible to the impacts of extreme heat and cold weather events. Recent extreme weather events have shown the risk that such events can pose to the reliable operation of the BPS, and have highlighted the high risk to life and extreme economic impacts that can result from unplanned load shed during such conditions. Long-term transmission planning, along with other measures, can play an important role in identifying and helping to minimize these risks. Accordingly, this project will revise the NERC transmission planning Reliability Standards, consistent with FERC Order No. 896,[2] to address the study of extreme heat and cold conditions. The impact of concurrent failures of BPS generation and transmission equipment and the potential for cascading outages that may be caused by extreme heat and cold weather events should be studied and corrective actions should be identified and implemented. These standard(s) should use benchmark extreme heat and cold weather events for the required studies, and require the development of planning cases with appropriate sensitivities over a wide-area. The standard should also require the identification and implementation of corrective actions where system performance requirements are not met, including appropriate coordination and communication of studies.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
Consistent with FERC Order No. 896, this purpose of this project is to address the reliability gap pertaining to the consideration of extreme heat and cold weather events that exist in current transmission planning standards (e.g., NERC Reliability Standard TPL-001-5.1 – Transmission System Planning Performance Requirements). In Order No. 896, NERC was directed to develop a new or modified Reliability Standard ("Standard") that requires the following: (1) the development of benchmark planning cases based on information such as major prior extreme heat and cold weather events and/or future meteorological projections; (2) planning for extreme heat and cold weather events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios, including expected availability of the resource mix during extreme heat and cold weather conditions, and including the broad area impacts of extreme

[2] Order No. 896, *Transmission System Planning Performance Requirements for Extreme Weather*, 183 FERC ¶ 61,191 (2023), available at https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20230615-3100&optimized=false.

Requested information
heat and cold weather; and (3) the development of corrective action plans that mitigate specified instances where performance requirements during extreme heat and cold weather events are not met.
Project Scope (Define the parameters of the proposed project):
The scope of the proposed project is to develop a new transmission planning Standard, or modify an existing Standard, to address the directives from FERC Order No. 896 pertaining to the study of extreme heat and cold events. New or revised definitions may be required. This project may also need to revise Standard MOD-032-1 – Data for Power System Modeling and Analysis[3] for data sharing.
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[4] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
The drafting team is responsible for the development of new Standard or the revision of Standard TPL-001-5.1 that shall achieve the actions listed below related to addressing concerns pertaining to transmission system planning for extreme heat and cold weather events outlined in the Order that impact the Reliable Operation of the Bulk-Power System. The technical justification of the reliability-related benefits of developing a new Standard, modified Standard, or industry definition were addressed in the NOPR[5] and Order. The following actions have been listed in a sequence consistent with the directives in the Order. **A. Develop New or Modified Standard** Develop a new or modified Standard[6] to require the following:[7] 1. Development of benchmark planning cases based on major prior extreme heat and cold weather events and/or meteorological projections; 2. Planning for extreme heat and cold weather events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios including the expected resource mix's availability during extreme heat and cold weather conditions, and including the wide-area impacts of extreme heat and cold weather; and

[3] See MOD-032-1 at https://www.nerc.com/pa/Stand/Reliability%20Standards/MOD-032-1.pdf.
[4] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.
[5] See Docket RM22-10-000, NOPR 179 FERC ¶ 61,195, document number 2022-13471 at https://www.federalregister.gov/documents/2022/06/27/2022-13471/transmission-system-planning-performance-requirements-for-extreme-weather.
[6] Order at P25.
[7] Order at P27.

Requested information
3. Development of corrective action plans that mitigate specified instances where performance requirements for extreme heat and cold weather events are not met.[8] Also, identify the responsible entities for developing benchmark planning cases and conducting wide-area studies. **B. Develop Benchmark Events and Planning Cases Based on Major Prior Extreme Heat and Cold Weather Events and/or Meteorological Projections** The drafting team must consider approaches that would provide a uniform framework for developing benchmark events while still recognizing regional differences. For example, consider defining benchmark events around: • a projected frequency (e.g., 1-in-50-year event); or • a probability distribution (95th percentile event). Although the NOPR did not specify how these benchmark events should be developed, the NOPR provided two examples: (1) the drafting team could develop the benchmark event or events during the standard development process; or (2) the drafting team could include in the new or modified Standard a framework establishing a common design basis for the development of benchmark events. In developing a new of modified Standard, responsible entities are to be required to:[57] 1. Develop extreme heat and cold weather benchmark events;[9] 2. Develop benchmark planning cases based on identified benchmark events; and 3. Describe/define the types of heat and cold scenarios/events that responsible entities must study.[10] For instance, a benchmark event could be constructed based on data from a major prior extreme heat or cold event, with adjustments if necessary to account for the fact that future meteorological projections may estimate that similar events in the future are likely to be more extreme.[11] The drafting must consider the examples of approaches for defining benchmark events identified in the NOPR (e.g., the use of projected frequency or probability distribution).[12] The drafting must ensure that benchmark events that all responsible entities likely to be impacted by the same extreme weather events use consistent benchmark events. Doing so is important to ensuring that neighboring planning regions are assuming similar weather conditions and are able to coordinate

[8] NOPR, 179 FERC ¶ 61,195 at P 51.
[9] Benchmark events will form the basis for a planner's benchmark planning case— i.e., the base case representing system conditions under the relevant benchmark event—that will be used to study the potential wide-area impacts of anticipated extreme heat and cold weather events.
[10] Order at P35.
[11] NOPR, 179 FERC ¶ 61,195 at P47.
[12] Order at P36.

Requested information
their assumptions accordingly. Allowing responsible entities significant discretion to determine the applicable meteorological conditions would not meet the objectives of the Order.[13] Extreme heat and cold benchmark events must reflect regional differences in climate and weather patterns.[14] The drafting team may and is encouraged to engage the national labs, RTOs, NOAA, and other agencies and organizations in developing benchmark events.[15] To provide for a common design basis for responsible entities to follow when creating benchmark planning cases, case are to represent:[16] 1. Potential weather-related contingencies (*e.g.,* concurrent/correlated generation and transmission outages, derates) and expected future conditions of the system such as changes in load: 2. Transfers; 3. Generation resource mix; and 4. Impacts on generators sensitive to extreme heat or cold (due to the weather conditions indicated in the benchmark events). The drafting team must ensure the new or modified Standard contains appropriate mechanisms for ensuring the benchmark event reflects up-to-date meteorological data. A mechanism to update the benchmark event at least every five years would strike a reasonable balance between the benefits of using the most up-to-date meteorological data and administrative the burdens of collecting and analyzing such data.[17] **C. Defining “Wide-Area”** The drafting team in developing a new or modified Standard must include that transmission planning studies consider the wide-area impacts of extreme heat and cold weather.[18] The drafting team should consider approaches in defining “wide-area” over a geographical area consistent with weather and electrically, and how these two approaches correlate.[19] The drafting team must clearly describe the process that a responsible entity must use to define the wide-area boundaries.[20]

[13] Order at P37.
[14] Order at P38.
[15] Order at P37.
[16] Order at P39.
[17] Order at P40.
[18] Order at P41.
[19] Order at P47.
[20] Order at P50.

D. Entities Responsible for Developing Benchmark Events and Planning Cases, and for Conducting Transmission Planning Studies of Wide-Area Events

a. Entity Responsible for Establishing Benchmark Events

The Order directed NERC to develop requirements that address the types of extreme heat and cold weather scenarios responsible entities are required to study, including the development of benchmark events and benchmark planning cases.

The drafting team shall develop the new or modified Standard consistent with the approach the Commission took in Order No. 779 (i.e., TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events). Also, define mechanisms to periodically update extreme heat and cold weather benchmark events.[21]

The drafting team may use an existing functional entity or a group of functional entities (e.g., a group of planning coordinators) to designate the tasks of developing benchmark planning cases and conducting wide-area studies.[22]

b. Entities Responsible for Development of Planning Cases and Conducting Transmission Planning Studies of Wide-Area Events

The drafting team is to (1) designate the responsible entities responsible for developing benchmark planning cases, and (2) specify which responsible entities have an obligation to conduct wide-area studies under the new or modified Standard.[23]

The drafting team may designate the tasks of developing benchmark planning cases <u>and</u> conducting wide-area studies to an existing functional entity or a group of functional entities (*e.g.,* a group of planning coordinators). If needed, the drafting team may propose to establish a new functional entity registration to undertake these tasks by working with NERC registration and legal staffs. The drafting team, if considering such an approach, will need to consider that a new functional registration will require a modification to the NERC Rules of Procedure, which can take additional time to complete.[24]

E. Coordination Among Registered Entities and Sharing of Data and Study

In determining the responsible entities that will be developing benchmark planning cases and conducting wide-area studies, the drafting team must ensure there is a mechanism is place to ensure the sharing of data and studies. For example, it is possible that the selected responsible entities under the new or modified Standard will not be able to request and receive needed data pursuant to MOD–032–1, absent modification to that Standard.[25]

The drafting team must require system information and study results sharing and coordination among planning coordinators and transmission planners with transmission operators, transmission owners, and generator owners for extreme heat and cold weather events.[26]

The drafting team must address wide-area coordination among giving due consideration to relevant factors identified by commenters in the Order and NOPR[27,28] At a minimum, the drafting team must require responsible entities to share the results of their wide-area studies with other registered entities

Requested information
consistent with TPL-00-1-5.1 (e.g., transmission operators, transmission owners, and generator owners that have a reliability related need for the studies).[29] **F. Concurrent/Correlated Generator and Transmission Outages** The drafting team must require the study of concurrent/correlated generator and transmission outages due to extreme heat and cold events in benchmark events as described in more detail below. Previous extreme weather events have demonstrated that there is a high correlation between generator outages and cold temperatures, indicating that as temperatures decrease, unplanned generator outages and derates increase. Because of this correlation, it is necessary that responsible entities evaluate the risk of correlated or concurrent outages and derates of all types of generation resources and transmission facilities as a result of extreme heat and cold events. Some generators may be unavailable under extreme heat or cold conditions and thus their potential outages must be considered in extreme heat and cold weather planning scenarios. The drafting team may strike a balance between allowing responsible entities discretion to ensure the study incorporates their operating experience and the need to create a robust framework that ensures extreme heat and cold events are adequately studied.[30] **G. Conduct Transmission System Planning Studies for Extreme Heat and Cold Weather Events** **1. Steady State and Transient Stability Analyses** In a steady state analysis, the system components are modeled as either in-service or out-of-service and the result is a single point-in-time snapshot of the system in a state of operating equilibrium. A transient stability (dynamic) analysis examines the system from the start to the end of a disturbance to determine if the system regains a state of operating equilibrium. Performing both analyses ensures that the system has been thoroughly assessed for instability, uncontrolled separation, and cascading failures in both the steady state and the transient stability realms. The drafting team must require that responsible entities: 1. Perform both steady state and transient stability (dynamic) analyses in the extreme heat and cold weather planning studies (in the long-term planning horizon[31]);

[21] Order at P59. See also Order No. 779 at https://www.federalregister.gov/documents/2016/09/30/2016-23441/reliability-standard-for-transmission-system-planned-performance-for-geomagnetic-disturbance-events.
[22] Order at P62.
[23] Order at P60.
[24] Order at P62.
[25] Order at P73.
[26] Order at P65.
[27] See Appendix A, P81 and P82 for additional information.
[28] See Appendix B, P57, P64, and P70.
[29] Order at P77.
[30] Order at P88 through P91.
[31] Order at P95.

Requested information
2. Define a set of contingencies that responsible entities will be required to consider when conducting wide-area studies of extreme heat and cold weather events under the new or modified Standard; 3. Develop specific criteria for determining which outages should be considered in the benchmark planning case; and 4. Model demand load response in their extreme weather event planning area.[32] **2. Sensitivity Analysis** Sensitivity analyses help a transmission planner to determine if the results of the base case are sensitive to changes in the inputs. The use of sensitivity analyses is particularly necessary when studying extreme heat and cold events because some of the assumptions made when developing a base case may change if temperatures change. For example, during extreme cold events, load may increase as temperatures decrease, while a decrease in temperature may result in a decrease in generation.[33] In developing sensitivities the drafting must: 1. Require the use of sensitivity cases to demonstrate the impact of changes to the assumptions used in the benchmark planning case; and 2. Establish a baseline set of sensitivities for the new or modified Standard. FERC stated that while it would not require the inclusion of any specific sensitivity in Order No. 896, NERC should consider including conditions that vary with temperature such as load, generation, and system transfers.[34] **3. Modifications to the Traditional Planning Approach** The drafting team must require the use of planning methods that ensure adequate consideration of the broad characteristics of extreme heat and cold weather conditions that also address: 1. Whether probabilistic elements can be incorporated into the new or modified Standard and implemented presently by responsible entities, and 2. Identify any probabilistic planning methods that would improve upon existing planning practices, but are infeasible to include in a new or modified Standard at this time.[35] **H. Implement a Corrective Action Plan if Performance Standards Are Not Met** The Order specifies that NERC must develop standards that require Corrective Action Plans that include mitigation for any instances where performance requirements for extreme heat and cold events are not

[32] Order at P111 through P116.
[33] Order at P124 and also at P126.
[34] Order at P124.
[35] Order at P134, P138, and P158.

met; therefore, the drafting must require the development of extreme weather corrective action plans that:

1. Identify specified instances when performance standards are not met;
2. Require certain processes to facilitate interaction and coordination with applicable regulatory authorities or governing bodies responsible for retail electric service as appropriate in implementing a corrective action plan;
3. Require mitigation for specified instances where performance requirements for extreme heat and cold events are not met (*i.e.,* when certain studies conducted under the Standard show that an extreme heat or cold event would result in cascading outages, uncontrolled separation, or instability);
4. Determine whether corrective action plans should be required for single or multiple sensitivity cases;
5. Determine whether corrective action plans should be developed if a contingency event that is not already included in benchmark planning case would result in cascading outages, uncontrolled separation, or instability;
6. Establish required study contingencies and baseline sensitivities for which a corrective action plan is required; and
7. Require that responsible entities share their corrective action plans with, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.[36]

I. Other Extreme Weather-Related Events and Issues

Reliability Standard Implementation Timeline

NERC must submit a responsive Reliability Standard to FERC by December 23, 2024.

The proposed implementation timeline for a new or modified Reliability Standard must have an implementation beginning no later than 12 months after the effective date of a Commission order approving the proposed new or modified Reliability Standard.[37]

The drafting team in developing the standard has the discretion to develop a phased-in implementation timeline for the different requirements of the proposed Reliability Standard (*i.e.,* developing benchmark cases, conducting studies, developing corrective action plans, etc.). However, this phased-in implementation must begin within 12 months of the effective date of a Commission order approving the proposed Reliability Standard and must include a clear deadline for implementation of all requirements.[38]

Other

There is a concern that there is limited modeling of protection systems in dynamic assessments currently, and any dynamic simulation of extreme events would require significant modeling of protection systems to provide for convergence of the numerical simulation. The drafting team in developing the planning requirements for extreme heat and cold weather must take into account any

Requested information
deficiencies in dynamic modeling of protection systems. The dynamics databases used for transient stability simulations by various interconnections typically do not include comprehensive dynamic models of relays installed in the interconnection. The drafting team should consider wide-area applications by various interconnections that may not typically include comprehensive dynamic models of relays installed in the interconnection.[39] The drafting team should consider the cost impacts to responsible entities.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
The cost impact is unknown and will be considered during drafting team meetings. However, The SAR proposes to either create a new Standard or modify an existing Standard(s) that would require responsible entities to create Corrective Action Plans to address risks related to transmission system planning performance for extreme weather directed in the Order. The costs associated are anticipated to be comparable to those associated with a responsible entity's performance of TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
BES facilities may be uniquely impacted by the results of improved studies that incorporate enhanced extreme heat and cold weather scenarios and sensitivity analyses performed by the transmission planners. Mitigating and corrective actions may require transmission system topology changes, including but not limited to re-evaluating load shedding plans as a safety net in response to high demand in extreme heat and cold weather over a wide-area. For example, if studies reveal thermal violations that could be anticipated during extreme weather, transmission facilities may need to be upgraded. Generation facilities may be impacted by having to change the way concurrent or coincident generator outages are managed and planned to reduce the likelihood of not meeting high demands over a wide-area. For example, if multiple generators are disrupted due to pipeline issues and don't have dual fuel capability.
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.*, Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
The development of a new or modified Standard should consider drafting team individuals from the following functional entities: Balancing Authority, Generator Owner, Planning Coordinator, Reliability Coordinator, Transmission Owner, and Transmission Planner.

[36] Order at P152 through P158, and P165.
[37] Order at P188.
[38] Order at P193.
[39] Order at P68 and P74.

Requested information
Do you know of any consensus building activities[40] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
In Order No. 896, FERC highlighted that industry experts agreed that extreme weather events are likely to become more severe and frequent in the future and there is a need to address them in the long-term planning horizon.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so, which standard(s) or project number(s)?
TPL-001-5.1a and MOD-032-1.
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
None.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those 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.

Market Interface Principles	
Does the proposed standard development project comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes

[40] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Market Interface Principles	
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
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

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
e.g., NPCC	No needed Regional or Interconnection variances were identified. The Order did acknowledge that the drafting team consider approaches that would provide a uniform framework for developing benchmark events while still recognizing regional differences in climate and weather patterns, among other considerations; therefore, the use of region is considered to be the common geographical understanding and not NERC Regional Entity footprints. The Commission disagreed that Regional Entities and reliability coordinators should not lead the development of benchmark events and that the drafting team should.[41]

For Use by NERC Only

SAR Status Tracking (Check off as appropriate).	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised

[41] Order at P58.

2	June 28, 2017	Standards Information Staff	Updated template
3	February 22, 2019	Standards Information Staff	Added instructions to submit via Help Desk
4	February 25, 2020	Standards Information Staff	Updated template footer

Appendix A

Excerpts from NOPR, 179 FERC ¶ 61,195

P51. February 2011 Southwest Cold Weather Event and January 2014 Polar Vortex Cold Weather Event

81. While balancing authorities and other entities must share system information and study results with their transmission and planning coordinator pursuant to Reliability Standards MOD-032-1 and TPL-001-5.1 as described above, there is no required sharing of such information—**or required coordination**—among planning coordinators and transmission planners with transmission operators, transmission owners, and generator owners, thus limiting the benefits of additional modeling. Sharing system information and study results and **enhancing coordination** among these entities for extreme heat and cold weather events could result in more representative planning models by better:

> (1) integrating and including operations concerns (e.g., lessons learned from past issues including corrective actions and projected outcomes from these actions, evolving issues concerning extreme heat/cold) in planning models; and
>
> (2) conveying reliability concerns from planning studies (e.g., potential widespread cascading, islanding, significant loss of load, blackout, etc.) as they pertain to extreme heat or cold.

82. Therefore, as part of its revisions, NERC should require system information and study results sharing, and **coordination** among planning coordinators and transmission planners with transmission operators, transmission owners, and generator owners for extreme heat and cold weather events. To better understand the benefits of the suggested actions, we are inviting comments on:

> (1) the parameters and timing of coordination and sharing;
>
> (2) specific protocols that may need to be established for efficient coordination practices; and
>
> (3) potential impediments to the proposed coordination efforts.

Appendix B

Excerpts from Order No. 896
57. Environmental Defense Fund (EDF), Tri-State, and Eversource Energy Service Company (Eversource) propose that reliability coordinators should have the responsibility to perform wide-area planning and coordination in collaboration with other impacted reliability coordinators

64. there is no required sharing of such information related to extreme heat or cold weather events—or required coordination—among planning coordinators and transmission planners with transmission operators, transmission owners, and generator owners. Sharing system information and study results and enhancing coordination among these entities for extreme heat and cold weather events could result in more representative planning models by better integrating and including operations concerns (*e.g.,* lessons learned from past issues including corrective actions and projected outcomes from these actions, evolving issues concerning extreme heat/cold) in planning models; and conveying reliability concerns from planning studies (*e.g.,* potential widespread cascading, islanding, significant loss of load, blackout, etc.) as they pertain to extreme heat or cold.[42]

70. Tri-State suggests that the balancing authority should address the results of the studies and how they should communicate those results among the transmission planners. Tri-State also asserts that the balancing authority is responsible for resource adequacy and should communicate resource needs for the area with the responsible transmission planners who can evaluate system needs and "provide access to remove" resource needs.

[42] NOPR at P81.

Project 2023-07 Transmission System Planning Performance Requirements for Extreme Weather

Action

Approve the following waiver of provisions of the Standard Processes Manual (SPM) for Project 2023-07 Transmission System Planning Performance Requirements for Extreme Weather:

- Initial formal comment and ballot period reduced from 45 days to as few as 25 calendar days, with ballot pools formed in the first 10 days of the comment period. (Sections 4.9 and 4.12)
- Additional formal comment and ballot period(s) reduced from 45 days to as few as 15 calendar days, with ballot(s) conducted during the last five days of the comment period. (Sections 4.9 and 4.12)
- Final ballot period reduced from 10 days to as few as five calendar days. (Section 4.9)

Background

Section 16.0 of the SPM allows the Standards Committee to waive any provision in the SPM for good cause, including for the following reasons:

> *Where the Standards Committee determines that a modification to a proposed Reliability Standard or its Requirement(s), a modification to a defined term, a modification to an Interpretation, or a modification to a Variance has already been vetted by the industry through the standards development process or is so insubstantial that developing the modification through the processes contained in this manual will add significant time delay.*

On June 15, 2023, FERC issued FERC Order 896, directing NERC to develop a new or modified Reliability Standard to address a need for long-term planning requirement(s) for extreme heat and cold weather events. Specifically, FERC directed NERC to develop modifications to Reliability Standard TPL-001-5.1 or a new Reliability Standard, to require the following: (1) development of benchmark planning cases based on major prior extreme heat and cold weather events and/or meteorological projections; (2) planning for extreme heat and cold weather events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios including the expected resource mix's availability during extreme heat and cold weather conditions, and including the wide-area impacts of extreme heat and cold weather; and (3) development of corrective action plans that mitigate any instances where performance requirements for extreme heat and cold weather events are not met. In addition to these directives, FERC directed NERC to modify an existing or create a new Reliability Standard by December 2024.

Summary

Given the stage of the directed due date of December 2024, the drafting team needs flexibility to condense the ballot and comment periods necessary to meet this due date while following the NERC processes therefore Project 2023-07 DT leadership and NERC staff recommend that the SC shorten the initial formal comment and ballot period from 45 days to as few as 25 days and any additional formal comment and ballot period(s) from 45 days to as few as 15 days. In addition, Project 2023-07 DT leadership and NERC staff recommend shortening the final ballot from 10 days to 5 days.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

TPL-008-1 is posted for a 45-day formal comment and initial ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	July 19, 2023
SAR posted for comment	August 8 – September 27, 2023

Anticipated Actions	Date
45-day formal comment period with initial ballot	March 20 – May 3, 2024
45-day formal comment period with additional ballot	June 2024
45-day formal comment period with additional ballot	September 2024
10-day final ballot	November 2024
Board adoption	December 2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

Extreme Temperature Assessment – Documented evaluation of future Transmission System performance for extreme heat and extreme cold temperature benchmark events.

A. Introduction

1. **Title:** Transmission System Planning Performance Requirements for Extreme Temperature Events

2. **Number:** TPL-008-1

3. **Purpose:** Establish requirements for Transmission system planning performance for extreme heat and extreme cold temperature events

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Transmission Planner

   4.1.2. Planning Coordinator

5. **Effective Date:** See Implementation Plan for Project 2023-07.

B. Requirements and Measures

R1. Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall determine and identify each entity's individual and joint responsibilities for performing the studies needed to complete the Extreme Temperature Assessment. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M1. Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall provide documentation of each entity's individual and joint responsibilities, such as meeting minutes, agreements, copies of procedures or protocols in effect between entities or between departments of a vertically integrated system, or email correspondence that identifies an agreement has been reached on individual and joint responsibilities for performing the studies needed to complete the Extreme Temperature Assessment.

R2. Each responsible entity, as identified in Requirement R1, shall select one extreme heat benchmark event and one extreme cold benchmark event, from the approved benchmark library maintained by the Electric Reliability Organization (ERO), for performing the Extreme Temperature Assessment. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M2. Each responsible entity, as identified in Requirement R1, shall have evidence in either electronic or hard copy format of its selected extreme heat benchmark event and extreme cold benchmark event for performing the Extreme Temperature Assessment.

R3. Each Planning Coordinator shall develop and implement a process for coordinating the development of benchmark planning cases among impacted Planning Coordinator(s), Transmission Planner(s), and other designated study entities based on the selected benchmark events as identified in Requirement R2. This process shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Define the planning study area boundary based on the selected benchmark events.

3.2. Modify the benchmark planning cases to include seasonal and temperature dependent adjustment for Load, generation, Transmission, and transfers which represents the selected benchmark events.

M3. Each Planning Coordinator shall provide dated evidence of a process for coordinating the development of benchmark planning cases among impacted Planning Coordinators, and Transmission Planner(s) as specified in Requirement R3. Acceptable evidence may include, but is not limited to, the following dated documentation (electronic or hardcopy format): records defining the planning study area boundary based on the selected benchmark events and modifications to the benchmark planning cases that include seasonal and temperature dependent adjustment for Load, generation, Transmission, and transfers which represent the selected benchmark events.

R4. Each responsible entity, as identified in Requirement R1, shall develop and maintain System models within its planning area for performing the Extreme Temperature Assessment. The System models shall use data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, and shall represent projected System conditions based on the selected benchmark events as identified in Requirement R2. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M4. Each responsible entity, as identified in Requirement R1, shall have evidence in either electronic or hard copy format that it developed and maintained System models of the responsible entity's planning area for performing the Extreme Temperature Assessment.

R5. Each responsible entity, as identified in Requirement R1, shall have criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations for performing the Extreme Temperature Assessment in accordance with Requirement R3. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M5. Each responsible entity, as identified in Requirement R1, shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations for performing the Extreme Temperature Assessment in accordance with Requirement R5.

R6. Each responsible entity, as identified in Requirement R1, shall define and document the criteria or methodology used in the Extreme Temperature Assessment analysis to identify instability, uncontrolled separation, or Cascading. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M6. Each responsible entity, as identified in Requirement R1, shall provide dated evidence such as electronic or hard copy documentation of the defined and documented criteria or methodology used to identify instability, uncontrolled separation, or Cascading used in the Extreme Temperature Assessment analysis in accordance with Requirement R6.

R7. Each responsible entity, as identified in Requirement R1, shall identify Contingencies used in performing the Extreme Temperature Assessment for each of the event categories in Table 1 that are expected to produce more severe System impacts within its planning area. The rationale for those Contingencies selected for evaluation shall be available as supporting information. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M7. Each responsible entity, as identified in Requirement R1, shall provide dated evidence such as electronic or hard copy documentation that it has identified Contingencies for performing the Extreme Temperature Assessment for each of the event categories in Table 1 that are expected to produce more severe System impacts within its planning area and the supporting rationale, in accordance with Requirement R7, such as electronic or hard copies of documents identifying the Contingencies with supporting rationale.

R8. Each responsible entity, as identified in Requirement R1, shall complete an Extreme Temperature Assessment of the Long-Term Transmission Planning Horizon at least once every five calendar years, using the benchmark planning cases and the System models identified in Requirement R3 and R4, and the Contingencies identified in Requirement R7 for each of the event categories in Table 1, and document assumptions and results of the steady state and stability analyses. The Extreme Temperature Assessment shall include the following. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

8.1. Assessment of the benchmark planning cases developed under Requirement R4, for one of the years in the Long-Term Transmission Planning Horizon. The rationale for the year selected for evaluation shall be available as supporting information.

8.2. Sensitivity analysis to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Extreme Temperature Assessment shall include, at a minimum, changes to one of the following conditions:

- Generation;
- Real and reactive forecasted Load; or
- Transfers

M8. Each responsible entity, as identified in Requirement R1, shall provide dated evidence that it performed an Extreme Temperature Assessment, such as electronic or hard copies of the assessment, meeting all the requirements in Requirement R8.

R9. Each responsible entity, as identified in Requirement R1, shall develop a Corrective Action Plan(s) (CAPs) when the benchmark planning case study results indicate the System is unable to meet performance requirements for Table 1 P0 or P1 Contingencies. The responsible entities shall share their CAPs with, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues. In addition, where Load shed is allowed as an element of a CAP for the Table 1 P1 Contingency, the responsible entity shall document the alternative(s) considered, as mentioned in Requirement R10, and notify the applicable regulatory authorities or governing bodies responsible for retail electric service issues. Revisions to the CAP(s) are allowed in subsequent Extreme Temperature Assessments, but the planned System shall continue to meet the performance requirements. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M9. Each responsible entity, as identified in Requirement R1, shall provide dated evidence such as electronic or hard copy documentation of a CAP, including any revision history, when the benchmark planning case study results indicate the System is unable to meet performance requirements for the Table 1 P0 or P1 Contingencies in accordance with Requirement R9.

R10. Each responsible entity, as identified in Requirement R1, shall evaluate and document possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts when the benchmark planning case study results indicate the System could result in instability, uncontrolled separation, or Cascading for the Table 1 P2, P4, P5, and P7 Contingencies. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M10. Each responsible entity, as identified in Requirement R1, shall provide the dated evidence that it evaluated and documented possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts when the benchmark planning case study results indicate the System could result in instability, uncontrolled separation, or Cascading for the Table 1 P2, P4, P5, and P7 Contingencies in accordance with Requirement R10, such as electronic or hard copies of the assessment detailing such actions.

R11. Each responsible entity, as identified in Requirement R1, shall provide its Extreme Temperature Assessment results within 60 calendar days of a request to any functional entity that has a reliability related need and submits a written request for the information. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M11. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient; or a demonstration of a public posting that it provided its Extreme Temperature Assessment to any functional entity who has a reliability need within 60 calendar days of a written request.

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. **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.

    - Each responsible entity shall retain evidence of compliance with each requirement in this standard for five calendar years or one complete Extreme Temperature Assessment cycle, whichever is longer.

    1.3. **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.

Table 1: Contingencies and Performance Criteria						
Event	**P0**	**P1**	**P2**	**P4**	**P5**	**P7**
Facility Voltage Level of Contingency	Applicable to: • BES level 200 kV and above • Any common structure that includes a Facility 200kV and above Reference Voltages: • Non-generator step up transformer outage events, the reference voltage applies to the low-side winding. • Generator and generator step-up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the step-up transformer).					
Steady State Performance Criteria	• Applicable Facility Ratings shall not be exceeded. • System steady state voltages shall be within acceptable limits as defined in Requirement R5.	• Applicable Facility ratings shall not be exceeded • System steady state voltages shall be within acceptable limits as defined in Requirement R5.	Evaluation for uncontrolled separation or Cascading, as defined in Requirement R6.			
Stability Performance Criteria	Initialization without oscillation	Instability, uncontrolled separation, or Cascading, as defined in Requirement R6, shall not occur.	Evaluation for instability, uncontrolled separation, or Cascading, as defined in Requirement R6.			
Corrective Action Plan Required	Yes (See Requirement R9)	Yes (See Requirement R9)	No (See Requirement R10)			
Non-Consequential Load Loss Allowed	No (See Requirement R9)	Yes (See Requirement R9)	Yes			

Table 1: Contingencies and Performance Criteria			
Category	**Initial Condition**	**Event**	**Fault Type** [1]
P0 No Contingency	Normal System	None	N/A
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device[2]	3Ø
		5. Single Pole of a DC line	SLG
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [3]	N/A
		2. Bus Section Fault	SLG
		3. Internal Breaker Fault[4] (non-Bus-tie Breaker)	SLG
		4. Internal Breaker Fault (Bus-tie Breaker)[4]	SLG

<table>
<tr><th colspan="4">Table 1: Contingencies and Performance Criteria</th></tr>
<tr><th>Category</th><th>Initial Condition</th><th>Event</th><th>Fault Type [1]</th></tr>
<tr><td rowspan="2">P4
Multiple Contingency
(Fault plus stuck breaker[10])</td><td rowspan="2">Normal System</td><td>Loss of multiple elements caused by a stuck breaker[5](non-Bus-tie Breaker) attempting to clear a Fault on one of the following:
1. Generator
2. Transmission Circuit
3. Transformer
4. Shunt Device[2]
5. Bus Section</td><td>SLG</td></tr>
<tr><td>6. Loss of multiple elements caused by a stuck breaker[5] (Bus-tie Breaker) attempting to clear a Fault on the associated bus</td><td>SLG</td></tr>
<tr><td>P5
Multiple Contingency
(Fault plus non-redundant component of a Protection System failure to operate)</td><td>Normal System</td><td colspan="2">Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System[7] protecting the Faulted element to operate as designed, for one of the following:
1. Generator
2. Transmission Circuit
3. Transformer
4. Shunt Device[2]
5. Bus Section</td></tr>
<tr><td>P7
Multiple Contingency
(Common Structure)</td><td>Normal System</td><td>The loss of:
1. Any two adjacent (vertically or horizontally) circuits on common structure [6]
2. Loss of a bipolar DC line</td><td>SLG</td></tr>
</table>

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
2. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
3. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
4. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
5. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
6. Excludes circuits that share a common structure (Planning event P7) for one mile or less.
7. For purposes of this standard, non-redundant components of a Protection System to consider are as follows: a. A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times; b. A single communications system associated with protective functions, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing (an exception is a single communications system that is both monitored and reported at a Control Center); c. A single station dc supply associated with protective functions required for Normal Clearing (an exception is a single station dc supply that is both monitored and reported at a Control Center for both low voltage and open circuit); d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply through and including the trip coil(s) of the circuit breakers or other interrupting devices, required for Normal Clearing (the trip coil may be excluded if it is both monitored and reported at a Control Center).

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Planning Coordinator, in conjunction with its Transmission Planner(s), failed to determine and identify individual and joint responsibilities for performing the required studies for the Extreme Temperature Assessment.
R2.	N/A	N/A	The responsible entity did not select an extreme heat benchmark event or extreme cold benchmark event from the ERO approved benchmark library.	The responsible entity did not select an extreme heat benchmark event and extreme cold benchmark event from the ERO approved benchmark library.
R3.	N/A	N/A	N/A	The Planning Coordinator did not develop or implement a process for coordinating the development of benchmark planning cases among impacted Planning Coordinator(s), Transmission Planner(s), and other designated study entities. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				The Planning Coordinator developed and implemented a process for coordinating the development of benchmark planning cases among impacted Planning Coordinator(s), Transmission Planner(s), and other designated study entities, but this process did not define the planning study area boundary based off the selected benchmark events. OR The Planning Coordinator developed and implemented a process for coordinating the development of benchmark planning cases among impacted Planning Coordinator(s), Transmission Planner(s), and other designated study entities, but this process did not modify the benchmark planning cases to include seasonal and temperature dependent adjustments load, generation, Transmission, and transfers.

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R4.	N/A	N/A	N/A	The responsible entity did not develop or maintain System models of the responsible entity's planning area for performing Extreme Temperature Assessment. OR The responsible entity developed and maintained System models for performing Extreme Temperature Assessment, but the System model did not use data consistent with that provided in accordance with the MOD-032 standard supplemented by other sources as needed.
R5.	N/A	N/A	N/A	The responsible entity, as determined in Requirement R1, did not have criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations for performing Extreme Temperature Assessment.

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R6.	N/A	N/A	N/A	The responsible entity failed to define and document, the criteria or methodology used in the analysis to identify System instability, uncontrolled separation, or Cascading.
R7.	N/A	N/A	The responsible entity, as determined in Requirement R1, identified Contingencies for performing Extreme Temperature Assessment for each of the event categories in Table 1 that are expected to produce more severe System impacts within its planning area, but did not include the rationale for those Contingencies selected for evaluation as supporting documentation.	The responsible entity, as determined in Requirement R1, did not identify Contingencies for performing Extreme Temperature Assessment for each of the event categories in Table 1 that are expected to produce more severe System impacts within its planning area.
R8.	The responsible entity, as determined in Requirement R1, completed an Extreme Temperature Assessment, but it was completed less than or equal to six months late.	The responsible entity, as determined in Requirement R1, completed an Extreme Temperature Assessment, but it was completed more than six months but less than or equal to 12 months late.	The responsible entity, as determined in Requirement R1, completed an Extreme Temperature Assessment, but it was completed more than 12 months but less than or equal to than 18 months late.	The responsible entity, as determined in Requirement R1, completed an Extreme Temperature Assessment, but it was more than 18 months late.

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
				OR The responsible entity, as determined in Requirement R1, did not complete an Extreme Temperature Assessment. OR The responsible entity, as determined in Requirement R1, completed an Extreme Temperature Assessment, but it was missing one or more of the required elements in Requirement R8.
R9.	N/A	N/A	The responsible entity, as determined in Requirement R1, developed a CAP, but failed to solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.	The responsible entity, as determined in Requirement R1, failed to develop a Corrective Action Plan when the benchmark planning case study results indicate the System is unable to meet performance requirements for the Table 1 P0 or P1 Contingencies.
R10.	N/A	N/A	N/A	Each responsible entity, as determined in Requirement

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				R1, failed to evaluate and document possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts when the benchmark planning case study results indicate the System could result in instability, uncontrolled separation, or Cascading for the Table 1 P2, P4, P5, and P7 Contingencies.
R11.	The responsible entity, as determined in Requirement R1, distributed its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 60 days but less than or equal to 80 days following the request.	The responsible entity, as determined in Requirement R1, distributed its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 80 days but less than or equal to 100 days following the request.	The responsible entity, as determined in Requirement R1, distributed its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 100 days but less than or equal to 120 days following the request.	The responsible entity, as determined in Requirement R1, distributed its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 120 days following the request. OR The responsible entity, as determined in Requirement R1, did not distribute its Extreme Temperature Assessment results to functional entities having a

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				reliability related need who requested the information in writing.

D. Regional Variances

None.

E. Associated Documents

- Implementation Plan for 2023-07
- Technical Rationale Document
- Consideration of Issues and Directives for FERC Order 896.

Version History

Version	Date	Action	Change Tracking
1	TBD	Addressing FERC Order 896	New Standard

Implementation Plan

Project 2023-07 Transmission System Planning Performance Requirements for Extreme Weather

Applicable Standard

- TPL-008-1 – Transmission System Planning Performance Requirements for Extreme Temperature Events

Requested Retirement

- Not applicable

Prerequisite Standard

- Not applicable

Applicable Entities

- Planning Coordinators
- Transmission Planners

New Terms in the NERC Glossary of Terms

- Extreme Temperature Assessment

Background

On June 15, 2023, FERC issued a Final Rulemaking directing NERC to develop a new or modified Reliability Standard to address the lack of a long-term planning requirement(s) for extreme heat and cold weather events. Specifically, FERC directed NERC to develop modifications to Reliability Standard TPL-001-5.1 or develop a new Reliability Standard that require the following: (1) development of benchmark planning cases based on major prior extreme heat and cold weather events and/or meteorological projections; (2) planning for extreme heat and cold weather events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios including the expected resource mix's availability during extreme heat and cold weather conditions, and including the wide-area impacts of extreme heat and cold weather; and (3) development of Corrective Action Plans that mitigate any instances where performance requirements for extreme heat and cold weather events are not met.

Effective Date

The effective date for the proposed Reliability Standard is provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of the proposed Reliability Standard (e.g., an entire Requirement or a portion thereof), the additional time for compliance with that section is specified below. These phased-in compliance dates represent the dates that entities must begin to comply with that particular section of the Reliability Standard, even where the Reliability Standard goes into effect at an earlier date.

TPL-008-1

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Phased-In Compliance Dates

Compliance Date for TPL-008-1 Requirements R1

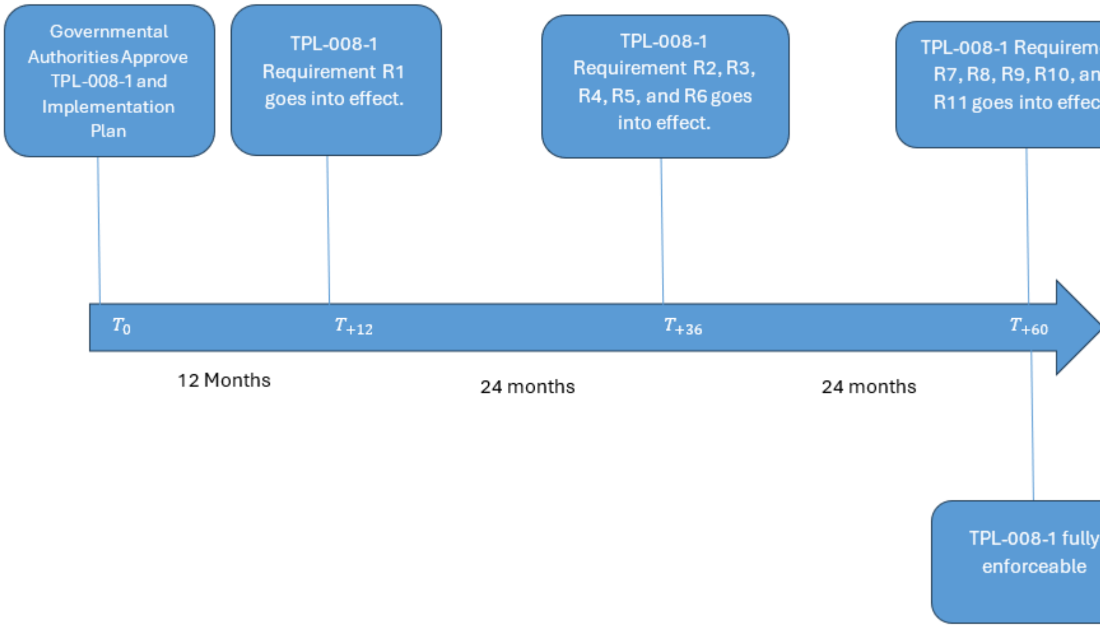
Entities shall be required to comply with Requirements R1 upon the effective date of Reliability Standard TPL-008-1.

Compliance Date for TPL-008-1 Requirements R2, R3, R4, R5, R6

Entities shall not be required to comply with Requirement R2, R3, R4, R5, and R6 until thirty-six (36) months after the effective date of Reliability Standard TPL-008-1.

Compliance Date for TPL-008-1 Requirements R7, R8, R9, R10, R11

Entities shall not be required to comply with Requirement R7, R8, R9, R10, R11 until sixty (60) months after the effective date of Reliability Standard TPL-008-1.


Governmental Authorities Approve TPL-008-1 and Implementation Plan
TPL-008-1 Requirement R1 goes into effect.
TPL-008-1 Requirement R2, R3, R4, R5, and R6 goes into effect.
TPL-008-1 Requirement R7, R8, R9, R10, and R11 goes into effect.
T_0
T_{+12}
T_{+36}
T_{+60}
12 Months
24 months
24 months
TPL-008-1 fully enforceable

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Technical Rationale and Justification for TPL-008-1

Project 2023-07 Transmission Planning Performance Requirements for Extreme Weather

March 2024

RELIABILITY | RESILIENCE | SECURITY

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Suite 600, North Tower
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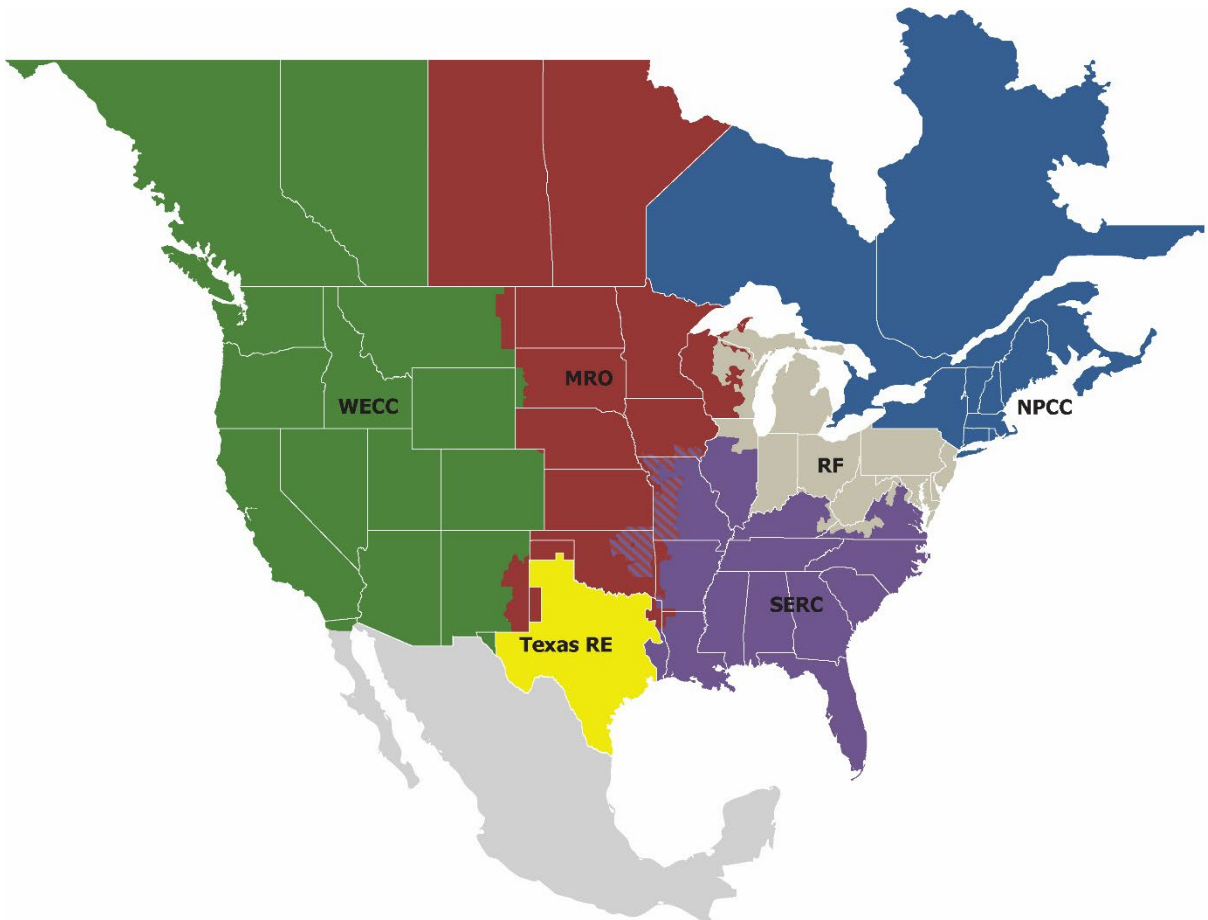
Table of Contents

Preface

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

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

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



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

Introduction

This document explains the technical rationale and justification for the proposed Reliability Standard TPL-008-1. It provides stakeholders and the ERO Enterprise with an understanding of the technology and technical requirements in the Reliability Standard. This Technical Rationale and Justification for TPL-008-1 is not a Reliability Standard and should not be considered mandatory and enforceable.

Background

On June 15, 2023, FERC issued FERC Order No. 896 that acknowledges the "challenges associated with planning for extreme heat and cold weather events, particularly those that occur during periods when the Bulk-Power System must meet unexpectedly high demand. Extreme heat and cold weather events have occurred with greater frequency in recent years and are projected to occur with even greater frequency in the future. These events have shown that load shed during extreme temperatures result in unacceptable risk to life and have extreme economic impact. As such, the impact of concurrent failures of Bulk-Power System generation and transmission equipment and the potential for cascading outages that may be caused by extreme heat and cold weather events should be studied and corrective actions should be identified and implemented."[1]

Therefore, the Commission directed in FERC Order No. 896 to develop a new or modified Reliability Standard to address a lack of long-term planning requirement(s) for extreme heat and cold weather events. Specifically, FERC directed NERC to develop modifications to Reliability Standard TPL-001-5.1 or a new Reliability Standard, to require the following: (1) development of benchmark planning cases based on major prior extreme heat and cold weather events and/or meteorological projections; (2) planning for extreme heat and cold weather events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios including the expected resource mix's availability during extreme heat and cold weather conditions, and including the wide-area impacts of extreme heat and cold weather; and (3) development of corrective action plans that mitigate any instances where performance requirements for extreme heat and cold weather events are not met.

[1] N. Am. Elec. Reliability Corp., 183 FERC ¶ 61,191 (2023) (FERC Order), Final Rule. eLibrary | File List (ferc.gov)

Defined Terms

The drafting team defined one term to be added to the NERC Glossary of terms to make the requirements easier to read and understand.

Extreme Temperature Assessment
Documented evaluation of future Transmission System performance for extreme heat and extreme cold temperature benchmark events.

The definition of Extreme Temperature Assessment was developed by the drafting team to limit wordiness throughout the requirements.

TPL-008-1 Standard

The FERC Order No. 896 directed NERC to submit a new Reliability Standard or modifications to Reliability Standard TPL-001-5.1 to address the concerns pertaining to transmission system planning for extreme heat and cold weather events that impact the Reliable Operation of the Bulk-Power System.

The drafting team developed TPL-008-1 to address the FERC directive and determined that a new Reliability standard was the cleanest way to address all directives versus modifying TPL-001-5.1. While the TPL-008-1 standard pulls in similar requirements, this allows industry to have one standard that focuses on extreme heat and extreme cold weather benchmark planning analysis requirements.

Requirement R1

Requirement R1 was drafted to allow Planning Coordinator (PC) and Transmission Planner(s) (TP) within the PC's footprint, to sync up regarding their individual and joint responsibilities when performing the required studies. This will assist entities with clarity on who will complete the other respective requirements within the TPL-008-1 Reliability Standard.

Requirement R2

Requirement R2 describes the need to select foundational weather data necessary for the creation of benchmark planning cases. Specifically, extreme hot and cold temperatures experienced during benchmark events are assumed to be outside the ranges used as the basis of planning cases studied under TPL-005-1.1. Since temperature levels and associated weather conditions affect load levels, generation performance, and transfer levels, the selection of benchmark events is critical to ensuring the Extreme Temperature Assessment appropriately evaluates probable system conditions.

The Standard Drafting Team (SDT) determined that the extreme heat and cold temperatures selected must have a verified statistical basis based on weather data from credible sources. However, because there are many factors to consider in selecting benchmark events (e.g., temperature magnitude, duration of the event, geographical area impacted, etc.) the SDT is not in a position to provide that statistical basis or determine the appropriateness of any specific event. Therefore, to ensure consistency across regions, it is necessary for the ERO to have the responsibility for determining the suitability of benchmark events to represent probable future conditions. The ERO will maintain a library of benchmark events and develop a process to incorporate additional events proposed by responsible entities. Responsible entities will then have access to vetted benchmark weather data in a format that can be incorporated into benchmark planning cases.

Since any region can experience temperatures that are higher or lower than normal, each responsible entity must select at least one case that includes hotter temperature assumptions and one case that includes colder temperature assumptions. While it is understood that, for example, one region may typically experience hotter summers and milder winters than another region, both a hotter than average summer and a colder than average winter could result in reliability concerns. Therefore, the requirement is for at least one case specific to extreme heat and at least one case specific to extreme cold conditions to be studied for the Extreme Temperature Assessment.

Requirement R3

Requirement R3 aligns with directives in FERC Order 896, emphasizing the importance of coordinating the development of benchmark planning cases amongst impacted responsible entities, where the scope of extreme temperature event studies will likely cover large geographical areas exceeding smaller individual planning areas.

Requirement R3, Part 3.1 addresses directives in FERC Order 896, paragraph 50, to consider the wide-area impacts of extreme heat and cold weather and define the wide-area boundaries in transmission planning studies. Additionally, Requirement R3, Part 3.2 addresses directives in FERC Order 896, paragraph 124, which requires the use of sensitivity cases to demonstrate the impact of changes to the assumptions used in the benchmark planning case(s). Specifically, paragraph 124 emphasizes the importance of including conditions that vary with temperature such as load, generation, and system transfers.

Requirement R4

The Extreme Temperature Assessment requires System models, developed in accordance with the MOD-032 standard, for conducting steady state power flow and stability analysis. This aligns with directives in FERC Order 896, emphasizing the requirement of both steady state and transient stability analysis be conducted for extreme heat and cold weather events as part of transmission planning studies. Requirement R4 is consistent with how Reliability Standard TPL-001-5.1 cross-references Reliability Standard MOD-032, which establishes consistent modeling data requirements and reporting procedures for the development of planning horizon cases necessary to support analysis of the reliability of the interconnected system.

Requirement R5

Requirement R5 was drafted to require each responsible entity to set the criteria needed for limits that will be used to evaluate the voltage results from the Extreme Temperature Assessment. The establishment of these criteria allows auditors to compare the results of the assessment with the established criteria.

Requirement R6

This requirement addresses directives in FERC Order No. 896 for responsible entities to perform both steady state and transient stability (dynamic) analyses to ensure that the system has been thoroughly assessed for instability, uncontrolled separation, and Cascading in both the steady state and the transient stability realms.

Adequate criteria should be built into the Extreme Temperature Assessment when performing steady state and transient stability analyses and should be documented clearly. The identification of instability, uncontrolled separation, and Cascading analyses should include thorough technical criteria and supporting information.

Requirement R7

This requirement addresses directives in FERC Order No. 896 to define a set of Contingencies that responsible entities will be required to consider when conducting wide-area studies of extreme heat and cold weather events. FERC's preference to rely on established Contingency definitions, "[w]e believe that it is necessary to establish a set of common contingencies for all responsible entities to analyze. Required contingencies, such as those listed in Table 1 of Reliability Standard TPL-001-5.1 (i.e., category P1 through P7), establish common planning events that set the starting point for transmission system planning assessments," was also considered by the SDT. It is necessary to establish a set of common Contingencies for all responsible entities to analyze. Requiring the study of predefined Contingencies, such as those listed in Table 1, will ensure a level of uniformity across planning regions, considering that extreme heat and cold weather events often exceed the geographic boundaries of most existing planning footprints. Defining the Contingencies in Table 1 consistently with Table 1 of Reliability Standard TPL-001-5.1 meets FERC's preference for commonality.

If feasible, all Contingencies listed in Table 1 should be considered for evaluation by the responsible entity; however, the language affords flexibility in identifying the most appropriate Contingencies. As such, the responsible entity should implement a method and establish sufficient supporting rationale to ensure Contingencies that are expected to produce more severe System impacts within its planning area are adequately identified.

Some, but not all, items to consider when developing the rationale are:

- Past studies,
- Subject matter expert knowledge and judgment of the responsible entity's System (to be supplemented with data or analysis), and
- Historical data from past operating events.

Requirement R8

Requirement R8 was drafted to provide clarity on the following:

1. Frequency of the Extreme Temperature Assessment (Assessment):

   Due to significant level of data collection and coordination between the Planning Coordinator(s) and Transmission Planner(s) for the potential wide-area extreme cold or extreme heat benchmark events, as well as the need to document the assumptions and study results, the SDT opined that performing and completing of the Assessment once every five calendar years is a reasonable timeframe to allow responsible entities to coordinate, prepare, perform and document the Assessment study results. To the extent that responsible entities want to perform more than one set of Assessment for an extreme heat and extreme cold benchmark event, they can do so, but the minimum requirement is once every five calendar years to perform and complete one set of Assessment.

2. What planning study cases are required?

   The Requirement R8 includes the following minimum number of assessments to complete the Extreme Temperature Assessment and address FERC 896 directives per paragraph 111 that "direct NERC to require in the proposed new or modified Reliability Standard that responsible entities perform both steady state and transient stability (dynamic) analyses in the extreme heat and cold weather planning studies". In addition, Requirement R8 also addresses FERC 896 directives per paragraph 124 that "require the use of sensitivity cases to demonstrate the impact of changes to the assumptions used in the benchmark planning case". Requirement R8 also addresses FERC directives per paragraph 124 that sensitivity cases "should consider including conditions that vary with temperature such as load, generation, and system transfers." Since the benchmark planning case(s) already include System conditions under extreme heat or extreme cold events, the sensitivity analysis is to include, at a minimum, changes to one of the assumptions in generation, loads or transfers. Since the minimum requirement includes changes to one of these conditions, the PCs and the TPs can include further sensitivity assessments to change more conditions if they choose to do so.

   The following provides the minimum number of assessments required to complete the Extreme Temperature Assessment for the benchmark planning cases, as well as for sensitivity assessments.

Type of Extreme Temperature Assessment	Extreme Cold Temperature Event	Extreme Heat Temperature Event	Total
Benchmark Planning Case Analysis	A minimum of one extreme cold benchmark planning case assessment	A minimum of one extreme heat benchmark planning case assessment	Total Minimum: Two benchmark planning case assessments
Sensitivity Analysis	A minimum of one sensitivity study case for one of the following: 1. Changes in generation availability, or 2. Changes in load level (real and reactive), or	A minimum of one sensitivity study case for one of the following: 1. Changes in generation availability, or 2. Changes in load level (real and reactive), or	Total Minimum: Two sensitivity cases analysis

Type of Extreme Temperature Assessment	Extreme Cold Temperature Event	Extreme Heat Temperature Event	Total
	3. Changes in transfer level	3. Changes in transfer level	
Total			A minimum total of four assessments to complete the Extreme Temperature Assessment

3. What are the types of power flow related analyses?

There are two types of power flow related analyses: a steady-state and a stability analysis that are applied for the minimum of four planning study cases as identified in the above table. This requirement is to satisfy FERC Order 896 directive paragraph 111.

Requirement R9

FERC Order 896 identifies a deficiency in the existing NERC TPL-001-5.1 Transmission Planning Reliability Standard where "planning coordinators and transmission planners are required to evaluate possible actions to reduce the likelihood or mitigate the consequences of extreme temperature events but are not obligated to develop corrective action plans" (¶139).

Given potential severe consequences of extreme cold and extreme heat events, FERC Order 896 raises the bar and "directs NERC to require in the new or modified Reliability Standard the development of extreme weather corrective action plans for specified instances when performance standards are not met" (¶152).

Due to higher likelihood of P1 Contingencies, performance requirements for P0 and P1 Contingencies are held to a higher performance standard, and Corrective Action Plans (CAPs) are required to address performance deficiencies for P0 and P1 Contingencies in the Extreme Temperature Assessments.

Furthermore, having a CAP requirement for P0 and P1 contingencies aligns with ensuring resilience during future extreme cold and extreme heat events, when transmission system is required to be P1-secure (using contingency analysis, voltage stability and transient stability).

As per Order 896, paragraph 94, it is clarified that resource adequacy benchmarks are not within the scope of TPL-008-1. The intent of the standard is to evaluate benchmark events where sufficient generation is available to supply load. However, under an extreme heat or extreme cold temperature condition, there may instances where the benchmark planning cases and/or sensitivity cases may not have sufficient available generation to supply the load. In these scenarios, it may be acceptable for the responsible entity to either curtail load, or model most likely future resources in the interconnection queue, to achieve a solution for the benchmark planning case. Under these conditions, the amount of load curtailment or potential new resources assumed in the benchmark planning cases need to be documented Extreme Temperature Assessment to be reported to the applicable regulatory authorities or governing bodies responsible for retail electric service issues.

Given that a P0 Contingency represents a continuous system condition without any system disturbances, the SDT opined that load shedding should not be considered as a CAP. However, the SDT has determined that load curtailment may be considered for a P1 Contingency as a CAP where load shed is allowed to prevent system-wide failures and ensuring the continued operation of essential services under a critical P1 Contingency in the extreme heat and cold events. The SDT also emphasizes that other alternative solutions, other than firm load curtailment, are evaluated in higher priorities. In the event that firm Load shed is included in the CAP for a P1 contingency, the responsible entity shall document the alternative(s) considered, as mentioned in Requirement R10, and notify the applicable regulatory authorities or governing bodies responsible for retail electric service issues.

Requirement R10

The requirement for responsible entities to assess and document possible actions designed to reduce the likelihood or mitigate the consequences of System instability, uncontrolled separation, or Cascading failures during P2, P4, P5, and P7 Contingencies is in response to directives outlined in FERC Order 896.

The P2, P4, P5, and P7 Contingencies involve multiple element outages resulting from a single event, making them relatively less likely to occur compared to P0 and P1 Contingencies but potentially causing more severe system impacts. Considering both the likelihood of these Contingencies and the fact that the Extreme Temperature Assessment already addresses low-probability system conditions, the SDT determined that no corrective action is required for P2, P3, P4, and P7 Contingencies. However, due to their potential severity resulting from single-Contingency multiple element outages, the SDT believes it is appropriate for responsible entities to at least evaluate and document possible mitigation actions to reduce the likelihood or mitigate the consequences and adverse impacts.

The SDT finds it reasonable to exclude P3 and P6 Contingencies from the Extreme Temperature Assessment. Part of the decision stems from the complexity of P3 and P6, which involve multiple element outages triggered by multiple Contingencies, with system adjustments allowed between them. Consequently, the occurrence likelihood of P3 and P6 could be even lower compared to P2, P4, P5, and P7 Contingencies. Moreover, aligning with the directives set forth in FERC Order 896, which emphasizes the importance of incorporating derated generation, transmission capacity, and the availability of generation and transmission in the development of benchmark planning cases, it becomes imperative for responsible entities to consider potential concurrent or correlated generation and transmission outages and derates within relevant benchmark planning cases. This ensures that the benchmark planning case accurately reflects system conditions under extreme temperatures, with generation and transmission outages already factored in. Therefore, the SDT believes excluding P3 and P6 is justified, as generation and transmission outages are already accounted for within the benchmark planning cases.

Requirement R11

The requirement for responsible entities to share Extreme Temperature Assessment results aligns with directives in FERC Order 896, emphasizing coordination and sharing of study findings. It ensures collaboration among stakeholders and timely dissemination of critical information to entities with reliability-related needs. This fosters a collective understanding of reliability concerns identified in wide-area studies, thereby enhancing overall grid reliability.

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Unofficial Comment Form

Project 2023-07 Transmission Planning Performance Requirements for Extreme Weather

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on draft one of **TPL-008-1 – Transmission System Planning Performance Requirements for Extreme Temperature Events** by **8 p.m. Eastern, Friday, May 3, 2024.**

Additional information is available on the project page. If you have questions, contact Standards Developer, Jordan Mallory (via email), or at 470-479-7538.

Background Information

On June 15, 2023, FERC issued FERC Order No. 896 that acknowledges the "challenges associated with planning for extreme heat and cold weather events, particularly those that occur during periods when the Bulk-Power System must meet unexpectedly high demand. Extreme heat and cold weather events have occurred with greater frequency in recent years, and are projected to occur with even greater frequency in the future. These events have shown that load shed during extreme temperature result in unacceptable risk to life and have extreme economic impact. As such, the impact of concurrent failures of Bulk-Power System generation and transmission equipment and the potential for cascading outages that may be caused by extreme heat and cold weather events should be studied and corrective actions should be identified and implemented."[1]

Therefore, the Commission directed in FERC Order No. 896 to develop a new or modified Reliability Standard to address a lack of long-term planning requirement(s) for extreme heat and cold weather events. Specifically, FERC directed NERC to develop modifications to Reliability Standard TPL-001-5.1 or a new Reliability Standard, to require the following: (1) development of benchmark planning cases based on major prior extreme heat and cold weather events and/or meteorological projections; (2) planning for extreme heat and cold weather events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios including the expected resource mix's availability during extreme heat and cold weather conditions, and including the wide-area impacts of extreme heat and cold weather; and (3) development of corrective action plans that mitigate any instances where performance requirements for extreme heat and cold weather events are not met.

[1] N. Am. Elec. Reliability Corp., 183 FERC ¶ 61,191 (2023) (FERC Order), Final Rule. eLibrary | File List (ferc.gov)

Questions

1. Do you agree with the proposed definition of Extreme Temperature Assessment? If you do not agree, please provide your recommendation and, if appropriate, technical justification.
   ☐ Yes
   ☐ No

   Comments:

2. Do you agree with the proposed TPL-008-1 Reliability Standard Requirement R1? If you do not agree, please provide your recommendation and, if appropriate, technical justification.
   ☐ Yes
   ☐ No

   Comments:

3. Do you agree with the proposed TPL-008-1 Reliability Standard Requirement R2 (Benchmark events)? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.
   ☐ Yes
   ☐ No

   Comments:

4. Do you agree with the proposed TPL-008-1 Reliability Standard Requirements R3 – R8 (benchmark planning cases and analyses)? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.
   ☐ Yes
   ☐ No

   Comments:

5. Do you agree with the proposed TPL-008-1 Reliability Standard Requirements R9 – R10 (CAPs and possible actions)? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.
   ☐ Yes
   ☐ No

   Comments:

6. Do you agree with the proposed TPL-008-1 Reliability Standard Requirement R11 (Sharing Extreme Temperature Assessment results)? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.
   ☐ Yes
   ☐ No

   Comments:

7. Do you agree with the proposed TPL-008-1 Table 1? If you do not agree, please provide your recommendation and technical justification.
   ☐ Yes
   ☐ No

   Comments:

8. The Standard Drafting Team (SDT) is proposing a phased-in implementation plan approach. Do you agree with the proposed phased-in timeframes? If you do not agree, please provide your recommendation and technical justification.
   ☐ Yes
   ☐ No

   Comments:

9. Provide any additional comments for the SDT to consider, including the provided technical rationale document, if desired.

   Comments:

Violation Risk Factor and Violation Severity Level Justifications

Project 2023-07 Transmission System Planning Performance Requirements for Extreme Weather

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Project 2023-07 Transmission System Planning Performance Requirements for Extreme Weather. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for TPL-008-1, Requirement R1	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to the fact that the Planning Coordinators, in conjunction with its Transmission Planner(s) will determine joint responsibilities for requirements throughout TPL-008-1.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Planning Coordinator, in conjunction with its Transmission Planner(s), failed to determine and identify individual and joint responsibilities for performing the required studies for the Extreme Temperature Assessment.

VSL Justifications for TPL-008-1, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL has been assigned as a binary due to the Planning Coordinator and Transmission Planner to determine who completes the responsibilities throughout TPL-008-1. The responsibilities documentation will either be developed or not.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R2	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of high is appropriate due to the fact that selecting a benchmark event to perform an extreme temperature assessment can affect the grid based on planning analysis for future events.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The responsible entity did not select an extreme heat benchmark event or extreme cold benchmark event from the ERO approved benchmark library.	The responsible entity did not select an extreme heat benchmark event and extreme cold benchmark event from the ERO approved benchmark library.

VSL Justifications for TPL-008-1, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	This VSL has been assigned as a binary due to the benchmark event needing to be selected for benchmark planning cases to be completed. You either select a benchmark event or not.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R3	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of high is appropriate due to the fact that it is important to develop and maintain System models within an entity's planning area for performing Extreme Temperature Assessments. Connecting to MOD-032 to provide important data needed to assist entities with System models is also important for accurate information to be used.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Planning Coordinator did not develop or implement a process for coordinating the development of benchmark planning cases among impacted Planning Coordinator(s) Transmission Planner(s), and other designated study entities. OR The Planning Coordinator developed and implemented a process for coordinating the development of benchmark planning cases among impacted Planning Coordinator(s), Transmission Planner(s), and other designated study entities, but this process did not define the planning study area boundary based off the selected benchmark events. OR The Planning Coordinator developed and implemented a process for coordinating the development of benchmark planning cases among impacted Planning Coordinator(s), Transmission Planner(s), and other designated study entities, but this process did not modify the

			benchmark planning cases to include seasonal and temperature dependent adjustments load, generation, Transmission, and transfers.

VSL Justifications for TPL-008-1, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL has been assigned as a binary due to the responsible entity either develops and maintains the System models within its planning area or it does not develop and maintain the System models within its planning area.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R4	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity did not develop or maintain System models of the responsible entity's planning area for performing Extreme Temperature Assessment. OR The responsible entity developed and maintained System models for performing Extreme Temperature Assessment, but the System model did not use data consistent with that provided in accordance with the MOD-032 standard supplemented by other sources as needed.

VSL Justifications for TPL-008-1, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL has been assigned as a binary due to the Planning Coordinator to develop and implement a process for coordinating the development of benchmark planning cases. The benchmark planning cases will either be developed and implemented or not.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R5	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate due to the importance of having a criteria for acceptable System steady state voltage limits of post-Contingency voltage deviations for performing Extreme Temperature Assessments.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity, as determined in Requirement R1, did not have criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations for performing Extreme Temperature Assessment.

VSL Justifications for TPL-008-1, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL has been assigned as a binary due to the responsible entity either having acceptable criteria for System steady state voltage limits and post-contingency voltage deviations or not.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R6	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate due to the importance of defining and documenting the criteria or methodology for System instability, uncontrolled separation, or Cascading.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity failed to define and document, the criteria or methodology used in the analysis to identify System instability, uncontrolled separation, or Cascading.

VSL Justifications for TPL-008-1, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R7	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate for this requirement. Identifying Contingencies for performing Extreme Temperature Assessments for each of the event categories in Table 1 can directly impact the BES.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The responsible entity, as determined in Requirement R1, identified Contingencies for performing Extreme Temperature Assessment for each of the event categories in Table 1 that are expected to produce more severe System impacts within its planning area, but did not include the rationale for those Contingencies selected for evaluation as supporting documentation.	The responsible entity, as determined in Requirement R1, did not identify Contingencies for performing Extreme Temperature Assessment for each of the event categories in Table 1 that are expected to produce more severe System impacts within its planning area.

VSL Justifications for TPL-008-1, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R8	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate due to the importance of performing an Extreme Temperature Assessment every 5 years.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
The responsible entity, as determined in Requirement R1, completed an Extreme Temperature Assessment, but it was completed less than or equal to six months late.	The responsible entity, as determined in Requirement R1, completed an Extreme Temperature Assessment, but it was completed more than six months but less than or equal to 12 months late.	The responsible entity, as determined in Requirement R1, completed an Extreme Temperature Assessment, but it was completed more than 12 months but less than or equal to 18 months late.	The responsible entity, as determined in Requirement R1, completed an Extreme Temperature Assessment, but it was more than 18 months late. OR The responsible entity, as determined in Requirement R1, did not complete an Extreme Temperature Assessment. OR The responsible entity, as determined in Requirement R1, completed an Extreme Temperature Assessment, but it was missing one or more of the required elements in Requirement R8.

VSL Justifications for TPL-008-1, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R9	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate for this requirement. Developing a Corrective Action Plan is important to the BES as it assists entities when Systems are unable to meet performance requirements.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R9			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The responsible entity, as determined in Requirement R1, failed to solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.	The responsible entity, as determined in Requirement R1, failed to develop a Corrective Action Plan when the benchmark planning case study results indicate the System is unable to meet performance requirements for the Table 1 P0 or P1 Contingencies.

VSL Justifications for TPL-008-1, Requirement R9	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL has been assigned as a binary due to the responsible entity either having acceptable criteria for System steady state voltage limits and post-contingency voltage deviations or not.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R10	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of lower has been assigned to Requirement R10. Documenting possible actions to reduce the likelihood or mitigate the consequences and adverse impacts are administrative in nature.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R10			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	Each responsible entity, as determined in Requirement R1, failed to evaluate and document possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts when the benchmark planning case study results indicate the System could result in instability, uncontrolled separation, or Cascading for the Table 1 P2, P4, P5, and P7 Contingencies.

VSL Justifications for TPL-008-1, Requirement R10	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL has been assigned as a binary due to the fact that the responsible entity will either have evaluated and documented possible actions to mitigate adverse impacts.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R11	
Proposed VRF	**Medium**
NERC VRF Discussion	The VRF of Medium is appropriate because it could directly affect the electrical state or capability of the BES if entities are not aware of the results from its Extreme Temperature Assessment results.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R11			
Lower	**Moderate**	**High**	**Severe**
The responsible entity, as determined in Requirement R1, distributed its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 60 days but less than or equal to 80 days following the request.	The responsible entity, as determined in Requirement R1, distributed its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 80 days but less than or equal to 100 days following the request.	The responsible entity, as determined in Requirement R1, distributed its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 100 days but less than or equal to 120 days following the request.	The responsible entity, as determined in Requirement R1, distributed its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 120 days following the request. OR The responsible entity, as determined in Requirement R1, did not distribute its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing.

VSL Justifications for TPL-008-1, Requirement R11	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

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Consideration of FERC Order 896 Directives

Project 2023-07 Transmission System Planning Performance Requirements for Extreme Weather
March 2024

On June 15, 2023, FERC issued a Final Rulemaking to direct NERC to develop a new or modified Reliability Standard to address a lack of a long-term planning requirement(s) for extreme heat and cold weather events. Specifically, FERC directed NERC to develop modifications to Reliability Standard TPL-001-5.1 or a new Reliability Standard, to require the following: (1) development of benchmark planning cases based on major prior extreme heat and cold weather events and/or meteorological projections; (2) planning for extreme heat and cold weather events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios including the expected resource mix's availability during extreme heat and cold weather conditions, and including the wide-area impacts of extreme heat and cold weather; and (3) development of corrective action plans that mitigate any instances where performance requirements for extreme heat and cold weather events are not met. The below provides FERC Order 896 Directive language along with the drafting teams consideration of the directives.

FERC Order 896 Directives	
Directive Language	**Consideration of Directives**
P35. "[W]e direct NERC to: (1) develop extreme heat and cold weather benchmark events, and (2) require the development of benchmark planning cases based on identified benchmark events." **P 36**: "…As recommended by commenters, NERC should consider the examples of approaches for defining benchmark events identified in the NOPR (e.g., the use of projected frequency or probability distribution). NERC may also consider other approaches that achieve the objectives outlined in this final rule."	The ERO will work with respective subject matter experts, including climate experts, the six regions, etc., and develop extreme heat and extreme cold weather benchmark events. An ERO-maintained library will be created, and all developed extreme heat and extreme cold weather benchmark events will be retained. From this library, responsible entities will be able to review and select the appropriate benchmark events to assist with the development of its benchmark planning cases. The drafting team developed requirements within TPL-008-1 to require responsible entities to select one extreme heat benchmark event and extreme cold benchmark event from the approved ERO library

FERC Order 896 Directives	
Directive Language	**Consideration of Directives**
	(Requirement R2). After selecting its benchmark events, the responsible entity is required to develop and implement a process for coordinating the development of benchmark planning cases among the respective entities (Requirement R3) and develop and maintain System models (Requirement R4).
P38. "[I]n developing extreme heat and cold benchmark events, NERC shall ensure that benchmark events reflect regional differences in climate and weather patterns."	The ERO will work with respective subject matter experts, including climate experts, the six regions, etc., to ensure regional differences in climate and weather patterns are reflected within the developed benchmark events.
P39. "We also direct NERC to include in the Reliability Standard the framework and criteria that responsible entities shall use to develop from the relevant benchmark event planning cases to represent potential weather-related contingencies (e.g., concurrent/correlated generation and transmission outages, derates) and expected future conditions of the system such as changes in load, transfers, and generation resource mix, and impacts on generators sensitive to extreme heat or cold, due to the weather conditions indicated in the benchmark events. Developing such a framework would provide a common design basis for responsible entities to follow when creating benchmark planning cases. This would not only help establish a clear set of expectations for responsible entities to follow when developing benchmark planning events, but also facilitate auditing and enforcement of the Standard."	The directive is addressed in proposed TPL-008-1 through Requirement R3, R4, and R8. Requirement R3 obligates the Planning Coordinator to develop and implement a process to coordinate the development of the benchmark planning cases. Requirement R4 obligates the responsible entity to develop and maintain System models for performing the Extreme Temperature Assessment which represents projected System conditions based on the selected benchmark events Requirement R8 obligates the responsible entity to assess and complete an Extreme Temperature Assessment for one of the years in the Long-Term Transmission Planning Horizon, for the benchmark planning cases as well as sensitivity analysis which includes changes to one of these conditions: generation, real or reactive forecasted Load, or transfers.
P40. "We also direct NERC to ensure the reliability standard contains appropriate mechanisms for ensuring the benchmark event reflects up-to-date meteorological data."	The drafting team discussed a similar process to how BAL-003 gathers data. It was determined that the ERO is in the best situation to provide a review with the respective subject matter experts, including climate experts, the

FERC Order 896 Directives	
Directive Language	**Consideration of Directives**
	six regions, etc., and update the benchmark events to reflect up-to-date meteorological data every 5 years via a NERC process document.
P50. [W]e…direct NERC to require that transmission planning studies under the new or revised Reliability Standard consider the wide-area impacts of extreme heat and cold weather. We direct NERC to clearly describe the process that an entity must use to define the wide-area boundaries. While commenters provide various views in favor of both a geographical approach and electrical approach to defining wide-area boundaries, we do not adopt any one approach in this final rule…NERC should consider the comments in this proceeding when developing a new or modified reliability standard that considers the broad area impacts of extreme heat and cold weather.”	The SDT reviewed all the extreme weather events mentioned within the FERC Order 896. The selected benchmark event will determine the impacted wide area. The directive is addressed in proposed TPL-008-1 through requirement R2 and R3 Part 3.1.
P58. “[W]e…direct NERC to develop benchmark events for extreme heat and cold weather events through the Reliability Standards development process.”	The ERO will work with respective subject matter experts, including climate experts, the six regions, etc., to develop benchmark events. These events will be uploaded to an ERO library where responsible entities will then select their respective benchmark events from the ERO library to develop the benchmark planning cases. The directive is addressed in proposed TPL-008-1 through requirement R2. Requirement R2 obligates the responsible entity to select one extreme heat benchmark event and extreme cold benchmark event for performing the Extreme Temperature Assessment, from the approved benchmark library, maintained by the ERO.
P60. “[W]e…direct NERC to designate the type(s) of entities responsible for developing benchmark planning cases and conducting wide-area studies under the new or modified Reliability Standard…benchmark planning cases should be developed by registered entities such as large planning coordinators, or groups of planning coordinators, with the capability of planning on a regional scope.”	The drafting team discussed that the Transmission Planner (TP) and/or Planning Coordinator (PC) would be the responsible entities to address TPL-008-1 Requirements. Requirement R1 obligates both the TP and PC to identify individual and joint responsibilities.

FERC Order 896 Directives	
Directive Language	**Consideration of Directives**
P 61: "We believe the designated responsible entities should have certain characteristics, including having a wide-area view of the Bulk-Power System and the ability to conduct long-term planning studies across a wide geographic area. The responsible entities should also have the planning tools, expertise, processes, and procedures to develop benchmark planning cases and analyze extreme weather events in the long-term planning horizon." **P 62**: To comply with this directive, NERC may designate the tasks of developing benchmark planning cases and conducting wide-area studies to an existing functional entity or a group of functional entities (e.g., a group of planning coordinators). NERC may also establish a new functional entity registration to undertake these tasks. In the petition accompanying the proposed Reliability Standard NERC should explain how the applicable registered entity or entities meet the objectives outlined above.	The drafting team reviewed all the extreme weather events mentioned within the FERC Order 896. The selected benchmark event will determine the impacted wide area. Requirement R3 Part 3.1 obligates each the responsible entity to define the planning study area boundary based on the selected benchmark events.
P72. "[W]e direct NERC to require functional entities to share with the entities responsible for developing benchmark planning cases and conducting wide-area studies the system information necessary to develop benchmark planning cases and conduct wide-area studies. Further, responsible entities must share the study results with affected transmission operators, transmission owners, generator owners, and other functional entities with a reliability need for the studies."	The directive is addressed in proposed TPL-008-1 through requirement R3 and R11. R3 obligates the Planning Coordinator to develop and implement a process for coordinating the development of benchmark planning cases among impacted Planning Coordinator(s), Transmission Planner(s), and other designated study entities. R11 obligates Planning Coordinator(s), Transmission Planner(s), and other designated study entities to provide its Extreme Temperature Assessment results within 60 calendar days of a request to any functional entity that has a reliability related need and submits a written request for the information.
P73. "Because in this final rule we direct NERC to determine the responsible entities that will be developing benchmark planning cases and	The drafting team discussed and determined that data needed to address the Extreme Temperature Assessment would still be appropriate through

FERC Order 896 Directives	
Directive Language	**Consideration of Directives**
conducting wide-area studies, it is possible that the selected responsible entities under the new or modified Reliability Standard will not be able to request and receive needed data pursuant to MOD-032-1, absent modification to that Standard.”	MOD-032 and additional functional entities are not needed throughout this standards development process to address FERC Order 896. The directive is addressed in proposed TPL-008-1 through Requirement R1, R3 Part 3.1, R4 and R8. Requirement R1 obligates the Planning Coordinator, in conjunction with its Transmission Planner, to determine and identify each entity’s individual and joint responsibilities for performing the studies needed to complete the Extreme Temperature Assessment.
P76: “[W]e…direct NERC to address the requirement for wide-area coordination through the standards development process, giving due consideration to relevant factors identified by commenters in this proceeding.”	The drafting team reviewed all the extreme weather events mentioned within the FERC Order 896. The selected benchmark event will determine the impacted wide area. Requirement R3 Part 3.1 obligates each the responsible entity to define the planning study area boundary based on the selected benchmark events.
P77. “[W]e direct NERC to require in the new or modified Reliability Standard that responsible entities share the results of their wide-area studies with other registered entities such as transmission operators, transmission owners, and generator owners that have a reliability related need for the studies.”	This directive is addressed in proposed TPL-008-1 Requirement R11. Requirement R11 obligates each responsible entity to provide the wide area study results within 60 calendar days of a request to any functional entity that has a reliability related need and has submitted a written request for the information.
P88. direct NERC to require under the new or revised Reliability Standard the study of concurrent/correlated generator and transmission outages due to extreme heat and cold events in benchmark events as described in more detail below.	This directive is addressed in proposed TPL-008-1 through Requirement R3 Part 3.2. The responsible entity is obligated to modify the benchmark planning cases to include seasonal and temperature dependent adjustment for Load, generation, Transmission, and transfers which represent the selected benchmark events.

FERC Order 896 Directives	
Directive Language	**Consideration of Directives**
P111. "[W]e direct NERC to require in the proposed new or modified Reliability Standard that responsible entities perform both steady state and transient stability (dynamic) analyses in the extreme heat and cold weather planning studies. In a steady state analysis, the system components are modeled as either in-service or out-of-service and the result is a single point-in-time snapshot of the system in a state of operating equilibrium. A transient stability (dynamic) analysis examines the system from the start to the end of a disturbance to determine if the system regains a state of operating equilibrium. Performing both analyses ensures that the system has been thoroughly assessed for instability, uncontrolled separation, and cascading failures in both the steady state and the transient stability realms." (internal citations omitted).	This directive is addressed in proposed TPL-008-1 through Requirement R8 and Table 1. Requirement R8 requires the documentation of results of both steady state and stability analyses. Table 1 obligates each responsible entity to perform both steady state and stability analyses and compare the study results against performance criteria.
P112. "[W]e direct NERC to define a set of contingencies that responsible entities will be required to consider when conducting wide-area studies of extreme heat and cold weather events under the new or modified Reliability Standard. We believe that it is necessary to establish a set of common contingencies for all responsible entities to analyze. Required contingencies, such as those listed in Table 1 of Reliability Standard TPL-001-5.1 (i.e., category P1 through P7), establish common planning events that set the starting point for transmission system planning assessments. Requiring the study of predefined contingencies will ensure a level of uniformity across planning regions—a feature that will be necessary in the new or revised Reliability Standard considering that extreme heat and cold weather events often exceed the geographic boundaries of most existing planning footprints." **P113:** "[T]he contingencies required in the new or revised Reliability Standards should reflect the complexities of transmission system planning studies for extreme heat and cold weather events."	TPL-008-1 meets this directive by requiring each responsible entity to identify Contingencies for performing the Extreme Temperature Assessment. (See R7 and Table 1.) The Contingency categories in Table 1 of TPL-008 correspond to the well-established Contingency events defined in TPL-001.

FERC Order 896 Directives	
Directive Language	**Consideration of Directives**
P116. "[W]e direct NERC to require in the new or modified Reliability Standard that responsible entities model demand load response in their extreme weather event planning area. As indicated by several commenters, because demand load response is generally a mitigating action that involves reducing distribution load during periods of stress to stabilize the Bulk-Power System, its effect during an extreme weather event should be modeled." **P 117:** "[I]n addressing this directive, we expect NERC to determine whether responsible entities will need to take additional steps to ensure that the impacts of demand load response are accurately modeled in extreme weather studies, such as by analyzing demand load response as a sensitivity, as is currently the case under Reliability Standard TPL-001-5.1."	TPL-008-1 meets this directive by requiring each responsible entity to develop and maintain System models within its planning area consistent with that of MOD-032 standard. (See R4.) Specifically, Attachment 1 of MOD-032 requires information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes.
P124. "[W]e direct NERC to require the use of sensitivity cases to demonstrate the impact of changes to the assumptions used in the benchmark planning case. Sensitivity analyses help a transmission planner to determine if the results of the base case are sensitive to changes in the inputs. The use of sensitivity analyses is particularly necessary when studying extreme heat and cold events because some of the assumptions made when developing a base case may change if temperatures change – for example, during extreme cold events, load may increase as temperatures decrease, while a decrease in temperature may result in a decrease in generation. We AEP, and we direct NERC to define during the Reliability Standard development process a baseline set of sensitivities for the new or modified Reliability Standard. While we do not require the inclusion of any specific sensitivity in this final rule, NERC should consider including conditions that vary with temperature such as load, generation, and system transfers." **P125**. "We…believe that responsible entities should be free to study additional sensitivities relevant to their planning areas…cooperation will be	TPL-008-1 meets this directive by requiring each responsible entity to perform steady state and stability analyses on benchmark planning cases (R8.1) and sensitivity cases (R8.2). Furthermore, R8.2 provides a baseline set of variable conditions that include changes to generation, load, or transfers that are expected to change with extreme heat or extreme cold temperatures. .

FERC Order 896 Directives	
Directive Language	**Consideration of Directives**
necessary between responsible entities conducting extreme heat and extreme cold weather studies and other registered entities within their extreme weather study footprints to ensure the selection of appropriate sensitivities.”	
P134. “[W]e directs NERC to require in the new or modified Reliability Standard the use of planning methods that ensure adequate consideration of the broad characteristics of extreme heat and cold weather conditions. We further direct NERC to determine during the standard development process whether probabilistic elements can be incorporated into the new or modified Reliability Standard and implemented presently by responsible entities. If NERC identifies probabilistic elements which responsible entities can feasibly implement and that would improve upon existing planning practices, we expect the inclusion of those methods in the proposed Reliability Standard.”	The Standard Drafting Team discussed probabilistic elements and determined while probabilistic analysis would be a good step forward, it would be better suited for the future as the methodology, process, and tools mature. A specific example could be that future updates or revision to TPL-008 may provide an avenue for incorporating probabilistic elements into the planning process, allowing for a more robust and accurate assessment of system reliability and resilience. Probabilistic assessment of generation and transmission facilities for the benchmark planning cases was discussed during the process of drafting the TPL-008-1 standard. However, based on the actual extreme heat and extreme cold events that have occurred, outages for generation and transmission facilities were unique for each of these events. Thus, it was challenging to draw correlation for the outages that occurred for different extreme heat and cold events for different regions and different timeframe. In addition, the data that were available from these events were limited to perform an adequate probabilistic assessment. Due to these reasons, the Standard Drafting Team has decided not to pursue any probabilistic assessment for the current TPL-008-1 standard. This, however, does not preclude future development of probabilistic assessment when having additional data, as well as mature methodology, process and tools that can provide meaningful probabilistic assessment for generation and transmission outages under extreme temperature conditions.
P138. “[W]e direct NERC to identify during the standard development process any probabilistic planning methods that would improve upon	Please see the response above for P134.

FERC Order 896 Directives	
Directive Language	**Consideration of Directives**
existing planning practices, but that NERC deems infeasible to include in the proposed Reliability Standard at this time. If any such methods are identified, NERC shall describe in its petition for approval of the proposed Reliability Standard the barriers preventing the implementation of those probabilistic elements. We intend to use this information to determine whether and what next steps may be warranted to facilitate the use of probabilistic methods in transmission system planning practices.”	
P152. “[W]e direct NERC to require in the new or modified Reliability Standard the development of extreme weather corrective action plans for specified instances when performance standards are not met. In addition, as explained below, we direct NERC to develop certain processes to facilitate interaction and coordination with applicable regulatory authorities or governing bodies responsible for retail electric service as appropriate in implementing a corrective action plan.” **P155**: “[T]he Commission is not directing any specific result or content of the corrective action plan.”	The directive is addressed in the proposed TPL-008-1 Requirement R9. When the benchmark planning case study results indicate the System is unable to meet performance requirements for P0 and P1 Contingencies, Corrective Action Plans must be developed. Additionally, the responsible entities shall share their Corrective Action Plans with, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.
P157. “[W]e direct NERC to require in the new or modified Reliability Standard the development of corrective action plans that include mitigation for specified instances where performance requirements for extreme heat and cold events are not met—i.e., when certain studies conducted under the Standard show that an extreme heat or cold event would result in cascading outages, uncontrolled separation, or instability.” **P158**: “[W]e give NERC in this final rule the flexibility to specify the circumstances that require the development of a corrective action plan.”	The directive is addressed in the proposed TPL-008-1 Requirement R9. When the benchmark planning case study results indicate the system is unable to meet performance requirements for P0 and P1 Contingencies, Corrective Action Plans must be developed.
P165. “[w]e direct NERC to require in the new or modified Reliability Standard that responsible entities share their corrective action plans with, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.”	The directive is addressed in the proposed TPL-008-1 Requirement R9.

FERC Order 896 Directives	
Directive Language	**Consideration of Directives**
	R9 obligates the responsible entities shall share their Corrective Action Plans with, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.
P167. "Further, because an important goal of transmission planning is to avoid load shed, any responsible entity that includes non-consequential load loss in its corrective action plan should also identify and share with applicable regulatory authorities or governing bodies responsible for retail electric service alternative corrective actions that would, if approved and implemented, avoid the use of load shedding."	This directive is addressed in proposed TPL-008-1 Requirement R9. Where Load shed is allowed as an element of a Corrective Action Plan for the Table 1 P1 Contingency, the responsible entity shall document the alternative(s) considered, as mentioned in Requirement R10, and notify the applicable regulatory authorities or governing bodies responsible for retail electric service issues.
P188. "[W]e direct NERC to submit a new or modified Reliability Standard within 18 months of the date of publication of this final rule in the Federal Register. Further, we direct NERC to propose an implementation timeline for the new or modified Reliability Standard, with implementation beginning no later than 12 months after the effective date of a Commission order approving the proposed Reliability Standard."	The directive is addressed with the publication of TPL-008-1 and will be filed with the regulatory government no later than December 15, 2024, within 18 months of the date of publication of Order 896.
P193. "[W]e direct NERC to establish an implementation timeline for the proposed Reliability Standard. In complying with this directive, NERC will have discretion to develop a phased-in implementation timeline for the different requirements of the proposed Reliability Standard (i.e., developing benchmark cases, conducting studies, developing corrective action plans). However, this phased-in implementation must begin within 12 months of the effective date of a Commission order approving the proposed Reliability Standard and must include a clear deadline for implementation of all requirements."	The implementation plan addresses Requirement R1 becoming effective 12 months from the effective date of the Commission order approving the TPL-008-1. In addition, phased-in approaches have been provided for other Requirements needing additional time. See the TPL-008-1 Implementation Plan.

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Standards Announcement

Project 2023-07 Transmission Planning Performance Requirements for Extreme Weather

Formal Comment Period Open through May 3, 2024
Ballot Pools Forming through April 18, 2024

Now Available

A 45-day formal comment period for draft one of **TPL-008-1 – Transmission System Planning Performance Requirements for Extreme Temperature Events** is open through 8 p.m. Eastern, **Friday, May 3, 2024**.

Commenting
Use the Standards Balloting and Commenting System (SBS) to submit comments. An unofficial Word version of the comment form is posted on the project page.

Reminder Regarding Corporate RBB Memberships
Under the NERC Rules of Procedure, each entity and its affiliates is collectively permitted one voting membership per Registered Ballot Body Segment. Each entity that undergoes a change in corporate structure (such as a merger or acquisition) that results in the entity or affiliated entities having more than the one permitted representative in a particular Segment must withdraw the duplicate membership(s) prior to joining new ballot pools or voting on anything as part of an existing ballot pool. Contact ballotadmin@nerc.net to assist with the removal of any duplicate registrations.

Ballot Pools
Ballot pools are being formed through **8 p.m. Eastern, Thursday, April 18, 2024.** Registered Ballot Body members can join the ballot pools here.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps
Initial ballots for the standard and implementation plan, as well as a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **April 24 – May 3, 2024**.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Jordan Mallory (via email) or at 404-479-7358. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify "Project 2023-07 Transmission Planning Performance Requirements for Extreme Weather observer list" in the Description Box.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comment Report

Project Name:	2023-07 Transmission Planning Performance Requirements for Extreme Weather | Draft 1
Comment Period Start Date:	3/20/2024
Comment Period End Date:	5/3/2024
Associated Ballots:	2023-07 Transmission Planning Performance Requirements for Extreme Weather Implementation Plan IN 1 OT 2023-07 Transmission Planning Performance Requirements for Extreme Weather TPL-008-1 IN 1 ST

There were 78 sets of responses, including comments from approximately 179 different people from approximately 99 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the proposed definition of Extreme Temperature Assessment? If you do not agree, please provide your recommendation and, if appropriate, technical justification.

2. Do you agree with the proposed TPL-008-1 Reliability Standard Requirement R1? If you do not agree, please provide your recommendation and, if appropriate, technical justification.

3. Do you agree with the proposed TPL-008-1 Reliability Standard Requirement R2 (Benchmark events)? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

4. Do you agree with the proposed TPL-008-1 Reliability Standard Requirements R3 – R8 (benchmark planning cases and analyses)? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

5. Do you agree with the proposed TPL-008-1 Reliability Standard Requirements R9 – R10 (CAPs and possible actions)? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

6. Do you agree with the proposed TPL-008-1 Reliability Standard Requirement R11 (Sharing Extreme Temperature Assessment results)? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

7. Do you agree with the proposed TPL-008-1 Table 1? If you do not agree, please provide your recommendation and technical justification.

8. The Standard Drafting Team (SDT) is proposing a phased-in implementation plan approach. Do you agree with the proposed phased-in timeframes? If you do not agree, please provide your recommendation and technical justification.

9. Provide any additional comments for the SDT to consider, including the provided technical rationale document, if desired.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
BC Hydro and Power Authority	Adrian Andreoiu	1	WECC	BC Hydro	Hootan Jarollahi	BC Hydro and Power Authority	3	WECC
					Helen Hamilton Harding	BC Hydro and Power Authority	5	WECC
					Adrian Andreoiu	BC Hydro and Power Authority	1	WECC
Adrian Harris	Adrian Harris			RTO/ISO Council Standard Review Committee Project 2023-07 TPL-008	Elizabeth Davis	PJM	2	RF
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Adrian Harris	MISO	2	RF
					Helen Lainis	Independent Electricity System Operator	2	NPCC
					Charles Yeung	SPP	2	MRO
Santee Cooper	Chris Wagner	1		Santee Cooper	Chris Wagner	Santee Cooper	1,3,5,6	SERC
					Weijian Cong	Santee Cooper	1,3,5,6	SERC
					Rene' Free	Santee Cooper	1,3,5,6	SERC
Southern Company - Southern Company Services, Inc.	Colby Galloway	1,3,5,6	MRO,RF,SERC,Texas RE,WECC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC

					Leslie Burke	Southern Company - Southern Company Generation	5	SERC
Eversource Energy	Joshua London	1		Eversource	Joshua London	Eversource Energy	1	NPCC
					Vicki O'Leary	Eversource Energy	3	NPCC
Public Utility District No. 1 of Chelan County	Joyce Gundry	3		CHPD	Rebecca Zahler	Public Utility District No. 1 of Chelan County	5	WECC
					Tamarra Hardie	Public Utility District No. 1 of Chelan County	6	WECC
					Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC
					Diane Landry	Public Utility District No. 1 of Chelan County	1	WECC
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	RF
Northern California Power Agency	Michael Whitney	3		NCPA	Scott Tomashefsky	Northern California Power Agency	4	WECC
					Marty Hostler	Northern California Power Agency	5,6	WECC

					Marty Hostler	Northern California Power Agency	5,6	WECC
Black Hills Corporation	Rachel Schuldt	6		Black Hills Corporation - All Segments	Micah Runner	Black Hills Corporation	1	WECC
					Josh Combs	Black Hills Corporation	3	WECC
					Rachel Schuldt	Black Hills Corporation	6	WECC
					Carly Miller	Black Hills Corporation	5	WECC
					Sheila Suurmeier	Black Hills Corporation	5	WECC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
					Randy Buswell	Vermont Electric Power Company	1	NPCC
					James Grant	NYISO	2	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					David Burke	Orange and Rockland	3	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC

					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
					David Kwan	Ontario Power Generation	4	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
					Sean Cavote	PSEG	4	NPCC
					Jason Chandler	Con Edison	5	NPCC
					Tracy MacNicoll	Utility Services	5	NPCC
					Shivaz Chopra	New York Power Authority	6	NPCC
					Vijay Puran	New York State Department of Public Service	6	NPCC
					David Kiguel	Independent	7	NPCC
					Joel Charlebois	AESI	7	NPCC
					Joshua London	Eversource Energy	1	NPCC
					Emma Halilovic	Hydro One Networks, Inc.	1,2	NPCC
					Emma Halilovic	Hydro One Networks, Inc.	1,2	NPCC
					Chantal Mazza	Hydro Quebec	1,2	NPCC
					Emma Halilovic	Hydro One Networks, Inc.	1,2	NPCC
					Chantal Mazza	Hydro Quebec	1,2	NPCC
					Nicolas Turcotte	Hydro-Quebec (HQ)	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC
					Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC
					Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC
					Joel Charlebois	AESI	7	NPCC

Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Connie Lowe	Dominion - Dominion Resources, Inc.	3	NA - Not Applicable
					Lou Oberski	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
					Larry Nash	Dominion - Dominion Virginia Power	1	NA - Not Applicable
					Rachel Snead	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	MRO,SPP RE,WECC	SPP RTO	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Mia Wilson	Southwest Power Pool Inc.	2	MRO
					Josh Phillips	Southwest Power Pool Inc.	2	MRO
					Eddie Watson	Southwest Power Pool Inc.	2	MRO
					Jim William	Southwest Power Pool Inc.	2	MRO
					Jeff McDiarmid	Southwest Power Pool Inc.	2	MRO
					Mason Favazza	Southwest Power Pool Inc.	2	MRO
					Jonathan Hayes	Southwest Power Pool Inc.	2	MRO
					Scott Jordan	Southwest Power Pool Inc.	2	MRO
					Dee Edmondson	Southwest Power Pool Inc.	2	MRO

					Sherri Maxey	Southwest Power Pool Inc.	2	MRO
					Lottie Jones	Southwest Power Pool Inc.	2	MRO
					Nathan Bean	Southwest Power Pool Inc	2	MRO
Stephen Whaite	Stephen Whaite		RF	ReliabilityFirst Ballot Body Member and Proxies	Lindsey Mannion	ReliabilityFirst	10	RF
					Stephen Whaite	ReliabilityFirst	10	RF
					Tyler Schwendiman	ReliabilityFirst	10	RF
					Greg Sorenson	ReliabilityFirst	10	RF
Western Electricity Coordinating Council	Steven Rueckert	10		WECC	Steve Rueckert	WECC	10	WECC
					Curtis Crews	WECC	10	WECC
Tim Kelley	Tim Kelley		WECC	SMUD and BANC	Nicole Looney	Sacramento Municipal Utility District	3	WECC
					Charles Norton	Sacramento Municipal Utility District	6	WECC
					Wei Shao	Sacramento Municipal Utility District	1	WECC
					Foung Mua	Sacramento Municipal Utility District	4	WECC
					Nicole Goi	Sacramento Municipal Utility District	5	WECC
					Kevin Smith	Balancing Authority of Northern California	1	WECC
Associated Electric Cooperative, Inc.	Todd Bennett	3		AECI	Michael Bax	Central Electric Power Cooperative (Missouri)	1	SERC
					Adam Weber	Central Electric Power Cooperative (Missouri)	3	SERC

					Gary Dollins	M and A Electric Power Cooperative	3	SERC
					William Price	M and A Electric Power Cooperative	1	SERC
					Olivia Olson	Sho-Me Power Electric Cooperative	1	SERC
					Mark Ramsey	N.W. Electric Power Cooperative, Inc.	1	SERC
					Heath Henry	NW Electric Power Cooperative, Inc.	3	SERC
					Tony Gott	KAMO Electric Cooperative	3	SERC
					Micah Breedlove	KAMO Electric Cooperative	1	SERC
					Brett Douglas	Northeast Missouri Electric Power Cooperative	1	SERC
					Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	3	SERC
					Mark Riley	Associated Electric Cooperative, Inc.	1	SERC
					Brian Ackermann	Associated Electric Cooperative, Inc.	6	SERC
					Chuck Booth	Associated Electric Cooperative, Inc.	5	SERC
					Jarrod Murdaugh	Sho-Me Power Electric Cooperative	3	SERC

1. Do you agree with the proposed definition of Extreme Temperature Assessment? If you do not agree, please provide your recommendation and, if appropriate, technical justification.

Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD

Answer	No
Document Name	
Comment	

The definition appears to be in the same line as Extreme Cold Weather Temperature (ECWT) which is assessing extreme temperatures based on historic data. Extreme Temperature Assessment sounds like it similarly assesses extreme temperature, but it is an assessment of transmission system performance during extreme temperatures. Perhaps Extreme Temperature Transmission Assessment (ETTA) would be a better title?

Another point of possible clarification is what is the expected de-minimis scope of this assessment? For example, TPL-008 requires voltage and stability criteria be documented, but it’s not clear if this is required to be part of the assessment or may 'live outside' the assessment. Similar for CAPs, are CAPS required to be in the assessment, or may they “live outside” the assessment?

Likes 1	Lakeland Electric, 1, Watt Larry
Dislikes 0	
Response	

Robert Follini - Avista - Avista Corporation - 3

Answer	No
Document Name	
Comment	

Extreme temperature needs to be defined.

Likes 0	
Dislikes 0	
Response	

Ben Hammer - Western Area Power Administration - 1

Answer	No
Document Name	
Comment	

More information regarding “benchmark events” is requested prior to approving the definition.

Likes 0	
Dislikes 0	

Response

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF

Answer	No
Document Name	

Comment

Consumers Energy agrees with CHPD comment:

The definition appears to be in the same line as Extreme Cold Weather Temperature (ECWT) which is assessing extreme temperatures based on historic data. Extreme Temperature Assessment sounds like it similarly assesses extreme temperature, but it is an assessment of transmission system performance during extreme temperatures. Perhaps Extreme Temperature Transmission Assessment (ETTA) would be a better title?

Likes 0	
Dislikes 0	

Response

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	

Comment

CEHE has identified a few issues related to the ERO library. First, there is little clarity in the standard that details exactly what the library will contain, how it will get populated, or which forms of data will be kept. Second, there is no requirement that authorizes the upkeep and ongoing maintenance of said library. Third, using one extreme heat benchmark, and one extreme cold benchmark, as approved by the ERO, ignores local extreme temperature events, and may exclude entities who may experience micro weather events. Extreme Temperature Assessments should include regional and significant local events. It is not clear who in the ERO approves and maintains a library of benchmarked events, or how this process is done for transparency. It is difficult to support or offer suggested edits to the proposed language if the ERO has not provided the library and defined “Extreme Temperature Assessment” criteria or defined benchmark event criteria. CEHE would like clarification on the benchmark events, and further clarification on criteria to determine this responsibility. The approved library of benchmark events is currently not available to the Transmission Planners (TPs), therefore, CEHE cannot support any of the proposed requirements as written.

Likes 0	
Dislikes 0	

Response

Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	No
Document Name	
Comment	
Southern Indiana Gas & Electric Company d/b/a CenterPoint Energy Indiana South (SIGE) does not support the current definition for Extreme Temperature Assessment without a better understanding of the 'benchmark events' and 'benchmark library'. SIGE is unable to fully evaluate the definition at this time. During the recent Project 2023-07 Industry Webinar, the Drafting Team stated examples should be available by the July posting (Draft 2). After reviewing the examples, SIGE will provide more definitive feedback.	
Likes 0	
Dislikes 0	
Response	
Apollonia Gonzales - PNM Resources - 1,3 - WECC,Texas RE	
Answer	No
Document Name	
Comment	
PNMR agrees with EEI's comments in not supporting the proposed definition.	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	No
Document Name	
Comment	
For this initial ballot, it is difficult to fully agree with the proposed definition without knowing what "benchmark events" are.	
Likes 0	
Dislikes 0	

Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	No
Document Name	
Comment	
Too general. What is included in the assessment? Steady State? Transient Stability?	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
MPC supports comments submitted by the MRO NERC Standards Review Forum (NSRF).	
Likes 0	
Dislikes 0	
Response	

Stephen Whaite - Stephen Whaite On Behalf of: Tyler Schwendiman, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
Answer	No
Document Name	
Comment	
RF is concerned that "extreme heat and extreme cold temperature" is left undefined. RF recommends the definition include defined thresholds that can be easily measured.	
Likes 0	
Dislikes 0	
Response	
Michele Tondalo - United Illuminating Co. - 1	
Answer	No
Document Name	
Comment	
There is an inconsistency between the proposed definition of an "Extreme Temperature Assessment" and the existing definition of a "Planning Assessment"; specifically, the Planning Assessment definition includes indication of Corrective Action Plans to remedy identified deficiencies.	
Likes 0	
Dislikes 0	
Response	
Michele Shafer - New York State Electric & Gas (NYSEG) - 6	
Answer	No
Document Name	
Comment	
There is an inconsistency between the proposed definition of an "Extreme Temperature Assessment" and the existing definition of a "Planning Assessment"; specifically, the Planning Assessment definition includes indication of Corrective Action Plans to remedy identified deficiencies.	
Likes 0	
Dislikes 0	
Response	

Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	No
Document Name	
Comment	
The following recommended wording addition attempts to incorporate references to the approximation that is typically part of an assessment and type of analysis the assessment is based on. "Documented evaluation or estimation of future Transmission System performance for specified contingencies and electric scenarios applicable to extreme heat and extreme cold temperature benchmark events."	
Likes 0	
Dislikes 0	
Response	

Brittany Millard - Lincoln Electric System - 5	
Answer	No
Document Name	
Comment	
LES supports comments submitted by the MRO NERC Standards Review Forum (NSRF).	
Likes 0	
Dislikes 0	
Response	

Katrina Lyons - Georgia System Operations Corporation - 4	
Answer	No
Document Name	
Comment	
GSOC supports Georgia Transmission Corporation's comments: The following recommended wording addition attempts to incorporate references to the approximation that is typically part of an assessment and type of analysis the assessment is based on. "Documented evaluation or estimation of future Transmission System performance for specified contingencies and electric scenarios applicable to extreme heat and extreme cold temperature benchmark events."	

Likes 0	
Dislikes 0	

Response

Carver Powers - Utility Services, Inc. - 4

Answer	No
Document Name	

Comment

Do not agree that you can evaluate future performance. Suggested edit is “documentation of expected performance during future Transmission System extreme heat and extreme cold temperature benchmark events.”

Likes 0	
Dislikes 0	

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer	No
Document Name	

Comment

AECI supports comment provided by Georgia Transmission Corporation

Likes 0	
Dislikes 0	

Response

Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen

Answer	No
Document Name	

Comment

While the definition seems appropriate, ISO-NE reserves its determination until a complete list of the “benchmark events” is made available.

Likes 0	

Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren suggests removing the word "documented" from the definition.	
Likes 0	
Dislikes 0	
Response	
Colby Galloway - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Southern Company seeks clarification to benchmark events.	
Likes 0	
Dislikes 0	
Response	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	No
Document Name	
Comment	
Although the wording is fine, the definition is inconsistent with “extreme weather,” there is no definition of extreme weather – rather, the proposed standard alludes to benchmark events. Since such extreme weather events could vary geographically, it is recommended that the drafting team add in language ensuring that regional variances be recognized. Adding this would resolve the discrepancy in using the term “extreme weather”. Except if there is a possibility of extending TPL-008 to other weather/natural emergencies, NERC TPL-008 documents should clarify that the standard is to only address temperature extremes.	

Likes 0	
Dislikes 0	

Response

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3

Answer	No
Document Name	

Comment

NIPSCO is unable to support the current definition without more information that provides a better understanding of “benchmark events” and “benchmark library”. NIPSCO further agrees that clarity would be brought to the current definition if it included defined and measurable thresholds for “extreme heat and extreme cold temperature”, and that adding transmission to the title would also bring clarity since it is an assessment of transmission system performance during extreme temperatures.

Likes 0	
Dislikes 0	

Response

Amy Wilke - American Transmission Company, LLC - 1

Answer	No
Document Name	

Comment

ATC generally supports the MRO NSRF comments.

Likes 0	
Dislikes 0	

Response

Wayne Guttormson - SaskPower - 1

Answer	No
Document Name	

Comment

Support the MRO NSRF comments.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO

Answer	No
Document Name	

Comment

SPP has concerns that the term “extreme” does not truly define the expectations of the assessment. For example, there could be a 100-degree day with no major events. However, there could be a week where the temperature was 90 degrees, and you have an extreme event happen during that timeframe. The initial assumption would be that the term “extreme” aligns better with the 100-dgree scenario; however, the actual event took place in the 90-degree temperature range.

Furthermore, there is a concern that a forced generator outage could be impacted by other factors besides temperature. At this point, the question would be are those other factors considered criteria that support the expectation of the term “extreme event”?

SPP recommends that the drafting team provide clarity on the expectation on the term “extreme event”. Also, we recommend the drafting team consider developing some type of checklist to help them structure criteria to define an “extreme event. “

Likes 0	
Dislikes 0	

Response

Adrian Harris - Adrian Harris On Behalf of: Bobbi Welch, Midcontinent ISO, Inc., 2; - Adrian Harris, Group Name RTO/ISO Council Standard Review Committee Project 2023-07 TPL-008

Answer	No
Document Name	

Comment

Q1. Conceptually, the proposed definition for Extreme Temperature Assessment does not presently appear to present any issues; however, the ISO/RTO Council Standards Review Committee (SRC) is unable to fully evaluate the definition without more information regarding the “benchmark events” that will be key to performing Extreme Temperature Assessments.

Our understanding is that NERC intends to post sample benchmark event(s) on or around July 9, 2024. The SRC will be able to provide more definitive feedback once this information is available.

Extreme Temperature Assessment – Documented evaluation of future Transmission System performance for extreme heat and extreme cold temperature benchmark events.

Planning Assessment - Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies.	
Likes 0	
Dislikes 0	
Response	
Catrina Martin - Archer Energy Solutions, LLC - 5	
Answer	No
Document Name	
Comment	

The current definition focuses on temperature, but in other NERC documents the focus is on "extreme weather." Since extreme weather events could be a broader topic (e.g., hurricanes, ice storms, blizzards, wind storms, wildfires), it would be helpful for all NERC documents to be clear that we are only addressing extreme temperature with TPL-008, unless we want to expand the scope of TPL-008 to include other weather disasters. More severe weather events would typically be addressed in the planning horizon by extreme events studied under TPL-001 or in real time with emergency operating plans and restoration plans. As a result, extreme weather events are already addressed by other standards.

The definition also relies on the phrase "extreme heat and extreme cold temperature benchmark events," which are not defined. TPL-007, which is similar to TPL-008, includes Attachment 1 which defines the benchmark GMD event. We recommend that a similar Attachment that describes benchmark events or definition for Extreme Heat Benchmark Event and Extreme Cold Temperature Benchmark Event be developed. A lack of clarity on this issue will make it very difficult to get any consistency on a regional or nationwide basis.

Some utilities already study 1-in-10 year load forecasts which include temperature-adjusted loads. In some ways that is a 1-in-10 year heat storm for summer peaking areas or 1-in-10 year cold snap for winter peaking areas. Of course, that is backward looking, so we might need to include some sort of adjustment for climate change going forward. All of these issues could be addressed in a benchmark event attachment for TPL-008.

Likes 0	
Dislikes 0	
Response	
Srikanth Chennupati - Entergy - Entergy Services, Inc. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	

Entergy questions whether this definition is necessary.

Likes 0	
Dislikes 0	

Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation agrees with EEI and supports the proposed definition for Extreme Temperature Assessment.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy has no concerns with the proposed term.	
Likes 0	
Dislikes 0	
Response	
Lenise Kimes - City and County of San Francisco - 1,5 - WECC	
Answer	Yes
Document Name	
Comment	
While the definition itself is acceptable, there is some conflict with the term “extreme weather” which is in the name of the program itself. Since extreme weather could be a broader topic (e.g., hurricanes, ice storms, blizzards), it would be helpful for all NERC documents to be clear that we are only addressing extreme temperature with TPL-008, unless we want to expand the scope of TPL-008 to include other weather disasters. More severe events would typically be addressed with emergency operating plans.	
Likes 1	Lakeland Electric, 1, Watt Larry
Dislikes 0	

Response	
Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the proposed definition for Extreme Temperature Assessment.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Rebika Yitna - Rebika Yitna On Behalf of: David Weekley, MEAG Power, 3, 1; Roger Brand, MEAG Power, 3, 1; - Rebika Yitna	
Answer	Yes
Document Name	
Comment	
Further clarity needed on the NERC developed benchmark events and library.	
Likes 0	
Dislikes 0	
Response	

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
ITC supports the definition of Extreme Temperature Assessment. Did the team consider an Extreme Weather Assessment rather than ETA? ITC also is looking for additional information on the benchmark events.	
Likes 0	
Dislikes 0	
Response	

Robert Jones - Seattle City Light - 1,3,4,6	
Answer	Yes
Document Name	
Comment	
The definition of Extreme Temperature Assessment is vague. Each utility's understanding of the extreme temperature can be different and guidance to define extreme temperature criteria and what to study should be provided in the standard. Perhaps, TPL-001 should cover extreme temperature assessment.	
Likes 0	
Dislikes 0	
Response	

Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	
"See comments submitted by the Edison Electric Institute"	
Likes 0	
Dislikes 0	
Response	

Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon supports the proposed definition for Extreme Temperature Assessment.	
Likes 0	
Dislikes 0	
Response	

Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon supports the proposed definition for Extreme Temperature Assessment.	
Likes 0	
Dislikes 0	
Response	

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
NV Energy supports the proposed definition for Extreme Temperature Assessment.	
Likes 0	
Dislikes 0	
Response	

Kevin Conway - Western Power Pool - 4	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Streifling - NB Power Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lauren Giordano - Lauren Giordano On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; Michael Whitney, Northern California Power Agency, 4, 6, 3, 5; - Lauren Giordano	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Whitney - Northern California Power Agency - 3, Group Name NCPA	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Isidoro Behar - Long Island Power Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Matthew Jaramilla, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Broc Bruton - Broc Bruton On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Broc Bruton	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Chantal Mazza On Behalf of: Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lidija Efremova - Lidija Efremova On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Lidija Efremova	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Junji Yamaguchi - Hydro-Quebec (HQ) - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	
Document Name	

Comment	
Constellation has no comments Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	
Document Name	
Comment	
Constellation has no comments Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Given the range of temperatures across the United States, Texas RE recommends the following revisions to the definition of Extreme Temperature Assessment (in bold): Documented evaluation of future Transmission System performance for extreme heat and extreme cold temperature benchmark events **based on the geographical location**.	
Likes 0	
Dislikes 0	
Response	

2. Do you agree with the proposed TPL-008-1 Reliability Standard Requirement R1? If you do not agree, please provide your recommendation and, if appropriate, technical justification.

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	
NIPSCO supports the comments provided by BPA, CMS Energy, CHPD, and TVA.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren believes it should be clearer who is responsible for performing the Extreme Temperature Assessment. R1 should determine specific roles for both the PC and TP.	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	No
Document Name	
Comment	
AECI supports comment provided by Georgia Transmission Corporation	
Likes 0	
Dislikes 0	
Response	

Katrina Lyons - Georgia System Operations Corporation - 4	
Answer	No
Document Name	
Comment	
GSOC supports Georgia Transmission Corporation's comments:: The following wording suggestion adds modeling responsibilities to the requirement. “Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall determine and identify each entity’s individual and joint responsibilities for maintaining models and performing the studies needed to complete the Extreme Temperature Assessment.”	
Likes 0	
Dislikes 0	
Response	
Brittany Millard - Lincoln Electric System - 5	
Answer	No
Document Name	
Comment	
LES supports comments submitted by the MRO NERC Standards Review Forum (NSRF).	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	No
Document Name	
Comment	
The following wording suggestion adds modeling responsibilities to the requirement. “Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall determine and identify each entity’s individual and joint responsibilities for maintaining models and performing the studies needed to complete the Extreme Temperature Assessment.”	
Likes 0	

Dislikes 0	
Response	
Michele Shafer - New York State Electric & Gas (NYSEG) - 6	
Answer	No
Document Name	
Comment	
The wording used in TPL-008-1 R1 calls out defining responsibilities for "…performing studies…" which is similar to TPL-007; but it is not clear if TPL-008 assumes that each of the subsequent Requirements that state "Each responsible entity, as identified in Requirement R1…" are considered part of study performance, developing the assessment, or a separate preparation activity. Suggest wording in R1 be changed to "…shall determine and identify each entity's individual and joint responsibilities for performing the necessary studies and development of the Extreme Temperature Assessment(s)…"	
Likes 0	
Dislikes 0	
Response	
Michele Tondalo - United Illuminating Co. - 1	
Answer	No
Document Name	
Comment	
The wording used in TPL-008-1 R1 calls out defining responsibilities for "…performing studies…" which is similar to TPL-007; but it is not clear if TPL-008 assumes that each of the subsequent Requirements that state "Each responsible entity, as identified in Requirement R1…" are considered part of study performance, developing the assessment, or a separate preparation activity. Suggest wording in R1 be changed to "…shall determine and identify each entity's individual and joint responsibilities for performing the necessary studies and development of the Extreme Temperature Assessment(s)…"	
Likes 0	
Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	No
Document Name	
Comment	
Need more clarity on definition of Benchmark event (Last 5 years? Last 30 years?	

Likes 0	
Dislikes 0	

Response

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

BPA recommends extreme benchmark events be evaluated for their impact in a larger region than just the TP/PC area. As such, utilities in the region need to assess the impact on the region. BPA recommends the Regional Entities perform these assessments in collaboration with the utilities in the region, this would help ensure utilities are better suited to consider mitigation actions in their system. Footprints of the benchmark events should be defined by the Regional Entity and consider the electrical boundaries. Coordination should be done with the responsible entities (adjacent PCs and TPs) within that footprint, as well as the Regional Entity.

Likes 1	Lakeland Electric, 1, Watt Larry
Dislikes 0	

Response

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	

Comment

Please refer to Question 1 comments.

Likes 0	
Dislikes 0	

Response

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF

Answer	No
Document Name	

Comment

Consumers Energy Agrees with the comments by WPP:

R1 reads as if the Planning Coordinator is solely responsible for compliance to this Requirement. "...in conjunction with its Transmission Planners(s)...implies that the transmission planners are passive participants and are not responsible for compliance. If this was not the intent of the drafting team, then this should more clearly state that the "Planning Coordinators and associated Transmission Planner(s) shall coordinate each entity's individual and joint responsibilities..."	
Likes 0	
Dislikes 0	
Response	
Michael Whitney - Northern California Power Agency - 3, Group Name NCPA	
Answer	No
Document Name	
Comment	
NO, These assessment should be performed by the Regional Entities. There appears to be too much room for coordination issues having one Transmission Planner (TP) or Planning Coordinator (PC) having to rely on other TPs or PCs to meet their requirement deadlines.	
Likes 0	
Dislikes 0	
Response	
Lauren Giordano - Lauren Giordano On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; Michael Whitney, Northern California Power Agency, 4, 6, 3, 5; - Lauren Giordano	
Answer	No
Document Name	
Comment	
NO, These assessment should be performed by the Regional Entities. There appears to be too much room for coordination issues having one Transmission Planner (TP) or Planning Coordinator (PC) having to rely on other TPs or PCs to meet their requirement deadlines.	
Likes 1	Lakeland Electric, 1, Watt Larry
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	No
Document Name	

Comment	
Leads to double jeopardy since this language is included in TPL-001-5.1 and TPL-007-4. No problem if the requirement was only in a single standard.	
Likes 0	
Dislikes 0	
Response	

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
It does not seem appropriate to agree to a requirement that has yet to be fully developed. Based on the technical rationale, there is an expectation that the ERO will determine suitability and make available benchmark events representative of probable futures. Once the initial library of events have been developed, we would be in a better position to consider support for this requirement.	
Likes 0	
Dislikes 0	
Response	

Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	No
Document Name	
Comment	
The term ‘the studies’ is somewhat vague. The studies themselves are expected to be steady state and stability (FERC Order 896 uses ‘transient stability’, as the preferred descriptor to clarify from other types of stability), but the compliance reader does not discover this until R8. The effort may also include the building of cases (R3) based on the R2 benchmark events, but these are not themselves study activities, but rather case-build activities. R1 likely should address performing the study (R8) and case build activities (R2, R3). In conclusion, the term ‘the studies’ is vague, and it turns out possibly misleading. Assigned duties are much greater in scope. An alternate approach could be “Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall determine and identify each entity’s individual and joint responsibilities for performing the steady state and stability studies and activities needed to complete the Extreme Temperature Assessment”. The existing language at the end of the R1, “needed to complete the Extreme Temperature Assessment” finishes the thought adequately (although as noted in the comment #1, the scope of ETA should be clarified).	
Likes 1	Lakeland Electric, 1, Watt Larry

Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	No
Document Name	
Comment	

R1 reads as if the Planning Coordinator is solely responsible for compliance to this Requirement. "...in conjunction with its Transmission Planners(s)...implies that the transmission planners are passive participants and are not responsible for compliance. If this was not the intent of the drafting team, then this should more clearly state that the "Planning Coordinators and associated Transmission Planner(s) shall coordinate each entity's individual and joint responsibilities..."

Alternatively, the Planning Coordinator can simply assign the responsibilities, and a new requirement for Transmission Planners would require them to perform studies as specified by the Planning Coordinator.

Likes 1	Lakeland Electric, 1, Watt Larry
Dislikes 0	
Response	
Apollonia Gonzales - PNM Resources - 1,3 - WECC,Texas RE	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Catrina Martin - Archer Energy Solutions, LLC - 5	
Answer	Yes
Document Name	
Comment	

While the wording on R1 is consistent with TPL-001, there are some concerns about negotiating the workload impacts of additional studies between the PC and TP entities. As additional responsibilities are added for PC and TP entities, this negotiation becomes increasingly difficult. The level of detail and periodicity of TPL-008 studies will further increase the workload on already overstressed entities. The human resources requirements for TPL-008 should be considered when setting the requirements.

Likes 0	
Dislikes 0	

Response

Adrian Harris - Adrian Harris On Behalf of: Bobbi Welch, Midcontinent ISO, Inc., 2; - Adrian Harris, Group Name RTO/ISO Council Standard Review Committee Project 2023-07 TPL-008

Answer	Yes
Document Name	

Comment

The SRC supports modeling proposed TPL-008, requirement R1 after TPL-001-5.1, requirement R7 and TPL-007, requirement R1.

Likes 0	
Dislikes 0	

Response

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	Yes
Document Name	

Comment

NV Energy does not have any objections to the proposed language for Requirement R1.

Likes 0	
Dislikes 0	

Response

Wayne Guttormson - SaskPower - 1

Answer	Yes
Document Name	

Comment

Support the MRO NSRF comments.

Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon does not have any objections to the proposed language for Requirement R1.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon does not have any objections to the proposed language for Requirement R1.	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	
“See comments submitted by the Edison Electric Institute”	
Likes 0	
Dislikes 0	

Response

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	Yes
Document Name	

Comment

ITC supports modeling proposed TPL-008, requirement R1 after TPL-001-5.1, requirement R7 and TPL-007, requirement R1.

Likes 0	
Dislikes 0	

Response

Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle

Answer	Yes
Document Name	

Comment

The proposed TPL-008-1 Reliability Standard Requirement R1 seems to be an extension of TPL-001-5, however, it will require for each responsible entities to ramp up the workforce to conduct these studies, analyze the events and develop CAPs. Hence, human resources need is a crucial element to consider while creating requirements for TPL-008.

Likes 0	
Dislikes 0	

Response

Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen

Answer	Yes
Document Name	

Comment

No Additional Comments

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	

Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI does not have any objections to the proposed language for Requirement R1.	
Likes 0	
Dislikes 0	
Response	

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	Yes
Document Name	
Comment	
MPC supports comments submitted by the MRO NERC Standards Review Forum (NSRF).	
Likes 0	
Dislikes 0	
Response	

Lenise Kimes - City and County of San Francisco - 1,5 - WECC	
Answer	Yes
Document Name	
Comment	
While the wording on R1 is consistent with TPL-001, there are some concerns about negotiating the workload impacts of additional studies between the PC and TP entities. As additional responsibilities are added for PC and TP entities, this negotiation becomes increasingly difficult. The level of detail and periodicity of TPL-008 studies will further increase the workload on already overstressed entities. The human resources requirements for TPL-008 should be considered when setting the requirements.	
Likes 0	
Dislikes 0	
Response	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
No additional comment.	
Likes 0	
Dislikes 0	
Response	

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation agrees with EEI and does not have any objections to the proposed language for Requirement R1.	
Likes 0	
Dislikes 0	
Response	

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Jones - Seattle City Light - 1,3,4,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rebika Yitna - Rebika Yitna On Behalf of: David Weekley, MEAG Power, 3, 1; Roger Brand, MEAG Power, 3, 1; - Rebika Yitna	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Galloway - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Junji Yamaguchi - Hydro-Quebec (HQ) - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lidija Efremova - Lidija Efremova On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Lidija Efremova	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Chantal Mazza On Behalf of: Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Stephen Whaite - Stephen Whaite On Behalf of: Tyler Schwendiman, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Broc Bruton - Broc Bruton On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Broc Bruton	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Matthew Jaramilla, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Isidoro Behar - Long Island Power Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Streifling - NB Power Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Srikanth Chennupati - Entergy - Entergy Services, Inc. - 1,3,5,6 - SERC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE recommends the PC and TP have a formal agreement defining each individual and joint responsibilities for their respective areas. Texas RE suggests the following additional language (in bold):

R1. Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall determine and identify each entity's individual and joint responsibilities for performing the studies needed to complete the Extreme Temperature Assessment **within its respective area**.

Regarding Measure M1, Texas RE posits that while meeting minutes may help support compliance for Requirement R1, meeting minutes alone would not constitute proper evidence of compliance with Requirement R1. Texas RE recommends removing meeting minutes from Measure M1.

Likes 0	
Dislikes 0	
Response	

Alison MacKellar - Constellation - 5

Answer	
Document Name	

Comment

Constellation has no comments

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	

Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	
Document Name	
Comment	
Constellation has no comments Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

3. Do you agree with the proposed TPL-008-1 Reliability Standard Requirement R2 (Benchmark events)? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Kevin Conway - Western Power Pool - 4	
Answer	No
Document Name	
Comment	

As R1 currently reads, only the Planning Coordinator is responsible for compliance.

Assuming that the Drafting Team would like to hold the Transmission Planner(s) accountable, this should be specifically called out.

The ERO library creates consternation for utilities. There is little clarity in the standard that details exactly what the library will contain, how it will get populated, or which forms of data will be kept. There is no requirement that authorizes the upkeep and ongoing maintenance of said library.

Using one extreme heat benchmark, and one extreme cold benchmark, as approved by the ERO, ignores local extreme temperature events and may exclude entities who are geographic regions who may experience micro weather climates. Extreme Temperature Assessments should include regional and significant local events. It is not clear who in the ERO approves and maintains a library of benchmarked events, or how this process is done for transparency.

Likes 0	
Dislikes 0	
Response	

Srikanth Chennupati - Entergy - Entergy Services, Inc. - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	

Entergy believes R2 seems to bypass the idea that standards requirements go through the usual process of development and approval. It lets NERC arbitrarily change the benchmark events library. With the scale of the work required in this standard, it seems similar to having TPL-001-5 Table 1 be a document on NERC's website that they can change at will. I would far prefer to see the standard require that the event library be developed/maintained by (at least) the PCs and regions in collaboration with NERC rather than have it something entirely under NERC's control.

Likes 1	Lakeland Electric, 1, Watt Larry
Dislikes 0	
Response	

Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No

Document Name	
Comment	
It is not clear what data the ERO will be using and who will be approving/maintaining the library. Is there a process in place for how this will be accomplished?	
Likes 1	Lakeland Electric, 1, Watt Larry
Dislikes 0	
Response	
Jeffrey Streifling - NB Power Corporation - 1	
Answer	No
Document Name	
Comment	
Should there be any requirements for developing and maintaining benchmark libraries (in co-operation with EROs), or if that is mandated through another means?	
Likes 0	
Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	No
Document Name	
Comment	
There is a possible gap as it doesn't appear the ERO is required to maintain a benchmark library, or requirements to determine what this process should look like. We do not see a mechanism to compel the ERO to sufficiently develop and maintain this benchmark library in an ongoing manner. This may be a better activity suited for regional entities (RE) with input from Reliability Coordinators (RCs), and regional stakeholders to ensure useful and meaningful scenarios at a more local level. An alternate approach could be to allow the PC to either select an ERO event or select one of their own choosing, with a provided technical rationale. Our concern is the ERO process is very high level, and to get the required level of attention for appropriate events will likely not produce meaningful events for each region.	
Likes 1	Lakeland Electric, 1, Watt Larry
Dislikes 0	
Response	

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

While AEP agrees with the substance of R2, we would like to recommend that the phrase “or more” be added to the requirement so that it instead states “shall select one *or more* extreme heat benchmark event(s) and one *or more* extreme cold benchmark event(s).”

Regarding the phrase “each responsible entity”, our understanding is that only one entity will be responsible for selecting the benchmark. The SDT may wish to consider instead using the phrase “the responsible entity established in R1.”

Likes 0	
Dislikes 0	
Response	

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	

While we might agree with the overall intent to develop a process to coordinate development of a benchmark planning case, implementation is not clear how individual entities (i.e., “smaller individual planning areas” per the Technical Rationale document) will be able to and responsible for coordinating scenarios with other impacted parties, such as those outside planning boundaries and when including items such as interchange / transfers. Additionally, it is not clear what the expectation might be for, and therefore the capability of, modifying cases to include temperature adjustments (if excessively extreme).

Likes 0	
Dislikes 0	
Response	

Lauren Giordano - Lauren Giordano On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; Michael Whitney, Northern California Power Agency, 4, 6, 3, 5; - Lauren Giordano	
Answer	No
Document Name	
Comment	

NO, These assessment should be performed by the Regional Entities. There appears to be too much room for coordination issues having one Transmission Planner (TP) or Planning Coordinator (PC) having to rely on other TPs or PCs to meet their requirement deadlines.

Likes 0	
Dislikes 0	

Response

Michael Whitney - Northern California Power Agency - 3, Group Name NCPA

Answer	No
Document Name	

Comment

NO, These assessment should be performed by the Regional Entities. There appears to be too much room for coordination issues having one Transmission Planner (TP) or Planning Coordinator (PC) having to rely on other TPs or PCs to meet their requirement deadlines.

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments

Answer	No
Document Name	

Comment

Black Hills Corporation agrees with EEI's proposed changes for Requirement R2; requiring the extreme weather events as an attachment to the standard gives entities visibility into a key part of the new standard and allows for industry review and input.

EEI is concerned that proposed Reliability Standard, TPL-008-1, is being moved forward for industry approval without any insights into a key element of this Reliability Standard which is the extreme temperature benchmark event library. EEI additionally does not support making this library a separate document outside of this Reliability Standard. It should be included in the Reliability Standard for industry review or input. This library should be an attachment within this Reliability Standard, and we offer the following proposed changes to Requirement R2 to address this concern in boldface below:

R2. Each responsible entity, as identified in Requirement R1, shall select one extreme heat benchmark event and one extreme cold benchmark event, from the **Attachment X (*remove:* approved ERO)** (Extreme Temperature Benchmark Library) for performing the Extreme Temperature Assessment. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

Likes 0	
Dislikes 0	

Response

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
Even though Manitoba Hydro supports R2, we are withholding formal support until we can see and evaluate some examples of what the ERO intends to include as benchmark events in the library.	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	No
Document Name	
Comment	
Define extreme temperature probability rather than using a historical benchmark.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
With lack of intent of what will encompass the benchmark library, FirstEnergy cannot support R2. For R2, FirstEnergy asks the Drafting Team to determine if the TP would replace “Each responsible entity” for the TB to have sole responsibility for selecting the benchmark events.	
Likes 0	
Dislikes 0	
Response	

Ben Hammer - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
More information on what the ERO intends to include as “benchmark events” is requested prior to approving R2.	
Likes 0	
Dislikes 0	
Response	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	No
Document Name	
Comment	
The draft TPL-008-1 R2 implies an expectation that the ERO will maintain a library of extreme heat and extreme cold events from which responsible entities will select events. MRO is concerned about potential conflicts if the responsible entities are dependent on ERO in order to be compliant. Consider modifying R2 by providing an alternative means for entities to comply in a way that is not dependent on the ERO’s maintenance of a library of events.	
Likes 0	
Dislikes 0	
Response	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	No
Document Name	
Comment	
Consumers Energy agrees with the comments by WPP: The ERO library creates consternation for utilities. There is little clarity in the standard that details exactly what the library will contain, how it will get populated, or which forms of data will be kept. There is no requirement that authorizes the upkeep and ongoing maintenance of said library. Using one extreme heat benchmark, and one extreme cold benchmark, as approved by the ERO, ignores local extreme temperature events and may exclude entities who are geographic regions who may experience micro weather climates. Extreme Temperature Assessments should include regional	

and significant local events. It is not clear who in the ERO approves and maintains a library of benchmarked events, or how this process is done for transparency

Likes 0	
Dislikes 0	

Response

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro

Answer	No
Document Name	

Comment

BC Hydro appreciates the drafting team efforts and the opportunity to comment.

Requirement R2 indicates that the ERO maintains the "benchmark library" and that this library will need to be approved. The TPL-008-1 Technical Rationale clarifies that the drafting team is not in a position to provide a statistical basis or determine appropriateness of any specific event and assigns this responsibility to the ERO.

BC Hydro suggests that it would be appropriate that the ERO develop a process to assess events suitability, which should include criteria for benchmark event selection. It is also suggested that industry input in the maintenance of the benchmark event library will be beneficial and recommend that the ERO process accommodate this.

It also seems unclear which information the ERO intends to include for the benchmark events in the library in order to assess the usability in developing adequate study basecases. Geographical area information should be included and additional Standard provisions for regional variances that allow flexibility based on regional weather conditions.

Likes 1	Lakeland Electric, 1, Watt Larry
Dislikes 0	

Response

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	

Comment

Please refer to Question 1 comments.

Likes 0	
Dislikes 0	

Response

Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	No
Document Name	
Comment	

Southern Indiana Gas & Electric Company d/b/a CenterPoint Energy Indiana South (SIGE) is unable to fully evaluate Requirement R2 without additional information about the benchmark event library.

SIGE supports CenterPoint Energy Houston Electric, LLC (CEHE) comment that there is little clarity in the standard that details exactly what the library will contain, how it will get populated, or which forms of data will be kept. There is no requirement that authorizes the upkeep and ongoing maintenance of said library. Additionally, it is not clear who in the ERO approves and maintains a library of benchmarked events, or how this process is done for transparency.

For consideration in developing the benchmark library, SIGE recommends that Planning Coordinators be allowed to submit, extreme heat and cold events that are impactful to the reliability of the system based on their historical weather events and statistical analysis for inclusion in the library.

Likes 0	
Dislikes 0	
Response	
Apollonia Gonzales - PNM Resources - 1,3 - WECC,Texas RE	
Answer	No
Document Name	
Comment	

Each responsible entity, as identified in Requirement R1, shall select one extreme heat benchmark event and one extreme cold benchmark event, from the approved benchmark library that most closely aligns with temperature extremes from past historical events within their region maintained, for performing the Extreme Temperature Assessment. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

BPA recommends that the benchmark events be developed and maintained by the Regional Entities (MRO, NPCC, RF, SECR, Texas RE, and WECC) as opposed to NERC so that there are applicable events for the region.	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	No
Document Name	
Comment	
Aligning with our comment in Question 1 on the definition of Extreme Temperature Assessment, it is difficult to fully agree with Requirement R2 without knowing what a “benchmark event” is. The benchmark library needs a methodology that the ERO Enterprise will use as a consistent foundation for creating the benchmark events.	
Likes 0	
Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	No
Document Name	
Comment	
Put emphasis on Regional, not ERO. Not required for ERO to maintain this library. Such libraries are better maintained at a Regional level. For smaller utilities, not sure how they are using the same criteria for Extrement Temperature Assessment.	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	No

Document Name	
Comment	
There is not a clear mechanism for the ERO (or the regional entities if delegated) to maintain a library with such information. Also, the size of the library could be significant as there are 70+ PCs and 200+TPs across the ERO Enterprise. It may be best if NERC undertook the library, but it may be the PC owning the library for its TPs would be betteer?? Security of such a system would need to be considered as well.	
Likes 0	
Dislikes 0	
Response	
Lenise Kimes - City and County of San Francisco - 1,5 - WECC	
Answer	No
Document Name	
Comment	
Without specifically stating it, the current wording of this requirement puts the responsibility for determining the library of events in the hands of the ERO and does not explicitly provide the ability for the PC or TP entities to be involved at any point in the development of this library. If the ERO develops a library of events that are too extreme, this could significantly impact cost of the transmission investment of the PC and TP entities and ultimately the customers within the PC and TP footprints. If the events are not extreme enough or turn out to be overly severe in one local area or region and not severe enough in another due to a lack of engagement from regional and local experts, this could also cause distortions in appropriate planning. Because the PC and TP entities know their systems (and likely the local climate and weather patterns) better than the ERO, shouldn't those entities be at least involved in determining the library of events from which they must select? We suggest that the requirement be reworded to provide the ability for PCs and TPs to have some control and input for the conditions that are studied for their systems, or even to require the ERO to collaborate with the PCs and TPs in developing these scenarios, with the ERO having the final decision after considering feedback and comments. There should also be some guidance provided as to how severe the benchmark cases should be. For example, California's history of severe weather is very limited and infrequent due to the tempering effects of the Pacific Ocean, whereas the Midwest (and Texas) is more prone to severe swings in weather and extreme conditions. Some climate change forecasts predict that this situation may change, but which forecast, if any, should be considered when preparing the benchmark cases should be at least up for discussion.	
Likes 1	Lakeland Electric, 1, Watt Larry
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Matthew Jaramilla, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	No
Document Name	

Comment	
SRP agrees and supports JEA's comment that the "approved benchmark library maintained by the Electric Reliability Organization" creates consternation for utilities due to its ambiguity. We support the idea of The ERO maintaining a library, but there needs to be clarity or some kind of vetting process with the participation from the industry on the approval process. In addition, SRP strongly recommends separating the extreme heat and extreme cold scenarios in Requirement R2 to allow entities to perform them separately, but still both to be done every 5 years.	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Broc Bruton - Broc Bruton On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Broc Bruton	
Answer	No
Document Name	
Comment	
Oncor would like to ensure transparency in how the benchmark events are developed, chosen, calculated, and maintained. We agree with Entergy's comments in that we would like to see the PCs maintain the benchmark event data for the applicable region rather than the data and library being entirely at one location under NERC control. This approach would likely make the data more transparent and accessible to the affected utilities than having a sole central repository at NERC for all regions of the country.	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No

Document Name	
Comment	
Dominion Energy supports EEI comments. In addition, the benchmark cases are not well defined, still being developed, and unclear how they apply to our Planning Region. This proposed standard is premature and should be delayed until the repository is developed and criteria more clearly established.	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
MPC supports comments submitted by the MRO NERC Standards Review Forum (NSRF).	
Likes 1	Lakeland Electric, 1, Watt Larry
Dislikes 0	
Response	
Stephen Whaite - Stephen Whaite On Behalf of: Tyler Schwendiman, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
Answer	No
Document Name	
Comment	
RF is concerned that the proposed requirement does not provide any specifications for quantifiable metrics to be used by the PC in identifying appropriate benchmark events for its region. As written, this requirement may not ensure selected benchmark events for each region will be comparable in severity and may open the possibility that a PC could select an event that it believes will cause less of an issue in its footprint for ease of study. PCs in the northern US should choose events to study and establish requirements for Transmission system planning performance for extreme heat and extreme cold temperature events based upon their geographic location. PC in the southern US should do the same.	
Likes 0	
Dislikes 0	
Response	

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 3	
Likes 0	
Dislikes 0	
Response	
Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI is concerned that proposed Reliability Standard, TPL-008-1, is being moved forward for industry approval without any insights into a key element of this Reliability Standard which is the extreme temperature benchmark event library. EEI additionally does not support making this library a separate document outside of this Reliability Standard. It should be included in the Reliability Standard for industry review or input. This library should be an attachment within this Reliability Standard and we offer the following proposed changes to Requirement R2 to address this concern in boldface below: **R2.** Each responsible entity, as identified in Requirement R1, shall select one extreme heat benchmark event and one extreme cold benchmark event, from the **Attachment X** (Extreme Temperature Benchmark Library) for performing the Extreme Temperature Assessment. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
The standard is not clear on the criteria in which the responsible entity can use to select the extreme benchmark events from the benchmark library maintained by the ERO. There is little information on the events library at this point or how these events are defined and approved.	

Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
LG&E and KU agrees with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Chantal Mazza On Behalf of: Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	No
Document Name	
Comment	
• Should there be any requirements for developing and maintaining benchmark libraries (in co-operation with EROs), or if that is mandated through another means? • “Responsible entity” should be defined in the Applicability section or should replaced with “Each Planning Coordinator, in conjunction with its Transmission Planner(s)...”Suggest to replace 4.1 to “Responsible Entity” instead of “Functional Entity”.	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
EEI is concerned that proposed Reliability Standard, TPL-008-1, is being moved forward for industry approval without any insights into a key element of this Reliability Standard which is the extreme temperature benchmark event library. EEI additionally does not support making this library a separate	

document outside of this Reliability Standard. It should be included in the Reliability Standard for industry review or input. This library should be an attachment within this Reliability Standard and we offer the following proposed changes to Requirement R2 to address this concern

in boldface below:

R2. Each responsible entity, as identified in Requirement R1, shall select one extreme heat benchmark event and one extreme cold benchmark event, from the **Attachment** (Extreme Temperature Benchmark Library) for performing the Extreme Temperature Assessment. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	No
Document Name	
Comment	

It is understood the ERO is tasked with developing and maintaining a benchmark events library for use by the responsible entity in the required assessment. It is not clear what the events will ultimately be and how the benchmark events library is to be maintained and updated. The SDT should define and clarify the process for maintaining the benchmark library. GTC also recommends that the PC & TP be involved in the development and/or approval of the benchmark events.

Likes 0	
Dislikes 0	
Response	
Brittany Millard - Lincoln Electric System - 5	
Answer	No
Document Name	
Comment	

LES supports comments submitted by the MRO NERC Standards Review Forum (NSRF).

Likes 0	
Dislikes 0	
Response	

Katrina Lyons - Georgia System Operations Corporation - 4	
Answer	No
Document Name	
Comment	
GSOC supports Georgia Transmission Corporation's comments: It is understood the ERO is tasked with developing and maintaining a benchmark events library for use by the responsible entity in the required assessment. It is not clear what the events will ultimately be and how the benchmark events library is to be maintained and updated.	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	No
Document Name	
Comment	
It is challenging to agree with the proposal due to the vagueness of the requirement. Request an example of the approved benchmark library in order to assess how requirements R3-R8 will be completed.	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
We support EEI's comments.	
Likes 0	
Dislikes 0	
Response	

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer	No
Document Name	

Comment

AECI supports comment provided by Georgia Transmission Corporation

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	No
Document Name	

Comment

Duke Energy does not support suggested R2 language. This requirement requires additional information such as the source of weather data, who will create cases, how industry input will be incorporated, etc.

Likes 0	
Dislikes 0	

Response

Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen

Answer	No
Document Name	

Comment

ISO will need to see the list of Benchmark Events provided by NERC before making a full determination on the R2 Requirement. Initial view is that R2 is appropriate with the inclusion of responsible entity as this allows flexibility for coordination amongst planning entities.

Likes 0	
Dislikes 0	

Response

David Jendras Sr - Ameren - Ameren Services - 3

Answer	No
Document Name	

Comment

Ameren has concerns about the ERO's Library. What if it is unavailable when we need to perform the study?

Likes 0	
Dislikes 0	

Response

Colby Galloway - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

Southern Company has concerns about not being involved in the development of the benchmark events. NERC should set boundaries and guidelines for the development of extreme weather conditions for analysis, but should not be unilaterally defining the events. It is recommended that "benchmark event" be defined and the approval process be clarified. The SDT should define and clarify the process for maintaining the benchmark library. In the spirit of collaboration and mutual interest in benchmark events, it is recommended that entities be involved in the approval of benchmark events. If NERC is defining benchmark events, then language should also be included to outline how benchmark events are determined and defined, while allowing for entities to adjust benchmark events for their system, similar to R3.2.

Likes 0	
Dislikes 0	

Response

Rebika Yitna - Rebika Yitna On Behalf of: David Weekley, MEAG Power, 3, 1; Roger Brand, MEAG Power, 3, 1; - Rebika Yitna

Answer	No
Document Name	

Comment

It is recommended that entities be involved in the development of the benchmark events library. It is not clear how NERC defines and determines the benchmark events.

Likes 0	
Dislikes 0	

Response

Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	No
Document Name	
Comment	

Without specifically stating it, the current wording of this requirement puts the responsibility for determining the library of events in the hands of the ERO and does not explicitly provide the ability for the PC or TP entities to be involved at any point in the development of this library.

If the ERO develops a library of events that are too extreme, this could significantly impact cost of the transmission investment of the PC and TP entities and ultimately the customers within the PC and TP footprints. If the events are not extreme enough or turn out to be overly severe in one local area or region and not severe enough in another due to a lack of engagement from regional and local experts, this could also cause distortions in appropriate planning.

Because the PC and TP entities know their systems (and likely the local climate and weather patterns) better than the ERO, shouldn't those entities be at least involved in determining the library of events from which they must select? We suggest that the requirement be reworded to provide the ability for PCs and TPs to have some control and input for the conditions that are studied for their systems, or even to require the ERO to collaborate with the PCs and TPs in developing these scenarios, with the ERO having the final decision after considering feedback and comments. There should also be some guidance provided as to how severe the benchmark cases should be. For example, California's history of severe weather is very limited and infrequent due to the tempering effects of the Pacific Ocean, whereas the East coast, Midwest, southwest (and Texas) is more prone to severe swings in weather and extreme conditions. Some climate change forecasts predict that this situation may change, but which forecast, if any, should be considered when preparing the benchmark cases should be at least up for discussion.

Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	

Although ITC conceptually supports requirement R2, we are withholding formal support until we can see and evaluate some examples of what the ERO intends to include as benchmark events in the library.

In addition, we support the "responsible entity as identified in requirement R1" language in R2 as it allows flexibility among planning entities to collectively determine who (e.g., the PC and/or TP) will perform R2.

Likes 0	
Dislikes 0	
Response	

Robert Jones - Seattle City Light - 1,3,4,6	
Answer	No
Document Name	
Comment	
Needs more clarity on the definition of the Extreme Temperature Event. It is unclear how the benchmark events will be chosen. There is no guarantee that there will be an event relevant for every entity. The selection of benchmark events should either be 1) defined as part of the standard and done by more local entities or 2) allow TPs/PCs to define their own benchmark event if they feel none of the ones offered by the ERO are relevant/appropriate.	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	
NIPSCO supports the comments provided by Entergy, ReliabilityFirst, TVA, CHPD, CMS Energy, and MRO.	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	No
Document Name	
Comment	
“See comments submitted by the Edison Electric Institute”	
Likes 0	
Dislikes 0	
Response	

Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	

Exelon believes it is not appropriate to assign the Electric Reliability Organization (ERO) responsibility that directly impacts the compliance to a standard requirement. Interested in seeing more detail about how the benchmark library will be managed. There will need to be outlined guidance on where this data will be stored and who will have access to it. How will the responsible entity work with the Transmission Planner and Planning Coordinator to determine what goes into these cases and what are the expectations for providing feedback into them? Would it be better for Planning Coordinators to collaborate to create these instead?

Likes 0	
Dislikes 0	
Response	

Amy Wilke - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	

ATC generally supports the MRO NSRF comments, and is supplementing them as described below.

More information (and examples) is needed to agree with R2 (including who will develop/ maintain the database and what happens if it is not maintained, or if data is inaccurate, etc). We appreciate the potential value in having a benchmark event library that acts as a consistent database where experts have helped to translate the weather data into useable planning information (if done well). There could be considerable work for responsible entities if the data is not useable or properly maintained, and the responsible entities do not have control over the benchmark event library.

More clarification on criteria and how alternative cases could be submitted for use in the Assessment is needed.

It should be clear that TPL-008 will only be required to use temperature information from the selected benchmark events.

Likes 0	
Dislikes 0	
Response	

Kinte Whitehead - Exelon - 3	
Answer	No
Document Name	
Comment	

Exelon believes it is not appropriate to assign the Electric Reliability Organization (ERO) responsibility that directly impacts the compliance to a standard requirement. Interested in seeing more detail about how the benchmark library will be managed. There will need to be outlined guidance on where this data will be stored and who will have access to it. How will the responsible entity work with the Transmission Planner and Planning Coordinator to determine what goes into these cases and what are the expectations for providing feedback into them? Would it be better for Planning Coordinators to collaborate to create these instead?

Likes 0	
Dislikes 0	

Response

Wayne Guttormson - SaskPower - 1

Answer	No
Document Name	

Comment

Support the MRO NSRF and EEI comments.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO

Answer	No
Document Name	

Comment

SPP has concerns about Requirement R2 as its expectations for the responsible entities to conduct an assessment from a library that does not currently exist. We understand that EPRI is working with NERC to construct the library to support the requirement's effort. However, we will find it difficult for the responsible entities to support this requirement while there is no data to review.

Additionally, we have a concern about the assessment results and how they should align with an area that was closer to the extreme event versus greater distance from the impacted area.

As we stated before, there is no official library data available for the responsible entities to conduct an assessment as well as compare those results with other entities to ensure quality results have been produced. Again, it will be difficult for the responsible entities to support this requirement while there is no data to review and compare results.

SPP recommends that the drafting team coordinate with NERC staff and ensure that the library has been finalized before moving forward with this requirement. It will be difficult to convince industry to support this effort when there are still too many unresolved issues at this point.

Also, SPP recommends that the drafting team provide more clarity on the expectation of what type of results these assessments are to produce.

Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	

NV Energy believes that it is too vague. NV Energy is concerned that proposed Reliability Standard, TPL-008-1, is being moved forward for industry approval without any insights into a key element of this Reliability Standard which is the extreme temperature benchmark event library. EEI additionally does not support making this library a separate document outside of this Reliability Standard. It should be included in the Reliability Standard for industry review or input. This library should be an attachment within this Reliability Standard and we offer the following proposed changes to Requirement R2 to address this concern

in boldface below:

R2. Each responsible entity, as identified in Requirement R1, shall select one extreme heat benchmark event and one extreme cold benchmark event, from the **Attachment Xapproved ERO** (Extreme Temperature Benchmark Library) for performing the Extreme Temperature Assessment. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	

ERCOT is unable to formulate a position on this question without additional information on how the approved benchmark library managed by ERO will be established and populated, including the underlying criteria, approach, and assumptions. An open and transparent process is crucial, and ERCOT recommends that Planning Coordinators be allowed to submit extreme heat and cold events based on their historical weather events and statistical analysis for inclusion in the library.

Likes 0	
Dislikes 0	

Response	
Adrian Harris - Adrian Harris On Behalf of: Bobbi Welch, Midcontinent ISO, Inc., 2; - Adrian Harris, Group Name RTO/ISO Council Standard Review Committee Project 2023-07 TPL-008	
Answer	No
Document Name	
Comment	

As with the Extreme Temperature Assessment definition, the SRC is unable to fully evaluate Requirement R2 without being able to see and evaluate some example(s) of what the ERO intends to include as benchmark events in the library. Full evaluation of this requirement also requires additional information on how the approved benchmark library managed by the ERO will be established, populated and maintained over time, including the underlying criteria, approach and assumptions. An open and transparent process is crucial, and the SRC recommends that Planning Coordinators be allowed to submit, extreme heat and cold events that are impactful to the reliability of the system based on their historical weather events and statistical analysis for inclusion in the library.

Additionally, the SRC notes that historical weather events may not fully reflect the potential risks posed by future weather events as the severity, duration, and complexity of such weather events may increase through time resulting in extreme temperatures, wind lulls and persistent cloud coverage negatively impacting generation availability and exacerbating electric demands. It is important that the library events, whether synthetic or historical, present the full time-series of key weather concepts over multiple days to provide entities with sufficient data to build out a full set of system impacts.

Current language does not offer guidance on whether responsible entities should seek to choose more likely or more severe benchmark events from the approved library in the event these goals conflict. Could lead to under- or overidentification of needs. See for contrast the language around choosing contingencies: "expected to have more severe System impacts" Will there be an expectation that we justify the events that are chosen?

In addition, the SRC supports the “responsible entity as identified in requirement R1” language in R2 as it allows flexibility among planning entities to collectively determine who (e.g., the PC and/or TP) will perform R2.

From an improvement perspective, the SRC recommends several edits to the text of **R2**:

- The word “temperature” be added to benchmark events to align with the **Extreme Temperature Assessment** definition and to clarify the scope of the benchmarks being developed.
- The word “industry” be added to indicate industry needs to be part of the vetting and approval process to ensure that temperature benchmarks do not result in infeasible construction requirements.

R2. Each responsible entity, as identified in Requirement R1, shall select one extreme heat **temperature** benchmark event and one extreme cold **temperature** benchmark event, from the **industry** approved benchmark library maintained by the Electric Reliability Organization (ERO)

Likes 0	
Dislikes 0	
Response	
Catrina Martin - Archer Energy Solutions, LLC - 5	
Answer	No
Document Name	

Comment	
Without specifically stating it, the current wording of this requirement puts the responsibility for determining the library of events in the hands of the ERO and does not explicitly provide the ability for the PC or TP entities to be involved at any point in the development of this library. If the ERO develops a library of events that are too extreme, this could significantly impact cost of the transmission investment of the PC and TP entities and ultimately the customers within the PC and TP footprints. If the events are not extreme enough or turn out to be overly severe in one local area or region and not severe enough in another due to a lack of engagement from regional and local experts, this could also cause distortions in appropriate planning. Because the PC and TP entities know their systems (and likely the local climate and weather patterns) better than the ERO, shouldn't those entities be at least involved in determining the library of events from which they must select? We suggest that the requirement be reworded to provide the ability for PCs and TPs to have some control and input for the conditions that are studied for their systems, or even to require the ERO to collaborate with the PCs and TPs in developing these scenarios, with the ERO having the final decision after considering feedback and comments. There should also be some guidance provided as to how severe the benchmark cases should be. For example, California's history of severe weather is very limited and infrequent due to the tempering effects of the Pacific Ocean, whereas the Midwest (and Texas) is more prone to severe swings in weather and extreme conditions. Some climate change forecasts predict that this situation may change, but which forecast, if any, should be considered when preparing the benchmark cases should be at least up for discussion.	
Likes 0	
Dislikes 0	
Response	
Joseph McClung - JEA - 1	
Answer	No
Document Name	
Comment	
The requirement R2 states "approved benchmark library maintained by the Electric Reliability Organization", which creates consternation for utilities due to its ambiguity. Who is approving the benchmark event – the ERO, the Commission, NOAA (or similar agency), Planning Coordinator, Transmission Planner? The SDT has clearly stated they are not in the position to provide the basis or determine the appropriateness of any specific event. The ERO may maintain the library, but there needs to be clarity or some kind of vetting process with the participation from the industry on the approval process to benchmark any extreme heat or cold weather event that gets added to the library of events. Due consideration needs to be given to the geographic regions and variances in the weather patterns.	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	Yes
Document Name	

Comment	
Events in the ERO library should have industry review and approval prior to inclusion in the ERO library.	
Likes 0	
Dislikes 0	
Response	
Isidoro Behar - Long Island Power Authority - 1	
Answer	Yes
Document Name	
Comment	
Section 4 (Applicability) should be expanded to indicate and clarify that the ERO is responsible for developing the extreme heat benchmark event(s) and extreme cold benchmark event(s), and maintaining the benchmark library.	
Likes 0	
Dislikes 0	
Response	
Michele Tondalo - United Illuminating Co. - 1	
Answer	Yes
Document Name	
Comment	
I agree with this Requirement though I believe that affected Transmission Planners are eager to see what these benchmark events look like; and if the event data will include all of the necessary information for development of the study cases. Furthermore, will these Benchmark events be inclusive of the impacts from climate change; particularly on the extreme heat events?	
Likes 0	
Dislikes 0	
Response	
Michele Shafer - New York State Electric & Gas (NYSEG) - 6	
Answer	Yes
Document Name	

Comment	
Our SME agrees with this Requirement though he believes that affected Transmission Planners are eager to see what these benchmark events look like; and if the event data will include all of the necessary information for development of the study cases. Furthermore, will these Benchmark events be inclusive of the impacts from climate change; particularly on the extreme heat events?	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lidija Efremova - Lidija Efremova On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Lidija Efremova	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	
Document Name	
Comment	
Constellation has no comments Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	
Document Name	
Comment	
Constellation has no comments Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Junji Yamaguchi - Hydro-Quebec (HQ) - 5	
Answer	
Document Name	
Comment	
Should there be any requirements for developing and maintaining benchmark libraries (in co-operation with EROs), or if that is mandated through another means?	

“Responsible entity” should be defined in the Applicability section or should replaced with “Each Planning Coordinator, in conjunction with its Transmission Planner(s)...”Suggest to replace 4.1 to “Responsible Entity” instead of “Functional Entity”.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC

Answer	
Document Name	

Comment

Should there be any requirements for developing and maintaining benchmark libraries (in co-operation with EROs), or if that is mandated through another means?

“Responsible entity” should be defined in the Applicability section or should replace with “Each Planning Coordinator, in conjunction with its Transmission Planner(s)...” Suggest replacing 4.1 to “Responsible Entity” instead of “Functional Entity”.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE noticed Requirement R2 requires the Electric Reliability Organization (ERO) to maintain a benchmark library so each responsible entity can select one extreme heat benchmark event and one extreme cold benchmark event. Texas RE requests the SDT’s reasoning for choosing the ERO as the responsible entity to maintain the benchmark library, rather than the RC or PC. Texas RE notes that, as currently drafted, it appears entities could select any available benchmark case. Is the SDT’s intent that as part of the ERO’s maintenance activities, the ERO select appropriate cold and heat benchmark cases for responsible entities?

Texas RE notes that there is a significant amount of variation in extreme heat and cold benchmark events depending upon the climatological zone in which an applicable transmission planning entity is located. As an alternative, the SDT may wish to consider establishing more objective criteria for responsible entities to select benchmark events based on their particular circumstances. By way of example, benchmark events could be established

based on the 95th percentile maximum or minimum temperature events experienced over a 72-hour period, which has been adopted for transmission and generation weatherization activities in the ERCOT Interconnection.

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	
Document Name	
Comment	
OPG supports NPCC Regional Standards Committee's comments.	
Likes 0	
Dislikes 0	
Response	

4. Do you agree with the proposed TPL-008-1 Reliability Standard Requirements R3 – R8 (benchmark planning cases and analyses)? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Michael Goggin - Grid Strategies LLC - 5	
Answer	No
Document Name	
Comment	

First, to comply with FERC Order 896, the standard should specify that benchmark events and Extreme Temperature Assessments will account for concurrent/correlated outages of generators during extreme heat and cold events. In Order 896 paragraph 88, FERC directs “NERC to require under the new or revised Reliability Standard the study of concurrent/correlated generator and transmission outages due to extreme heat and cold events in benchmark events,” explaining in paragraph 89 that “it is necessary that responsible entities evaluate the risk of correlated or concurrent outages and derates of all types of generation resources and transmission facilities as a result of extreme heat and cold events.”

The drafts of TPL-008 and the associated “Consideration of FERC Order 896 Directives” document appear to put the burden on responsible entities and not NERC for accounting for correlated outages: “This directive is addressed in proposed TPL-008-1 through Requirement R3 Part 3.2. The responsible entity is obligated to modify the benchmark planning cases to include seasonal and temperature dependent adjustment for Load, generation, Transmission, and transfers which represent the selected benchmark events.”[1]

Having responsible entities and not NERC conduct this adjustment increases the risk that different regions will use inconsistent methods for doing so, and at worst responsible entities that want to avoid addressing reliability concerns through a Corrective Action Plan will use unrealistically low assumptions for the rate of correlated generator outages or other input assumptions like load and transfers. This assumption can have such a large impact on results it cannot be left to responsible entities, and should be made by NERC. The drafting team’s Technical Rationale used similar logic in deciding that NERC (the Electric Reliability Organization or ERO) should assemble the benchmark planning cases: “to ensure consistency across regions, it is necessary for the ERO to have the responsibility for determining the suitability of benchmark events to represent probable future conditions.”

Given the significant variation in the rates at which different fuel types experience correlated outages,[2] and rapid changes in the generation mix that may cause the future power system to have greater or lesser exposure to correlated outage risk, it is particularly important for the benchmark events and Extreme Temperature Assessments to account for the concurrent/correlated outage risk of each fuel type in the future generation mix. In recent cold snap events, gas generator outages due to equipment failures and fuel supply interruptions have accounted for the majority of outages. NERC GADS data can be used to assess the rate of correlated outages and derates of generators by fuel type.{C}[3]

Second, the benchmark cases and Extreme Temperature Assessments should account for changes to generation, demand, and transmission resulting from climate change, electrification of heating, and other factors that are affecting the risk posed by extreme heat and cold. Accounting for how climate change is increasing the frequency and magnitude of extreme heat and cold events is consistent with FERC’s Order 896 directive in paragraph 40: “We also direct NERC to ensure the reliability standard contains appropriate mechanisms for ensuring the benchmark event reflects up-to-date meteorological data. The increasing intensity, frequency, and unpredictability of extreme weather conditions requires that key aspects of the benchmark events be reviewed, and if necessary, updated periodically to ensure the corresponding benchmark planning cases reflect updated meteorological data.” Electrification of heating is also increasing the sensitivity of electricity demand to extreme cold conditions, which should be accounted for in the benchmark cases and Extreme Temperature Assessments.

Third, due to the impact of climate change, electrification, and rapid changes in the generation mix, requirement R8 should require responsible entities to complete an Extreme Temperature Assessment more frequently than at least once every five calendar years. As noted above, FERC Order 896 specifies that the meteorology underlying benchmark cases should be updated at least every five years, but the generation mix and other grid conditions can change more rapidly than that. TPL-001 requirement R2 requires Planning Assessments to be conducted annually, and a similar annual requirement for Extreme Temperature Assessments is appropriate given that extreme heat and cold events are the largest threat to electric reliability.

Finally, the requirement in Section 8.1 under R8 is unclear and may be inadequate. That section states that the Extreme Temperature Assessment shall include "Assessment of the benchmark planning cases developed under Requirement R4, for one of the years in the Long-Term Transmission Planning Horizon. The rationale for the year selected for evaluation shall be available as supporting information." At minimum, that section of R8 should be modified to provide responsible entities with greater direction on which year or years to assess the planning cases developed under R4. Because extreme heat and cold risks can evolve over time due to changes in the generation mix, load, and the impact of climate change, R8 should require the responsible entity to document that the year selected is likely to pose the greatest reliability risk. If it cannot be determined which year is likely to pose the greatest risk, then the responsible entity should be required to conduct the assessment for all years that may pose the greatest risk. This is important because of the long and ambiguous timeframe covered by the Long-Term Transmission Planning Horizon, which the NERC Glossary indicates is the "Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete." Planning for multiple years is consistent with the requirement in Section 2.1.1. of requirement R2 for TPL-001, which requires Planning Assessments to examine multiple years by incorporating "System peak Load for either Year One or year two, and for year five."[4]

{C}[1]{C} NERC, *Consideration of FERC Order 896 Directives* (March 2024), https://www.nerc.com/pa/Stand/Project202307ModtoTPL00151TransSystPlanPerfReqExWe/2023-07_Consideration%20of%20FERC%20Order%20896%20Directives%20Final_032024.pdf, at 5

{C}[2]{C} *See, e.g.*, FERC and NERC*, Winter Storm Elliott Report: Inquiry into Bulk-Power System Operations During December 2022* (October 2023), https://www.ferc.gov/media/winter-storm-elliott-report-inquiry-bulk-power-system-operations-during-december-2022, at 17; FERC and NERC, *The February 2021 Cold Weather Outages in Texas and the South Central United States* (November 2021), https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and, at 16; FERC and NERC, *2019 FERC and NERC Staff Report: The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018* (July 2019), https://www.ferc.gov/legal/staff-reports/2019/07-18-19-ferc-nerc-report.pdf; PJM, *Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events* (May 2014), https://www.pjm.com/~/media/library/reports-notices/weather-related/20140509-analysis-of-operational-events-and-market-impacts-during-the-jan-2014-cold-weather-events.ashx.

{C}[3]{C} For example, see the analysis of GADS data provided in S. Murphy et al., *Resource adequacy risks to the bulk power system in North America* (February 2018), https://www.sciencedirect.com/science/article/pii/S0306261917318202, with Supplementary Material including outage data available at https://ars.els-cdn.com/content/image/1-s2.0-S0306261917318202-mmc1.zip

{C}[4]{C} https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-4.pdf

Likes 0	
Dislikes 0	

Response

Catrina Martin - Archer Energy Solutions, LLC - 5

Answer	No
Document Name	

Comment

R3 - The responsibility is assigned to "each PC," but the weather events selected from the ERO library will certainly cross multiple PC footprints in almost every case. This argues for the development of regional processes and the development of base cases that could be used by multiple PC entities. Regional planning groups or the regional entities (such as WECC) may be better groups for developing these processes and base cases than the PC.

o As currently written, R3 does not appear to preclude PCs from working together on this requirement. Does the drafting team envision this as an acceptable way to meet R3?

o If so, an alternative wording might be: *Each Planning Coordinator shall coordinate with other impacted Planning Coordinator(s), Transmission Planner(s), and other designated study entities to develop and implement joint and/or individual processes for coordinating the development of benchmark planning cases based on the selected benchmark events as identified in Requirement R2.*

R4 - It would be helpful if this requirement (or other NERC guidance for this requirement) would provide additional details on what additional system models (e.g., steady state and stability) are required and how the required modeling data differs from the current MOD-032 and TPL-001 requirements. There may also be some data requirements for the Extreme Temperature Assessment that are not addressed by the current version of MOD-032, such as special high/cold temperature Facility Ratings, generation de-rating and dispatch patterns, or climate change forecasts that could impact the temperature assumptions for load models. Since MOD-032 does not currently address these data requirements, they need to be addressed in TPL-008 as an appendix, in a Guidelines and Technical Basis section, or in a future modification to MOD-032 itself.

R5 - As with TPL-007 and TPL-001, it appears that the study criteria are set by the “responsible entity” which is negotiated under R1. While the responsible entity is charged with maintaining system reliability, the criteria will also determine the number of CAPs and amount of transmission investment that are required to meet TPL-008. TPL-001-5.1 is already triggering the need for additional transmission investment over the coming years, so TO/GO entities that will actually pay for the upgrades will be further taxed by TPL-008. The implementation plan needs to be long enough so that the investments for TPL-008 do not coincide closely with the TPL-001-5.1 implementation period.

R5 – This requirement states that the responsible entity “shall have criteria” while R6 states that the responsible entity “shall define and document criteria?” The wording in R6 appears to be better, since both sets of criteria should be “defined and documented” in each Extreme Temperature Assessment report. It is suggested that the wording from R6 be used for R5.

R6 - Instability criteria are generally not “adjustable” limits. That is, the system is either unstable or it is not. If the events in the ERO library are too severe and lead to a significant increase in the events that trigger instability, these could be expensive problems to fix. See comments for R2.

R7 - It would be helpful to see this requirement address the differences between the set of contingencies for TPL-001 rather than an absolute set - this provides more value for all entities rather than showing a largely duplicative full set of outages.

R7 - P5 events are already very unlikely since they require a fault event plus an equipment failure, which is essentially a multiple outage on par with the likelihood of a P6 event (which is excluded from this standard). The Extreme Temperature event benchmark cases are very unlikely extreme events to begin with (and an extreme sensitivity to the TPL-001 studies), which further reduces the likelihood of having a P5 event during an Extreme Temperature event. In addition, the severity of significant P5 events strongly suggests upgrades will already be identified by the annual Assessment required by TPL-001.

o Given the amount of work already added by this standard, the low likelihood of the P5 events on par with other excluded events from TPL-001 (such as P6), and the strong likelihood that impacts from these events are already adequately captured by the TPL-001 Assessment studies, we strongly recommend removing P5 events from Table 1 of TPL-008.

R8 - While it is a helpful limitation to only require one assessment year from the Long-Term Planning Horizon, this may not be practicable for the development of CAPs that involve capital investment as these projects require multiple years to permit and construct. The CAPs that involve capital investment will need to be reviewed and refined as the potential violations move into the Near-Term Planning Horizon and prior to the operating horizon. TPL-001 studies will not include the conditions and criteria required to address these studies, so separate Extreme Temperature event benchmark cases will need to be developed for the Near-Term Transmission Planning Horizon to address these cases.

R8 - Especially for the very first Extreme Temperature Assessment, it is possible that a large number of CAPs may be identified for criteria violations that already exist in the Near-Term Planning Horizon. This will create a backlog of projects which will need to be started immediately to meet the implementation plan period. These projects will be on top of the P5 projects that are already backlogged for implementation of TPL-001-5.1.

o It is recommended that the implementation plan allow a ten-year period for implementation of CAPs that require capital investment to construct new facilities. This would also match up well with performing these studies for the Long-Term Transmission Planning Horizon since the studied case could be a ten year case.

R8.2 - Sensitivity to generation, load and transfers are already studied as part of TPL-001-5.1. The sensitivity additional studies proposed for R8.2 are unlikely to yield any new information and will be duplicative work for Transmission Planners. The Extreme Temperature Assessment is already a very extreme sensitivity study itself that should already capture modified load, generation, transmission, and transfers befitting this analysis per R3, so it is not needed nor appropriate to study sensitivities for sensitivity cases.

R8.2 should be removed entirely to reduce unnecessary workload which will provide information that is duplicative and provide no additional value since the studies under this standard are already in effect sensitivities in comparison to the Assessment studies under TPL-001.

Likes 0	
Dislikes 0	

Response

Adrian Harris - Adrian Harris On Behalf of: Bobbi Welch, Midcontinent ISO, Inc., 2; - Adrian Harris, Group Name RTO/ISO Council Standard Review Committee Project 2023-07 TPL-008

Answer	No
Document Name	

Comment

The SRC requests the SDT address the following in requirements R3-R8:

R3: The SRC requests the SDT clarify obligations when coordinating with neighboring PCs to perform an Extreme Temperature Assessment. If a PC performs a planning area study for a “selected benchmark event” that only includes a portion of the PC’s footprint (Part 3.1), the SDT should confirm that the PC and its associated Transmission Planners have satisfied the obligation under R2 for completing an Extreme Temperature Assessment for either “one extreme heat benchmark event or one extreme cold benchmark event” for that five-calendar year period (R8).

Does R3.2 imply that inter-Area transfers should be different that those coordinated through the ERAG MMWG process which considers “all transactions that have confirmed annual firm transmission service along the entire path from source to sink and have a firm energy contract for the resource”? While operationally during extreme heatwaves and cold snaps each Area should plan their system so as to not rely on neighbors beyond what is contractually obligated and coordained through the ERAG MMWG process.

In addition, the SRC requests the SDT clarify the “process for coordinating the development of benchmark planning cases among impacted Planning Coordinator(s),” and specifically:

- How far must an entity go, i.e. are Tier 1 neighbors sufficient or must an entity go further?
- Can coordinating on the model build for a given event satisfy this requirement?

Similarly, Requirement R3 should also be revised to clarify how conflicts will be resolved if different Planning Coordinators within the same Interconnection have incompatible processes for selecting benchmark events, defining the planning study boundary area, and coordinating with other impacted entities. This clarification should address scenarios in which three or more impacted, geographically contiguous Planning Coordinators within the same Interconnection all select different, incompatible benchmark events (as allowed by Requirement R1) to study. The SRC requests that this clarification address the following topics, along with any other topics that may need to be addressed:

- Does the standard require all PCs to support all alternate PC studies including data exchange for the various temperature dependent information as well as the study schedule?
- What happens if an entity is unwilling to cooperate?

Finally, to maintain consistency with existing practice under TPL-001-5.1 and avoid introducing unnecessary complexity to the TPL-008 coordination process, Requirement R3 should be revised to indicate that Planning Coordinators and Transmission Planners are not required to coordinate with entities in different Interconnections. TPL-001-5.1 Requirement R8 requires Planning Coordinators to distribute Planning Assessment results to adjacent Planning Coordinators. However, Revising Requirement R3 in TPL-008 to indicate that coordination with entities in other Interconnections is not required would help optimize the overall efficiency and effectiveness of TPL-008.

R4. The SRC supports the use of MOD-032 to obtain the necessary data and asks the SDT to consider whether MOD-032 needs to be modified to acquire information unique to TPL-008. The SRC is concerned that MOD-032 does not currently include requirements addressing the necessary temperature-dependent information for load, generation, transmission, and transfers. If this is not specifically addressed in MOD-032 it will be very difficult to require the provision of this information.

R5. The SRC has concerns with R5 as it may be duplicative of work that is already occurring under TPL-001-5.1. Specifically, it is unclear how the criteria for "steady state voltage limits and post-Contingency voltage deviations" under TPL-008, R5 differs from what entities have defined under TPL-001-5.1, and consequently, it is unclear why Requirement R5 is needed. **The SRC requests that the drafting team provide an explanation of the need for R5.**

R6. The SRC has concerns with R6 as R6 may duplicate work that is already occurring under TPL-001-5.1, PRC-006, and other Reliability Standards. Therefore, the SRC asks the SDT to describe the need drivers for R6 by identifying where extreme temperature events have resulted in system instability, uncontrolled separation, or Cascading.

***R6.** Does "instability" need to be further defined under this standard? R6 already qualifies instability as the prior IROL definition: "identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding."*

The SRC recommends leaving this flexible as many entities have already defined this for their footprint in accordance with FAC-014.

R7. To clarify that the Extreme Temperature Assessment is limited to the planning study area boundary defined in Part 3.1, the SRC requests the SDT modify requirement R7 as follows:

R7. Each responsible entity, as identified in Requirement R1, shall identify Contingencies used in performing the Extreme Temperature Assessment for each of the event categories in Table 1 that are expected to produce more severe System impacts within the planning study area **boundary defined in Part 3.1**. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

R8. The SRC recommends that Requirement R8 be revised to clarify whether the case used needs to be a Long-Term case at the time the study is completed or it just when the case building is completed, as two to three years typically elapse between the completion of the case build and the completion of the studies that use the case

The technical rationale for R8 quotes the FERC order that sensitivity cases, "should consider including conditions that vary with temperature such as load, generation, and system transfers." If the temperature is changed, does that imply that a different storm is selected from R2 which would then also change the study boundary conditions? Also this would increase the complexity of the temperature dependence of generation and transmission resources.

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
OPG supports NPCC Regional Standards Committee's comments.	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
Requirement R3: To maintain consistency with existing practice under TPL-001-5.1 and avoid introducing unnecessary complexity to the TPL-008 coordination process, Requirement R3 should be revised to indicate that Planning Coordinators and Transmission Planners are not required to coordinate with entities in different Interconnections. TPL-001-5.1 Requirement R8 requires Planning Coordinators to distribute Planning Assessment results to adjacent Planning Coordinators. However, ERCOT and its neighboring Planning Coordinators in the Eastern and Western Interconnections have not historically construed Requirement R8 to require distribution of Planning Assessment results between them. Requiring such communication would be unnecessary because Interconnections connect to each other only through direct current (DC) ties, and DC ties cannot be used to solve planning criteria violations on an alternating current (AC) system because the operation of DC ties is solely determined by manual actions requiring approval by multiple entities. Because the various Interconnections are not synchronized with each other, the only purpose that could be served by requiring Planning Coordinators in different Interconnections to coordinate extreme weather planning would be to address a forecasted generation insufficiency in one Interconnection. However, as the Technical Rationale notes, resource adequacy issues are beyond the scope of this proceeding under Order No. 896. Revising Requirement R3 in TPL-008 to indicate that coordination with entities in other Interconnections is not required would help optimize the overall efficiency and effectiveness of TPL-008. Requirement R3 should also be revised to clarify how conflicts will be resolved if different Planning Coordinators within the same Interconnection have incompatible processes for selecting benchmark events, defining the planning study boundary area, and coordinating with other impacted entities. This clarification should address scenarios in which three or more impacted, geographically contiguous Planning Coordinators within the same Interconnection all select different, incompatible benchmark events (as allowed by Requirement R1) to study. Requirement R8: ERCOT recommends that Requirement R8 be revised to clarify whether the case used needs to be a Long-Term case at the time the study is completed or just when the case building is completed, as two to three years typically elapse between the completion of the case build and the completion of the studies that use the case.	
Likes 0	

Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	

EEI does not agree with the language contained in requirements R3, R4, R7, and R8 for the reasons expressed below. (See the proposed changes in boldface to Requirement R3 below)

Proposed changes to Requirement R3:

{C}1. {C}EEI suggests it would be clearer to replace "impacted" with adjoining or neighboring Planning Coordinators since they would be the only impacted PCs.

{C}2. {C}EEI also suggests some changes to the subparts of Requirement R3 to better clarify the required tasks under the PC process.

R3. Each Planning Coordinator shall develop and implement a process for coordinating the development of benchmark planning cases among **adjoining** Planning Coordinator(s), Transmission Planner(s), and other designated study entities **under their purviewbased on the selected to ensure** benchmark events as identified in Requirement R2 **are coordinated.** This process shall **include**: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

{C}**3.1. Define theReview of the** planning study area **boundary boundaries under each Transmission Planner, based to ensure study completeness**.

{C}**3.2. Verification that Modify** the benchmark planning cases **to** include seasonal and temperature dependent adjustment for Load, generation, Transmission, and transfers which represents the selected benchmark events.

Proposed revisions to Requirement R4

EEI suggests the subparts of Requirement R8 are better placed under Requirement R4 with the edits suggested below:

R4. Each responsible entity, as identified in Requirement R1, shall develop and maintain System models within its planning area for performing the Extreme Temperature Assessment. The System models shall use data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, **and shall represent projected System conditions based on the selected benchmark events as identified in Requirement R2. System models shall be developed for the following conditions:** [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

4.1 System conditions based on each benchmark event selected in Requirement R2 for one of the years in the Long-Term Transmission Planning Horizon.

4.2 For each of the models developed for Requirement R4 Part 4.1, a sensitivity model shall be developed to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity model shall include, at a minimum, changes to one of the following conditions:

{C}· **Generation,**

{C}· **Real and reactive forecasted Load, or**

{C}· **Transfers.**

Proposed change to Requirement R7:

EEI disagrees with including a requirement to have a documented rationale for the Contingencies selected because it represents an unnecessary administrative burden.

R7. Each responsible entity, as identified in Requirement R1, shall identify the Contingencies used in performing the Extreme Temperature Assessment for each of the event categories in Table 1 that are expected to produce more severe System impacts within its planning area. **The rationale for those Contingencies selected for evaluation shall be available as supporting information.** *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

Proposed changes to Requirement R8

EEI suggests that subparts 8.1 and 8.2 should be placed under Requirement R4. In addition to this change the last sentence in R8 referencing those subparts should be removed. See EEI comments to Requirement R4 below.

R8 Each responsible entity, as identified in Requirement R1, shall complete an Extreme Temperature Assessment of the Long-Term Transmission Planning Horizon at least once every five calendar years, using the benchmark planning cases and the System models identified in Requirement R3 and R4, and the Contingencies identified in Requirement R7 for each of the event categories in Table 1, and document assumptions and results of the steady state and stability analyses. **The Extreme Temperature Assessment shall include the following.** [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	No
Document Name	
Comment	

SPP raises concerns regarding the coordination among all entities impacted by Requirement R3. We understand that this coordination extends to all Planning Coordinators, including those outside the event area, potentially leading to unnecessary administrative burdens.

Additionally, there's apprehension about planning models not adequately reflecting real-time operational needs. It's challenging to envision a process ensuring proper alignment between planning and operational models, especially given unresolved issues like data collection discrepancies between different models.

Regarding Requirement R4 and the use of the MOD-032 Standard for data collection, SPP questions its suitability for assessing Inverter-Based, Distributed Energy, and Energy Storage Resources, given unresolved project directives.

Concerning Requirement R7, ambiguity exists regarding whether specific studies or all studies implied by Table 1 are required. SPP suggests the drafting team clarify expectations and align efforts with Project 2022-02 regarding MOD-032.

Lastly, SPP seeks clarification on the purpose of sensitivity analyses in sub-part 8.2 and its association with MOD-032 data collection. They recommend clarity on the necessity of sensitivity analyses and its relation to data collection from the MOD-032 model build.

Likes 0	
Dislikes 0	

Response

Wayne Guttormson - SaskPower - 1

Answer	No
Document Name	

Comment

Support the MRO NSRF and EEI comments.

Likes 0	
Dislikes 0	

Response

Kinte Whitehead - Exelon - 3

Answer	No
Document Name	

Comment

R3 - Would like more information about how the boundary is determined/defined. Perhaps specify factors in more detail that would need to be considered when building base case (N-0).

R4- It is not clear how the ratings set will be identified. Additionally, there is language that states, “develop and maintain System models within its planning area for performing the Extreme Temperature Assessment.” While the assessment is performed at least once every five years, is there an expectation that these models are built and maintained more frequently? These models could be ad-hoc, which would not be maintained.

Additional suggestion: Add two terms to the NERC Glossary defining System Models and Planning Cases.

R7 – Need clarification on what projects to include in model year selected.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC

Answer	No
Document Name	

Comment

Regarding R3 and R4—it is not clear what the difference is between “planning cases” (R3) and “system models” (R4). These are not defined in the NERC glossary, and their use here should be clarified.

Regarding R5, FAC-014-3 R6 requires Planning Coordinators and Transmission Planners to use facility ratings, voltage and stability limits that are equal or more limiting than its respective Reliability Coordinators. Presumably this is intended to give PCs/TPs more leeway in criteria for extreme events, but unless some exception is made for FAC-014-3 R6, there may be no further room possible (particularly if the ordinary planning limits are equal to the operational limits, which is probably typical).

R7 should clearly indicate which contingency categories are required.

R4, R5, R6, R7 and R8: “Responsible entity” should be defined in the Applicability section or should replace with “Each Planning Coordinator, in conjunction with its Transmission Planner(s)...”). Suggest replacing 4.1 to “Responsible Entity” instead of “Functional Entity”.

R6: “….to identify instability, uncontrolled separation, or Cascading” of what? The System? Outages? If that is the case, suggest specifying “to identify instability, uncontrolled separation, or Cascading of the System” or “to identify instability, uncontrolled separation, or Cascading outages”.

Likes 0	
Dislikes 0	

Response

Amy Wilke - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	

ATC generally supports the MRO NSRF comments, and is supplementing them as described below.

R4: During the 4/12/24 workshop, SDT mentioned that one purpose of including R4 and the reference to MOD-032 is to allow the collection of generation and transmission data related to the extreme heat and cold benchmark events. How will MOD-032 allow for the collection of additional information related to the extreme heat and cold events? We recognize that MOD-032-1 Attachment 1 includes a provision for "other information requested by the PC or TP necessary for modeling purposes" but believe that this has not been successful/ adequate in the past and may not be appropriate in TPL-008. Given this, would updates or modifications be needed to MOD-032 or related documents to get extreme weather load data? Does the extreme temperature data collection need to involve changes to MOD-031 for extreme weather load forecast data?

R4: Besides establishing the ability for responsible entities to collect data related to extreme heat/ cold, how is R4 different from R3? If a reference to MOD-032 will not adequately allow for the collection of extreme temperature data, then R4 should a) be updated with an existing method for data collection, b) the team may need to propose additional changes to exiting processes, or c) remove R4.

R5: Why does R5 only reference voltage and not thermal constraints? If the Extreme Weather Assessment voltage criteria could be different than regular criteria, then could thermal criteria be different as well?

R6: Is the identification of "instability, uncontrolled separation, or Cascading" expected to be different for the Extreme Temperature Assessment? And not the same as IROL?

R5, R6, R7: Because there are no longer Planning Horizon SOLs with the new FAC-014-3 and the PC and TP need to follow the RC SOL Methodology, R5, R6, and R7 should not contradict that.

R8: Should R8 refer to "modified benchmark planning cases" per R3.2?

R8.2: It is not clear how many sensitivities may be needed (believe only one for heat and cold each). We do not want this analysis to become onerous.

Likes 0	
Dislikes 0	
Response	

Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	

R3 - Would like more information about how the boundary is determined/defined. Perhaps specify factors in more detail that would need to be considered when building base case (N-0).

R4- It is not clear how the ratings set will be identified. Additionally, there is language that states, “develop and maintain System models within its planning area for performing the Extreme Temperature Assessment.” While the assessment is performed at least once every five years, is there an expectation that these models are built and maintained more frequently? These models could be ad-hoc, which would not be maintained.

Additional suggestion: Add two terms to the NERC Glossary defining System Models and Planning Cases.

R7 – Need clarification on what projects to include in model year selected.

Likes 0	
Dislikes 0	

Response

Selene Willis - Edison International - Southern California Edison Company - 5

Answer	No
Document Name	

Comment

“See comments submitted by the Edison Electric Institute”

Likes 0	
Dislikes 0	

Response

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3

Answer	No
Document Name	

Comment

NIPSCO supports the comments provided by Entergy, ReliabilityFirst, AEP, BPA, WPP, and CMS Energy.

Likes 0	
Dislikes 0	

Response

Robert Jones - Seattle City Light - 1,3,4,6

Answer	No
Document Name	

Comment	
R3: Need more clarification on the requirements of the process among impacted utilities (who is impacted? And why?). The benchmark base cases may not be covered by R3 depending on how utilities may define their process or methodology. The boundary or the area may not match the benchmark event. Will PCs/TPs have to participate in development of multiple benchmark cases from various adjacent/impacted utilities? What requirements exist to enforce TPs participating in case building for a benchmark case they have not selected? Or will there only be one benchmark event per area (in which case why is each separate PC defining their own coordination process). R4: No comments. R5: Wouldn't this overlap with TPL-001? Are they expected to be different criteria? R6: Same comment as R5. This appears to overlap TPL-001… is there any reason the criteria/methodology would be different than for TPL-001? Need more guidance. A benchmark event may not fall under entity's (utilities) criteria or methodology depending on interpretation and definition of Extreme Temperature by each entity. Need more regional guidance. R7: The table should be reformatted. It appears to be two tables in one. R8: The language in this requirement is very vague. Does this apply to steady state or transient stability? According to Table 1 contingency definitions seem to include all. What about existing generation outages? Do we run P3 and P6 contingencies on top of the existing outages?	
Likes 0	
Dislikes 0	
Response	

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
ITC requests clarification on the following: R3. Please clarify the drafting team's intent for the coordinate with others. Is this just the adjacent PCs. Additionally, for events that only cover a limited portion of the PCs footprint, is the intent that they would need to complete a second set of hot and cold events for the remaining portion of their footprint? R4. Does the drafting team feel it would be necessary to add any additional data to the table in MOD-032 to complete this work?	

R5 and R6. If a TP or PC believes that the work performed for a different standard will cover work required under TPL-008, can a provision for this be added to the standard?

R7 and R8. No comment.

Likes 0	
Dislikes 0	

Response

Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle

Answer	No
Document Name	

Comment

R3 - The responsibility is assigned to "each PC," but the weather events selected from the ERO library will certainly cross multiple PC footprints in almost every case. This argues for the development of regional processes and the development of base cases that could be used by multiple PC entities.

As currently written, R3 does not appear to preclude PCs from working together on this requirement. Does the drafting team envision this as an acceptable way to meet R3?

If so, an alternative wording might be: *Each Planning Coordinator shall coordinate with other impacted Planning Coordinator(s), Transmission Planner(s), and other designated study entities to develop and implement joint and/or individual processes for coordinating the development of benchmark planning cases based on the selected benchmark events as identified in Requirement R2.*

R4 - It would be helpful if this requirement (or other NERC guidance for this requirement) would provide additional details on what additional system models (e.g., steady state and stability) are required and how the required modeling data differs from the current MOD-032 and TPL-001 requirements. There may also be some data requirements for the Extreme Temperature Assessment that are not addressed by the current version of MOD-032, such as special high/cold temperature Facility Ratings, generation de-rating and dispatch patterns, or climate change forecasts that could impact the temperature assumptions for load models. Since MOD-032 does not currently address these data requirements, they need to be addressed in TPL-008 as an appendix, in a Guidelines and Technical Basis section, or in a future modification to MOD-032 itself.

R5 – This requirement states that the responsible entity "shall have criteria" while R6 states that the responsible entity "shall define and document criteria?" The wording in R6 appears to be better, since both sets of criteria should be "defined and documented" in each Extreme Temperature Assessment report. It is suggested that the wording from R6 be used for R5.

R6 - Instability criteria are generally not "adjustable" limits. That is, the system is either unstable or it is not. If the events in the ERO library are too severe and lead to a significant increase in the events that trigger instability, these could require extensive CAPs. See comments for R2.

R7 - It would be helpful to see this requirement address the differences between the set of contingencies for TPL-001 rather than an absolute set - this provides more value for all entities rather than showing a largely duplicative full set of outages.

R7 - P5 events are already very unlikely since they require a fault event plus an equipment failure, which is essentially a multiple outage on par with the likelihood of a P6 event (which is already excluded from this standard). Furthermore, the severity of significant P5 events strongly suggests upgrades will already be identified by the annual Assessment required by TPL-001. Provided the strong likelihood that impacts from these events are already adequately captured by the TPL-001 Assessment studies, we strongly recommend removing P5 events from Table 1 of TPL-008.

R8 – In order to avoid backlog of projects which will need to be started immediately to meet the implementation plan period, it is recommended that the implementation plan allow a ten-year period for implementation of CAPs that require capital investment to construct new facilities. This would also match up well with performing these studies for the Long-Term Transmission Planning Horizon.

R8.2 - The Extreme Temperature Assessment is already a very extreme sensitivity study itself that should already capture modified load, generation, transmission, and transfers befitting this analysis per R3, so it is not needed nor appropriate to study sensitivities for sensitivity cases. As a result, we strongly recommend R8.2 to be removed. Instead, PG&E recommends requiring in the benchmark cases that load, generation, system configurations, facility ratings, etc. should match the assumptions for extreme weather conditions.

Likes 0	
Dislikes 0	

Response

Rebika Yitna - Rebika Yitna On Behalf of: David Weekley, MEAG Power, 3, 1; Roger Brand, MEAG Power, 3, 1; - Rebika Yitna

Answer	No
Document Name	

Comment

SDT should consider combining R3 and R4.

Likes 0	
Dislikes 0	

Response

Colby Galloway - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

Southern Company recommends that the standard drafting team clarify R3.1 and the broader process for R3. As written, an unintended consequence will likely be an extreme amount of workload for the Planning Coordinator(s) to develop cases. The requirement of impacted Planning Coordinator(s) to provide support in a timely manner should also be defined.

Likes 0	
Dislikes 0	

Response

David Jendras Sr - Ameren - Ameren Services - 3

Answer	No
Document Name	

Comment

R3.1: Ameren suggests making a definition of wide area because it is currently unclear.

R3.2: The requirement includes "Transmission", do Transmission line ratings need to be modified to reflect the extreme temperature assessment?

R4: Currently, MOD-032 does not specifically require extreme temperature data for load and generation. Does MOD-032 need to be updated to consider the extreme temperature data requirement as part of this standard?

R5: Is the expectation of the standard drafting team to have two different acceptable voltage limits for TPL-001-5 and TPL-008, or is it up to the Responsible Entity to determine if they can both align?

R7: In Table 1, the criteria are not clear as to whether the steady state performance criteria apply to all of the BES or just BES elements 200kv and above.

Likes 0	
Dislikes 0	

Response

Junji Yamaguchi - Hydro-Quebec (HQ) - 5

Answer	No
Document Name	

Comment

Regarding R3 and R4—it is not clear what the difference is between “planning cases” (R3) and “system models” (R4). These are not defined in the NERC glossary, and their use here should be clarified.

Regarding R5, FAC-014-3 R6 requires Planning Coordinators and Transmission Planners to use facility ratings, voltage and stability limits that are equal or more limiting than its respective Reliability Coordinators. Presumably this is intended to give PCs/TPs more leeway in criteria for extreme events, but unless some exception is made for FAC-014-3 R6, there may be no further room possible (particularly if the ordinary planning limits are equal to the operational limits, which is probably typical).

R7 should clearly indicate which contingency categories are required.

R4, R5, R6, R7 and R8: “Responsible entity” should be defined in the Applicability section or should replaced with “Each Planning Coordinator, in conjunction with its Transmission Planner(s)...”). Suggest to replace 4.1 to “Responsible Entity” instead of “Functional Entity”.

R6: please complete the phrase“….to identify instability, uncontrolled separation, or Cascading”. For example, are we identifying instability, uncontrolled separation, or Cascading of the System? The Interconnection? If that is the case, we suggest to specify “to identify instability, uncontrolled separation, or Cascading of the System” or “to identify instability, uncontrolled separation, or Cascading Interconnection”.

Likes 0	
Dislikes 0	
Response	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	No
Document Name	
Comment	

For R3: Coordination between RCs needs to be clarified. If each RC were to choose a different Benchmark Event to study, does each neighboring RC need to provide data to others? What If two or more PCs choose different benchmark events to study. Will this create an additional work load for those neighboring entities?

For R3.1. This calls for a defined “planning study area”. Is this meant to be different than a PC’s “Planning Area”. Clarification is needed to show that the planning study area remains within the PC’s planning area, so that for example a Benchmark Event affecting Ohio does not need to be studied by New England.

R4: Should be changed so that the System Model only needs to be updated for the year in which studies will be performed versus annual model updates as required by MOD-032.

R5: Is this duplicative to TPL-001? Could this create a Double Jeopardy situation where two requirements would be violated for a single issue?

R6: Is this duplicative to TPL-001 or other standards (PRC?)? Will this create a Double Jeopardy situation where two requirements would be violated for a single issue?

R7: Suggest changing “Planning area” to “Planning Study Area”. Same reasoning as R3.1 comment above.

R8: No Additional Comments

Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	

Answer	No
Document Name	
Comment	
R3.2 includes “Transmission” which is omitted from the Rationale Document (R3) – please define intent of using Transmission in R3.2. Additionally, R3 uses the phrase “and other designated study entities” – please define who the other entities are and why they are needed relative to this standard.	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	No
Document Name	
Comment	
AECI supports comment provided by Georgia Transmission Corporation	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
We support EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Katrina Lyons - Georgia System Operations Corporation - 4	
Answer	No
Document Name	

Comment	

GSOC supports Georgia Transmission Corporation's comments:

R3:

- Replace “Each Planning Coordinator shall” with “Each responsible entity, as identified in Requirement R1, shall”. This may require supplemental wording edits in the requirement.
- The inclusion of “other designated study entities” is not clear.
- The SDT should consider combining this requirement with R4.

R4:

- The SDT should consider combining this requirement with R3.

R5:

- The SDT should consider utilizing the recently adopted NERC Glossary term, System Voltage Limits, in this requirement. “…shall have a criteria for acceptable System Voltage Limits for performing the Extreme Temperature Assessment…”
- Since this requirement appears to refer to steady-state voltage, the post contingency voltage deviation portion of the existing requirement should be removed. The resultant steady-state voltage level being outside of acceptable high and low limits is the point of concern. For example, if a low voltage criterion is 0.92 p.u., then voltages below this limit would violate this particular criteria regardless of whether the beginning voltage was 0.95 p.u., 0.98 p.u., or any other voltage level.

R6:

- The following bullet contains a wording addition to clarify the applicability of this requirement to System-wide impacts. This is also consistent with wording in other Reliability Standards when referencing these types of impacts.
- “Each responsible entity, as identified in Requirement R1, shall define and document the criteria or methodology used in the Extreme Temperature Assessment analysis to identify instability, uncontrolled separation, or Cascading of the Bulk Electric System.”

R7 & R8:

- It does not appear likely that P0 events would be “expected to produce more severe System impacts”. Therefore, those events would likely not be part of a benchmark assessment as R7 & R8 are currently written. This is true to a lesser extent to P1 events. Additional clarity to this requirement is needed to determine when and if P0 and P1 events are required.
- The standard does not clearly and specifically state whether steady-state and/or stability analysis is to be performed for the identified events as TPL-001 does for instance. The SDT should consider modifying R7 to allow the responsible entity to develop a methodology or rationale in the performance of a benchmark event to appropriately assess it for that entity’s planning area, otherwise, additional clarity in the analysis expectations is needed. Different weather events would require a different consideration of applicable contingencies and analysis approaches.
- Some of the lack of clarity may be related to the lack of clarity around the composition of the benchmark events to be determined. If these benchmark events are limited to temperature profiles versus temperature profiles and potential resultant generation unavailability (for example), the responsible entity’s analysis approach will potentially vary.

Likes 0	
Dislikes 0	

Response

Brittany Millard - Lincoln Electric System - 5

Answer	No

Document Name	
Comment	

LES supports comments submitted by the MRO NERC Standards Review Forum (NSRF).

Likes 0	
Dislikes 0	
Response	

Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford

Answer	No
Document Name	
Comment	

R3:

- Replace “Each Planning Coordinator shall” with “Each responsible entity, as identified in Requirement R1, shall”. This may require supplemental wording edits in the requirement.
- The inclusion of “other designated study entities” is not clear.
- The SDT should consider combining this requirement with R4.

R4:

- The SDT should consider combining this requirement with R3.

R5:

- The SDT should consider utilizing the recently adopted NERC Glossary term, System Voltage Limits, in this requirement. “…shall have a criteria for acceptable System Voltage Limits for performing the Extreme Temperature Assessment…”
- {Since this requirement appears to refer to steady-state voltage, the post contingency voltage deviation portion of the existing requirement should be removed. The resultant steady-state voltage level being outside of acceptable high and low limits is the point of concern. For example, if a low voltage criterion is 0.92 p.u., then voltages below this limit would violate this particular criteria regardless of whether the beginning voltage was 0.95 p.u., 0.98 p.u., or any other voltage level.

R6:

- The following bullet contains a wording addition to clarify the applicability of this requirement to System-wide impacts. This is also consistent with wording in other Reliability Standards when referencing these types of impacts.
- “Each responsible entity, as identified in Requirement R1, shall define and document the criteria or methodology used in the Extreme Temperature Assessment analysis to identify instability, uncontrolled separation, or Cascading of the Bulk Electric System.”

R7 & R8:

- It does not appear likely that P0 events would be “expected to produce more severe System impacts”. Therefore, those events would likely not be part of a benchmark assessment as R7 & R8 are currently written. This is true to a lesser extent to P1 events. Additional clarity to this requirement is needed to determine when and if P0 and P1 events are required.

- The standard does not clearly and specifically state whether steady-state and/or stability analysis is to be performed for the identified events as TPL-001 does for instance. The SDT should consider modifying R7 to allow the responsible entity to develop a methodology or rationale in the performance of a benchmark event to appropriately assess it for that entity's planning area, otherwise, additional clarity in the analysis expectations is needed. Different weather events would require a different consideration of applicable contingencies and analysis approaches.
- Some of the lack of clarity may be related to the lack of clarity around the composition of the benchmark events to be determined. If these benchmark events are limited to temperature profiles versus temperature profiles and potential resultant generation unavailability (for example), the responsible entity's analysis approach will potentially vary.

Likes 0	
Dislikes 0	

Response

Daniela Atanasovski - APS - Arizona Public Service Co. - 1

Answer	No
Document Name	

Comment

For R3, AZPS suggests it would be clearer to replace "impacted" with adjoining or neighboring Planning Coordinators since they would be the only impacted PCs.

For R4, AZPS is in agreement with developing system models as described, however, AZPS does not agree that it is necessary to maintain or update the model between studies. AZPS suggests the words "and maintain" be struck.

Likes 0	
Dislikes 0	

Response

Glen Farmer - Avista - Avista Corporation - 5

Answer	No
Document Name	

Comment

EEI does not agree with the language contained in requirements R3, R4, R7, and R8 for the reasons expressed below. (See the proposed changes in boldface to Requirement R3 below)

Proposed changes to Requirement R3:

1. EEI suggests it would be clearer to replace "impacted" with adjoining or neighboring Planning Coordinators since they would be the only impacted PCs.

2. EEI also suggests some changes to the subparts of Requirement R3 to better clarify the required tasks under the PC process.

R3. Each Planning Coordinator shall develop and implement a process for coordinating the development of benchmark planning cases among adjoining Planning Coordinator(s), Transmission Planner(s), and other designated study entities under their purview to ensure benchmark events as identified in Requirement R2 are coordinated. This process shall include: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

3.1. Review of the planning study area boundaries under each Transmission Planner, to ensure study completeness.

3.2. Verification that the benchmark planning cases include seasonal and temperature dependent adjustment for Load, generation, Transmission, and transfers which represents the selected benchmark events.

Proposed revisions to Requirement R4

EEI suggests the subparts of Requirement R8 are better placed under Requirement R4 with the edits suggested below:

R4. Each responsible entity, as identified in Requirement R1, shall develop and maintain System models within its planning area for performing the Extreme Temperature Assessment. The System models shall use data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed. System models shall be developed for the following conditions: [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

4.1 System conditions based on each benchmark event selected in Requirement R2 for one of the years in the Long-Term Transmission Planning Horizon.

4.2 For each of the models developed for Requirement R4 Part 4.1, a sensitivity analysis shall be performed to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis shall include, at a minimum, changes to one of the following conditions:

• Generation,

• Real and reactive forecasted Load, or

• Transfers.

Proposed change to Requirement R7:

EEI disagrees with including a requirement to have a documented rationale for the Contingencies selected because it represents an unnecessary administrative burden.

R7. Each responsible entity, as identified in Requirement R1, shall identify the Contingencies used in performing the Extreme Temperature Assessment for each of the event categories in Table 1 that are expected to produce more severe System impacts within its planning area. [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

Proposed changes to Requirement R8

EEI suggests that subparts 8.1 and 8.2 should be placed under Requirement R4. In addition to this change the last sentence in R8 referencing those subparts should be removed. See EEI comments to Requirement R4 below.

R8 Each responsible entity, as identified in Requirement R1, shall complete an Extreme Temperature Assessment of the Long-Term Transmission Planning Horizon at least once every five calendar years, using the benchmark planning cases and the System models identified in Requirement R3 and R4, and the Contingencies identified in Requirement R7 for each of the event categories in Table 1, and document assumptions and results of the steady state and stability analyses. [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

Likes 0	
Dislikes 0	

Response

Michele Shafer - New York State Electric & Gas (NYSEG) - 6

Answer	No
Document Name	

Comment

Our SMEs only over-arching concern with R's 3-8 are regarding potential discrepancy between TPL-008 and TPL-001 results. As far as I'm aware TPL-001 requires the evaluation of "peak load" and does not require a determination of how "extreme" this condition is. If the ERO's TPL-008 Benchmark event results in the derived TPL-008 case(s) being less stressful than an entity's TPL-001 assessment are TPL-001 Corrective Action Plans generated from non P0/P1 events invalidated?

Likes 0	
Dislikes 0	

Response

Michele Tondalo - United Illuminating Co. - 1

Answer	No
Document Name	

Comment

My only over-arching concern with R's 3-8 are regarding potential discrepancy between TPL-008 and TPL-001 results. As far as I'm aware TPL-001 requires the evaluation of "peak load" and does not require a determination of how "extreme" this condition is. If the ERO's TPL-008 Benchmark event results in the derived TPL-008 case(s) being less stressful than an entity's TPL-001 assessment are TPL-001 Corrective Action Plans generated from non P0/P1 events invalidated?

Likes 0	
Dislikes 0	

Response

Chantal Mazza - Chantal Mazza On Behalf of: Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza

Answer	No
Document Name	

Comment

- Regarding R3 and R4—it is not clear what the difference is between "planning cases" (R3) and "system models" (R4). These are not defined in the NERC glossary, and their use here should be clarified.

- Regarding R5, FAC-014-3 R6 requires Planning Coordinators and Transmission Planners to use facility ratings, voltage and stability limits that are equal or more limiting than its respective Reliability Coordinators. Presumably this is intended to give PCs/TPs more leeway in criteria for extreme events, but unless some exception is made for FAC-014-3 R6, there may be no further room possible (particularly if the ordinary planning limits are equal to the operational limits, which is probably typical).
- R7 should clearly indicate which contingency categories are required.
- R4, R5, R6, R7 and R8: "Responsible entity" should be defined in the Applicability section or should replaced with "Each Planning Coordinator, in conjunction with its Transmission Planner(s)..."). Suggest to replace 4.1 to "Responsible Entity" instead of "Functional Entity".
- R6: please complete the phrase"….to identify instability, uncontrolled separation, or Cascading". For example, are we identifying instability, uncontrolled separation, or Cascading of the System? The Interconnection? If that is the case, we suggest to specify "to identify instability, uncontrolled separation, or Cascading of the System" or "to identify instability, uncontrolled separation, or Cascading Interconnection".

Likes 0	
Dislikes 0	

Response

Richard Vendetti - NextEra Energy - 5

Answer	No
Document Name	

Comment

R3-Yes,

R4-Yes,

R5- Yes,

R6- “Due to the potential impact of thermal overloads that could require load drops but do not result in instability or cascading, entities should be required to establish acceptable load drop limit thresholds for addressing thermal overloads identified before utilizing non-consequential load drops as a corrective action plan.

R7- “Due to the prevalence of stuck breaker conditions and their impacts during extreme **cold** conditions, corrective action plans should be required for stuck breaker conditions resulting in voltage violations, thermal violations (beyond load drop limit), or cascading.

R8 – Yes, but comments for R6 & R7 should be addressed.

Likes 0	
Dislikes 0	

Response

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF

Answer	No
Document Name	

Comment

LG&E and KU agrees with EEI's comments.

Likes 0	
Dislikes 0	

Response

Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper

Answer	No
Document Name	

Comment

R3 requires Planning Coordinator (PC) to develop and implement a process to coordinate the development of benchmark planning cases but the benchmark event likely impacts the transmission system beyond the PC’s planning area. The planning cases would not be modeled correctly if it only includes the system conditions within the PC’s area alone. The responsibility of coordinating and developing the models is well beyond the entity’s alone. At a minimum, the Reliability Coordinator (RC) area should be included in the coordination and development process and the event can reach well beyond the RC area.

R4 requires the maintenance of the system models for performing the assessment. If the models have to be developed and coordinated on a regional basis and other entities need to perform the assessment at a different time or year (minimum once every 5 years), the requirement is not clear on the responsibility of the entity in developing and providing the extreme weather models to other entities for the year(s) that the assessment is required to be performed for the entity itself.

Likes 0	
Dislikes 0	

Response

Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	

Comment

EEI does not agree with the language contained in requirements R3, R4, R7, and R8 for the reasons expressed below. (See the proposed changes in boldface to Requirement R3 below)

Proposed changes to Requirement R3:

1. EEI suggests it would be clearer to replace "impacted" with adjoining or neighboring Planning Coordinators since they would be the only impacted PCs.

2. EEI also suggests some changes to the subparts of Requirement R3 to better clarify the required tasks under the PC process.

R3. Each Planning Coordinator shall develop and implement a process for coordinating the development of benchmark planning cases among **adjoining** Planning Coordinator(s), Transmission Planner(s), and other designated study entities **under their purview to ensure** benchmark events as identified in Requirement R2 **are coordinated.** This process shall **include**: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. **Review of the** planning study area **boundaries under each Transmission Planner to ensure study completeness**.

3.2. **Verification that** the benchmark planning cases include seasonal and temperature dependent adjustment for Load, generation, Transmission, and transfers which represents the selected benchmark events.

Proposed revisions to Requirement R4

EEI suggests the subparts of Requirement R8 are better placed under Requirement R4 with the edits suggested below:

R4. Each responsible entity, as identified in Requirement R1, shall develop and maintain System models within its planning area for performing the Extreme Temperature Assessment. The System models shall use data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed**. System models shall be developed for the following conditions:** [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

4.1 System conditions based on each benchmark event selected in Requirement R2 for one of the years in the Long-Term Transmission Planning Horizon.

4.2 For each of the models developed for Requirement R4 Part 4.1, a sensitivity analysis shall be performed to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis shall include, at a minimum, changes to one of the following conditions:

· **Generation,**

· **Real and reactive forecasted Load, or**

· **Transfers.**

Proposed change to Requirement R7:

EEI disagrees with including a requirement to have a documented rationale for the Contingencies selected because it represents an unnecessary administrative burden.

R7. Each responsible entity, as identified in Requirement R1, shall identify the Contingencies used in performing the Extreme Temperature Assessment for each of the event categories in Table 1 that are expected to produce more severe System impacts within its planning area. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

Proposed changes to Requirement R8

EEI suggests that subparts 8.1 and 8.2 should be placed under Requirement R4. In addition to this change the last sentence in R8 referencing those subparts should be removed. See EEI comments to Requirement R4 below.

R8. Each responsible entity, as identified in Requirement R1, shall complete an Extreme Temperature Assessment of the Long-Term Transmission Planning Horizon at least once every five calendar years, using the benchmark planning cases and the System models identified in Requirement R3 and R4, and the Contingencies identified in Requirement R7 for each of the event categories in Table 1, and document assumptions and results of the steady state and stability analyses. [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

Likes 0	
Dislikes 0	

Response

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples

Answer	No
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 4

Likes 0	
Dislikes 0	

Response

Stephen Whaite - Stephen Whaite On Behalf of: Tyler Schwendiman, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies

Answer	No
Document Name	

Comment

Under R6 and the Table 1 Stability Performance Criteria, does the SDT intend for dynamic stability simulation to be required to identify instability, uncontrolled separation, or Cascading consistent with the April 14, 2023 NERC report developed for Project 2023-06 CIP-014? Does the SDT intend for responsible entities to be required to run dynamics for all contingencies, or would for entities be permitted to develop criteria to identify a subset of contingencies for dynamic analysis? RF recommends the drafting team coordinate with the Project 2023-06 CIP-014 Risk Assessment Refinement drafting team to ensure that any best practices being developed by that team in support of drafting a standard to effectively require consistent and effective approaches for evaluating instability, uncontrolled separation, or Cascading are applied in drafting TPL-008.

Additionally, RF is concerned that R8 may not provide enough specificity regarding the time frame to be assessed from the Long-Term Transmission Planning Horizon. Does the SDT intend every year in the horizon to be studied at least once every five calendar years or one year in the horizon to be selected for study (e.g., TPL-001-5.2 R2 Part 2.2.1)?

Lastly, R8 Part 8.2 states that the Extreme Temperature Assessment shall include, at a minimum, changes to one of the following conditions: Generation; Real and reactive forecasted Load; or Transfers. RF is concerned that the assessment should not just consider one of the listed conditions but all of the listed conditions.

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer	No
Document Name	

Comment

MPC supports comments submitted by the MRO NERC Standards Review Forum (NSRF).

Likes 1	Lakeland Electric, 1, Watt Larry
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	No
Document Name	

Comment

Dominion Energy supports EEI comments. In addition, the expectations of what these cases will look like and just how they must be developed is not well-defined in R4.

Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	No
Document Name	
Comment	
R3: Eversource disagrees with the use of the word "impacted" in the following phrase "impacted Planning Coordinator(s), Transmission Planner(s), and other designated study entities…" Eversource suggests using the term "adjacent" as found in other planning standards. If other impacted entities want this information, they can request the entire assessment via R11.	
Likes 0	
Dislikes 0	
Response	
Broc Bruton - Broc Bruton On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Broc Bruton	
Answer	No
Document Name	
Comment	
For R3, Oncor agrees with the idea that the PC should have the responsibility for coordinating and developing benchmark planning cases. For R4, "Each responsible entity…" could be replaced with language that is similar to R3, and it would instead read "Each Planning Coordinator…." For R5, Oncor urges its comment from R4, particularly because the PC would develop and maintain the criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations. For R6, Oncor urges its comment from R5. The PC would need to ensure that all entities use the same methodology and criteria for instability, uncontrolled separation, or Cascading. For R8, Oncor asks whether language can be added to ensure that entities can take credit for studies that are run as part of the Extreme Temperature Assessment rather than running those studies again as part of the assessment to be conducted under TPL-001? For example, the Extreme Temperature Assessment could take the place of the sensitivity analysis required within the TPL-001 assessment.	
Likes 0	

Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Lenise Kimes - City and County of San Francisco - 1,5 - WECC	
Answer	No
Document Name	
Comment	

.

• R3 - The responsibility is assigned to "each PC," but the weather events selected from the ERO library will certainly cross multiple PC footprints in almost every case. This argues for the development of regional processes and the development of base cases that could be used by multiple PC entities. Regional planning groups or the regional entities (such as WECC) may be better groups for developing these processes and base cases than the PC.

o As currently written, R3 does not appear to preclude PCs from working together on this requirement. Does the drafting team envision this as an acceptable way to meet R3?

o If so, an alternative wording might be: Each Planning Coordinator shall coordinate with other impacted Planning Coordinator(s), Transmission Planner(s), and other designated study entities to develop and implement joint and/or individual processes for coordinating the development of benchmark planning cases based on the selected benchmark events as identified in Requirement R2.

• R4 - It would be helpful if this requirement (or other NERC guidance for this requirement) would provide additional details on what additional system models (e.g., steady state and stability) are required and how the required modeling data differs from the current MOD-032 and TPL-001 requirements. There may also be some data requirements for the Extreme Temperature Assessment that are not addressed by the current version of MOD-032, such as special high/cold temperature Facility Ratings, generation de-rating and dispatch patterns, or climate change forecasts that could impact the temperature assumptions for load models. Since MOD-032 does not currently address these data requirements, they need to be addressed in TPL-008 as an appendix, in a Guidelines and Technical Basis section, or in a future modification to MOD-032 itself.

• R5 - As with TPL-007 and TPL-001, it appears that the study criteria are set by the “responsible entity” which is negotiated under R1. While the responsible entity is charged with maintaining system reliability, the criteria will also determine the number of CAPs and amount of transmission investment that are required to meet TPL-008. TPL-001-5.1 is already triggering the need for additional transmission investment over the coming years, so TO/GO entities that will actually pay for the upgrades will be further taxed by TPL-008. The implementation plan needs to be long enough so that the investments for TPL-008 do not coincide closely with the TPL-001-5.1 implementation period.

• R5 – This requirement states that the responsible entity “shall have criteria” while R6 states that the responsible entity “shall define and document criteria?” The wording in R6 appears to be better, since both sets of criteria should be “defined and documented” in each Extreme Temperature Assessment report. It is suggested that the wording from R6 be used for R5.

• R6 - Instability criteria are generally not “adjustable” limits. That is, the system is either unstable or it is not. If the events in the ERO library are too severe and lead to a significant increase in the events that trigger instability, these could be expensive problems to fix. See comments for R2.

• R7 - It would be helpful to see this requirement address the differences between the set of contingencies for TPL-001 rather than an absolute set - this provides more value for all entities rather than showing a largely duplicative full set of outages.

• R7 - P5 events are already very unlikely since they require a fault event plus an equipment failure, which is essentially a multiple outage on par with the likelihood of a P6 event (which is excluded from this standard). The Extreme Temperature event benchmark cases are very unlikely extreme events to begin with (and an extreme sensitivity to the TPL-001 studies), which further reduces the likelihood of having a P5 event during an Extreme Temperature event. In addition, the severity of significant P5 events strongly suggests upgrades will already be identified by the annual Assessment required by TPL-001.

o Given the amount of work already added by this standard, the low likelihood of the P5 events on par with other excluded events from TPL-001 (such as P6), and the strong likelihood that impacts from these events are already adequately captured by the TPL-001 Assessment studies, we strongly recommend removing P5 events from Table 1 of TPL-008.

• R8 - While it is a helpful limitation to only require one assessment year from the Long-Term Planning Horizon, this may not be practicable for the development of CAPs that involve capital investment as these projects require multiple years to permit and construct. The CAPs that involve capital investment will need to be reviewed and refined as the potential violations move into the Near-Term Planning Horizon and prior to the operating horizon. TPL-001 studies will not include the conditions and criteria required to address these studies, so separate Extreme Temperature event benchmark cases will need to be developed for the Near-Term Transmission Planning Horizon to address these cases.

• R8 - Especially for the very first Extreme Temperature Assessment, it is possible that a large number of CAPs may be identified for criteria violations that already exist in the Near-Term Planning Horizon. This will create a backlog of projects which will need to be started immediately to meet the implementation plan period. These projects will be on top of the P5 projects that are already backlogged for implementation of TPL-001-5.1.

o It is recommended that the implementation plan allow a ten-year period for implementation of CAPs that require capital investment to construct new facilities. This would also match up well with performing these studies for the Long-Term Transmission Planning Horizon since the studied case could be a ten year case.

• R8.2 - Sensitivity to generation, load and transfers are already studied as part of TPL-001-5.1. The sensitivity additional studies proposed for R8.2 are unlikely to yield any new information and will be duplicative work for Transmission Planners. The Extreme Temperature Assessment is already a very extreme sensitivity study itself that should already capture modified load, generation, transmission, and transfers befitting this analysis per R3, so it is not needed nor appropriate to study sensitivities for sensitivity cases.

o R8.2 should be removed entirely to reduce unnecessary workload which will provide information that is duplicative and provide no additional value since the studies under this standard are already in effect sensitivities in comparison to the Assessment studies under TPL-001.

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC

Answer	No
Document Name	

Comment

The approval process for benchmark assessments is not clearly defined or mentioned so clarity would be needed there. "Extreme" weather will differ across the geographical footprints and in some cases across an individual TP/PCs footprint. There may be a need to consider impacts within areas of a TP/PCs footprint which may complicate issues but would reflect risks. While Requirement 3.1 appears to capture the thought, are mechanisms in place in planning study tools to accommodate the approach?

The phrase "other designated study entities" is unclear in Requirement R3. How will the parameters be limited (in terms of bandwidth) to allow planning to occur that "represents" the benchmark case? There are no limits as to how many benchmark cases will be developed and could be as simple as 2 (one cold and one hot weather). Is it clear that the benchmark cases will not exactly match the conditions that may need studied but if the flexibility in use is so broad, the benchmark event quality of the assessment could be lost. Requirement 4 – Is that already covered in TPL-001 (develop and maintain)? Requirement 5, Requirements 5, 6, and 7 appears to be very similar to Requirements R5 and R6 in TPL-001-5. In essence the language in R5/R6/R7 may be partially if not wholly duplicative of language in TPL-001-5 and the SDT should consider removal of the requirements and explain what is expected in the Technical Rationale. Requirement 8 sensitivity seems to be limited and may not reveal cases where the extreme weather conditions impose critical reliability issues. Are the sensitivities limited to the "boundary" as called out in Requirement R3.1?

Likes 0	
Dislikes 0	

Response

Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1

Answer	No
Document Name	

Comment

Stability expectations unclear and needs clarification for which sorts of analyses are expected (angular, voltage, freq). Language is similar to TPL-007 but should be more bases on TPL-001.Since this is for wide events,PC should be responsible, not TP.

Likes 0	
Dislikes 0	

Response

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC

Answer	No
Document Name	

Comment

The Standard Drafting Team should clarify how much coordination is required among neighboring PCs. Does "coordination" mean that neighboring PCs must choose the same benchmark event? If the planned study area boundary bisects a PC's planning area, does that PC have to do two benchmark planning cases?

Extreme weather events involve a large geographical area that extends beyond most PCs' footprints, so coordination among "impacted PCs" will be complicated and difficult. It will also be challenging to identify "impacted PCs" without the planning cases and Extreme Temperature Assessment. Using "adjacent PCs" is more practical.

For Requirement R8.2, requiring sensitivity studies on top of the new extreme weather events is extensive and unnecessary.

Likes 0	
Dislikes 0	

Response

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

BPA recommends extreme benchmark events be evaluated for their impact in a larger region than just the TP/PC area. Regional Entities are better situated to select base cases and perform assessments in collaboration with the utilities in the region. Thus, utilities will be better suited to consider mitigation plans in their system based on existing criteria, TPL-001-5.

BPA recommends the P0 base case include all transmission lines in service. While there could be transmission outages, particularly during extreme cold storms, these are addressed in the Operating Horizon by developing and implementing operating plans. Additionally, BPA seeks clarity on how the PC can justify why it selected one set of outages versus another, thereby setting the PC up for a potential compliance failure.

Likes 0	
Dislikes 0	

Response	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	No
Document Name	
Comment	

R3: For R3, Southern Indiana Gas & Electric Company d/b/a CenterPoint Energy Indiana South (SIGE) recommends adding "adjacent" before "impacted" as illustrated below:

R3. Each Planning Coordinator shall develop and implement a process for coordinating the development of benchmark planning cases among ***adjacent*** impacted Planning Coordinator(s), Transmission Planner(s), and other designated study entities based on the selected benchmark events as identified in Requirement R2…

R5: For R5, SIGE requests clarification as to how the criteria for "steady state voltage limits and post-Contingency voltage deviations" under TPL-008, R5 differs from what entities have defined under TPL-001-5.1. SIGE has concerns that R5 may duplicate work already occurring under TPL-001-5.1.

R7: For R7, SIGE recommends revisions to align with R3.1 as well as strike the last sentence of R7. Recommend revisions are illustrated below:

R7**.** Each responsible entity, as identified in Requirement R1, shall identify Contingencies used in performing the Extreme Temperature Assessment for each of the event categories in Table 1 that are expected to produce more severe System impacts within ***its*** planning ***study*** area ***boundary defined in Part 3.1***.

Likes 0	
Dislikes 0	
Response	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	

Please refer to Question 1 comments.

Likes 0	
Dislikes 0	
Response	

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	No
Document Name	
Comment	

BC Hydro appreciates the drafting team's efforts and the opportunity to comment.

1. Requirements R3 & R4: Individual PCs and TPs having to conduct Extreme Temperature Assessments may find these requirements burdensome. As extreme weather events may encompass multiple PC Areas, and depending on the information available in conjunction with benchmark events, the entity identification, benchmark planning cases and system models development and study assumptions can pose significant challenges.

At this stage of development it does not seem clear which entity(ies) will select most appropriate Events for study and how appropriate study basecases are to be created and eventually coordinate the study.

BC Hydro requests that the drafting team clarify obligations among the required entities, and BC Hydro suggests that a Regional Coordinator, such as Regional Reliability Organizations may be more suitable to take an active role in identifying the Events for study, and developing planning study cases that involve multiple PCs within their area. This approach is similar to TPL-007, where WECC collects data from PCs and creates planning cases for use in the PC’s studies.

2. Requirement R4 references MOD-032. Given the expanded scope of data models for the Extreme Temperature Assessments, the current MOD-032 data model specifications may not be adequate.

3. Requirement R8 mandates that entities conduct Extreme Temperature Assessments for both benchmark planning cases (Part 8.1) and sensitivity cases (Part 8.2). Given that extreme weather benchmark planning cases already encompass system conditions during extreme heat or extreme cold events, the benchmark extreme weather planning study may inherently serve as a sensitivity study in addition to the standard TPL-001-5 transmission planning assessment.

4. While recognizing the direction in FERC Order 896 to require sensitivity analyses, there does not seem to be an evaluation statistical/probabilistic or otherwise to inform the selection of adequate contingency and sensitivity scenarios that would lead to a measurable and improved outcome.

BC Hydro appreciates the Technical Rationale discussion and considerations vis-à-vis the FERC Order 896 directive, and suggests that additional analysis or other supporting documentation will be beneficial to further substantiate the required assessment methodology.

Likes 0	
Dislikes 0	
Response	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	No
Document Name	
Comment	

Consumers Energy agrees with the comments and suggestions from EEI:

EEI does not agree with the language contained in requirements R3, R4, R7, and R8 for the reasons expressed below. (See the proposed changes in boldface to Requirement R3 below)

Proposed changes to Requirement R3:

1. EEI suggests it would be clearer to replace “impacted” with adjoining or neighboring Planning Coordinators since they would be the only impacted PCs.

2. EEI also suggests some changes to the subparts of Requirement R3 to better clarify the required tasks under the PC process.

R3. Each Planning Coordinator shall develop and implement a process for coordinating the development of benchmark planning cases among adjoining Planning Coordinator(s), Transmission Planner(s), and other designated study entities under their purview (remove: based on the selected) to ensure benchmark events as identified in Requirement R2 are coordinated. This process shall include: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

3.1. (Remove: Define the) Review of the planning study area (remove: boundary) boundaries under each Transmission Planner, (remove: based) to ensure study completeness.

3.2. Verification that (remove: Modify) the benchmark planning cases (remove: to) include seasonal and temperature dependent adjustment for Load, generation, Transmission, and transfers which represents the selected benchmark events.

Proposed revisions to Requirement R4

EEI suggests the subparts of Requirement R8 are better placed under Requirement R4 with the edits suggested below:

R4. Each responsible entity, as identified in Requirement R1, shall develop and maintain System models within its planning area for performing the Extreme Temperature Assessment. The System models shall use data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed (remove:, and shall represent projected System conditions based on the selected benchmark events as identified in Requirement R2). System models shall be developed for the following conditions: [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

4.1 System conditions based on each benchmark event selected in Requirement R2 for one of the years in the Long-Term Transmission Planning Horizon.

4.2 For each of the models developed for Requirement R4 Part 4.1, a sensitivity model shall be developed to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity model shall include, at a minimum, changes to one of the following conditions:

Generation, Real and reactive forecasted Load, or Transfers.

Proposed change to Requirement R7:

EEI disagrees with including a requirement to have a documented rationale for the Contingencies selected because it represents an unnecessary administrative burden.

R7. Each responsible entity, as identified in Requirement R1, shall identify the Contingencies used in performing the Extreme Temperature Assessment for each of the event categories in Table 1 that are expected to produce more severe System impacts within its planning area. (Remove: The rationale for those Contingencies selected for evaluation shall be available as supporting information.) [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

Proposed changes to Requirement R8

EEI suggests that subparts 8.1 and 8.2 should be placed under Requirement R4. In addition to this change the last sentence in R8 referencing those subparts should be removed. See EEI comments to Requirement R4 below.

R8 Each responsible entity, as identified in Requirement R1, shall complete an Extreme Temperature Assessment of the Long-Term Transmission Planning Horizon at least once every five calendar years, using the benchmark planning cases and the System models identified in Requirement R3 and R4, and the Contingencies identified in Requirement R7 for each of the event categories in Table 1, and document assumptions and results of the steady state and stability analyses. (Remove: The Extreme Temperature Assessment shall include the following.) [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

Likes 0	
Dislikes 0	

Response

Isidoro Behar - Long Island Power Authority - 1

Answer	No
Document Name	

Comment

Regarding R3:

R3 requires the development of benchmark planning cases based on the selected benchmark events as identified in Requirement R2.

R3.2 states:

“The process shall… Modify the benchmark planning cases to include seasonal and temperature dependent adjustment for Load, generation, Transmission, and transfers which represents the selected benchmark events.”

The intent of the phrase “modify the benchmark planning cases” and the overall intent of R3.2 is not entirely clear.

We recommend to clarify the wording of “modify the benchmark planning cases”, and R3.2 as a whole - such as:

“3.2 The process shall require that the benchmark planning cases reflect seasonal and temperature dependent adjustment(s) for Load, generation, Transmission, and transfers that are representative of the selected benchmark events.”

In other words, the benchmark planning cases to be developed should reflect the adjustments specified in R3.2.

Regarding R4:

R4 mentions “shall represent projected System conditions based on the selected benchmark events as identified in Requirement R2”.

Question for SDT: is this phrasing consistent with (or redundant to) the wording in R3.2?

Regarding R3 and R4—it is not clear what the difference is between “planning cases” (R3) and “system models” (R4). These are not defined in the NERC glossary, and their use here should be clarified.

Regarding R5, which states:

”Each responsible entity, as identified in Requirement R1, shall have criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations for performing the Extreme Temperature Assessment in accordance with Requirement R3.”

We believe the reference to Requirement 3 is misplaced. Recommend to either remove the reference to R3, or change to reference to R8 (which specifies the completion of an Extreme Temperature Assessment).

Question for SDT: was thermal criteria intentionally omitted from R5?

Regarding Measure 5: We believe the reference to Requirement 5 is misplaced. Recommend to either remove the reference to R5, or change to reference to R8 (which specifies the completion of an Extreme Temperature Assessment).

Regarding R5, FAC-014-3 R6 requires Planning Coordinators and Transmission Planners to use facility ratings, voltage and stability limits that are equal or more limiting than its respective Reliability Coordinators.

Question for SDT: Does FAC-014-3 R6 still apply for the Extreme Temperature Assessment, or can the PC / TP choose less stringent criteria than the criteria specified in the RC’s SOL methodology?

Regarding R7:

“Each responsible entity, as identified in Requirement R1, shall identify Contingencies used in performing the Extreme Temperature Assessment for each of the event categories in Table 1 that are expected to produce more severe System impacts within its planning area. The rationale for those Contingencies selected for evaluation shall be available as supporting information.”

Recommend to replace the term “event categories” with the term “planning events, to be more consistent with TPL-001-5.1 R3.4.

Regarding R8:

It is recommended to expand this requirement to clearly indicate that steady state and stability analyses are both required for the Extreme Temperature assessment (for example, consider using the phrase “shall consist of steady state and stability analyses” ….).

Likes 0	
Dislikes 0	

Response

Ben Hammer - Western Area Power Administration - 1

Answer	No
Document Name	
Comment	

Please address the following in R3-R8:

R3 – Please clarify obligations on coordination with neighboring PCs to perform an Extreme Temperature Assessment. If the particular extreme heat or extreme cold benchmark event is only applicable to a limited portion of a PC's footprint (Part 3.1), verify that the PC has satisfied it obligation under R2 for completing an Extreme Temperature Assessment for either "one extreme heat benchmark event or one extreme cold benchmark event" for that five-calendar year period (R8).

R4 – Revisit after benchmark event cases are available.

R5 – R5 may be duplicative of work being performed under TPL-005.1. How is the criteria for steady state voltage limits and post-Contingency voltage deviations under TPL-008, R5 different than what entities have defined under TPL-001-5.1?

R6 - R6 may duplicate work that is already occurring under TPL-001-5.1, PRC-006, etc. or be excessive as found to be the case with Recommendation #11 in the FERC-NERC Winter Storm Elliott Report. In that case, inertia and frequency data indicated Winter Storm Elliott was not a low inertia event; but rather a shortage of generation event. As a shortage of generation event, Winter Storm Elliott no longer warrants the level of effort required to conduct an inertia study. In lieu of a study, a report will be written to describe the analysis completed in support of the recommendation. Similarly, Winter Storm Uri was tied to under-frequency load shed (UFLS) and UFLS design assessments performed pursuant to PRC-006.

Please justify the need for R6 by:

Describing where there have been extreme temperature events which have resulted in system instability, uncontrolled separation, or Cascading and

To consider providing planning entities with an "off-ramp" (e.g. written report) when analysis indicates an Extreme Temperature Assessment is not warranted.

R7 – To clarify that the Extreme Temperature Assessment is limited to the planning study area boundary defined in Part 3.1., it is requested that the SDT modify requirement R7 as follows:

R7. Each responsible entity, as identified in Requirement R1, shall identify Contingencies used in performing the Extreme Temperature Assessment for each of the event categories in Table 1 that are expected to produce more severe System impacts within the planning study area boundary defined in Part 3.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

Likes 1	Lakeland Electric, 1, Watt Larry
Dislikes 0	
Response	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	No
Document Name	
Comment	

FirstEnergy requests additional clarity on coordination when more than one PC/TP are impacted – basically the management of different processes across PC/TP footprints.

In addition, FirstEnergy requests the Drafting Team look at the possibility of a responsible entity to have multiple benchmark cases for those footprints that include differing extreme heat or extreme cold weather conditions in its single footprint of responsibility.

Likes 0	
Dislikes 0	
Response	

Robert Follini - Avista - Avista Corporation - 3

Answer	No
Document Name	
Comment	

The area of impact is vague and should be clearly defined.

Likes 0	
Dislikes 0	
Response	

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO

Answer	No
Document Name	
Comment	

Requirement 3.2 states that adjustments must be made for load, generation, transmission, and transfers. This will be a significant undertaking for industry load forecasting entities, generator owners, and transmission owners to respond to information requests from the entities responsible for the development of the benchmark planning cases (Planning Coordinators and Transmission Planners). It is recommended that NERC work with industry to develop a guideline and best practices document to determine where reasonable approximations can be made without submitting information requests to Distribution Providers, Generator Owners, and Transmission Owners.

It would be preferred if the ERO's review of past events could be used to develop relatively simple recommendations for the PC/TP to use in their extreme heat and extreme cold benchmarks. For example, the extreme cold event could consider a temperature 5C below historic maximum cold weather events. The PC/TP should document their assumptions on expected generator availability and imports.

The PC/TP are in the best position to develop their own planning cases that reflect seasonal and temperature dependent adjustments to load, generation and transfers. The planning study area boundary should be limited to the PC area in order to develop corrective action plans that have a chance on being implemented. Neighbouring PCs should have an opportunity to review cases (optional) and study plans and assumptions so that the availability of imports and generation can be modeled more accurately.

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments

Answer	No
Document Name	

Comment

Black Hills Corporation agrees with the proposed changes from EEI. 4.1 and 4.2 are better suited to be part of Requirement R4. Black Hills Corporation agrees with EEI's proposed changes to Requirements R7 and R8. This commentary from EEI is included below:

EEI does not agree with the language contained in requirements R3, R4, R7, and R8 for the reasons expressed below. (See the proposed changes in boldface to Requirement R3 below)

Proposed changes to Requirement R3:

1. EEI suggests it would be clearer to replace "impacted" with adjoining or neighboring Planning Coordinators since they would be the only impacted PCs.

2. EEI also suggests some changes to the subparts of Requirement R3 to better clarify the required tasks under the PC process.

R3. Each Planning Coordinator shall develop and implement a process for coordinating the development of benchmark planning cases among **adjoining** Planning Coordinator(s), Transmission Planner(s), and other designated study entities **under their purview (*remove:* based on the selected) to ensure** benchmark events as identified in Requirement R2 **are coordinated.** This process shall **include**: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. (*Remove:* Define the) Review of the planning study area (*remove:* **boundary) boundaries under each Transmission Planner, (*remove*: based) to ensure study completeness**.

3.2. Verification that (*remove:* Modify) the benchmark planning cases (*remove:* **to)** include seasonal and temperature dependent adjustment for Load, generation, Transmission, and transfers which represents the selected benchmark events.

Proposed revisions to Requirement R4

EEI suggests the subparts of Requirement R8 are better placed under Requirement R4 with the edits suggested below:

R4. Each responsible entity, as identified in Requirement R1, shall develop and maintain System models within its planning area for performing the Extreme Temperature Assessment. The System models shall use data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed (*remove:*, **and shall represent projected System conditions based on the selected benchmark events as identified in Requirement R2). System models shall be developed for the following conditions:** [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

4.1 System conditions based on each benchmark event selected in Requirement R2 for one of the years in the Long-Term Transmission Planning Horizon.

4.2 For each of the models developed for Requirement R4 Part 4.1, a sensitivity model shall be developed to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity model shall include, at a minimum, changes to one of the following conditions:

- **Generation,**
- **Real and reactive forecasted Load, or**
- **Transfers.**

Proposed change to Requirement R7:

EEI disagrees with including a requirement to have a documented rationale for the Contingencies selected because it represents an unnecessary administrative burden.

R7. Each responsible entity, as identified in Requirement R1, shall identify the Contingencies used in performing the Extreme Temperature Assessment for each of the event categories in Table 1 that are expected to produce more severe System impacts within its planning area. (*Remove:* **The rationale for those Contingencies selected for evaluation shall be available as supporting information.)** *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

Proposed changes to Requirement R8

EEI suggests that subparts 8.1 and 8.2 should be placed under Requirement R4. In addition to this change the last sentence in R8 referencing those subparts should be removed. See EEI comments to Requirement R4 below.

R8 Each responsible entity, as identified in Requirement R1, shall complete an Extreme Temperature Assessment of the Long-Term Transmission Planning Horizon at least once every five calendar years, using the benchmark planning cases and the System models identified in Requirement R3 and R4, and the Contingencies identified in Requirement R7 for each of the event categories in Table 1, and document assumptions and results of the steady state and stability analyses. (*Remove:* **The Extreme Temperature Assessment shall include the following.)** [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

Likes 0	
Dislikes 0	

Response

Michael Whitney - Northern California Power Agency - 3, Group Name NCPA	
Answer	No
Document Name	

Comment

NO, These assessment should be performed by the Regional Entities. There appears to be too much room for coordination issues having one Transmission Planner (TP) or Planning Coordinator (PC) having to rely on other TPs or PCs to meet their requirement deadlines.

Likes 0	
Dislikes 0	

Response

Lauren Giordano - Lauren Giordano On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; Michael Whitney, Northern California Power Agency, 4, 6, 3, 5; - Lauren Giordano

Answer	No
Document Name	

Comment

NO, These assessment should be performed by the Regional Entities. There appears to be too much room for coordination issues having one Transmission Planner (TP) or Planning Coordinator (PC) having to rely on other TPs or PCs to meet their requirement deadlines.

Likes 0	
Dislikes 0	

Response

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1 - WECC

Answer	No
Document Name	

Comment

R3: No. This requirement doesn't put boundaries on adjacent entities for requesting unlimited cases. Proposed language: **"Each PC shall develop and implement a process for development of benchmark planning cases among entities within its PC Area based on the benchmark events selected in Requirement R2. This process shall:**

3.1 (no change)

3.2 (no change)

R4-R6: No. The issue is with double jeopardy with TPL-001-5.1 not the language since it is already included as a similar requirement in TPL-001-5. No problem if this is in a single standard.

R7: Yes but should specify P0, P1, P2, P4, P5, P7 not refer to events in Table 1 of this standard. Table 1 is used to commonly refer to Table 1 of TPL-001-5 and the incomplete list of Planning Events can be confusing.

R8: No. Eliminate subrequirement 8.2. Sensitivity analysis is overly burdensome for an extreme weather scenario. We are already looking at unusual circumstances and now adding more on top of it with generation, load, or transfer changes.

Documenting assumptions and results is separate from performing analysis and should be in different requirements.	
Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	

We can agree with the majority of the requirements. However, we are unable to agree with the concept of a sensitivity analysis for an extreme scenario as likely contemplated by the benchmark scenarios required. As noted previously, we are unable to agree with R2 due to lack of clarity. Accordingly, we are not able to agree with R8.2, suggesting that a sensitivity analysis may be required to be performed in addition to what is likely to be an excessively extreme scenario, as determined by the extreme temperature assessment. This requirement seems to suggest we assess an extreme scenario in addition to the extreme scenario.

In summary, there is a current lack of detail about how the extreme weather event base cases will be constructed. The information is not present in either the standard or guidance document. Due to this lack of detail there are several possible objections to how the cases might be put together.

For example, since the study is already required to consider the contingencies listed in the Table 1, the extreme weather event base cases should only consider total system load and generation dispatch but not any additional transmission outages that were occurring at the time of the event.

Likes 1	Lakeland Electric, 1, Watt Larry
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

While it is reasonable to allow five years for both preparing-for and conducting a “first time study”, as well as for the frequency of updating benchmark data, we believe three years would be reasonable for conducting the subsequent studies. Refining those studies to properly reflect changes in system topology and connected generation equipment would not likely require five years, so the team may wish to consider a three-year frequency instead.

AEP disagrees with the proposed inclusion of load shed in the obligations of TPL-008. AEP believes that the Transmission system should be designed to securely operate at N-1 conditions and avoid preemptive load shed that would occur for secure operations. If load shed remains in the standard, it should be allowed only for conditions more stringent than N-1 conditions. We believe this opinion is supported by the observations made in FERC Order 896.

Likes 1	Lakeland Electric, 1, Watt Larry
Dislikes 0	

Response

Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD

Answer	No
Document Name	

Comment

TPL-008-1 R3 uses the term “impacted”, while TPL-001-5.1 uses “adjacent” under R3.4.1 and R4.4.1. TPL-008-1 R3 also includes “other designated study entities”, which is vague on the intent of this statement. “Impacted” is not a clear term for this requirement because one will not know who is impacted until a study is performed. Similarly, but on the opposite spectrum of the risk, one may have adjacent entities that one determines are not “impacted” and thus are not involved. It is better to have adjacent entities able to speak in to a process, whether or not a certain process determines they are impacted.

We recommend the statement “other designated study entities” be removed from R3. For example, “Each Planning Coordinator shall develop and implement a process for coordinating the development of benchmark planning cases among adjacent Planning Coordinator(s), and Transmission Planner(s) based on the selected benchmark events as identified in Requirement R2”.

R8 is not clear using the term “sensitivity”. TPL-001-5 more clearly calls out which cases and types of analysis are required for the sensitivity. From the existing language, it is unclear if applying the sensitivity to extreme heat OR extreme cold is sufficient, or if this should be extreme heat AND extreme cold. Similarly, is it steady state OR stability, or steady state AND stability? For example, “The sensitivity analysis should be run for each of the extreme heat and extreme cold event assessments, both for the steady state and transient stability portions of the assessment”. In this manner, the expectation is clear as to the scope of the sensitivity work.

In Order 881, the topic of ratings has become of interest for operations. A potentially beneficial sensitivity option not currently included would be a sensitivity of ratings. For example, assuming a higher temperature as input to the planning ratings. Such an additional sensitivity could be beneficial in helping entities better understand such relationships.

Likes 1	Lakeland Electric, 1, Watt Larry
Dislikes 0	

Response

Jeffrey Streifling - NB Power Corporation - 1

Answer	No
Document Name	

Comment

Regarding R3 and R4—it is not clear what the difference is between “planning cases” (R3) and “system models” (R4). These are not defined in the NERC glossary, and their use here should be clarified.

Regarding R5, FAC-014-3 R6 requires Planning Co-ordinators and Transmission Planners to use facility ratings, voltage and stability limits that are equal or more limiting than its respective Reliability Co-ordinators. Presumably this is intended to give PCs/TPs more leeway in criteria for extreme events, but unless some exception is made for FAC-014-3 R6, there may be no further room possible (particularly if the ordinary planning limits are equal to the operational limits, which is probably typical).

R7 should clearly indicate which contingency categories are required.

Likes 1	Lakeland Electric, 1, Watt Larry
Dislikes 0	

Response

Srikanth Chennupati - Entergy - Entergy Services, Inc. - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

Please Provide clarity in the difference between benchmark planning cases mentioned in R3 and system models mentioned in R4. R8 seems to use these interchangeably.

Likes 0	
Dislikes 0	

Response

Kevin Conway - Western Power Pool - 4

Answer	No
Document Name	

Comment

As R1 currently reads, only the Planning Coordinator is responsible for compliance.

The study boundary definition needs clarity. How is it defined? Is it fixed? Does it vary by Extreme Event?

For the setup of the base cases, is this a Mod 032 approach in that the gens/loads/transfers would be modeled in to match the conditions of the historical event and then outages be taken on that case? It is unclear if a generator that went out due to the extreme weather event in real-time would be modeled as in or out of service in the reference/benchmark case.

What if you and your neighbors disagree on the Event? The boundary? Etc.

Under R3 There's some debate about what a "Benchmark" case represents, since it's not very well defined. Transmission Planners are unsure what R3 requires them to do: Does this include modeling all generation outages, or not? Our interpretation is to adjust things based on temperature; if a generator cannot operate at “x” temperature, because it’s too hot or too cold, then it should be off. If the pipeline freezes up and can’t provide fuel at “x” temperature, you have plan for generator outages and should model it as such.

In reference to R4, citing MOD-032 is not a good practice in standards writing. It is possible that MOD-032 could be rewritten, superseded, or retired and that would negatively affect this proposed standard. Perhaps the wording should be modified to state that "The System models shall use data consistent with that provided in accordance with accepted Power System Modeling standards, supplemented by other sources as needed..."

In R5, shouldn't the Planning Coordinator ensure all entities are using the same criteria for acceptable System steady state voltage limits? If each entity uses something different then these studies are not fully coordinated, and it is the functional responsibility to coordinate these types of studies.

R6 has the same flaw that R5 has. The responsible entities need to meet criterion that the Planning Coordinator sets, not what is in its own best interest.

R7 must still be coordinated with the Planning Coordinator and should include both internal and external contingencies. Some entities may try and limit contingencies to what gives them the most manageable performance. Again, the Planning Coordinator must make sure there is consistency across all of the Transmission Planners in its area.

In R8 the need for each entity to complete an Extreme Temperature Assessment seems to duplicate work, when the Transmission Planners should be providing data to the Planning Coordinator and having them do it for the entire footprint. This also does not allow smaller entities to collaborate and combine resources to address a larger footprint. R8 does not address changes to assumptions once an assessment is done, nor does it address changes in the extreme heat benchmark events and extreme cold benchmark events, from the approved benchmark library maintained by the Electric Reliability Organization (ERO).

Likes 1	Lakeland Electric, 1, Watt Larry
Dislikes 0	

Response

Lidija Efremova - Lidija Efremova On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Lidija Efremova

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Carver Powers - Utility Services, Inc. - 4

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Matthew Jaramilla, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Apollonia Gonzales - PNM Resources - 1,3 - WECC,Texas RE

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Mark Flanary - Midwest Reliability Organization - 10

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE has the following comments:

- Requirement R3 includes "other designated study entities" in the requirement language, but is not clear who these "other designated study entities" are. Please clarify.
- In Requirement R5, Texas RE recommends stating an acceptable deviation range or by including 'acceptable based on common industry practice or technical basis as it is currently open-ended as to what criteria is "acceptable" for System steady state voltage limits and post-Contingency voltage deviations. Having a criteria would lead to more consistent application and oversight.

The provided Technical Rationale notes that, "The establishment of these criteria allows auditors to compare the results of the assessment with the established criteria." Texas RE is concerned, however, this could lead to an entity setting its criteria too broadly (allow for too much deviation) and circumvent the intent Requirement R5.

- In Requirement Part 8.2, Texas RE recommends adding the following language: "Justification for the particular condition changes to the Sensitivity analysis should be included."

Likes 0	
Dislikes 0	
Response	

Alison MacKellar - Constellation - 5	
Answer	
Document Name	
Comment	

Constellation has no comments

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6	
Answer	
Document Name	
Comment	

Constellation has no comments

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

5. Do you agree with the proposed TPL-008-1 Reliability Standard Requirements R9 – R10 (CAPs and possible actions)? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Kevin Conway - Western Power Pool - 4	
Answer	No
Document Name	
Comment	
The requirements for Corrective Action Plans, as discussed in R9 and R10, fail to have any associated detail regarding expectations, plan approvals and validation of completion. Maybe the Drafting Team should consider Mitigations rather than Corrective Action Plans, since the entity is trying to mitigate future problems through operation actions, construction or technology.	
Likes 0	
Dislikes 0	
Response	
Srikanth Chennupati - Entergy - Entergy Services, Inc. - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Transmission projects developed and constructed to meet R9 will quickly be invalidated. GIA and TSR studies will not include these extreme temperature assessments, resulting in the additional capacity that was built (at retail ratepayers' expense) to improve reliability in extreme circumstances being reallocated to allow generators to deliver power across the transmission system.	
Likes 1	Lakeland Electric, 1, Watt Larry
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
R10 - We can write-up recommendations but as as a Transmission Planner we don't have the authority,	
Likes 0	

Dislikes 0	
Response	
Jeffrey Streifling - NB Power Corporation - 1	
Answer	No
Document Name	
Comment	
R9 indicates that CAPs should be developed "…when the benchmark planning case study results indicate the System is unable to meet performance requirements…" but it is not clear whether the sensitivity analysis is included in "benchmark planning case study results". For comparison, TPL-001-5.1 states that "Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case…." Should something similar be stated in TPL-008, or is the intent that any case or sensitivity performance violation should trigger a CAP? Additionally, R9 requires that "The responsible entities shall share their CAPs with, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues." This is unique to this standard and should be removed.	
Likes 1	Lakeland Electric, 1, Watt Larry
Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	No
Document Name	
Comment	
It is unclear if CAPs are required for sensitivity deficiencies. TPL-001-5.1 addresses such things in R2.7.2, however TPL-008-1 does not. In addition, it is unclear if the sensitivity needs to be run on each R2/R4 case, or only one case. Again, TPL-001-5.1 uses clearer language in R2.1.3. During the 04/12/2024 Industry Webinar, the SDT indicated CAPs in R9 and the additional evaluation under R10 are not intended to be applicable to the sensitivity portion of the analysis. However, there is no language currently in the standard for this. An auditor, reading the existing language and TPL-001-5.1 precedence, could possibly expect additional analysis, which was not intended. Furthermore, the language regarding applicable regulatory authorities or governing bodies review of CAPs seems like it was originally from the TPL-001-5.1 language regarding the use of load shedding for certain P1, P2, and P3 events. As it is currently written, TPL-008 is not consistent with the risk based approach utilized by TPL-001-5.1 as the TPL-008-1 review by applicable regulatory authorities or governing bodies would be universally required for all CAPs, not just those that use load shedding as the solution for performance deficiencies (a more limited case under TPL-001-5.1). It is recommended this language/approach be modified to be consistent with TPL-001-5.1. CAPs themselves do not require such a level of regulatory review, but if an entity chooses to use load shedding as a solution under R9, then that choice would warrant the additional level of regulatory review.	
Likes 0	

Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	No
Document Name	

Comment

Please see our response to Question #4 regarding load shed considerations.

Likes 0	
Dislikes 0	

Response

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1 - WECC

Answer	No
Document Name	

Comment

R9: No CAPs are overkill for extreme weather events and will add an undue burden on the ratepayers for capital projects. Development of operating procedures up to and including non-consequential load loss and curtailment of firm transfers should be sufficient for mitigating extreme weather events.

R10: Acceptable

Likes 0	
Dislikes 0	

Response

Lauren Giordano - Lauren Giordano On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; Michael Whitney, Northern California Power Agency, 4, 6, 3, 5; - Lauren Giordano

Answer	No
Document Name	

Comment

NO, These assessment should be performed by the Regional Entities. There appears to be too much room for coordination issues having one Transmission Planner (TP) or Planning Coordinator (PC) having to rely on other TPs or PCs to meet their requirement deadlines.

Likes 0	
Dislikes 0	

Response

Michael Whitney - Northern California Power Agency - 3, Group Name NCPA	
Answer	No
Document Name	

Comment

NO, These assessment should be performed by the Regional Entities. There appears to be too much room for coordination issues having one Transmission Planner (TP) or Planning Coordinator (PC) having to rely on other TPs or PCs to meet their requirement deadlines.

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	No
Document Name	

Comment

Black Hills Corporation agrees with EEI's comments on Requirement R9. Modifying the language to match what is in TPL-001-5.1 would better suit this new standard.

EEI suggests the following modifications to Requirement R9 to better clarify entity obligations under a TPL-008 CAP:

1. The language in TPL-001 relative to Corrective Action Plans is clearer and we suggest closer alignment to that language (see the suggested language below).

2. While PCs and TPs have obligations to notify regulatory authorities and other governing bodies responsible for retail electric service where load shedding is incorporated into planning contingencies, this should not be included in a NERC Reliability Standard.

3. Add language similar to that used in Requirement 2, subpart 2.7.3 for situations where TPs and PCs are unable to meeting CAP timeframes.

Proposed Changes to Requirement R9

R9. For Extreme Weather Assessments, which fail to meet the performance requirements for Table 1 P0 or P1 Contingencies, the assessment shall include Corrective Action Plan(s) (CAPs) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments, but the planned System shall continue to meet the performance requirements in Table 1 P0 and P1.

9.1 If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

Likes 0	
Dislikes 0	

Response

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO

Answer	No
Document Name	

Comment

How are the criteria for steady-state voltage limits and post-contingency voltage deviations under TPL-008, R5 different from the criteria established for TPL-001-5.1?

Refer to question 7 comments regarding the requirement to develop Corrective Action Plans for P1 events where system steady state voltages are outside limits and applicable facility ratings are exceeded.

Likes 0	
Dislikes 0	

Response

Robert Follini - Avista - Avista Corporation - 3

Answer	No
Document Name	

Comment

The function of NERC is to ensure bulk electric system delivery of power, not ensure communication with regulatory authorities or governing bodies external to NERC.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	

FirstEnergy request clarification of who is the intended audience of the Drafting Team for “applicable regulatory authorities or governing bodies responsible for retail electric service issues” and request clarification and/or focus on NERC Registered Entity assigned in the standard who have responsibility for R9’s sharing of CAPs.

Likes 0	
Dislikes 0	
Response	

Ben Hammer - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	

WAPA understands that the draft TPL-008-1 Requirement R9 attempts to strike a compromise between obligations to notify and solicit feedback (“low bar”) from applicable regulatory authorities or governing bodies responsible for retail electric service, versus the precedent obligations (“high bar”) established by TPL-001-5.1 Attachment 1 where the “Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non- Consequential Load Loss under footnote 12.” WAPA agrees with the compromise that the Project 2023-07 SDT has drafted, but recommends a slight simplification to Requirement R9:

R9. Each responsible entity, as identified in Requirement R1, shall develop a Corrective Action Plan(s) (CAPs) when the benchmark planning case study results indicate the System is unable to meet performance requirements for Table 1 P0 or P1 Contingencies. The responsible entities *shall* make their CAP(s), *including alternative(s) considered where Load shed is an allowed element of a CAP, available to* applicable regulatory authorities or governing bodies responsible for retail electric service issues. Revisions to the CAP(s) are allowed in subsequent Extreme Temperature Assessments, but the planned System shall continue to meet the performance requirements.

As background, WAPA as a federal agency is not subject to state regulatory authorities that are responsible for retail electric service. As a result, WAPA would does not have an "applicable regulatory authority or governing body" for retail electric service issues.

Likes 0	
Dislikes 0	
Response	

Isidoro Behar - Long Island Power Authority - 1	
Answer	No
Document Name	

Comment	
Regarding R9: The use of the term "Load shed" should be replaced with "Non-Consequential Load Loss", to be consistent with Table 1: Contingencies and Performance Criteria. Regarding R9: In terms of developing a CAP for the "benchmark planning case study results", it is not clear if the development of a CAP is required for the sensitivity analysis. Consistency of language with TPL-001-5.1 R2.7 should be considered.	
Likes 0	
Dislikes 0	
Response	

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF

Answer	No
Document Name	
Comment	
Consumers Energy agrees with the ocmment by CHPD: It is unclear if CAPs are required for sensitivity deficiencies. TPL-001-5.1 addresses such things in R2.7.2, however TPL-008-1 does not. In addition, it is unclear if the sensitivity needs to be run on each R2/R4 case, or only one case. Again, TPL-001-5.1 uses clearer language in R2.1.3. During the 04/12/2024 Industry Webinar, the SDT indicated CAPs in R9 and the additional evaluation under R10 are not intended to be applicable to the sensitivity portion of the analysis. However, there is no language currently in the standard for this. An auditor, reading the existing language and TPL-001-5.1 precedence, could possibly expect additional analysis, which was not intended. Furthermore, the language regarding applicable regulatory authorities or governing bodies review of CAPs seems like it was originally from the TPL-001-5.1 language regarding the use of load shedding for certain P1, P2, and P3 events. As it is currently written, TPL-008 is not consistent with the risk based approach utilized by TPL-001-5.1 as the TPL-008-1 review by applicable regulatory authorities or governing bodies would be universally required for all CAPs, not just those that use load shedding as the solution for performance deficiencies (a more limited case under TPL-001-5.1). It is recommended this language/approach be modified to be consistent with TPL-001-5.1. CAPs themselves do not require such a level of regulatory review, but if an entity chooses to use load shedding as a solution under R9, then that choice would warrant the additional level of regulatory review.	
Likes 0	
Dislikes 0	
Response	

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No

Document Name	

Comment
Please refer to Question 1 comments.

Likes 0	
Dislikes 0	

Response

Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF

Answer	No
Document Name	

Comment

R9: Similarly to other commenters, Southern Indiana Gas & Electric Company d/b/a CenterPoint Energy Indiana South (SIGE) is requesting clarification as to whether CAPS are required for sensitivity deficiencies and if the sensitivity needs to be run on each R2/R4 case or only one case.

Additionally, SIGE is recommending removing “The responsible entities shall share their CAPs with, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues” and “but the planned System shall continue to meet the performance requirements.” Changes are illustrated below:

R9. Each responsible entity, as identified in Requirement R1, shall develop a Corrective Action Plan(s) (CAPs) when the benchmark planning case study results indicate the System is unable to meet performance requirements for Table 1 P0 or P1 Contingencies.

In addition, where Load shed is allowed as an element of a CAP for the Table 1 P1 Contingency, the responsible entity shall document the alternative(s) considered, as mentioned in Requirement R10, and notify the applicable regulatory authorities or governing bodies responsible for retail electric service issues. Revisions to the CAP(s) are allowed in subsequent Extreme Temperature Assessments.

Likes 0	
Dislikes 0	

Response

Apollonia Gonzales - PNM Resources - 1,3 - WECC,Texas RE

Answer	No
Document Name	

Comment

PNMR requests the SDT provide more justification for including the regulatory authorities or governing bodies responsible for retail electric service issues.

Likes 0	
Dislikes 0	

Response

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

Since the Standard covers the Planning Horizon, BPA recommends the P0 base case include all transmission lines in service. If P0 case already includes multiple transmission outages, it is very likely Corrective Action Plans will be cost-prohibitive and cause undue burden on transmission providers. P0 case transmission outages could be treated as sensitivities in R8 with no CAP requirement. BPA highly recommends that P5 not be included as part of the required studies because extreme weather conditions expose outdoor EHV elements and do not affect protective relaying.

Likes 0	
Dislikes 0	

Response

Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1

Answer	No
Document Name	

Comment

Proposed TPL-008 has sensitivities, unclear if CAPs are needed. Requirement R9 does not capture how TPL-001 approach.

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC

Answer	No
Document Name	

Comment

R9 language is similar to a footnote in TPL-001 that requires a process (now captured in the ERO Enterprise Periodic Data Schedule.) As such clarity and consistency with the language should be sought out. Additionally, does the language meet the requirements within TPL-001? "Sharing" of the CAPs is not defined and more clarity on timing, method, and expectations needs to be provided. R10--It is not clear what the responsible entity will do with the "possible actions". If anything they should be provided to the operators (BA/RC/TOPs) to prepare Plans/Processes as needed. In one respect if the Assessment is only done once per 5 calendar years, how valuable are the corrective actions for the assessment without updates as the system changes are/are not implemented?	
Likes 0	
Dislikes 0	
Response	

Lenise Kimes - City and County of San Francisco - 1,5 - WECC	
Answer	No
Document Name	
Comment	

• R9 – As written, this requirement states that the responsible entity “shall develop” CAPs for P0 and P1, but does not state if these CAPs must be “implemented” prior to the operating horizon. TPL-001-5.1, R2.7.3 allows use of NCLL under circumstances where CAPs cannot be implemented in the required timeframe (i.e., prior to the operating horizon). TPL-008, Table 1 allows for use of NCLL for P1, P2, P4, P5 and P7 events, but not for P0.

o Are entities required to implement CAPs prior to the operating horizon, including construction of capital projects?

o If an entity is unable to complete a capital project or implement an Operating Plan prior to the operating horizon, would NCLL be allowed for P0?

o We recommend that this situation be addressed in a similar fashion to TPL-001.

• R9 uses the term “Load shed”, but Table 1 in TPL-008 and TPL-001 both use the term NCLL.

o We recommend that R9 be revised to use the term “NCLL” instead of “Load shed” for consistency and clarity.

• R10 – As discussed in the comments for R7, we strongly recommend that P5 be removed from R7, R10, and Table 1 due to the low probability of such events during Extreme Temperature events.

Likes 0	
Dislikes 0	
Response	

Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Matthew Jaramilla, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	No
Document Name	
Comment	
SRP feels that this is far too much in a single requirement. Develop a CAP and communicate the CAP should be broken out. Additionally, what is meant by "solicit feedback". Finally, the load shed stipulation should be criteria, not part of the requirement.	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Broc Bruton - Broc Bruton On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Broc Bruton	
Answer	No
Document Name	
Comment	
Oncor strongly disagrees with the following statement in R9: "The responsible entities shall share their CAPs with, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues." We propose that "applicable regulatory authorities or governing bodies" be defined and limited. For example, a TP should only need to provide their PC with CAP information. In addition, we disagree with the following phrase "…and notify the applicable regulatory authorities or governing bodies responsible for retail electric service issues" as it relates to Load Shed. The intended regulatory audience needs to be clearly defined. Oncor disagrees with R10 as well. The requirement does not give TPs the ability to create CAPs for the listed contingencies.	

Likes 0	
Dislikes 0	

Response

Joshua London - Eversource Energy - 1, Group Name Eversource

Answer	No
Document Name	

Comment

R9: Eversource suggests language be added similar to TPL-001 stating that CAPs are not required for sensitivity analysis.

Eversource also questions the statement “solicit feedback from applicable regulatory authorities or governing bodies responsible for retail electric service issues.” If an applicable governing body disagrees with the result or says no to the CAP, is it no longer required to perform it?

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	No
Document Name	

Comment

Dominion Energy supports EEI comments. In addition, Developing CAPs for extreme events that are selected from a library of “approved cases” will not necessarily protect the BES from future extreme events. Providing the results of these analyses to other regulatory bodies is of concern as to how that information will be used and understood.

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer	No
Document Name	

Comment

MPC supports comments submitted by the MRO NERC Standards Review Forum (NSRF).

Likes 0	
Dislikes 0	

Response

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	No
Document Name	

Comment
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 5

Likes 0	
Dislikes 0	

Response

Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	

Comment

EEI suggests the following modifications to Requirement R9 to better clarify entity obligations under a TPL-008 CAP:

1. The language in TPL-001 relative to Corrective Action Plans is clearer and we suggest closer alignment to that language (see the suggested language below).

2. While PCs and TPs may have obligations to notify regulatory authorities and other governing bodies responsible for retail electric service where load shedding is incorporated into planning contingencies, this should not be included in a NERC Reliability Standard.

3. Add language similar to that used in TPL-001 Requirement 2, subpart 2.7.3 for situations where TPs and PCs are unable to meet CAP timeframes.

Proposed Changes to Requirement R9

R9. For Extreme Weather Assessments, which fail to meet the performance requirements for Table 1 P0 or P1 Contingencies, the assessment shall include Corrective Action Plan(s) (CAPs) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments, but the planned System shall continue to meet the performance requirements in Table 1 P0 and P1.

9.1 If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

Likes 0	
Dislikes 0	

Response

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF

Answer	No
Document Name	

Comment

LG&E and KU agrees with EEI's comments.

Likes 0	
Dislikes 0	

Response

Richard Vendetti - NextEra Energy - 5

Answer	No
Document Name	

Comment

R9 – Disclosure of acceptable thresholds mentioned in question #4 comments should also be provided to relevant regulatory authorities.

R10 – As noted, thermal overloads or cascades mitigated by load drops should not exceed an established threshold documented by PC and TP.

Likes 0	
Dislikes 0	

Response

Chantal Mazza - Chantal Mazza On Behalf of: Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza

Answer	No
Document Name	
Comment	

- R9 indicates that CAPs should be developed "…when the benchmark planning case study results indicate the System is unable to meet performance requirements…" but it is not clear whether the sensitivity analysis is included in "benchmark planning case study results". For comparison, TPL-001-5.1 states that "Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case.…" Should something similar be stated in TPL-008, or is the intent that any case or sensitivity performance violation should trigger a CAP?
- Additionally, R9 requires that "The responsible entities shall share their CAPs with, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues." This is unique to this standard and should be removed.
- R9, R10: "Responsible entity" should be defined in the Applicability section or should replaced with "Each Planning Coordinator, in conjunction with its Transmission Planner(s)..."). Suggest to replace 4.1 to "Responsible Entity" instead of "Functional Entity".

Likes 0	
Dislikes 0	
Response	

Michele Tondalo - United Illuminating Co. - 1

Answer	No
Document Name	
Comment	

R9 requires soliciting feedback from external, non-registered entities ("…applicable regulatory authorities…") but it is not clear what to do with this feedback and if there is the potential for an auditor and Registered Entity disagree with how feedback is used. I recommend considering updates to this wording to include similar steps as CIP-014 R2.3 which could allow for modification or documentation of technical rationale for not making modification, if requested by the applicable regulatory authorities.

Likes 0	
Dislikes 0	
Response	

Michele Shafer - New York State Electric & Gas (NYSEG) - 6

Answer	No
Document Name	
Comment	

R9 requires soliciting feedback from external, non-registered entities ("…applicable regulatory authorities…") but it is not clear what to do with this feedback and if there is the potential for an auditor and Registered Entity disagree with how feedback is used. I recommend considering updates to this wording to include similar steps as CIP-014 R2.3 which could allow for modification or documentation of technical rationale for not making modification, if requested by the applicable regulatory authorities.

Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	

EEI suggests the following modifications to Requirement R9 to better clarify entity obligations under a TPL-008 CAP:

1. The language in TPL-001 relative to Corrective Action Plans is clearer and we suggest closer alignment to that language (see the suggested language below).

2. While PCs and TPs may have obligations to notify regulatory authorities and other governing bodies responsible for retail electric service where load shedding is incorporated into planning contingencies, this should not be included in a NERC Reliability Standard.

3. Add language similar to that used in TPL-001 Requirement 2, subpart 2.7.3 for situations where TPs and PCs are unable to meet CAP timeframes.

Proposed Changes to Requirement R9

R9. For Extreme Weather Assessments, which fail to meet the performance requirements for Table 1 P0 or P1 Contingencies, the assessment shall include Corrective Action Plan(s) (CAPs) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments, but the planned System shall continue to meet the performance requirements in Table 1 P0 and P1.

9.1 If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

Likes 0	
Dislikes 0	
Response	

Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	No
Document Name	
Comment	

- The purpose and required response actions related to the sharing of CAPs and solicitation of feedback is not clear.
- The role of the TO and/or GO in implementing or otherwise responding to CAPs that may require additions or modifications to their systems/facilities is not captured in these requirements.
- There appears to be a significant amount of outside review required but no clear actions the responsible entity is required to take, particularly if there is a dispute.
- The purpose and reliability benefit of R10 is ambiguous. It is understood that P2, P4, P5, & P7 events tend to be lower probability but documenting possible mitigations every 5 years for these low-probability events in an extreme weather condition appears more administrative than reliability-based as the requirement is currently written.
- The exclusion of the P3 & P6 events from these requirements is appropriate. The SDT should consider if specific P2, P4, P5, & P7 events should likewise be excluded so the standard only addresses those events that must be evaluated and mitigated.

Likes 0	
Dislikes 0	
Response	

Brittany Millard - Lincoln Electric System - 5	
Answer	No
Document Name	
Comment	

LES supports comments submitted by the MRO NERC Standards Review Forum (NSRF).

Likes 0	
Dislikes 0	
Response	

Katrina Lyons - Georgia System Operations Corporation - 4	
Answer	No
Document Name	
Comment	

GSOC supports Georgia Transmission Corporation's comments:

- The purpose and required response actions related to the sharing of CAPs and solicitation of feedback is not clear.
- The role of the TO and/or GO in implementing or otherwise responding to CAPs that may require additions or modifications to their systems/facilities is not captured in these requirements.

- There appears to be a significant amount of outside review required but no clear actions the responsible entity is required to take, particularly if there is a dispute.
- The purpose and reliability benefit of R10 is ambiguous. It is understood that P2, P4, P5, & P7 events tend to be lower probability but documenting possible mitigations every 5 years for these low-probability events in an extreme weather condition appears more administrative than reliability-based as the requirement is currently written.
- The exclusion of the P3 & P6 events from these requirements is appropriate. The SDT should consider if specific P2, P4, P5, & P7 events should likewise be excluded so the standard only addresses those events that must be evaluated and mitigated.

Likes 0	
Dislikes 0	

Response

Mike Magruder - Avista - Avista Corporation - 1

Answer	No
Document Name	

Comment

We support EEI's comments.

Likes 0	
Dislikes 0	

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer	No
Document Name	

Comment

AECI supports comment provided by Georgia Transmission Corporation

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	No
Document Name	

Comment

Duke Energy agrees with and endorses EEI comments.

Likes 0	
Dislikes 0	

Response

Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen

Answer	No
Document Name	

Comment

In R9, a CAP must to be provided to a regulatory authority for a Long-term planning assessment. ISO agrees a CAP should be documented with possible actions, however this is a planning assessment. Providing a CAP to regulatory authorities may only cause more confusion and work for the industry. Additionally, a CAP developed through the planning process may require implementation of tariff processes before the CAP may proceed. Providing a CAP to a regulator would be premature if the tariff required processes have not been completed.

Likes 0	
Dislikes 0	

Response

Junji Yamaguchi - Hydro-Quebec (HQ) - 5

Answer	No
Document Name	

Comment

R9 indicates that CAPs should be developed "…when the benchmark planning case study results indicate the System is unable to meet performance requirements…" but it is not clear whether the sensitivity analysis is included in "benchmark planning case study results". For comparison, TPL-001-5.1 states that "Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case.…" Should something similar be stated in TPL-008, or is the intent that any case or sensitivity performance violation should trigger a CAP?

Additionally, R9 requires that "The responsible entities shall share their CAPs with, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues." This is unique to this standard and should be removed.

R9, R10: "Responsible entity" should be defined in the Applicability section or should replaced with "Each Planning Coordinator, in conjunction with its Transmission Planner(s)..."). Suggest to replace 4.1 to "Responsible Entity" instead of "Functional Entity".

Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	

R9: Ameren does not support reporting benchmark planning case study results to applicable entities. TPL-001 does not have a similar requirement for reporting retail electric service issues.

R10: Ameren suggests removing the phrase "reduce the likelihood or" from the requirement.

Likes 0	
Dislikes 0	
Response	
Colby Galloway - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	

Southern Company disagrees with the statement that it should solicit CAP feedback from applicable regulatory bodies or governing bodies. The action of regulatory feedback/approval does not comport with a risk-based action and only serves as an administrative burden that could further delay reliability to the BES. This is a compliance risk without a Reliability benefit. The NERC standard should solely focus on identifying the problem and identifying the projects, not mandating a regulatory strategy for the implementation of projects. This is beyond the purview of a reliability standard. It is Southern Company's recommendation that requirements to share CAPs and solicit feedback from regulatory bodies in R9 should be removed from the standard. It has been a well document practice to create/implment CAPs, giving greater assurity of corrective measures that impact the BES and these are auditable for Reginal Entity assurance. What is now becoming more administrative is the requirement to report and "wait" for approval, which could unduly delay a Registered Entity from implementing and thus cause undue harm to the BES.

Likes 0	
Dislikes 0	
Response	
Rebika Yitna - Rebika Yitna On Behalf of: David Weekley, MEAG Power, 3, 1; Roger Brand, MEAG Power, 3, 1; - Rebika Yitna	
Answer	No

Document Name	
Comment	

It is not clear why R9 is requiring soliciting CAP feedback from regulatory authorities for retail electric service issues.

Likes 0	
Dislikes 0	
Response	

Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle

Answer	No
Document Name	
Comment	

R9 – As written, this requirement states that the responsible entity “shall develop” CAPs for P0 and P1, but does not state if these CAPs must be “implemented” prior to the operating horizon. TPL-001-5.1, R2.7.3 allows use of NCLL under circumstances where CAPs cannot be implemented in the required timeframe (i.e., prior to the operating horizon).

If an entity is unable to complete a capital project or implement an Operating Plan prior to the operating horizon, we recommend that NCLL be allowed for P0 under the extreme weather condition

R9 uses the term “Load shed”, but Table 1 in TPL-008 and TPL-001 both use the term NCLL.

We recommend that R9 be revised to use the term “NCLL” instead of “Load shed” for consistency and clarity.

R10 – As discussed in the comments for R7, we strongly recommend that P5 be removed from R7, R10, and Table 1 due to the low probability of such events during Extreme Temperature events.

Likes 0	
Dislikes 0	
Response	

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	No
Document Name	
Comment	

Should GOs have applicability in the standard if a concern is identified that too much generation is unavailable due to the parameters for the hot and cold events?

Proposed wording change for part of R9:

“Revisions to the CAP(s) are allowed in subsequent Extreme Temperature Assessments, so long as but the planned System shall continues to meet the performance requirements.”

Likes 0	
Dislikes 0	
Response	
Robert Jones - Seattle City Light - 1,3,4,6	
Answer	No
Document Name	
Comment	

The language is not very specific as compared to TPL-001. Does it pertain to Steady state, sensitivities, and/or transient stability studies? Depending on how the criteria or methodology is defined by each entity, an entity may exclude sensitivities from a CAP if there is a violation. The point is the language in this standard is vague.

Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	

NIPSCO supports the comments provided by AEP, FE, WAPA, CHPD, CMS Energy, and WPP.

Likes 0	
Dislikes 0	
Response	

Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	No
Document Name	
Comment	
"See comments submitted by the Edison Electric Institute"	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
R10 - Perhaps more clarity on how that might differ from stability studies on P0 and P1 contingencies can be added to this requirement. Additionally, Exelon supports the comments provided by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
ATC generally supports the MRO NSRF comments, and is supplementing them as described below. R9, R10: Please verify that the sensitivities do not require CAPs or documentation of possible mitigating actions and are for information only. R10: It might be helpful to document why R10's requirement to come up with potential CAPs for non-P0 and P1s is needed. What actually happens with the possible actions required under R10? Is this similar to how extreme events are currently treated?	
Likes 0	

Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	No
Document Name	

Comment

R9 indicates that CAPs should be developed "…when the benchmark planning case study results indicate the System is unable to meet performance requirements…" but it is not clear whether the sensitivity analysis is included in "benchmark planning case study results". For comparison, TPL-001-5.1 states that "Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case…." Should something similar be stated in TPL-008, or is the intent that any case or sensitivity performance violation should trigger a CAP?

Additionally, R9 requires that "The responsible entities shall share their CAPs with, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues." This is unique to this standard and should be removed.

R9, R10: "Responsible entity" should be defined in the Applicability section or should replace with "Each Planning Coordinator, in conjunction with its Transmission Planner(s)..."). Suggest replacing

4.1 to "Responsible Entity" instead of "Functional Entity".

Likes 0	
Dislikes 0	

Response

Kinte Whitehead - Exelon - 3	
Answer	No
Document Name	

Comment

R10 - Perhaps more clarity on how that might differ from stability studies on P0 and P1 contingencies can be added to this requirement.

Additionally, Exelon supports the comments provided by the EEI for this question.

Likes 0	
Dislikes 0	

Response

Wayne Guttormson - SaskPower - 1	
Answer	No
Document Name	
Comment	
Support the MRO NSRF and EEI comments.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	No
Document Name	
Comment	
SPP has a concern about language in Requirement R9 as it talks about "governing bodies". It is unclear who identifies and aligns with that role and responsibility. SPP recommends that the drafting team provide clarity on which entities qualify for the role and responsibility.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
NV Energy suggests the following modifications to Requirement R9 to better clarify entity obligations under a TPL-008 CAP:	

{C}1.	{C}The language in TPL-001 relative to Corrective Action Plans is clearer and we suggest closer alignment to that language (see the suggested language below).

{C}2.	{C}While PCs and TPs have obligations to notify regulatory authorities and other governing bodies responsible for retail electric service where load shedding is incorporated into planning contingencies, this should not be included in a NERC Reliability Standard.

{C}3.	{C}Add language similar to that used in Requirement 2, subpart 2.7.3 for situations where TPs and PCs are unable to meeting CAP timeframes.

Proposed Changes to Requirement R9

R9. For Extreme Weather Assessments, which fail to meet the performance requirements for Table 1 P0 or P1 Contingencies, the assessment shall include Corrective Action Plan(s) (CAPs) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments, but the planned System shall continue to meet the performance requirements in Table 1 P0 and P1.

9.1 If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

Likes 0	
Dislikes 0	

Response

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2

Answer	No
Document Name	

Comment

ERCOT recommends that the drafting team resolve an apparent inconsistency regarding the P0 analysis. Specifically, the Technical Rationale appears to suggest that Load shedding is permitted to establish a solvable P0 system condition. However, Requirement R9 and Table 1 do not seem to allow Load shedding for solvable P0 system condition. ERCOT recommends that the drafting team address this by revising Requirement R9 to explicitly indicate that Load shed is allowed to establish a solvable P0 system condition. This is necessary to ensure that the study can assume sufficient resources are available in a P0 state. This, in turn, is necessary to prevent the standard from straying into the realm of resource adequacy. As noted in the Technical Rationale, resource adequacy is not in scope for this project under paragraph 94 of FERC Order No. 896.

It is also unclear why Requirement R9 requires entities to submit CAPs to regulatory authorities or governing bodies responsible for “retail electric service issues.” These types of regulatory authorities are not subject to NERC requirements, but do generally have authority over generation planning. Consequently, the mandate to submit CAPs to these regulatory authorities or governing bodies appears to address a resource adequacy

issue. However, as noted in the Technical Rationale, paragraph 94 of FERC Order No. 896 provides that resource adequacy is not in scope for this project. ERCOT therefore recommends that the requirement to submit CAPs to regulatory authorities or governing bodies be removed from the standard.	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
OPG supports NPCC Regional Standards Committee's comments.	
Likes 0	
Dislikes 0	
Response	
Catrina Martin - Archer Energy Solutions, LLC - 5	
Answer	No
Document Name	
Comment	

R9 – As written, this requirement states that the responsible entity "shall develop" CAPs for P0 and P1, but does not state if these CAPs must be "implemented" prior to the operating horizon. TPL-001-5.1, R2.7.3 allows use of NCLL under circumstances where CAPs cannot be implemented in the required timeframe (i.e., prior to the operating horizon). TPL-008, Table 1 allows for use of NCLL for P1, P2, P4, P5 and P7 events, but not for P0.

o Are entities required to implement CAPs prior to the operating horizon, including construction of capital projects?

o If an entity is unable to complete a capital project or implement an Operating Plan prior to the operating horizon, would NCLL be allowed for P0?

o We recommend that this situation be addressed in a similar fashion to TPL-001.

R9 uses the term "Load shed", but Table 1 in TPL-008 and TPL-001 both use the term NCLL.

o We recommend that R9 be revised to use the term "NCLL" instead of "Load shed" for consistency and clarity.

R10 – As discussed in the comments for R7, we strongly recommend that P5 be removed from R7, R10, and Table 1 due to the low probability of such events during Extreme Temperature events.

Likes 0	
Dislikes 0	

Response

Michael Goggin - Grid Strategies LLC - 5

Answer	No
Document Name	

Comment

a. Requirement R9 should be modified to specify that the expected impact of extreme heat and cold should be accounted for when designing and measuring the impact of the solutions proposed in a Corrective Action Plan (CAP). Many potential solutions in a CAP can have greater or lesser impact under extreme heat or cold conditions. For example, a CAP that relies on adding gas generation can be less effective under extreme heat due to output reductions due to ambient temperature derates, and under extreme cold due to correlated gas generator outages. Gas generator outages due to equipment failures and fuel supply interruptions have accounted for the majority of outages during recent cold snap events.{C}[1] As noted above in response to question 4, FERC's directive in paragraph 89 of Order 896 states that "it is necessary that responsible entities evaluate the risk of correlated or concurrent outages and derates of all types of generation resources and transmission facilities as a result of extreme heat and cold events." On the other hand, CAPs that include demand response and energy efficiency programs related to building HVAC systems can offer contributions that are larger than expected during extreme heat or cold because load associated with cooling or heating is higher during such events.

During extreme cold events, expanded transmission ties with neighboring grid operators can also exceed the benefits they offer under normal conditions because transmission line thermal limits are higher during extreme cold and wind chill conditions. Transmission ties also tend to offer large benefits during extreme heat and cold, as severe weather events tend to be at their most extreme in geographically confined areas, ensuring at least some nearby grid operators are not experiencing shortfalls in generation.[2] The benefits of interregional transmission are even greater at higher renewable penetrations.[3] The value of transmission ties during extreme heat and cold events should be accounted for when assessing baseline performance during benchmark events as well as quantifying the value of expanding these ties as part of a CAP.

The higher transfer capacity of advanced conductors under extreme heat and cold conditions should also be accounted for, as carbon and composite core conductors sag roughly half as much as comparable ACSR conductors. Finally, Grid-Enhancing Technologies like dynamic line ratings, topology optimization, and power flow control devices offer significant benefits when the grid may be congested due to extreme temperatures. Dynamic line ratings are particularly valuable for enabling operators to safely use transmission lines' higher thermal limits during extreme cold and wind chill conditions.

Accounting for how a CAP will fare under the extreme heat or cold conditions it is designed to solve is essential for ensuring reliability. Without accounting for the reduced effectiveness of some CAP elements under extreme heat or cold, planners will be blind to potential reliability risks. In other cases, failing to account for the effectiveness of specific CAP measures under extreme heat or cold will result in a suboptimal selection of solutions. Extreme heat and cold must not only be accounted for in identifying reliability risks, but also designing solutions to those risks.

b. The draft of R9 also includes two potential loopholes that a responsible entity could use to avoid implementing a CAP that is needed to address reliability concerns. The Technical Rationale document explains that "under an extreme heat or extreme cold temperature condition, there may instances where the benchmark planning cases and/or sensitivity cases may not have sufficient available generation to supply the load. In these scenarios, it may be acceptable for the responsible entity to either curtail load, or model most likely future resources in the interconnection queue, to achieve a solution for the benchmark planning case." That document also notes that "the SDT has determined that load curtailment may be considered for a P1 Contingency as a CAP where load shed is allowed to prevent system-wide failures and ensuring the continued operation of essential services under a critical P1 Contingency in the extreme heat and cold events."

First, allowing load curtailment for a P1 contingency under TPL-008 is a major departure from the requirements of TPL-001, which do not allow load shedding for a P1 contingency.{C}[4] Allowing responsible entities plans' to include load shed when they experience a single P1 contingency under extreme heat or cold conditions is contrary to FERC's intent in Order 896 that NERC enact a standard that will ensure reliable operations under extreme heat and cold conditions.

Second, for the option to "model most likely future resources in the interconnection queue, to achieve a solution for the benchmark planning case" to be an effective solution to reliability concerns, it must be accompanied by requirements for those resources to have signed procurement contracts or at least be included in a load-serving entity's plan, and/or a requirement to later confirm that those resources have actually been built. Without such a requirement, a responsible entity could comply with TPL-008 by simply speculating that some share of the large backlog of proposed resources currently in the interconnection queue in nearly all regions will be built.

More generally, a major concern with the draft standard is that there is no compliance mechanism to ensure CAPs are implemented. As drafted, R9 and the other requirements only require that "The responsible entities shall share their CAPs with, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.... Revisions to the CAP(s) are allowed in subsequent Extreme Temperature Assessments, but the planned System shall continue to meet the performance requirements." If implementing some CAP solutions requires action by an entity other than the transmission planner or planning coordinator responsible entities, the draft standard should be revised to include such a requirement on those entities. Other draft NERC standards include requirements to implement CAPs, and similar language could be adopted for TPL-008. For example, requirement R9 of the PRC-028 draft requires a generator or transmission owner to "develop, maintain, and implement a Corrective Action Plan to provide the required capability,"{C}[5] and requirement R6 of the PRC-030 draft requires "Each applicable Generator Owner shall, for each of its CAPs developed pursuant to Requirement R5:

6.1. Implement the CAP;

6.2. Update the CAP if actions or timetables change; and

6.3. Notify each applicable Reliability Coordinator if CAP actions or timetables change and when the CAP is completed."[6]{C}

{C}[1]{C} *See, e.g.*, FERC and NERC, *Winter Storm Elliott Report: Inquiry into Bulk-Power System Operations During December 2022* (October 2023), https://www.ferc.gov/media/winter-storm-elliott-report-inquiry-bulk-power-system-operations-during-december-2022, at 17; FERC and NERC, *The February 2021 Cold Weather Outages in Texas and the South Central United States* (November 2021), https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and, at 16; FERC and NERC, *2019 FERC and NERC Staff Report: The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018* (July 2019), https://www.ferc.gov/legal/staff-reports/2019/07-18-19-ferc-nerc-report.pdf; PJM, *Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events* (May 2014), https://www.pjm.com/~/media/library/reports-notices/weather-related/20140509-analysis-of-operational-events-and-market-impacts-during-the-jan-2014-cold-weather-events.ashx.

{C}[2]{C} https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf

{C}[3]{C} https://www.nrel.gov/docs/fy22osti/78394.pdf

{C}[4]{C} https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-5.pdf, at 21

{C}[5]{C} https://www.nerc.com/pa/Stand/Project202104ModificationstoPRC0022DL/2021-04_AB_PRC-028-1_Clean_03182024.pdf

{C}[6]{C} https://www.nerc.com/pa/Stand/Project202302PerformanceofIBRsDL/2023-02%20PRC-030-1_032524.pdf

Likes 0	
Dislikes 0	

Response	
Adrian Harris - Adrian Harris On Behalf of: Bobbi Welch, Midcontinent ISO, Inc., 2; - Adrian Harris, Group Name RTO/ISO Council Standard Review Committee Project 2023-07 TPL-008	
Answer	Yes
Document Name	
Comment	

R9. The SRC observes that R9 requires responsible entities to share their CAPs with, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues in all cases. This may extend the amount of time needed for CAP approval.

The SRC recommends that the drafting team resolve an apparent inconsistency regarding the P0 analysis. Specifically, the technical rationale appears to suggest that Load shedding is permitted to establish a solvable P0 system condition. However, Requirement R9 and Table 1 do not seem to allow load shedding for solvable P0 system condition. The SRC recommends that the drafting team address this by revising Requirement R9 to explicitly indicate that Load shed is allowed to establish a solvable P0 system condition. This is necessary to ensure that the study can assume sufficient resources are available in a P0 state. This, in turn, is necessary to prevent the standard from straying into the realm of resource adequacy. As noted in the Technical Rationale, resource adequacy is not in scope for this project under paragraph 94 of FERC Order No. 896.

It is also unclear why Requirement R9 requires entities to submit CAPs to regulatory authorities or governing bodies responsible for "retail electric service issues." These types of regulatory authorities are not subject to NERC requirements, but do generally have authority over generation planning. Consequently, the mandate to submit CAPs to these regulatory authorities or governing bodies appears to address a resource adequacy issue. However, as noted in the Technical Rationale, paragraph 94 of FERC Order No. 896 provides that resource adequacy is not in scope for this project. The SRC therefore recommends that the requirement to submit CAPs to regulatory authorities or governing bodies be removed from the standard.If this requirement is not removed, the SRC notes that the requirement to solicit feedback from applicable regulatory authorities responsible for retail electric service issues imposes a higher burden beyond what is required in TPL-001, and requests that the drafting team provide an explanation or justification regarding the need for this higher burden.

IESO Abstains from Question 5

Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Whaite - Stephen Whaite On Behalf of: Tyler Schwendiman, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lidija Efremova - Lidija Efremova On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Lidija Efremova	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	
Document Name	

Comment

Constellation has no comments

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5

Answer	
Document Name	

Comment

Constellation has no comments

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE has the following comments:

- Texas RE recommends including a timeframe for which the CAPs need to be developed once the benchmark planning case study results indicate the System is unable to meet performance requirements.
- Requirement R9 is essentially three requirements. It would be easier to read if each Requirement R9 contained subparts or bullets:

R9. Each responsible entity, as identified in Requirement R1, shall develop a Corrective Action Plan(s) (CAPs) when the benchmark planning case study results indicate the System is unable to meet performance requirements for Table 1 P0 or P1 Contingencies.

9.1 The responsible entities shall share their CAPs with, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.

9.2 In addition, where Load shed is allowed as an element of a CAP for the Table 1 P1 Contingency, the responsible entity shall document the alternative(s) considered, as mentioned in Requirement R10, and notify the applicable regulatory authorities or governing bodies responsible for retail electric service issues

9.3 Revisions to the CAP(s) are allowed in subsequent Extreme Temperature Assessments, but the planned System shall continue to meet the performance requirements.

- Texas RE noticed the Performance Criteria states that non-consequential Load loss is allowed for P1 contingencies for Requirement R9, but a limit for the maximum amount of non-consequential load loss is not specified. This seems to indicate that any level of firm-load shed is allowed for any of the P1 contingencies. SDT should consider providing additional clarifications on the firm-load shed levels, how to manage model uncertainties, etc. when developing Corrective Action Plans and the implementation schedule.

Likes 0	
Dislikes 0	

Response

6. Do you agree with the proposed TPL-008-1 Reliability Standard Requirement R11 (Sharing Extreme Temperature Assessment results)? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Adrian Harris - Adrian Harris On Behalf of: Bobbi Welch, Midcontinent ISO, Inc., 2; - Adrian Harris, Group Name RTO/ISO Council Standard Review Committee Project 2023-07 TPL-008

Answer	No
Document Name	

Comment

The SRC supports the “upon request” nature of R11 and sharing Extreme Temperature Assessment results with those having a “reliability need.”

That said, the wording of Requirement R11 is unclear. In light of NERC’s retirement of the functional model, referring to a “NERC-registered entity” instead of a “functional entity” would be clearer. Alternatively, if Requirement R11 is only intended to require provision of the assessment results to Transmission Planners and Planning Coordinators, Requirement R11 should be revised to explicitly reference these two types of entities.

R11. Each responsible entity, as identified in Requirement R1, shall provide its Extreme Temperature Assessment results within 90 calendar days of a request to any NERC-registered entity that has a reliability related need and submits a written request for the information.

Q7. The SRC recommends the following clarifications to Table 1:

- in the Facility Voltage Level of Contingency row, change the commas to colons,
- in the Facility Voltage Level of Contingency row, clarify what is meant by “reference voltage,” and
- in the Stability Performance Criteria row, clarify what is meant by “initialization.”

Additionally, the SRC recommends that the drafting team either include the full set of footnotes from TPL-001-5.1 Table 1 or clarify why TPL-008 contains only a limited subset of the footnotes to Table 1.The SRC also requests that the drafting team confirm that Table 1 will be limited to 200 kV and above facilities and not include contingencies below 200 kV, as this could miss contingency events below 200 kV that could be limiting to the 200 kV and up system.

Finally, consistent with the SRC’s comments on the need for Requirement R9 to clarify that Load shed is allowed to establish a solvable P0 system condition, the SRC recommends that Table 1 be revised to contain the same clarification as Requirement R9. This is necessary to ensure that the standard complies with paragraph 94 of FERC Order No. 896, which (as noted in the Technical Rationale) states that resource adequacy is not in scope for this project.

Likes 0	
Dislikes 0	

Response

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2

Answer	No
Document Name	

Comment

The wording of Requirement R11 is unclear. In light of NERC's retirement of the functional model, referring to a "registered entity" instead of a "functional entity" would be clearer. Alternatively, if Requirement R11 is only intended to require provision of the assessment results to Transmission Planners and Planning Coordinators, Requirement R11 should be revised to explicitly reference these two types of entities.

Likes 0	
Dislikes 0	

Response

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	No
Document Name	

Comment

NV Energy supports the intent of Requirement R11 but suggest replacing "functional entity" with registered entity because functional entity is not a defined term, while registered entity makes it clear Extreme Temperature Assessment results are to be shared on a need to know basis with registered entities that they have enacted a non-disclosure agreement.

Likes 0	
Dislikes 0	

Response

Wayne Guttormson - SaskPower - 1

Answer	No
Document Name	

Comment

Support the MRO NSRF and EEI comments.

Likes 0	
Dislikes 0	

Response

Amy Wilke - American Transmission Company, LLC - 1

Answer	No
Document Name	

Comment

We would prefer language similar to TPL-001-5.1 R8 requiring distribution of the Extreme Temperature Assessment results to adjacent PCs and TPs:

"Each responsible entity, as identified in Requirement R1, shall distribute its Extreme Temperature Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Extreme Temperature Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request."

Likes 0	
Dislikes 0	

Response

Selene Willis - Edison International - Southern California Edison Company - 5

Answer	No
Document Name	

Comment

"See comments submitted by the Edison Electric Institute"

Likes 0	
Dislikes 0	

Response

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3

Answer	No
Document Name	

Comment

NIPSCO supports the comments provided by ReliabilityFirst, CHPD, and WPP.

Likes 0	
Dislikes 0	

Response

Colby Galloway - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

Southern Company supports the intent of Requirement R11 but suggests replacing “functional entity” with Registered Entity because functional entity is not a defined term, while registered entity makes it clear Extreme Temperature Assessment results are to be shared on a need-to-know basis with Registered Entities that have executed a non-disclosure agreement.

Likes 0	
Dislikes 0	

Response
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	No
Document Name	

Comment
Duke Energy agrees with and endorses EEI comments.

Likes 0	
Dislikes 0	

Response
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer	No
Document Name	

Comment
AECI supports comment provided by Georgia Transmission Corporation

Likes 0	
Dislikes 0	

Response
Mike Magruder - Avista - Avista Corporation - 1

Answer	No
Document Name	

Comment

We support EEI's comments.

Likes 0	
Dislikes 0	
Response	
Katrina Lyons - Georgia System Operations Corporation - 4	
Answer	No
Document Name	
Comment	

GSOC supports Georgia Transmission Corporation's comments:

- With the nature of this evaluation, it appears appropriate to distribute the assessment and CAP to specific entities such as operators, owners, and impacted planning entities.
- More specifics on metrics that constitute a valid reliability-related need is needed.

Likes 0	
Dislikes 0	
Response	
Brittany Millard - Lincoln Electric System - 5	
Answer	No
Document Name	
Comment	

LES supports comments submitted by the MRO NERC Standards Review Forum (NSRF).

Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	No
Document Name	
Comment	

- With the nature of this evaluation, it appears appropriate to distribute the assessment and CAP to specific entities such as operators, owners, and impacted planning entities.
- More specifics on metrics that constitute a valid reliability-related need is needed.

Likes 0	
Dislikes 0	

Response

Glen Farmer - Avista - Avista Corporation - 5

Answer	No
Document Name	

Comment

EEI supports the intent of Requirement R11 but suggest replacing "functional entity" with registered entity because functional entity is not a defined term, while registered entity makes it clear Extreme Temperature Assessment results are to be shared on a need-to-know basis between registered entities that have executed a non-disclosure agreement.

Likes 0	
Dislikes 0	

Response

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF

Answer	No
Document Name	

Comment

LG&E and KU agrees with EEI's comments.

Likes 0	
Dislikes 0	

Response

Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment

EEI supports the intent of Requirement R11 but suggest replacing “functional entity” with registered entity because functional entity is not a defined term, while registered entity makes it clear Extreme Temperature Assessment results are to be shared on a need-to-know basis between registered entities that have executed a non-disclosure agreement.

Likes 0	
Dislikes 0	

Response

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples

Answer	No
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 6

Likes 0	
Dislikes 0	

Response

Stephen Whaite - Stephen Whaite On Behalf of: Tyler Schwendiman, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies

Answer	No
Document Name	

Comment

RF believes a timeframe of 30 calendar days would be more appropriate.

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer	No
Document Name	

Comment	
MPC supports comments submitted by the MRO NERC Standards Review Forum (NSRF).	
Likes 1	Lakeland Electric, 1, Watt Larry
Dislikes 0	
Response	
Broc Bruton - Broc Bruton On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Broc Bruton	
Answer	No
Document Name	
Comment	
Oncor would like for "functional entity" to be defined and limited to PCs only. We share the concerns of the Western Power Pool. It may be burdensome for a responsible entity to reply to requests from "any functional entity" that claims it has a reliability related need to receive our Extreme Temperature Assessment results.	
Likes 0	
Dislikes 0	
Response	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	No
Document Name	
Comment	
Southern Indiana Gas & Electric Company d/b/a CenterPoint Energy Indiana South (SIGE) recommends the following changes: • Modify "60" to "90" calendar days to align with TPL-001-5.1, R8, Part 8.1 • Add "NERC" to functional entity for clarity • Add "documented" for clarity SIGE's recommended changes are illustrated below: **R11.** Each responsible entity, as identified in Requirement R1, shall provide its Extreme Temperature Assessment results within ***90*** calendar days of a request to any ***NERC registered*** functional entity that has a ***documented*** reliability related need and submits a written request for the information.	
Likes 0	
Dislikes 0	
Response	

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
Please refer to Question 1 comments.	
Likes 0	
Dislikes 0	
Response	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
TPL-001-5 requires sharing the results of its Planning Assessment results to adjacent PCs and adjacent TPs within 90 calendars of completing the Assessment. Therefore, FirstEnergy requests the Drafting Team view the 60-day timeframe under R11 to update to 90 calendar days to be consistent with TPL-005.	
Likes 0	
Dislikes 0	
Response	

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	No
Document Name	
Comment	
Black Hills Corporation is aligned with EEI's comments. EEI supports the intent of Requirement R11 but suggest replacing "functional entity" with registered entity because functional entity is not a defined term, while registered entity makes it clear Extreme Temperature Assessment results are to be shared on a need to know basis with registered entities that they have enacted a non-disclosure agreement.	
Likes 0	
Dislikes 0	
Response	

Michael Whitney - Northern California Power Agency - 3, Group Name NCPA	
Answer	No
Document Name	
Comment	
NO, These assessment should be performed by the Regional Entities. There appears to be too much room for coordination issues having one Transmission Planner (TP) or Planning Coordinator (PC) having to rely on other TPs or PCs to meet their requirement deadlines.	
Likes 0	
Dislikes 0	
Response	
Lauren Giordano - Lauren Giordano On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; Michael Whitney, Northern California Power Agency, 4, 6, 3, 5; - Lauren Giordano	
Answer	No
Document Name	
Comment	
NO, These assessment should be performed by the Regional Entities. There appears to be too much room for coordination issues having one Transmission Planner (TP) or Planning Coordinator (PC) having to rely on other TPs or PCs to meet their requirement deadlines.	
Likes 0	
Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	No
Document Name	
Comment	
Given the timeframe of this study, it will be difficult to know when a new study is available for an entity to submit a written request. At minimum, a notification the study has been completed could be warranted. Such language exists currently for TPL-001-5.1 and may be similarly leveraged for the less frequent TPL-008 assessment. For example: “Each responsible entity, as identified in R1, shall distribute its Extreme Temperature Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Extreme Temperature Assessment and within 60 calendar days of a request to any functional entity that has a reliability related need and submits a written request for the information”.	

Likes 0	
Dislikes 0	

Response

Srikanth Chennupati - Entergy - Entergy Services, Inc. - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

Entergy recommends changing wording of “has a reliability related need” with “has a *documented* reliability related need”.

Likes 0	
Dislikes 0	

Response

Kevin Conway - Western Power Pool - 4

Answer	No
Document Name	

Comment

What is the technical justification for R11? The Transmission Planners should provide their assessments to it's TOP(s), BA(s), RP(s), RC, and PC since they are all directly affected by the assessment results. The results of the assessment may be considered confidential and shouldn't be distributed an further than what is necessary. R11, as currently worded, there will be a need for the entity to monitor, track, and potentially address comments resulting from entities requesting a copy of the assessment results. This administratively complicates the need for an assessment and introduces administrative compliance risk.

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	Yes
Document Name	

Comment

OPG supports NPCC Regional Standards Committee’s comments.

Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Texas RE requests clarification of the phrase “reliability related need”.	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon does not have any objections to the proposed language for Requirement R11.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
R11: “Responsible entity” should be defined in the Applicability section or should replace with “Each Planning Coordinator, in conjunction with its Transmission Planner(s)...”). Suggest replacing 4.1 to “Responsible Entity” instead of “Functional Entity”.	
Likes 0	
Dislikes 0	

Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon does not have any objections to the proposed language for Requirement R11.	
Likes 0	
Dislikes 0	
Response	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	Yes
Document Name	
Comment	
We agree it is vital to have close coordination amongst all responsible entities during the assessment study period.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	

Junji Yamaguchi - Hydro-Quebec (HQ) - 5	
Answer	Yes
Document Name	
Comment	
R11: "Responsible entity" should be defined in the Applicability section or should replaced with "Each Planning Coordinator, in conjunction with its Transmission Planner(s)..."). Suggest to replace 4.1 to "Responsible Entity" instead of "Functional Entity".	
Likes 0	
Dislikes 0	
Response	

Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
ISO supports the "upon request" aspect of the requirement.	
Likes 0	
Dislikes 0	
Response	

Chantal Mazza - Chantal Mazza On Behalf of: Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	Yes
Document Name	
Comment	
R11: "Responsible entity" should be defined in the Applicability section or should replaced with "Each Planning Coordinator, in conjunction with its Transmission Planner(s)..."). Suggest to replace 4.1 to "Responsible Entity" instead of "Functional Entity".	
Likes 0	
Dislikes 0	
Response	

Lenise Kimes - City and County of San Francisco - 1,5 - WECC

Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
MH is OK with sharing the results upon request if there is a reliability related need.	
Likes 0	
Dislikes 0	
Response	
Catrina Martin - Archer Energy Solutions, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Robert Jones - Seattle City Light - 1,3,4,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rebika Yitna - Rebika Yitna On Behalf of: David Weekley, MEAG Power, 3, 1; Roger Brand, MEAG Power, 3, 1; - Rebika Yitna	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Lidija Efremova - Lidija Efremova On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Lidija Efremova	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michele Shafer - New York State Electric & Gas (NYSEG) - 6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Michele Tondalo - United Illuminating Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Matthew Jaramilla, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Apollonia Gonzales - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mark Flanary - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Isidoro Behar - Long Island Power Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jeffrey Streifling - NB Power Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Alison MacKellar - Constellation - 5	
Answer	
Document Name	
Comment	
Constellation has no comments Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	
Document Name	

Comment	
How does a responsible entity determine “reliability related need”? Without and parameters an applicable entity could say there is no "reliability related need" and not have to rspond to any written requests.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	
Document Name	
Comment	
Constellation has no comments Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

7. Do you agree with the proposed TPL-008-1 Table 1? If you do not agree, please provide your recommendation and technical justification.

Srikanth Chennupati - Entergy - Entergy Services, Inc. - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

Entergy recommends that the table should be split into three tables: "Table 1: Performance Criteria", "Table 2: Contingencies", and "Table 3: Steady State & Stability Footnotes".

Likes 0	
Dislikes 0	

Response

Jeffrey Streifling - NB Power Corporation - 1

Answer	No
Document Name	

Comment

On the first page of Table 1, “Corrective Action Plan Required” might be better phrased as “Corrective Action Plan Required for Performance Violations” or similar.

A fault type (3φ or SLG) should be given for P5 contingencies. To be consistent with TPL-001-5.1, this should be SLG.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	No
Document Name	

Comment

The SDT may wish to consider decreasing the 200kv voltage threshold in Table 1 to instead be 100kv. Industry has grown more reliant on generation which is connected at lower voltages, and contingencies on those lower voltages may be as impactful and even more frequent than at the higher voltages. AEP sees the potential reliability benefit of including facilities at a lower voltage threshold in Table 1.

Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	No
Document Name	
Comment	
Table should include all planning events to avoid confusion with TPL-001-5 Table 1. Information under P3 and P6 could be listed as N/A but it would avoid confusion.	
Likes 0	
Dislikes 0	
Response	
Lauren Giordano - Lauren Giordano On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; Michael Whitney, Northern California Power Agency, 4, 6, 3, 5; - Lauren Giordano	
Answer	No
Document Name	
Comment	
NO, These assessment should be performed by the Regional Entities. There appears to be too much room for coordination issues having one Transmission Planner (TP) or Planning Coordinator (PC) having to rely on other TPs or PCs to meet their requirement deadlines.	
Likes 0	
Dislikes 0	
Response	
Michael Whitney - Northern California Power Agency - 3, Group Name NCPA	
Answer	No
Document Name	
Comment	

NO, These assessment should be performed by the Regional Entities. There appears to be too much room for coordination issues having one Transmission Planner (TP) or Planning Coordinator (PC) having to rely on other TPs or PCs to meet their requirement deadlines.

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments

Answer	No
Document Name	

Comment

Black Hills Corporation agrees with EEI's comments and has no specific recommendations at this time.

While EEI does not yet have specific recommendations for Table 1 at this time, more work is needed to better address the Contingencies and Performance Criteria for Extreme Temperature Assessments.

Likes 0	
Dislikes 0	

Response

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO

Answer	No
Document Name	

Comment

We strongly support the applicability to 200 kV and above facilities. FERC Order 896 is concerned with the wide-area impacts of extreme temperature events and the impact of issues with facilities below 200 kV are typically localized. R9 and Table 1 requires the development of Corrective Action Plans for P1 events where applicable facility ratings are exceeded and steady state voltages are not within limits. This requirement goes beyond the directives in FERC Order 896. The FERC Order is concerned with cascading, instability, and uncontrolled islanding but not with facility overloads. It would be prudent for entities to consider Corrective Action Plans for P1 events but the requirement to develop Corrective Action Plans for all P1 issues will lead to increased costs for extremely low probability and in many cases low consequence events. For example, if an extreme temperature event occurs (low frequency and low duration), and a P1 event occurs in that time (low probability), then there may be a risk of an element overload. If it can be demonstrated that the overload does not lead to cascading, instability, or uncontrolled islanding, then the consequence may be reasonable such as a small degree of loss-of-life in a transformer. The standard, as written, will require the development of expensive Corrective Action Plans for many low probability, low consequence events and goes beyond FERC Order 896. It is recommended that the text Table 1 be changed under the 'P1' column from "Applicable facility ratings shall not be exceeded. System steady state voltages shall be within acceptable limits as defined in Requirement R5" to "uncontrolled separation or Cascading, as defined in Requirement R6, shall not occur".

Likes 0	

Dislikes 0	

Response

Isidoro Behar - Long Island Power Authority - 1

Answer	No
Document Name	

Comment

The first event row in Table 1 specifies “Facility Voltage Level of Contingency”.

Question: is the intent to limit the selection of planning events to events that comprise facilities 200 kV and above? Is so, this should be clarified and/or mentioned within R7.

The required fault type (3φ or SLG) to be assessed should be specified for P5 contingencies (i.e., SLG – to be consistent with TPL-001-5.1).

Likes 0	
Dislikes 0	

Response

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	

Comment

Please refer to Question 1 comments.

Likes 0	
Dislikes 0	

Response

Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF

Answer	No
Document Name	

Comment

Southern Indiana Gas & Electric Company d/b/a CenterPoint Energy Indiana South (SIGE) supports the recommend Table 1 changes provided by MRO NERC Standards Review Forum (NSRF) which include:

- in the Facility Voltage Level of Contingency row, change the commas to colons,
- in the Facility Voltage Level of Contingency row, clarify what is meant by “reference voltage,”
- in the Stability Performance Criteria row, clarify what is meant by “initialization.”

Additionally, SIGE request clarification as to why TPL-008’s Table 1 footnotes differ from TPL-001-5.1.

Likes 0	
Dislikes 0	

Response

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

BPA believes Table 1 would be appropriate ***if*** the P0 benchmark planning base case has all transmission elements in service. However, if P0 case already includes multiple transmission elements out of service, it is likely CAPs for P0 or any P1 contingency would be cost-prohibitive. Reliability of system operations under outage conditions is addressed in the Operating Horizon, where loss of load is allowed. Lessons learned from the previous extreme weather events inform us that it is inevitable to lose a lot of load due to the impact of the event itself. Additionally, BPA highly recommends that P5 not be included in Table 1 as part of the required studies because extreme weather conditions expose outdoor EHV elements and do not affect protective relaying.

Likes 0	
Dislikes 0	

Response

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC

Answer	No
Document Name	

Comment

To avoid confusion with TPL-001-5 Table 1, we recommend that new categories (not P0-P7) should be used in the new TPL-008-1 Standard. Also, TPL-008-1 Table 1, Category P4 has a footnote #10 in the Category column that is not included or defined in the footnotes.

Likes 0	
Dislikes 0	

Response

Lenise Kimes - City and County of San Francisco - 1,5 - WECC	
Answer	No
Document Name	
Comment	
• Table 1 – The performance requirements in Table 1 allow for the use of NCLL, but there does not appear to be any limit placed the amount of NCLL that can be used. Some entities have a maximum amount of NCLL included in their Cascading criteria and/or other planning criteria, but some entities do not. o For entities that do not have a maximum amount of NCLL specified, does this mean that they can mitigate any issues with unlimited use of NCLL? o If so, studying P1, P2, P4, P5 and P7 events would merely tell us how much load would be shed. Capital projects would never be required for P1, unless some other part of the defined Cascading criteria is violated. o Should there be some type of maximum NCLL limit for these events or do we just want to rely on the individual Cascading criteria of each PC and TP entity? • Table 1 - Table 1 appears to have a cut and paste issue. The title bar includes “(Planning Events and Extreme Events)”, but extreme events are not defined or otherwise referenced in TPL-008. We recommend removing “and Extreme Events” from the title bar of Table 1. • We strongly suggest removing P5 from Table 1 for multiple reasons. See R7 and R10 comments.	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Matthew Jaramilla, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	No
Document Name	
Comment	
SRP disagrees with the proposed TPL-008- Table 1. Would it be possible to simply reference TPL-001 table 1 instead? If not, every time we adjust or make modifications to TPL-001 Standard, we are going to need to open both Standards with a SAR.	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	

Answer	No
Document Name	
Comment	

A fault type for P5 contingencies is needed.

Likes 0	
Dislikes 0	
Response	

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer	No
Document Name	
Comment	

MPC supports comments submitted by the MRO NERC Standards Review Forum (NSRF).

Likes 1	Lakeland Electric, 1, Watt Larry
Dislikes 0	
Response	

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples

Answer	No
Document Name	
Comment	

No, Evergy supports and incorporates by reference the comments of the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 7

Likes 0	
Dislikes 0	
Response	

Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	No

Document Name	
Comment	

While EEI does not yet have specific recommendations for Table 1 at this time, more work is needed to better address the Contingencies and Performance Criteria for Extreme Temperature Assessments.

Likes 0	
Dislikes 0	
Response	

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF

Answer	No
Document Name	
Comment	

LG&E and KU does not support the proposed Table 1 Contingencies and Performance Requirements and recommend the following changes:

1) The voltage level of applicability should be Facilities at 300 kV or higher, which are designated as extra-high voltage (EHV) Facilities in TPL-001 Table 1. As the proposed TPL-008 mirrors TPL-001 events, it should use the same line of distinction as is used in TPL-001. Many entities will have existing processes and automation developed to distinguish between high voltage (HV) and EHV events. While the Technical Rationale does not provide an explanation as to why the analysis is limited to a subset of the BES, a 300 kV threshold appropriately identifies events with possible widespread impacts.

2) Interruption of Firm Transmission Service should be explicitly permitted in Table 1 where Non-consequential Load Loss is allowed.

3) Planning Events P4, P5, and P7 should be removed from Table 1. The Drafting Team correctly notes in the Technical Rationale that these events are “less likely to occur compared to P0 and P1 Contingencies” and that “the Extreme Temperature Assessment already addresses low-probability system conditions.”

The requirement to evaluate these events when no corrective action is required is unreasonable since the likelihood of the events occurring during extreme system conditions is extremely low, the evaluation of possible mitigation actions is unlikely to result in corrective actions, and because the evaluation requirements for more likely scenarios (known outages, loss of an element with a long lead spare) is limited to no more than category P0, P1 and P2 events. Furthermore, while some event categories are relatively straightforward to simulate, category P5 events can be exceedingly tedious to perform. These events also often represent highly unlikely events that are significantly less probable than category P3 or P6 events.

The evaluation of events in categories P0, P1, and P2 represent a reasonable level of analysis for the unlikely extreme conditions represented in the cases. These events also appropriately consider events that are likely to be monitored for in operational scenarios.

Likes 0	
Dislikes 0	
Response	

Richard Vendetti - NextEra Energy - 5

Answer	No
Document Name	

Comment

See comments in #4 and #5

Likes 0	
Dislikes 0	

Response

Chantal Mazza - Chantal Mazza On Behalf of: Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza

Answer	No
Document Name	

Comment

- On the first page of Table 1, “Corrective Action Plan Required” might be better phrased as “Corrective Action Plan Required for Performance Violations” or similar.
- A fault type (3φ or SLG) should be given for P5 contingencies. To be consistent with TPL-001-5.1, this should be SLG.
- Category P3 seems to be missing from the table.

Likes 0	
Dislikes 0	

Response

Glen Farmer - Avista - Avista Corporation - 5

Answer	No
Document Name	

Comment

While EEI does not yet have specific recommendations for Table 1 at this time, more work is needed to better address the Contingencies and Performance Criteria for Extreme Temperature Assessments.

Likes 0	
Dislikes 0	

Response

Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford

Answer	No
Document Name	
Comment	

- Consider separating the current Table 1 into separate, appropriately labeled tables.
- For the “Facility Voltage Level of Contingency” row, this does not fit within the table under the P event designations. Consider moving to a footnote section.
- “Any common structure that includes a Facility 200kV and above” should be defined within a specific P-event definition (such as P7). As currently worded, it appears to apply to all P events. Additionally, it is appropriate for the responsible entity to determine the specific common structure to assess as opposed to “any” common structure.

Likes 0	
Dislikes 0	
Response	

Brittany Millard - Lincoln Electric System - 5

Answer	No
Document Name	
Comment	

LES supports comments submitted by the MRO NERC Standards Review Forum (NSRF).

Likes 0	
Dislikes 0	
Response	

Katrina Lyons - Georgia System Operations Corporation - 4

Answer	No
Document Name	
Comment	

GSOC supports Georgia Transmission Corporation's comments:

- Consider separating the current Table 1 into separate, appropriately labeled tables.
- For the “Facility Voltage Level of Contingency” row, this does not fit within the table under the P event designations. Consider moving to a footnote section.
- “Any common structure that includes a Facility 200kV and above” should be defined within a specific P-event definition (such as P7). As currently worded, it appears to apply to all P events. Additionally, it is appropriate for the responsible entity to determine the specific common structure to assess as opposed to “any” common structure.

Likes 0	

Dislikes 0	

Response

Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
We support EEI's comments.	
Likes 0	
Dislikes 0	

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	No
Document Name	
Comment	
AECI supports comment provided by Georgia Transmission Corporation	
Likes 0	
Dislikes 0	

Response

Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	No
Document Name	
Comment	
In Table 1 there is no fault type for P5. This should probably be SLG Additionally, the SRC recommends that the drafting team either include the full set of footnotes from TPL-001-5.1 Table 1 or clarify why TPL-008 contains only a limited subset of the footnotes to Table 1.	
Likes 0	

Dislikes 0	
Response	
Junji Yamaguchi - Hydro-Quebec (HQ) - 5	
Answer	No
Document Name	
Comment	

On the first page of Table 1, “Corrective Action Plan Required” might be better phrased as “Corrective Action Plan Required for Performance Violations” or similar.

A fault type (3φ or SLG) should be given for P5 contingencies. To be consistent with TPL-001-5.1, this should be SLG.

Category P3 seems to be missing from the table.

Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	

Ameren believes Table 1 performance criteria does not clearly identify applicability. In the Steady State Performance Criteria, it is not clear whether it applies to all of the BES or just BES elements 200kv and above.

Likes 0	
Dislikes 0	
Response	
Colby Galloway - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	

Comment	
The Corrective Action Plan Requirement for P1 events on already extreme conditions and benchmark events is excessive and operating guides should be an appropriate solution. P1 events should be covered under R10 instead of R9. Southern Company believes that P2, P4, P5 and P7 events are not appropriate for such a high forecasted load period. P2, P4, P5, and P7 events are unnecessarily extreme conditions to assess on already extreme cases and load forecasts and should not be included in the scope of analysis. This is especially true for P5 which, under certain circumstances, can look like total loss of the station events.	
Likes 0	
Dislikes 0	
Response	

Rebika Yitna - Rebika Yitna On Behalf of: David Weekley, MEAG Power, 3, 1; Roger Brand, MEAG Power, 3, 1; - Rebika Yitna

Answer	No
Document Name	
Comment	
Take into consideration labeling Table 1 separately. In addition, for all P events, the phrase "Any Common structure that includes a Facility 200kV and above" needs to be clarified because the word "any" could be interpreted differently.	
Likes 0	
Dislikes 0	
Response	

Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle

Answer	No
Document Name	
Comment	

Table 1 – The performance requirements in Table 1 allow for the use of NCLL, but there does not appear to be any limit placed the amount of NCLL that can be used. Some entities have a maximum amount of NCLL included in their Cascading criteria and/or other planning criteria, but some entities do not.

For entities that do not have a maximum amount of NCLL specified, does this mean that they can mitigate any issues with unlimited use of NCLL?

If so, studying P1, P2, P4, P5 and P7 events would merely tell us how much load would be shed. Capital projects would never be required for P1, unless some other part of the defined Cascading criteria is violated.

Should there be some type of maximum NCLL limit for these events or do we just want to rely on the individual Cascading criteria of each PC and TP entity?

Table 1 - Table 1 appears to be mislabeled. The title bar includes “(Planning Events and Extreme Events)”, but extreme events are not defined or otherwise referenced in TPL-008. We recommend removing “and Extreme Events” from the title bar of Table 1.

We strongly suggest removing P5 from Table 1 for multiple reasons. See R7 and R10 comments.

Likes 0	
Dislikes 0	

Response

Robert Jones - Seattle City Light - 1,3,4,6

Answer	No
Document Name	

Comment

The table should be reformatted and split into two tables. In the top half, titling the first column “event” doesn’t make sense. The second half appears to be just a recreation of the TPL-001-5 table 1 and should be separate.

Likes 0	
Dislikes 0	

Response

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3

Answer	No
Document Name	

Comment

NIPSCO supports the comments provided by Entergy, AEP, and BPA.

Likes 0	
Dislikes 0	

Response

Selene Willis - Edison International - Southern California Edison Company - 5

Answer	No
Document Name	

Comment

"See comments submitted by the Edison Electric Institute"

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	

Exelon agrees with EEI that more work is needed to better address the Contingencies and Performance Criteria for the Extreme Temperature Assessments.

We offer the following suggestions:

Need clarification in Table 1 (page 9) regarding "any common structure that includes a Facility 200kV and above" The way this is written it includes common structure contingencies that include Facilities that are below 200kV. This seems odd since only singles greater than 200kV are included. Suggest "200kV and above Facilities on any common structure" and apply it to only P7 contingencies. Additionally, the first page of Table 1 is formatted differently than the second page. Perhaps Table 1 should be split into a Table 1.1 (Performance Criteria) and Table 1.2 (Contingency Category) Furthermore, the first row starting with "Facility Voltage Level…" doesn't fit the table format. "Facility Voltage Level…" isn't an Event. These notes would be better applied as footnotes.

Table 1 (page 10) "Initial Condition" is labeled as "Normal System," which is confusing because this isn't the system as it normally is but the system as it is modeled under an extreme temperature event. Suggest "System per benchmark planning case identified in R4."

Likes 0	
Dislikes 0	

Response

Amy Wilke - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	

ATC generally supports the MRO NSRF comments, and wants to emphasize that it would be helpful to have the standard document that monitored facilities should still generally include all BES facilities, but contingencies should be those 200 kV and above.

Likes 0	
Dislikes 0	

Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	No
Document Name	
Comment	

On the first page of Table 1, “Corrective Action Plan Required” might be better phrased as “Corrective Action Plan Required for Performance Violations” or similar.

A fault type (3φ or SLG) should be given for P5 contingencies. To be consistent with TPL-001-5.1, this should be SLG.

Category P3 seems to be missing from the table.

Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	No
Document Name	
Comment	

Exelon agrees with EEI that more work is needed to better address the Contingencies and Performance Criteria for the Extreme Temperature Assessments.

We offer the following suggestions:

Need clarification in Table 1 (page 9) regarding “any common structure that includes a Facility 200kV and above” The way this is written it includes common structure contingencies that include Facilities that are below 200kV. This seems odd since only singles greater than 200kV are included. Suggest “200kV and above Facilities on any common structure” and apply it to only P7 contingencies. Additionally, the first page of Table 1 is formatted differently than the second page. Perhaps Table 1 should be split into a Table 1.1 (Performance Criteria) and Table 1.2 (Contingency Category) Furthermore, the first row starting with “Facility Voltage Level…” doesn’t fit the table format. “Facility Voltage Level…” isn’t an Event. These notes would be better applied as footnotes.

Table 1 (page 10) “Initial Condition” is labeled as “Normal System,” which is confusing because this isn’t the system as it normally is but the system as it is modeled under an extreme temperature event. Suggest “System per benchmark planning case identified in R4.”

Likes 0	

Dislikes 0	

Response

Wayne Guttormson - SaskPower - 1

Answer	No
Document Name	

Comment

Support the MRO NSRF and EEI comments.

Likes 0	
Dislikes 0	

Response

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	No
Document Name	

Comment

While NV Energy does not yet have specific recommendations for Table 1 at this time, more work is needed to better address the Contingencies and Performance Criteria for Extreme Temperature Assessments.

Likes 0	
Dislikes 0	

Response

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2

Answer	No
Document Name	

Comment

ERCOT recommends the following clarifications to Table 1:

- in the Facility Voltage Level of Contingency row, change the commas to colons,

- in the Facility Voltage Level of Contingency row, clarify what is meant by “reference voltage,” and

- in the Stability Performance Criteria row, clarify what is meant by “initialization.”

Additionally, ERCOT recommends that the drafting team either include the full set of footnotes from TPL-001-5.1 Table 1 or clarify why TPL-008 contains only a limited subset of the footnotes to Table 1.

Finally, consistent with ERCOT’s comments on the need for Requirement R9 to clarify that Load shed is allowed to establish a solvable P0 system condition, ERCOT recommends that Table 1 be revised to contain the same clarification as Requirement R9. This is necessary to ensure that the standard complies with paragraph 94 of FERC Order No. 896, which (as noted in the Technical Rationale) states that resource adequacy is not in scope for this project.

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	No
Document Name	

Comment

OPG supports NPCC Regional Standards Committee’s comments.

Likes 0	
Dislikes 0	

Response

Adrian Harris - Adrian Harris On Behalf of: Bobbi Welch, Midcontinent ISO, Inc., 2; - Adrian Harris, Group Name RTO/ISO Council Standard Review Committee Project 2023-07 TPL-008

Answer	No
Document Name	

Comment

The SRC recommends the following clarifications to Table 1:

- in the Facility Voltage Level of Contingency row, change the commas to colons,
- in the Facility Voltage Level of Contingency row, clarify what is meant by “reference voltage,” and
- in the Stability Performance Criteria row, clarify what is meant by “initialization.”

Additionally, the SRC recommends that the drafting team either include the full set of footnotes from TPL-001-5.1 Table 1 or clarify why TPL-008 contains only a limited subset of the footnotes to Table 1.The SRC also requests that the drafting team confirm that Table 1 will be limited to 200 kV and above facilities and not include contingencies below 200 kV, as this could miss contingency events below 200 kV that could be limiting to the 200 kV and up system.

Finally, consistent with the SRC's comments on the need for Requirement R9 to clarify that Load shed is allowed to establish a solvable P0 system condition, the SRC recommends that Table 1 be revised to contain the same clarification as Requirement R9. This is necessary to ensure that the standard complies with paragraph 94 of FERC Order No. 896, which (as noted in the Technical Rationale) states that resource adequacy is not in scope for this project.

IESO Abstains from Question 7

Likes 0	
Dislikes 0	
Response	
Catrina Martin - Archer Energy Solutions, LLC - 5	
Answer	No
Document Name	
Comment	

Table 1 – The performance requirements in Table 1 allow for the use of NCLL, but there does not appear to be any limit placed the amount of NCLL that can be used. Some entities have a maximum amount of NCLL included in their Cascading criteria and/or other planning criteria, but some entities do not.

o For entities that do not have a maximum amount of NCLL specified, does this mean that they can mitigate any issues with unlimited use of NCLL?

o If so, studying P1, P2, P4, P5 and P7 events would merely tell us how much load would be shed. Capital projects would never be required for P1, unless some other part of the defined Cascading criteria is violated.

o Should there be some type of maximum NCLL limit for these events or do we just want to rely on the individual Cascading criteria of each PC and TP entity?

Table 1 - Table 1 appears to have a cut and paste issue. The title bar includes "(Planning Events and Extreme Events)", but extreme events are not defined or otherwise referenced in TPL-008. We recommend removing "and Extreme Events" from the title bar of Table 1.

We strongly suggest removing P5 from Table 1 for multiple reasons. See R7 and R10 comments.

Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
TPL-001-5.1 Table 1 includes 'BES Level' in-line with the P1-P7 events, as well as Interruption of Firm Transmission Service and whether Non-Consequential Load Loss is allowed. The information is generally captured in TPL-008 but having it in a similar table to TPL-001-5.1 could help for consistency between planning standards and allow for less searching for this information elsewhere in TPL-008. Similarly, the "notes" at the beginning of TPL-008's Table 1 are generally footnotes in the TPL-001-5.1 Table 1. While TPL-008's Table 1 works, functional alignment to how the information is laid out in TPL-001-5.1 would be appreciated as well. FERC ultimately did not indicate a required set of contingencies to be considered, leaving this to the SDT. However, in its commentary, FERC Order 896 seemed to highlight those contingencies that could be more related to extreme weather. It is not clear how or if the SDT assessed the weather relation to contingencies in its Technical Rationale discussion. Does the SDT have specific thoughts or considerations, or is the intent to pass this on to the applicable entities to make such determinations? In consideration of future Table 1 event selections, thoughts from the SDT on the relation between extreme weather and contingency selection would be appreciated.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
No Additional Comments.	
Likes 0	
Dislikes 0	
Response	

Broc Bruton - Broc Bruton On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Broc Bruton	
Answer	Yes
Document Name	
Comment	
Oncor would like to know the technical justification for only calling out BES 200kV and above instead of using BES 100kV and above.	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Suggest the DT ensures footnotes and numbering in Table 1 are consistent. I.e., Table 1 category P4 contains a footnote #10, however footnote #10 is missing from the table on page 12.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Apollonia Gonzales - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Whaite - Stephen Whaite On Behalf of: Tyler Schwendiman, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Michele Tondalo - United Illuminating Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michele Shafer - New York State Electric & Gas (NYSEG) - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lidija Efremova - Lidija Efremova On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Lidija Efremova	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	
Document Name	
Comment	
Constellation has no comments Kimberly Turco on behalf of Constellation Segments 5 and 6	

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC

Answer	
Document Name	

Comment

In general, yes but there may be some confusion as there are two parts to the Table. Again, this may be an opportunity to leverage what is done in TPL-001 and accent it accordingly for an Extreme Temperature Assessment.

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5

Answer	
Document Name	

Comment

Constellation has no comments

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE noticed that Table 1 is applicable to BES level 200 kV and above. The webinar recording, however, mentioned that the TP and PC should be monitoring the entire BES, not just 200 kV and above. Texas RE requests the Table 1 language clarify that the entire BES be monitored.

Likes 0	
Dislikes 0	
Response	

8. The Standard Drafting Team (SDT) is proposing a phased-in implementation plan approach. Do you agree with the proposed phased-in timeframes? If you do not agree, please provide your recommendation and technical justification.

Catrina Martin - Archer Energy Solutions, LLC - 5	
Answer	No
Document Name	
Comment	
If R9 is intended to include the construction of capital projects, there should be additional time allowed for construction of those projects after the completion of the first Extreme Temperature Assessment study. An additional 5 years is suggested for CAP's for R9 that involves capital investment.	
Likes 0	
Dislikes 0	
Response	

Adrian Harris - Adrian Harris On Behalf of: Bobbi Welch, Midcontinent ISO, Inc., 2; - Adrian Harris, Group Name RTO/ISO Council Standard Review Committee Project 2023-07 TPL-008	
Answer	No
Document Name	
Comment	
In general, the SRC supports the phased-in approach of the proposed implementation plan. That said, the SRC requests the SDT establish a "date certain" by which the ERO must publish its "approved benchmark library" envisioned under R2. The SRC suggests this be completed within 12 months of the effective date of TPL-008-1. This will allow planning entities at least **48** months ***after*** the ERO benchmark library is published to come into compliance with proposed requirements R2-R6. As the ERO may not be subject to the Implementation Plan, the SRC defers to NERC and the SDT to structure the required completion date for the benchmark library in an appropriate manner. • The SRC asks the SDT to share how the ERO plans to maintain ongoing updates to the benchmark event library, including the planned update schedule as well as the underlying criteria, approach and assumptions.	
Likes 0	
Dislikes 0	
Response	

Michael Goggin - Grid Strategies LLC - 5	
Answer	No
Document Name	
Comment	

The draft Implementation Plan proposes that requirements R7-R11, which require the Extreme Temperature Assessment and any resulting Corrective Action Plan, do not take effect until more than 6 years after the Standard is approved by FERC. This unnecessary delay is contrary to FERC's directive in Order 896 and the urgent importance of planning for extreme heat and cold events.

NERC's 2023 State of Reliability Overview concluded that "extreme weather events continue to pose the greatest risk to reliability due to the increase in frequency, footprint, duration, and severity." FERC Order 896 was also clear that the increasing frequency and magnitude of extreme weather events "have created an urgency to address the negative impact of extreme weather on the reliability of the Bulk-Power System" (at paragraphs 21-22). Waiting until after 2030 to address the largest threat to grid reliability does not make sense. Such a delay is also unnecessary, as entities responsible for TPL-008 already conduct nearly all of the elements of TPL-008 today to comply with TPL-001. TPL-008 effectively requires running similar analyses as TPL-001, but for extreme heat and cold scenarios. As a result, it should be straightforward for responsible entities to modify their existing planning practices to incorporate the two additional scenarios.

This unnecessary delay is also at odds with FERC's directive in Order 896. At paragraph 188, FERC directed "NERC to propose an implementation timeline for the new or modified Reliability Standard, with implementation beginning no later than 12 months after the effective date of a Commission order approving the proposed Reliability Standard." Under the draft Implementation Plan, the only requirement of TPL-008 that comes close to falling within the 12-month timeline FERC directed is compliance with R1, which begins "the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard."

More importantly, R1 is only the requirement that "Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall determine and identify each entity's individual and joint responsibilities for performing the studies needed to complete the Extreme Temperature Assessment," and as such is a minor procedural step towards implementing the actual Extreme Temperature Assessment and any resulting Corrective Action Plan in R7-R11. As noted above, those meaningful requirements do not begin until more than 6 years after the standard is approved by FERC. To comply with FERC's directive, the drafting team should require compliance with R7-R11 to begin within 12 months of FERC approval of the standard, and the interim steps in R2-R6 should also be moved up from the Implementation Plan's proposed deadline of 36 months after the effective date of the standard.

Likes 0	
Dislikes 0	

Response

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	No
Document Name	

Comment

NV Energy does not agree with making Requirement R1 effective on the effective date of TPL-008 because this requirement includes the development of processes that currently do not exist. Beyond this change, we have no other objections to the proposed Implementation Plan.

Likes 0	
Dislikes 0	

Response

Wayne Guttormson - SaskPower - 1

Answer	No

Document Name	
Comment	

Support the MRO NSRF and EEI comments.

Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	No
Document Name	
Comment	

Texas RE noticed that the phased-In Compliance Dates descriptions do not match the implementation diagram. The verbiage in the implementation plan says the following:

Phased In Compliance Dates

Effective Date = 12 months after the FERC Order

R1 = Effective Date of TPL-008-1

R2, R3, R4, R5, R6 = Effective Date + 36 months

R7, R8, R9, R10, R11 = Effective Date + 60 months

The diagram in the implementation plan shows the following:

R1 = Effective Date of TPL-008-1 (12 months after the FERC Order)

R2, R3, R4, R5, R6 = Effective Date for TPL-008-1 + 24 months

R7, R8, R9, R10, R11 = Effective Date for TPL-008-1 + 48 months

Texas RE requests the implementation plan descriptions and diagram be aligned. In particular, subsequent compliance activities should be consistently linked to the Standard Effective Date, which is 12 months following the first calendar quarter after the FERC Order approving the standard. As such, the chart should be adjusted or the narrative description shortened to reference the implementation period from the effective date.

Additionally, Requirement R8 states that the Extreme Temperature Assessment shall be done once every five calendar years. In the past, there has been confusion as to whether the first time a periodic activity is done by the effective date/compliance date or within the timeframe specified in the requirement of the compliance date. In this case, should the first Extreme Temperature Assessment be done by the compliance date or within five years of the compliance date? In the past, the term “initial performance” has been used in the implementation plan to indicate the first time an activity in a periodic requirement is to be done. Texas RE requests the implementation plan clarify when the first assessment shall be completed, and generally recommends establishing an explicit initial performance date upon the effective date of the requirement to avoid delaying compliance obligations an additional five years.

Likes 0	
Dislikes 0	

Response

Kinte Whitehead - Exelon - 3

Answer	No
Document Name	

Comment

Exelon supports EEI’s suggestion regarding Requirement 11.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	No
Document Name	

Comment

Exelon supports EEI’s suggestion regarding Requirement 11.

Likes 0	
Dislikes 0	

Response

Selene Willis - Edison International - Southern California Edison Company - 5

Answer	No
Document Name	

Comment

“See comments submitted by the Edison Electric Institute”

Likes 0	
Dislikes 0	

Response

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3

Answer	No
Document Name	

Comment

NIPSCO supports the comments provided by Entergy, WPP, FE, WAPA, CMS Energy, and WECC.

Likes 0	
Dislikes 0	

Response

Robert Jones - Seattle City Light - 1,3,4,6

Answer	No
Document Name	

Comment

It is unknown when the standard will be approved and go into effect. For R1, utilities should be given more time. Maybe 6 months after the standard goes into effect. The implementation timeline for other requirements is fair.

Likes 0	
Dislikes 0	

Response

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	No
Document Name	

Comment

In general, ITC supports the phased-in approach of the proposed implementation plan. That said, the ITC requests the SDT establish a “date certain” by which the ERO must publish its “approved benchmark library” envisioned under R2. ITC suggests this be completed within 12 months of the effective date of TPL-008-1 as detailed below. This will allow planning entities at least 24 months ***after*** the ERO benchmark library is published to come into compliance with proposed requirements R2-R6.

Alternative is to make the Implementation Plan effective dates for R2-R6 due no sooner than 24 months or 36 months after the benchmark cases are available and R7-11 due no sooner than 48 months or 60 months after the benchmark cases are available.

Likes 0	
Dislikes 0	

Response

Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle

Answer	No
Document Name	

Comment

If R9 is intended to include the construction of capital projects, there should be additional time allowed for construction of those projects after the completion of the first Extreme Temperature Assessment study. An additional 5-10 years is suggested for CAP's for R9 that involves capital investment.

Likes 0	
Dislikes 0	

Response

Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen

Answer	No
Document Name	

Comment

ISO-NE will reserve its decision on the phased in implementation until after a "benchmark event" list is posted.

Typically ISO will support a phased in implementation.

Likes 0	
Dislikes 0	

Response

Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
We support EEI's comments.	
Likes 0	
Dislikes 0	
Response	

Brittany Millard - Lincoln Electric System - 5	
Answer	No
Document Name	
Comment	
LES supports comments submitted by the MRO NERC Standards Review Forum (NSRF).	
Likes 0	
Dislikes 0	
Response	

Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
EEI does not agree with making Requirement R1 effective on the effective date of TPL-008 because this requirement includes the development of processes that currently do not exist. If the benchmark event library is maintained outside of the Standard, the implementation plan should not be initiated until the library is fully established and populated.	
Likes 0	
Dislikes 0	
Response	

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF

Answer	No
Document Name	
Comment	
LG&E and KU agrees with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	
It appears ability to comply is completely dependent on having an "approved benchmark library maintained by the Electric Reliability Organization " However, implementation plan is strictly calendar based and divorced from the establishment of the approved benchmark library. Details of the benchmark library are not found in either the Std or the Technical Rationale , and the ERO apparently has no obligation to create a library. Suggest Mitigation Plan, other than R1, be keyed to the library creation. Also suggest putting in Tech Rationale links or references where details of the library may be found, the process used to select the events, how the library will be maintained and controlled, etc Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI does not agree with making Requirement R1 effective on the effective date of TPL-008 because this requirement includes the development of processes that currently do not exist. If the benchmark event library is maintained outside of the Standard, the implementation plan should not be initiated until the library is fully established and populated.	
Likes 0	
Dislikes 0	

Response	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 8	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
MPC supports comments submitted by the MRO NERC Standards Review Forum (NSRF).	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
If the standard gets approved, we will need more implementation time due to other new studies that have to be implemented soon as the results of other NERC projects.	
Likes 0	
Dislikes 0	

Response	
Broc Bruton - Broc Bruton On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Broc Bruton	
Answer	No
Document Name	
Comment	
Oncor agrees with statement from Entergy that the timeline should not start until the ERO has developed the benchmark event library. Because of the complexity of the required study, the proposed standard is written to employ a five-year process. Final implementation of the proposed standard should be five years after the ERO has developed the benchmark event library.	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Lenise Kimes - City and County of San Francisco - 1,5 - WECC	
Answer	No
Document Name	
Comment	
If R9 is intended to include the construction of capital projects, there should be additional time allowed for construction of those projects after the completion of the first Extreme Temperature Assessment study. An additional 5 years is suggested for CAP's for R9 that involved capital investment.	
Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	No
Document Name	
Comment	
The timing is extensive and based on the TPL-001 requirements already in place and does not appear necessary with a few caveats—selection of the benchmark cases and applying the cases. In general some things are already in place (extreme heat in most places increases load---may impact Facility Ratings). How the process is done for an Extreme Temperature Assessment may not vary much from today's efforts. Not sure why R7 would be delayed as Contingencies are "ordinary" efforts for planning engineers. In essence, with the extended timeframe, and Extreme Weather Assessment may not occur for SDT timing, FERC approval, plus the implementation period which would be beyond 2030. To be clear, the Assessment in R8 should not take an additional 5 calendar years on top on the implementation plan. This Standard, while new, is not a completely new Standrad as a lot of the actions are already being done through TPL-001 processes today.	
Likes 0	
Dislikes 0	
Response	

Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	No
Document Name	
Comment	
Southern Indiana Gas & Electric Company d/b/a CenterPoint Energy Indiana South (SIGE) agrees with a phased-in approach for TPL-008; however, SIGE supports MRO NERC Standards Review Forum's (NSRF) request for the drafting team to establish a "date certain" by which the ERO must publish its "approved benchmark library" envisioned under R2. Additionally, SIGE agrees with MRO NSRF recommendation that this be completed within 12 months of the effective date of TPL-008-1. This will allow planning entities at least 24 months after the ERO benchmark library is published to come into compliance with proposed requirements R2-R6.	
Likes 0	
Dislikes 0	
Response	

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	

Please refer to Question 1 comments.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	No
Document Name	

Comment

It appears ability to comply is completely dependent on having an "approved benchmark library maintained by the Electric Reliability Organization " However, implementation plan is strictly calendar based and divorced from the establishment of the approved benchmark library. Details of the benchmark library are not found in either the Std or the Technical Rationale , and the ERO apparently has no obligation to create a library. Suggest Mitigation Plan, other than R1, be keyed to the library creation. Also suggest putting in Tech Rationale links or references where details of the library may be found, the process used to select the events, how the library will be maintained and controlled, etc.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro

Answer	No
Document Name	

Comment

Given the uncertainties detailed above, BC Hydro is unable to support the proposed implementation plan at this time.

Likes 0	
Dislikes 0	

Response

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF

Answer	No
Document Name	

Comment	
Consumers Energy agrees with the comments by WAPA: WAPA supports the phased-in approach of the proposed implementation plan. However, we request the SDT establish a “date certain” by which the ERO must publish its “approved benchmark library” envisioned under R2. We suggest this be completed within 12 months of the effective date of TPL-008-1 as detailed below. This will allow planning entities at least 24 months after the ERO benchmark library is published to come into compliance with proposed requirements R2-R6. Such as: Compliance Date for ERO Benchmark Library under TPL-008-1 Requirement R2:The Electric Reliability Organization (ERO) shall be required (commit in its filing to FERC) to publish the approved benchmark library for performing the Extreme Temperature Assessments within twelve (12) months after the effective date of Reliability Standard TPL-008-1. Also, we request the SDT to share how the ERO plans to maintain ongoing updates to the benchmark event library. Will this be on a continuous basis?	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
WAPA supports the phased-in approach of the proposed implementation plan. However, we request the SDT establish a “date certain” by which the ERO must publish its “approved benchmark library” envisioned under R2. We suggest this be completed within 12 months of the effective date of TPL-008-1 as detailed below. This will allow planning entities at least 24 months **after** the ERO benchmark library is published to come into compliance with proposed requirements R2-R6. Such as: **Compliance Date for ERO Benchmark Library under TPL-008-1 Requirement R2:**The Electric Reliability Organization (ERO) shall be required (commit in its filing to FERC) to publish the approved benchmark library for performing the Extreme Temperature Assessments within twelve (12) months after the effective date of Reliability Standard TPL-008-1. Also, we request the SDT to share how the ERO plans to maintain ongoing updates to the benchmark event library. Will this be on a continuous basis?	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	

Comment	
Until scope and direction of TPL-008's intent is clear, FirstEnergy cannot support the Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
This study is the first of its kind where multiple Planning Coordinators must coordinate the selection of the benchmark events and the development of the benchmark planning cases. Sufficient time is required to ensure thorough coordination between responsible entities in the initial Extreme Temperature Assessment. This may be possible in allotted time but will be difficult. An additional 24 months is required for R7, R8, R9 and R10 to allow time for planning, design, construction, and regulatory approvals of Corrective Action Plans. It is unclear when NERC plans to release the benchmarked planning cases. We recommend that the SDT revise the implementation plan with information on the benchmark library development plan (for example, within 12 months after FERC approval of the standard).	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	No
Document Name	
Comment	
Black Hills Corporation is in agreement with EEI. EEI does not agree with making Requirement R1 effective on the effective date of TPL-008 because this requirement includes the development of processes that currently do not exist. Beyond this change, we have no other objections to the proposed Implementation Plan.	
Likes 0	
Dislikes 0	
Response	

Michael Whitney - Northern California Power Agency - 3, Group Name NCPA	
Answer	No
Document Name	
Comment	
NO, These assessment should be performed by the Regional Entities. There appears to be too much room for coordination issues having one Transmission Planner (TP) or Planning Coordinator (PC) having to rely on other TPs or PCs to meet their requirement deadlines.	
Likes 0	
Dislikes 0	
Response	

Lauren Giordano - Lauren Giordano On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; Michael Whitney, Northern California Power Agency, 4, 6, 3, 5; - Lauren Giordano	
Answer	No
Document Name	
Comment	
NO, These assessment should be performed by the Regional Entities. There appears to be too much room for coordination issues having one Transmission Planner (TP) or Planning Coordinator (PC) having to rely on other TPs or PCs to meet their requirement deadlines.	
Likes 0	
Dislikes 0	
Response	

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	No
Document Name	
Comment	
Acceptable but should have development of operating procedures instead of CAPs.	
Likes 0	
Dislikes 0	
Response	

Srikanth Chennupati - Entergy - Entergy Services, Inc. - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Entergy believes the timeline should not start until ERO has developed benchmark event library. Because of the complexity of the study, standard is written as five-year process. Final implementation should be 5 years after the ERO has developed benchmark event library.	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	No
Document Name	
Comment	
The phased-in timeframes seem excessive. 12 months should be sufficient since this type of assessment would be done coincident with TPL-001 assessments.	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
OPG supports NPCC Regional Standards Committee’s comments.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	

Answer	Yes
Document Name	
Comment	

If the comments above reading “Responsible Entity” are retained, corresponding changes should be made to the VSL table.

If the comment above for R6 regarding “to identify instability, uncontrolled separation, or Cascading” is retained, corresponding changes should be made to the VSL table.

Likes 0	
Dislikes 0	

Response

David Jendras Sr - Ameren - Ameren Services - 3

Answer	Yes
Document Name	
Comment	

None.

Likes 0	
Dislikes 0	

Response

Junji Yamaguchi - Hydro-Quebec (HQ) - 5

Answer	Yes
Document Name	
Comment	

If the comments above reading “Responsible Entity” are retained, corresponding changes should be made to the VSL table.

If the comment above for R6 regarding “to identify instability, uncontrolled separation, or Cascading” is retained, corresponding changes should be made to the VSL table.

Likes 0	

Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	Yes
Document Name	
Comment	
AECI supports comment provided by Georgia Transmission Corporation	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Chantal Mazza On Behalf of: Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	Yes
Document Name	
Comment	
• If the comments above reading "Responsible Entity" are retained, corresponding changes should be made to the VSL table. • If the comment above for R6 regarding "to identify instability, uncontrolled separation, or Cascading" is retained, corresponding changes should be made to the VSL table	
Likes 0	
Dislikes 0	
Response	

Isidoro Behar - Long Island Power Authority - 1	
Answer	Yes
Document Name	
Comment	
Assuming that "development" of a CAP, "sharing" of a CAP and "soliciting feedback" on a CAP as part of R9 does not mean "implementing" a CAP, then we concur with the phased-in implementation plan approach.	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rebika Yitna - Rebika Yitna On Behalf of: David Weekley, MEAG Power, 3, 1; Roger Brand, MEAG Power, 3, 1; - Rebika Yitna	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Galloway - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lidija Efremova - Lidija Efremova On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Lidija Efremova	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Katrina Lyons - Georgia System Operations Corporation - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Michele Shafer - New York State Electric & Gas (NYSEG) - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michele Tondalo - United Illuminating Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Whaite - Stephen Whaite On Behalf of: Tyler Schwendiman, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Matthew Jaramilla, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Apollonia Gonzales - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 1	Lakeland Electric, 1, Watt Larry
Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Streifling - NB Power Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
BPA believes a minimum of five years would be the least amount of time to feasibly implement this standard.	
Likes 0	

Dislikes 0	
Response	

9. Provide any additional comments for the SDT to consider, including the provided technical rationale document, if desired.

Kevin Conway - Western Power Pool - 4	
Answer	
Document Name	
Comment	
Extreme temperature events seem to be more frequent and longer in duration than in the past. Entities need to ensure that that they properly plan for events such as these. The proposed TPL-008 tries to address the need for extreme temperature performance, but doesn't seem to address the duration, as well as the extreme temperature. The proposed standard also appears to hold Transmission Planners to a level of accountability that the Planning Coordinator is more appropriately set up to do.	
Likes 0	
Dislikes 0	
Response	

Srikanth Chennupati - Entergy - Entergy Services, Inc. - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
Entergy recommends that the time frame for the assessment be stated earlier. It could be written as follows: "R2: Each responsible entity, as identified in Requirement R1, shall complete an Extreme Temperature Assessment of the Long-Term Planning Horizon once every five calendar years, using the models and contingencies developed in the following requirements."	
Likes 0	
Dislikes 0	
Response	

Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
NA	

Likes 0	
Dislikes 0	

Response

Jeffrey Streifling - NB Power Corporation - 1

Answer	
Document Name	

Comment

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Likes 0	
Dislikes 0	

Response

Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD

Answer	
Document Name	

Comment

If the SDT is open to further aligning things with TPL-001-5.1, the TPL-001-5.1 standard addresses outages, spare equipment and associated criteria for its system assessments, TPL-008-1 does not. This is a potential for a reliability gap. Bad system events typically include pre-existing outages as part of the contributors to the larger event. Including such things in study work, is a reliability principle. During the 4/12/2024 Industry Webinar, it sounded like the SDT's expectation was outages (granted, this is 5-10 years out and typically not a lot of outages are planned out that far) were included either in the extreme weather case or effected by the use of the Table 1 contingencies. However, in actual operations, the outage is typically a long-duration event, and the need is to be secure for the next credible contingency event. Therefore, it is recommended the SDT re-consider how outages and potentially unavailable long lead-time equipment may be considered for the purposes of TPL-008.

Furthermore, while it's not likely this information is known for such timeframes, it is possible that multiple items could be expected to be out of service or unavailable. This is a scenario FERC seems to hint at in Order 896, Paragraph 88: "*Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to require under the new or revised Reliability Standard the study of concurrent/correlated generator and transmission outages due to extreme heat and cold events in benchmark events as described in more detail below*".

It is thought outages should be included in the benchmark planning case per Order 896, Paragraph 91, in part "…*Thus, while generation and transmission availability and concurrent outages must be included in the benchmark planning case, we defer to NERC to develop the framework and criteria that responsible entities shall use to represent potential weather-related contingencies*". There is no language currently in TPL-008 that includes pre-existing outages in the base state, only addressing the contingencies. Instead, the analysis, as currently contemplated, is performed, per Table 1, from "Normal System", without outages mentioned elsewhere in TPL-008.

FERC goes on further in Order 896, Paragraph 89 to note "*We disagree with comments suggesting that the modeling of concurrent/correlated generator and transmission outages is unnecessary. As discussed in the NOPR, and reinforced by commenters, the failures of individual generators during extreme weather events are not independent. Previous extreme weather events have demonstrated that there is a high correlation between generator* *outages and cold temperatures, indicating that as temperatures decrease, unplanned generator outages and derates increase. Because of this correlation, it is necessary that responsible entities evaluate the risk of correlated or concurrent outages and derates of all types of generation resources and transmission facilities as a result of extreme heat and cold events, as commenters suggest.*" This seems to indicate FERC is expecting an analysis that includes an assessment where there are broader outages than possibly what is contemplated under the current TPL-008 approach.

Another risk not discussed in this document and perhaps is more of a "Benchmark Event" topic, is the dispatch of certain types of resources in the case. In particular, the Pacific Northwest recently performed an assessment of cold weather conditions and found at load seasonal peaks, wind was typically around 15% of Pmax, solar at 10% of Pmax, and battery resources may become depleted during multi-day events. Similarly, as observed in the recent ERCOT events, cold weather may also render certain plants un-usable due to freezing conditions. Here in the Northwest, this may be realized in the form of a summer case where there is extreme water scarcity (drought) for the hydro system, during the extreme weather event. The risk in studies is these sorts of resources may be dispatched in an overly optimistic manner if attention is not called to their set up for these sorts of extreme weather analyses. We would recommend some sort of language in the ERO Benchmark Event process (or RE or PC process if this is changed) to include consideration of such details to ensure resulting studies are not performed with overly optimistic resource supply. We do not believe (and FERC acknowledges there is a balance of prescriptiveness vs reliability needs, Order 896, Paragraph 91) these are brought to light in the current support and discussion of the NERC guidance and material surrounding the proposed TPL-008. These constraints are very real and since the purpose of TPL-008 is to help entities understand potential future needs to provide resiliency for such events, activities such as considering the unavailability, de-rate, or decreased output of such resources is warranted.

Likes 0	
Dislikes 0	

Response

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1 - WECC

Answer	
Document Name	

Comment

The new requirements of this standard should be added to a new version of TPL-001. There are too many instances of double jeopardy. The extreme winter and summer events could be a new P8 Planning Event in Table 1 of TPL-001 where the performance requirements outlined in this standard are included.

Provide event templates in next posting.

Likes 0	
Dislikes 0	

Response

Michael Whitney - Northern California Power Agency - 3, Group Name NCPA

Answer	
Document Name	

Comment

No comment.

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments

Answer	
Document Name	

Comment

Black Hills Corporation recommends the SDT consider adding language in the proposed TPL-008-1 standard similar to section 2.6 of Requirement R2 of TPL-001-5.1 (see language in quotations below).

Adding this language to the standard will allow for entities to better phase out the new study work required of them over the five year period. Entities could examine an extreme weather event as a sensitivity for one of the long term planning cases and use that analysis as part of their compliance work for TPL-008-1.

"2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included."

Likes 0	
Dislikes 0	

Response

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO

Answer	
Document Name	

Comment

The success of this standard depends heavily on the quality, relevance, severity, and probability of the events in the "approved benchmark library maintained by the [ERO]". For example, if the events maintained in the approved benchmark library are severe low probability events, then more Corrective Action Plans will be required to comply with the standard. This approach, when taken to an extreme, introduces a risk of either over-building or under-building the Bulk Power System. We recommend that the process to develop benchmark events include a thorough consultation with industry stakeholders including Canadian entities to ensure that the severity and probability of the events are reasonable.

Once established, it is important to know how ERO plans to maintain the benchmark event library.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	
Document Name	

Comment

FirstEnergy requests the Drafting Team to be consistent with the obligations presented in TPL-008 with the obligations from TPL-001.

Likes 0	
Dislikes 0	

Response

Ben Hammer - Western Area Power Administration - 1

Answer	
Document Name	

Comment

WAPA would also like the SDT address:

Transparency – how will the process ensure ongoing impacted stakeholder participation in the ERO's development of future benchmark event cases?

Cost – how will the process limit the potential for infinite costs associated with CAPs (as currently written)?

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	
Document Name	

Comment

Constellation has no comments

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

BPA appreciates the efforts of the Standard Drafting Team in developing the FERC mandated standard.

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC

Answer	
Document Name	

Comment

The construct of the Standard and thought process behind it is sound and WECC appreciates the efforts. Additional clarity to avoid confusion and consideration of possibly duplicative work in TPL-001 may need addressed.

Likes 0	
Dislikes 0	

Response

Lenise Kimes - City and County of San Francisco - 1,5 - WECC

Answer	
Document Name	

Comment

a) The proposed standard is quite lengthy and is duplicative of much of the TPL-001-5.1 standard. While it is good to have consistency in the methodology, it does increase the need to update both standards if one of them is updated or it could increase the chances of discrepancies between TPL-001 and TPL-008. There are at least two possible solutions:

o Consider referencing the relevant parts of the TPL-001-5.1 standard in TPL-008, or

o Modify TPL-001-5.1 to include mandatory sensitivity studies for extreme temperature events that meet the requirements of the proposed TPL-008 with a frequency of every 5 years. These extreme temperature sensitivities would need to have the modified performance requirements that are currently included in TPL-008, however.

b) Most (not all) of the VSLs are very drastic/severe (0 to 100 in one step) leaving no room for possible explanations or maybe time delays. For instance, maybe 36 or 60 months noted in the Implementation Plan are not long enough for some entities, but they meet it at 38 or 62 months. The VSL table should be reworked to better reflect a more realistic severity of many of these items.

Likes 0	
Dislikes 0	

Response

Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Matthew Jaramilla, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez

Answer	
Document Name	

Comment

In addition to the comment in Question 3, SRP strongly recommends that if industry is not going to be part of the benchmarking approval process, that the SDT then provide regional examples of both ends of extreme weather events. This way, industry can at least understand the range of the different benchmarking events that the ERO will be selecting.

Likes 0	
Dislikes 0	

Response

Hillary Creurer - Allete - Minnesota Power, Inc. - 1

Answer	
Document Name	

Comment

Minnesota Power supports MRO’s NERC Standards Review Forum’s (NSRF) comments.

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer	
Document Name	

Comment

MPC supports comments submitted by the MRO NERC Standards Review Forum (NSRF).

Likes 0	
Dislikes 0	

Response

Stephen Whaite - Stephen Whaite On Behalf of: Tyler Schwendiman, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies

Answer	
Document Name	

Comment

RF appreciates the efforts of the standards drafting team on this project. While RF has submitted an affirmative vote in the associated ballot event, it encourages the drafting team to consider the concerns and suggestions outlined in this comment submission.

Likes 0	
Dislikes 0	

Response

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples

Answer	
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 9

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5

Answer	
Document Name	

Comment

Constellation has no additional comments

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Richard Vendetti - NextEra Energy - 5

Answer	
Document Name	

Comment

NextEra suggests that the NERC standards drafting committee, currently focused on extreme weather analysis, include requirements for each PC & TP to establish and report acceptable load drop thresholds as part of the standard. It's also crucial to mandate the reporting of these thresholds to relevant regulatory organizations before a PC & TP incorporates load drops into its corrective action plans.

Moreover, while the likelihood of extreme weather events, particularly cold weather occurrences, combined with a line fault and stuck breaker failure to operate event may appear low, stuck breakers are significantly more prone to occur during extreme cold events. Considering this heightened risk during cold weather events, along with the potential for load drop resulting in loss of human life, it's imperative to take into account. Thus, NextEra recommends that the NERC standards drafting committee, focusing on extreme weather events, strongly consider incorporating breaker failure events, particularly during PC and TP extreme cold analysis, and mandate the inclusion of mitigations in any corrective action plan

Likes 0	
Dislikes 0	

Response

Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	
Document Name	
Comment	

AZPS recommends that the requirement should be renumbered to reflect the order in which the work is performed (i.e. R5 moves to R2, R6 moves to R3, R2, moves to R4, R3 moves to R5 and R4 moves to R6)

Likes 0	
Dislikes 0	
Response	

Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	
Document Name	
Comment	

- In general, the development of an extreme weather benchmark event is reasonable. The difficulty in properly assessing this draft Reliability Standard is the unknowns around the benchmark events. Whether these events are solely temperature-based or if there is a related electrical system or resource availability embedded needs to be clarified in the standard language.

Likes 0	
Dislikes 0	
Response	

Katrina Lyons - Georgia System Operations Corporation - 4	
Answer	
Document Name	
Comment	

GSOC supports Georgia Transmission Corporation's comments:

- In general, the development of an extreme weather benchmark event is reasonable. The difficulty in properly assessing this draft Reliability Standard is the unknowns around the benchmark events. Whether these events are solely temperature-based or if there is a related electrical system or resource availability embedded needs to be clarified in the standard language.

Likes 0	
Dislikes 0	
Response	

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	
AECI supports comment provided by Georgia Transmission Corporation	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
Remove “Extreme Events” from Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events; Page 12 of 20) since there isn’t an “Extreme Events” category in the TPL-008-1 standard.	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	
Document Name	
Comment	
While ISO-NE supports the efforts of the SDT and the work that they have done to complete this initial draft quickly, ISO-NE reserves its determination on the Standard until a complete list of the “benchmark events” is made available.	
Likes 0	
Dislikes 0	
Response	

David Jendras Sr - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
Ameren suggests adding these requirements to TPL-001-5 instead of making a new standard to reduce the administrative burden of having to deal with multiple standards.	
Likes 0	
Dislikes 0	
Response	

Colby Galloway - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	
For these low probability, high load forecast extreme events, Southern Company recommends use of operating guides as an allowable solution. Investment should not be mandated. Further clarification on the definition and approval of benchmark events is needed within the standard.	
Likes 0	
Dislikes 0	
Response	

Rebika Yitna - Rebika Yitna On Behalf of: David Weekley, MEAG Power, 3, 1; Roger Brand, MEAG Power, 3, 1; - Rebika Yitna	
Answer	
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	

Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	
Document Name	

Comment

The proposed standard is quite lengthy and is duplicative of much of the TPL-001-5.1 standard. While it is good to have consistency in the methodology, it does increase the need to update both standards if one of them is updated or it could increase the chances of discrepancies between TPL-001 and TPL-008. There are at least two possible solutions:

Consider referencing the relevant parts of the TPL-001-5.1 standard in TPL-008, or

Modify TPL-001-5.1 to include mandatory sensitivity studies for extreme temperature events that meet the requirements of the proposed TPL-008 with a frequency of every 5 years. These extreme temperature sensitivities would need to have the modified performance requirements that are currently included in TPL-008, however.

Likes 0	
Dislikes 0	

Response

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	
Document Name	

Comment

Suggested R2 modifications. R2 – ITC recommends that temperature be added to benchmarks to clarify the scope of the benchmarks being developed.

Should industry be a part of the vetting and approval process for the temperature benchmarks events?

Likes 0	
Dislikes 0	

Response

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	
Document Name	

Comment

A completely new standard is unnecessary to address extreme weather events. This requirement could simply be incorporated into the existing TPL-001-5 standard. This incorporation could be accomplished by adding a new P8 category addressing extreme weather events, or an additional requirement could be added to the existing TPL-001-5 standard requiring review of extreme weather events every five years. Incorporation into one TPL standard would minimize and streamline the TPL system performance assessment process, while preventing any confusion and duplication that would be created between the existing TPL-001-5 standard and the proposed TPL-008-1 standard.

Likes 0	
Dislikes 0	

Response

Selene Willis - Edison International - Southern California Edison Company - 5

Answer	
Document Name	

Comment

“See comments submitted by the Edison Electric Institute”

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	
Document Name	

Comment

Overall, there are too many unknowns at this time, so Exelon is not able to fully support the current proposed standard. We suggest developing an additional formal guidance that specifies the creation and selection of the benchmark events.

Likes 0	
Dislikes 0	

Response

Amy Wilke - American Transmission Company, LLC - 1

Answer	
Document Name	

Comment	
ATC generally supports the MRO NSRF comments, and wants to emphasize the question: For "1.2 Evidence Retention" under section "C. Compliance", what is meant by "or one complete Extreme Temperature Assessment cycle, whichever is longer"?	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	
Document Name	
Comment	
Overall, there are too many unknowns at this time, so Exelon is not able to fully support the current proposed standard. We suggest developing an additional formal guidance that specifies the creation and selection of the benchmark events.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Adrian Harris - Adrian Harris On Behalf of: Bobbi Welch, Midcontinent ISO, Inc., 2; - Adrian Harris, Group Name RTO/ISO Council Standard Review Committee Project 2023-07 TPL-008	
Answer	
Document Name	

Comment	
Other concerns the SRC would like the SDT to address include: Transparency – As noted in the SRC's comments regarding Requirement R2, an open and transparent process for establishing and maintaining the benchmark library is crucial, and the SRC recommends that Planning Coordinators be allowed to submit extreme heat and cold events based on their historical weather events and statistical analysis for inclusion in the library.	
Likes 0	
Dislikes 0	
Response	

Catrina Martin - Archer Energy Solutions, LLC - 5	
Answer	
Document Name	
Comment	
The proposed standard is quite lengthy and is duplicative of much of the TPL-001-5.1 standard. While it is good to have consistency in the methodology, it does increase the need to update both standards if one of them is updated or it could increase the chances of discrepancies between TPL-001 and TPL-008. There are at least two possible solutions: o Consider referencing the relevant parts of the TPL-001-5.1 standard in TPL-008, or o Modify TPL-001-5.1 to include mandatory sensitivity studies for extreme temperature events that meet the requirements of the proposed TPL-008 with a frequency of every 5 years. These extreme temperature sensitivities would need to have the modified performance requirements that are currently included in TPL-008, however. Most (not all) of the VSLs are very drastic/severe (0 to 100 in one step) leaving no room for possible explanations or maybe time delays. For instance, maybe 36 or 60 months noted in the Implementation Plan are not long enough for some entities, but they meet it at 38 or 62 months. The VSL table should be reworked to better reflect a more realistic severity of many of these items.	
Likes 0	
Dislikes 0	
Response	

Comments submitted by MRO NSRF:

Questions

1. Do you agree with the proposed definition of Extreme Temperature Assessment? If you do not agree, please provide your recommendation and, if appropriate, technical justification.

☐ Yes
☒ No

Comments:

Conceptually, the proposed definition for Extreme Temperature Assessment does not presently appear to present any issues; however, the MRO NERC Standards Review Forum (NSRF) is unable to fully evaluate the definition without more information regarding the "benchmark events" that will be key to performing Extreme Temperature Assessments.

Our understanding is that NERC intends to post sample benchmark event(s) on or around July 9, 2024. The MRO NSRF will be able to provide more definitive feedback once this information is available.

2. Do you agree with the proposed TPL-008-1 Reliability Standard Requirement R1? If you do not agree, please provide your recommendation and, if appropriate, technical justification.

☒ Yes
☐ No

Comments:

The MRO NSRF supports modeling proposed TPL-008, requirement R1 after TPL-001-5.1, requirement R7 and TPL-007, requirement R1.

3. Do you agree with the proposed TPL-008-1 Reliability Standard Requirement R2 (Benchmark events)? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

☐ Yes
☒ No

Comments:

As with the Extreme Temperature Assessment definition, the MRO NSRF is unable to fully evaluate Requirement R2 without being able to see and evaluate some example(s) of what the ERO intends to include as benchmark events in the library. Full evaluation of this requirement also requires additional information on how the approved benchmark library managed by the ERO will be established, populated and maintained over time, including the underlying criteria, approach and assumptions. An open and transparent process is crucial, and the MRO NSRF recommends that Planning Coordinators be allowed to submit, extreme heat and cold events that are impactful to the reliability of the system based on their historical weather events and statistical analysis for inclusion in the library.

In addition, the MRO NSRF supports the "responsible entity as identified in requirement R1" language in R2 as it allows flexibility among planning entities to collectively determine who (e.g., the PC and/or TP) will perform R2.

From an improvement perspective, the MRO NSRF recommends several edits to the text of **R2**:

- The word "temperature" be added to benchmark events to align with the **Extreme Temperature Assessment** definition and to clarify the scope of the benchmarks being developed.
- The word "industry" be added to indicate industry needs to be part of the vetting and approval process to ensure that temperature benchmarks do not result in infeasible construction requirements.

R2. Each responsible entity, as identified in Requirement R1, shall select one extreme heat temperature benchmark event and one extreme cold temperature benchmark event, from the industry approved benchmark library maintained by the Electric Reliability Organization (ERO)

4. Do you agree with the proposed TPL-008-1 Reliability Standard Requirements R3 – R8 (benchmark planning cases and analyses)? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

☐ Yes
☒ No

Comments:

The MRO NSRF requests the SDT address the following in requirements R3-R8:

R3: The MRO NSRF requests the SDT clarify obligations when coordinating with neighboring PCs to perform an Extreme Temperature Assessment. If a PC performs a planning area study for a "selected benchmark event" that only includes a portion of the PC's footprint (Part 3.1), the SDT should confirm that the PC and its associated Transmission Planners have satisfied the obligation under R2 for completing an Extreme Temperature Assessment for either "one extreme heat benchmark event or one extreme cold benchmark event" for that five-calendar year period (R8).

In addition, the MRO NSRF requests the SDT clarify the "process for coordinating the development of benchmark planning cases among impacted Planning Coordinator(s)"

- How far must an entity go, i.e. are Tier 1 neighbors sufficient or must an entity go further?
- Can coordinating on the model build for a given event satisfy this requirement?

Similarly, Requirement R3 should also be revised to clarify how conflicts will be resolved if different Planning Coordinators within the same Interconnection have incompatible processes for selecting benchmark events, defining the planning study boundary area, and coordinating with other impacted entities. This clarification should address scenarios in which three or more impacted, geographically contiguous Planning Coordinators within the same Interconnection all select different, incompatible benchmark events (as allowed by Requirement R1) to study.

- Does the standard require all PCs to support all alternate PC studies?
- What happens if an entity is unwilling to cooperate?

Finally, since stability issues do not propagate over DC ties, Requirement R3 should be revised to indicate that Planning Coordinators and Transmission Planners are not required to coordinate with entities in different Interconnections.

R4: The System models shall use data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed,…"

The MRO NSRF supports the use of MOD-032 to obtain the necessary data and asks the SDT to consider, does MOD-032 need to be modified to acquire information unique to TPL-008?
R5: The MRO NSRF has concerns with R5 as it may be duplicative of work that is already occurring under TPL-001-5.1. Specifically, it is unclear how the criteria for "steady state voltage limits and post-Contingency voltage deviations" under TPL-008, R5 differs from what entities have defined under TPL-001-5.1, and consequently, it is unclear why Requirement R5 is needed. **Please explain.**

In addition, it is unclear why Requirement R5 only addresses voltage issues without also addressing thermal issues, as Table 1's reference to "facility ratings" would seem to include thermal issues. The absence of any reference to thermal issues in Requirement R5 would seem to imply that thermal issues (at least those that don't result in instability, uncontrolled separation, or Cascading) aren't to be considered. The MRO NSRF recommends that the drafting team clarify whether this is its intent. A possible method of addressing this ambiguity may be to revise Requirement R5 to use language along the lines of "operate within the criteria specified in Table 1."

R6. The MRO NSRF has concerns with R6 as R6 may duplicate work that is already occurring under TPL-001-5.1, PRC-006, and other Reliability Standards. Therefore, the MRO NSRF asks the SDT to describe the need drivers for R6 by identifying where extreme temperature events have resulted in system instability, uncontrolled separation, or Cascading.

R7. To clarify that the Extreme Temperature Assessment is limited to the planning study area boundary defined in Part 3.1, the MRO NSRF requests the SDT modify requirement R7 as follows:

R7. Each responsible entity, as identified in Requirement R1, shall identify Contingencies used in performing the Extreme Temperature Assessment for each of the event categories in Table 1 that are expected to produce more severe System impacts within the ~~its~~ planning study area boundary defined in Part 3.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

R8. The MRO NSRF recommends that Requirement R8 be revised to clarify whether the case used needs to be a Long-Term case at the time the study is completed or it just when the case building is completed, as two to three years typically elapse between the completion of the case build and the completion of the studies that use the case.

5. Do you agree with the proposed TPL-008-1 Reliability Standard Requirements R9 – R10 (CAPs and possible actions)? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

☐ Yes
☒ No

Comments:
R9. The MRO NSRF observes that R9 requires responsible entities to share their CAPs with, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues in all cases. This may extend the amount of time needed for CAP approval.

In addition, for entities that are not subject to an "applicable regulatory authority or governing body" for retail electric service issues, e.g., WAPA, does R9 apply to them? If that's the SDT's intent, the MRO NSRF recommends R9 clarify that non-jurisdictional entities are merely submitting their CAPs to the regulatory authority solely for the purpose of receiving comments and are not bound by the local regulatory or governing body. See proposed text to be added to R9 below:
"In the event a non-jurisdictional entity submits a CAP to a regulatory authority or governing body, the submission of the CAP is for informational purposes, feedback, and comment only. The submission of a CAP by a non-jurisdictional entity to a regulatory authority does not waive jurisdiction, immunity, or otherwise place the non-jurisdictional entity under the regulatory authority or the governing body."

The MRO NSRF recommends that the drafting team resolve an apparent inconsistency regarding the P0 analysis. Specifically, the technical rationale appears to suggest that Load shedding is permitted to establish a solvable P0 system condition. However, Requirement R9 and Table 1 do not seem to allow load shedding for solvable P0 system condition. The MRO NSRF recommends that the drafting team address this by revising Requirement R9 to explicitly indicate that Load shed is allowed to establish a solvable P0 system condition. This is necessary to ensure that the study can assume sufficient resources are available in a P0 state. This, in turn, is necessary to prevent the standard from straying into the realm of resource adequacy. As noted in the Technical Rationale, resource adequacy is not in scope for this project under paragraph 94 of FERC Order No. 896.

Finally, the MRO NSRF recommends the phrase "but the planned System shall continue to meet the performance requirements" be stricken from the standard, as it is phrased as an operation mandate, which is inappropriate for a standard focused on long-term planning objectives.

R9. "…Revisions to the CAP(s) are allowed in subsequent Extreme Temperature Assessments, ~~but the planned System shall continue to meet the performance requirements~~."

6. Do you agree with the proposed TPL-008-1 Reliability Standard Requirement R11 (Sharing Extreme Temperature Assessment results)? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.
   ☐ Yes
   ☒ No

   Comments:

   The MRO NSRF supports the "upon request" nature of R11 and sharing Extreme Temperature Assessment results with those having a "reliability need."

   That said, the MRO NSRF recommends the following edits for enhanced clarity and alignment as detailed below:
   - Modify "60" to "90" calendar days to align with TPL-001-5.1, R8, Part 8.1
   - Add "NERC" to functional entity for clarity.

R11. Each responsible entity, as identified in Requirement R1, shall provide its Extreme Temperature Assessment results within 90 ~~60~~ calendar days of a request to any NERC registered functional entity that has a reliability related need and submits a written request for the information.

7. Do you agree with the proposed TPL-008-1 Table 1? If you do not agree, please provide your recommendation and technical justification.
   ☐ Yes
   ☒ No

   Comments:

   The MRO NSRF recommends the following clarifications to Table 1:
   - in the Facility Voltage Level of Contingency row, change the commas to colons,
   - in the Facility Voltage Level of Contingency row, clarify what is meant by "reference voltage," and in the Stability Performance Criteria row, clarify what is meant by "initialization."

   The MRO NSRF recommends that the drafting team include the full set of footnotes from TPL-001-5.1 Table 1 or clarify why TPL-008 contains only a limited subset of the footnotes to Table 1.

   Finally, consistent with the MRO NSRF's comments on the need for Requirement R9 to clarify that Load shed is allowed to establish a solvable P0 system condition, the MRO NSRF recommends that Table 1 be revised to contain the same clarification as Requirement R9. This is necessary to ensure that the standard complies with paragraph 94 of FERC Order No. 896, which (as noted in the Technical Rationale) states that resource adequacy is not in scope for this project.

8. The Standard Drafting Team (SDT) is proposing a phased-in implementation plan approach. Do you agree with the proposed phased-in timeframes? If you do not agree, please provide your recommendation and technical justification.
   ☐ Yes
   ☒ No

   Comments:

   In general, the MRO NSRF supports the phased-in approach of the proposed implementation plan. That said, the MRO NSRF requests the SDT establish a "date certain" by which the ERO must publish its "approved benchmark library" envisioned under R2. The MRO NSRF suggests this be completed within 12 months of the effective date of TPL-008-1. This will allow planning entities at least 24 months ***after*** the ERO benchmark library is published to come into compliance with proposed requirements R2-R6. As the ERO may not be subject to the Implementation Plan, we leave it to NERC and the SDT to structure the required completion date for the benchmark library in an appropriate manner.

- The MRO NSRF asks the SDT to share how the ERO plans to maintain ongoing updates to the benchmark event library, including the planned update schedule as well as the underlying criteria, approach and assumptions.

Compliance Date for TPL-008-1 Requirements R2, R3, R4, R5, R6
Entities shall not be required to comply with Requirement R2, R3, R4, R5, and R6 until thirty-six (36) months after the effective date of Reliability Standard TPL-008-1

9. Provide any additional comments for the SDT to consider, including the provided technical rationale document, if desired.

Comments:

Other concerns the MRO NSRF would like the SDT to address include:

- Transparency – As noted in the MRO NSRF's comments regarding Requirement R2, an open and transparent process for establishing and maintaining the benchmark library is crucial, and the MRO NSRF recommends that Planning Coordinators be allowed to submit extreme heat and cold events based on their historical weather events and statistical analysis for inclusion in the library.
- Cost – how will the process limit the potential for infinite costs associated with CAPs (as currently written)?
- For "1.2 Evidence Retention" under section "C. Compliance", what is meant by "or one complete Extreme Temperature Assessment cycle, whichever is longer"?
    - for example, should this be defined to a specific period of time, 5 year, 10 years, etc…

Summary Response to TPL-008-1 Draft 1 Comments Received

NERC Project 2023-07 Transmission Planning Performance Requirements for Extreme Weather
July 2024

Comments Received Summary

There were 78 sets of responses, including comments from approximately 179 different people from approximately 99 companies representing 10 of the Industry Segments. A summary of comments submitted can be reviewed on the project page.

If you have an interest in joining the distribution list for this project, please reach out to Senior Standards Developer, Jordan Mallory.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact Manager of Standards Jamie Calderon (via email) or at (404) 960-0568.

Consideration of Comments

The NERC Project 2023-07 thanks all of industry for your time and comments. The Standard Drafting Team (SDT) feels that many great points have been provided for the SDT to consider during the drafting phase of this project. High level themes received from industry are located below (bolded is the high-level theme followed by the SDT's response).

Benchmark Events

Many commenters expressed concern that they cannot fully approve the Extreme Temperature Assessment and definition and TPL-008-1 Standard without having benchmark events information. In addition, some entities expressed concern about having to agree to a requirement that has yet to be fully developed. Based on the technical rationale, there is an expectation that the ERO will determine suitability and make available benchmark events representative of probable futures. Once the initial library of events has been developed, we would be in a better position to consider support for this requirement.

Drafting team response:

NERC is still committed to providing additional information regarding the criteria used in the development of this initial population of the benchmark event library, the process for maintaining the library, the process for entity submitted benchmark events and the criteria for which they will be evaluated for approval, as well as the future state envisioned for ongoing curation of the library with industry involvement and climate data SMEs.

To best assist the team when voting "No" please provide comments specific to the Standard and requirements that are within scope for the team to address. As NERC is directed by FERC to create the benchmark event library, it is unclear what improvement to the Standard that the drafting team is able to make to the Standard draft or definitions.

Submitting Benchmark Events Process

Entities with an interest in submitting their own benchmark events are seeking a timeframe as to when the process will be provided to industry.

Drafting team response:

NERC is still committed to providing additional information regarding the criteria used in the development of this initial population of the benchmark event library, the process for maintaining the library, the process for entity submitted benchmark events and the criteria for which they will be evaluated for approval, as well as the future state envisioned for ongoing curation of the library with industry involvement and climate data SMEs.

The process is expected to be initially posted on the NERC website and will be maintained to ensure it is up to date. This process is not included within the balloting process and should be considered separately to be consistent with the balloting process.

Regional Entities to Complete Assessments

Some commenters stated that Regional Entities should be the entity who completes the assessment.

Drafting team response:

Regional Entities are not subject to compliance of standards and thus cannot perform assessment to meet standard requirements. Planning Coordinators in coordination with Transmission Planners are the appropriate entities to complete planning assessments.

Definitions

The SDT received comments with proposed updated definitions for consideration. Below provides a high-level list of what was received.

- Updated proposed terms (no definition updates):
  - Extreme Weather Assessment
  - Extreme Temperature Transmission Assessment
  - Expected Scope Assessment
- Request SDT to define the following terms;
  - Extreme heat and extreme cold temperature benchmark events

Drafting team response:

The SDT appreciates all the proposed term update considerations. It was determined to leave Extreme Temperature Assessment for many reasons. Those reasons are 1) temperature focuses on this specific project with regards to extreme cold and heat planning cases being based on temperature; 2) Transmission is not an appropriate addition to this term as entities are supposed to be looking at generator information during transmission outages (See Requirement R3); and 3) the definition has been drafted at a high level for the purpose of specifics that need to be added like steady state, transient stability, etc. which are mentioned in the requirement.

Regarding extreme heat and extreme cold temperature benchmark events – This will be further explained in the NERC Process document.

TPL-008-1 Applicability and Standard Requirements

The SDT received comments on Requirements R1 through R11 and Table 1. Below takes a deeper look into the comments received and the consideration the SDT made.

Requirement R2

Benchmark events

Some comments asked for clarification on the benchmark events development and maintenance process including the responsible entity, the criteria for the selection of benchmark events and access restrictions to the library. Some comments also questioned if additional benchmark events can be submitted to the library.

Drafting team response:

Questions on the benchmark events library will be addressed through a separate process document provided by the ERO. There will not be an attachment to the standard. Also, the entities will be allowed to submit benchmark events to the library. Details on the approval process will be included in the process document.

Compliance Obligation Separation

Some comments questioned who the responsible entity was and raised coordination concerns among the different entities.

Drafting team response:

Responsible entities are defined in R1. One entity will be chosen as the primary entity. Language was revised to further clarify this. Replaced ‘Each responsible entity’ with ‘The responsible entity established in R1’. Some entities may use PC as the primary responsible entity and others may use TP as the primary responsible entity. The language was drafted to allow for this, Regional Entities and EROs are not applicable entities and hence will not be allowed to perform the study.

Number of benchmark events

Some comments questioned if more than one extreme heat benchmark event and one extreme cold benchmark event can be studied.

Drafting team response:

The standard requires that at least one benchmark heat and one benchmark cold event is studied. The Responsible Entity can choose to study more than one event if they want to. The language was updated to say "at least" one event should be studied.

Clarification on "Functional Entities" in the Applicability section

Some comments suggested that the "Functional Entities" in the Applicability section be changed to "Responsible Entities".

Drafting team response:

"Functional entities" in the Applicability section could mean the entities outside the Responsible Entities defined in R1 of the standard. The definition of "Functional Entity" is consistent with the other NERC TPL standards.

Minor wording changes

Some comments suggested that the word "temperature" be added to R2 when referencing extreme heat and cold benchmark events.

Drafting team response:

Comment accepted and R2 language was revised accordingly.

Requirement R3

Overlap with Other Reliability Standards

Some comments suggested the drafting team should add a provision that would allow work on other Reliability Standards to cover the requirements specified in TPL-008. Additionally, some suggested the responsible entity should follow the criteria set forth in FAC-014-3. Finally, some suggested the drafting team coordinate with Project 2023-06 CIP-014 Risk Assessment Refinement.

Drafting team response:

There are fundamental differences between TPL-001-5.1 and TPL-008 (e.g., TPL-001 has an annual periodicity while TPL-008 does not and TPL-008 requires broader coordination based on the selected benchmark temperature events). Nothing in the standard precludes the responsible entity from using similar information used in other standards to demonstrate compliance with TPL-008. Additionally, the requirements in TPL-008 do not contradict those in FAC-014-3 nor the CIP-014 drafting team efforts because they allow the responsible entity to determine the criteria, which may be the same or different than criteria used in other standards.

All Lines in Service

Some comments suggested P0 should be evaluated with all lines in service as a base case.

Drafting team response:

Line outages may be included in the base case if those outages are consistent with the conditions defined in the selected benchmark temperate events.

Justification of Contingencies

Some comments questioned how the responsible entity could justify one set of outages versus another.

Drafting team response:

In accordance with Requirement R7, the responsible entity must provide the technical rationale for the contingencies selected for evaluation. In accordance with the TPL-008 Technical Rationale document, some, but not all, items to consider when developing the rationale for selecting Contingencies are past studies, subject matter expert knowledge of the responsible entity's System (to be supplemented with data or analysis), and historical data from past operating events.

Adjust Timeline for Implementation of CAPs

Some comments suggested that the implementation plan allow a ten-year period for implementation of CAPs that require capital investment to construct new facilities.

Drafting team response:

The drafting team did not modify the implementation plan; however, a sub-requirement was added under Requirement R9 stating that if circumstances beyond the control of the responsible entity prevent the timely implementation of CAPs, responsible entities may use Non-Consequential Load Loss to address the issue, provided they document the situation, evaluate alternatives, and record the actions taken.

Differentiation of "Planning Cases" and "System Models"

Some comments suggested the difference between "planning cases" and "system models" should be clarified because they are not defined in the NERC Glossary of Terms.

Drafting team response:

The drafting team concluded system models are components that are necessary to include in the development of benchmark planning cases, which is consistent with NERC Reliability standard TPL-001-5.1.

Clarity on P0 Events

Some comments suggested additional clarity is needed to determine when and if P0 and P1 events are required.

Drafting team response:

The drafting team concluded the responsible entity must include P0 in the assessment. The TPL-008-1 Technical Rationale document provides further information.

Requirement R4

MOD-032 Data

Some commenters asked if the drafting team feel it would be necessary to add any additional data to the table in MOD-032 to complete this work. In addition, some sought clarification on how MOD-032 will allow for the collection of additional information related to extreme heat and cold events.

Drafting team response:

MOD-032 ensures an adequate means of data collection for transmission planning and requires applicable registered entities to provide steady-state, dynamic, and short circuit modeling data to their transmission planner(s) and planning coordinator(s). As outlined in R1 and Attachment 1 of MOD-032, MOD-032 allows various data collection such as in-service status and capability associated with demand, generation, and transmission associated with various case types, scenarios, system operating states, or conditions for the long-term planning horizon. MOD-032 also requires applicable registered entities to provide “other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes” for each of the three types of data required. Because the drafting team determined the responsible entities that will be developing benchmark planning cases are limited to planning coordinators and transmission planners, they will be able to request and receive needed data pursuant to MOD-032. Thus, the drafting team believes that there is no need to update MOD-032 because it allows planning coordinators and transmission planners to request any specific data needed for developing and maintaining benchmark planning cases required in R4 of TPL-008-1.

Requirement R5

Criteria for Thermal Constraints

Some comments questioned why voltage was being referenced but not thermal constraints.

Drafting team response:

The drafting team updated Requirement R5 to include “applicable Facility Ratings.”

Acceptable Deviation Range

Some comments suggested including an acceptable deviation range or acceptable based on common industry practice or technical basis as it is currently open-ended as to what criteria is “acceptable.”

Drafting team response:

The drafting team concluded the standard is flexible enough to allow for regional differences throughout the requirements, which is consistent with Reliability Standard TPL-001-5.1.

Language Change

Some comments suggested changing the language from “shall have criteria” to “shall define and document criteria” for consistency with Requirement R6.

Drafting team response:
The drafting team determined that "have" is the appropriate wording for this requirement as the responsible entity could be receiving this information from somewhere else based on how responsibilities are established in Requirement R1.

Language Change
Some comments suggested unless some exception is made for FAC-014-3 R6, there may be no further room possible with respect to operational limits.

Drafting team response:
The drafting team allowed flexibility on how the responsibility entity sets limits.

Use of "System Voltage Limits"
Some comments suggested using the recently adopted NERC Glossary term "System Voltage Limits."

Drafting team response:
The drafting team determined "System Voltage Limits" focuses on operations and planning information may differ. The drafting team concluded to maintain the proposed language consistent with Reliability Standard TPL-001-5.1.

Coordinated Criteria
Some comments questioned if the Planning Coordinator must ensure all entities are using the same criteria for acceptable System steady state voltage limits.

Drafting team response:
The drafting team determined some Transmission Planners under a Planning Coordinator could have different voltage limits. In accordance with Requirement R1, the Planning Coordinator, in conjunction with its Transmission Planner(s), must determine individual or joint responsibilities.

Documentation to be used from a different standard
If a TP or PC believes that the work performed for a different standard will cover work required under TPL-008, can a provision for this be added to the standard?

Drafting team response:
Provision language does not need to be added to the TPL-008-1 standard. If an entity feels that documentation from another Reliability Standard, such as TPL-001, is sufficient, the entity can use that same information for the evidence of TPL-008-1.

Requirement R6

"Instability, uncontrolled separation, or Cascading" and IROLs
Some comments questioned if the identification of "instability, uncontrolled separation, or Cascading" are expected to be different for the Extreme Temperature Assessment relative to Interconnection Reliability Operating Limits (IROLs).

Drafting team response:

The drafting team does not specify how instability, uncontrolled separation, or Cascading should be defined. Additionally, the requirement allows the responsible entity flexibility to determine the criteria or methodology, which may be the same or different than criteria used in other standards.

Severity of ERO Library Events

Some comments expressed concern that if the events in the ERO library are too severe and lead to a significant increase in the events that trigger instability, these could be expensive problems to fix.

Drafting team response:

The drafting team determined entities are welcome to develop their own benchmark temperature events should the ones within the ERO library not suffice. Additionally, per Requirement R9, Corrective Action Plans are only required for Table 1 P0 or P1 Contingencies.

"Instability, uncontrolled separation, or Cascading" Boundary

Some comments questioned if entities must identify instability, uncontrolled separation, or Cascading of the System or the Interconnection.

Drafting team response:

The drafting team added "within an Interconnection" to Requirement R6.

Multiple Violations for a Single Issue

Some comments questioned if this is duplicative to TPL-001-5.1 or other standards, and if this will create a situation where two requirements would be violated for a single issue.

Drafting team response:

The drafting team determined that Reliability Standard TPL-001-5.1 is for standard conditions while TPL-008-1 is for extreme conditions (i.e., extreme heat and extreme cold temperature events).

Acceptable Load Loss Thresholds

Some comments suggested entities should be required to establish acceptable load loss thresholds for addressing thermal overloads identified before utilizing non-consequential load drops as a corrective action plan.

Drafting team response:

The drafting team determined the responsible entity may choose to define load loss thresholds in its criteria or methodology, or in coordination with its regulatory authorities or governing bodies. Recognizing regional variations in requirements, the drafting team finds it impractical to set a maximum limit. Therefore, there is no set load loss identified in TPL-008; however, Table 1 allows for Non-Consequential Load Loss.

Requirement R7

Acceptable Load Loss Thresholds

Some entities expressed that R7 should clearly indicate which contingency categories are required.

Drafting team response:

Requirement R7 identifies the contingencies are listed in Table 1.

Requirement R8

Timeframe Specificity

Some entities expressed concern that R8 may not provide enough specificity regarding the time frame to be assessed from the Long-Term Transmission Planning Horizon.

Drafting team response

The standard provides flexibility within the standard, which is consistent with other drafting efforts.
R8 requires study be performed minimum every five years for at least one year in the long-term horizon.
The standard requires a minimum, one. Nothing precludes an entity from completing more than one condition, should it be needed.

MOD-032 Clarity and Need for Sensitivity Analysis

Some entities request clarification on the purpose of sensitivity analyses in sub-part 8.2 and its association with MOD-032 data collection. Recommend clarity on the necessity of sensitivity analyses and its relation to data collection from the MOD-032 model build.

Drafting team response

MOD-032 is the appropriate standard to gather data needed for this project scope. Sensitivity studies are required by FERC order 896.

Requirement R9

Regulatory Burden

Many commenters raised concerns about the requirement to submit CAPs to regulatory authorities, suggesting it could delay approval, lacks justification, need clearer definitions, and should be limited or removed.

Drafting team response

The SDT reviewed the comments and determined that the requirement is necessary to address the directives of Order 896, specifically the directives mentioned in paragraphs 152 and 165.

Allowing Non-Consequential Load Loss (NCLL) for P0, Concerns about Inadequate Available Generation, and Addressing Inconsistencies in R9

Various entities commented on allowing NCLL (i.e., Load Shed) for P0, addressing inconsistencies between R9 and the Technical Rationale regarding load shedding requirements for P0. They suggested explicitly permitting load shedding for solvable P0 system conditions, noting that resource adequacy is not within the scope of TPL-008 as per TR and Order 896, proposed allowing NCLL under extreme weather conditions for P0, and questioned if NCLL would be allowed for P0 if capital projects or Operating Plans are not completed before the operating horizon.

Drafting team response

The SDT reviewed the comments and updated the Technical Rationale to ensure consistency with Requirement R9. Specifically, the SDT removed the discussion on resource adequacy for P0 from the Technical Rationale for R9, as it is irrelevant to the Corrective Action Plan discussed in R9. Additionally, the SDT offered guidance on preparing solvable P0 cases in the Technical Rationale for R4 to address concerns about potential instances where benchmark planning cases and/or sensitivity cases might lack adequate available generation to meet demand.

The SDT added a sub-requirement under R9 stating that if circumstances beyond the control of the TP or PC prevent the timely implementation of a Corrective Action Plan, responsible entities may use Non-Consequential Load Loss to address the issue, provided they document the situation, evaluate alternatives, and record the actions taken.

Consistency and Clarity

Comments were made to improve clarity and address inconsistency between R9 and other related standards (TPL-008, TPL-001), such as Non-Consequential Load Loss and sharing CAPs.

Drafting team response

The SDT reviewed the comments and updated Requirement R9 for consistency and to provide clarity.

Clarity on Sensitivity Analysis

Various commenters questioned the necessity of a Corrective Action Plan for issues identified in sensitivity analysis, seeking clarity on how sensitivity analysis is handled.

Drafting team response

The SDT revised Requirement R9 to clarify that Corrective Action Plans are not required specifically for addressing performance requirements related to sensitivity cases.

Proposals Regarding Load Shedding

Some commenters recommended explicitly prohibiting load shedding as a CAP, while other entities suggested setting a maximum limit for non-consequential load loss.

Drafting team response

The SDT reviewed the comments and emphasizes that non-consequential load loss is explicitly prohibited for P0 as specified in Table 1 of TPL-008. Recognizing regional variations in requirements, the SDT finds it impractical to set a maximum limit for non-consequential load loss, leaving it to entities to determine for other planning events like P1. Additionally, R6 mandates defining and documenting criteria or methodologies in the Extreme Temperature Assessment to identify instability, uncontrolled separation, or cascading events. The SDT believes that the maximum limit for non-consequential load loss could be specified within the methodology.

Requirement R10

Reasons for Requiring Possible Actions and Restrictions in Creating CAPs

Certain commenters questioned why possible actions are required for P2, P4, P5, and P7 contingencies, while others disagreed due to limitations in creating CAPs for these contingencies.

Drafting team response

The SDT reviewed the comments and affirms that the Technical Rationale for R10 adequately clarified the necessity for possible actions. Additionally, it is important to note that TPL-008 sets a baseline to fulfill the directives from Order 896 and does not prohibit responsible entities from exceeding these requirements.

Clarity and Communication on Possible Actions

A commenter questioned what actions the responsible entity intends to take based on the identified "possible actions." There is uncertainty about how these actions will be executed. In addition, it suggested that these possible actions should be communicated to the operators so they can prepare necessary plans and processes accordingly.

Drafting team response

The SDT acknowledges the commenter's concerns regarding implementing 'possible actions' and their communication to operators. The SDT asserts that Requirement 11 outlines the expected actions, mandating responsible entities to share Extreme Temperature Assessment results with any functional entities with reliability-related needs to enhance readiness for extreme temperature events.

Exclusion of P2, P4, P5, and P7 Contingencies

Some commenters proposed removing P5, citing that extreme weather conditions affect outdoor EHV elements but do not impact protective relaying. Additionally, other comments suggested excluding P2, P4, P5, and P7 events from TPL-008.

Drafting team response

The SDT reviewed the comments and updated Requirement 10 and Table 1 to remove the P5 contingency from TPL-008. The rationale for this decision is detailed in the Technical Rationale of R7.

Requirement R11

Timeline for Distributing Assessment Results

Some comments questioned if the 60 calendar days was appropriate.

Drafting team response:

The drafting team determined to keep the requirement unchanged as this strikes a good balance between allowing enough time for the responsible entity to distribute the results and the functional entity requesting the information to receive them.

Distribution of Assessment Results

Some comments questioned if the distribution of the Extreme Temperature Assessment results should be limited to select registered entities.

Drafting team response:

The drafting team determined to keep the requirement unchanged as it meets the following FERC directive in FERC Order 896, Paragraph 72: "Further, responsible entities must share the study results with affected transmission operators, transmission owners, generator owners, and other functional entities with a reliability need for the studies." Therefore, the responsible entity must share with any functional entity that has a reliability related need and submits a written request for the information. Additionally, this is consistent with other approved NERC Reliability Standards (e.g., TPL-001-5.1 and TPL-007-4).

Metrics for "Reliability Related Need"

Some comments questioned if metrics should be associated with "reliability related need."

Drafting team response:

The drafting team determined to keep the requirement unchanged as this is consistent with other approved NERC Reliability Standards (e.g., TPL-001-5.1 and TPL-007-4).

Table 1

Grammatical/Clarifying Changes

Some commenters recommended grammatical/clarifying changes to Table 1.

- A commenter requested the Facility Voltage Level of Contingency row, change the commas to colons,
- A commenter requested the Facility Voltage Level of Contingency row, clarify what is meant by "reference voltage,"
- A commenter requested the Stability Performance Criteria row, clarify what is meant by "initialization."
- Many commenters recommended that the contingencies should be updated to 200 kV and above.
- Strongly suggest removing P5 from Table 1 for multiple reasons.
- Suggest the DT ensures footnotes and numbering in Table 1 are consistent. I.e., Table 1 category P4 contains a footnote #10, however footnote #10 is missing from the table on page 12.
- Some commenters said more work is needed to better address the Contingencies and Performance Criteria for Extreme Temperature Assessments.

Drafting team response:

Please see updated modifications to Table 1 based on comments received and listed above.

Monitor Entire BES

Table 1 is applicable to BES level 200 kV and above. The webinar recording, however, mentioned that the TP and PC should be monitoring the entire BES, not just 200 kV and above. A commenter requests the Table 1 language clarify that the entire BES be monitored.

Drafting team response:

Additional language has been added to the Purpose (Section A) and Requirement R9 to indicate that the performance criteria is applicable to all the BES.

Non-Consequential Load Loss

Some commenters questioned the performance requirements in Table 1 allow for the use of non-consequential load loss, but there does not appear to be any limit placed on the amount of non-consequential load loss that can be used. Some entities have a maximum amount of non-consequential load loss included in their Cascading criteria and/or other planning criteria, but some entities do not.

In addition, for entities that do not have a maximum amount of NCLL specified, does this mean that they can mitigate any issues with unlimited use of NCLL?

Drafting team response:

Please see the revised TPL-008-1 Requirement R9 for revised language regarding the Non-Consequential Load Loss where it is allowed and utilized. In addition, a maximum value for Non-Consequential Load Loss is not provided in the TPL-008-1 because of regional variances and requirements regarding criteria for identifying instability, uncontrolled separation, or Cascading.

Footnote Section of Table 1

Some commenters recommend the drafting team either include the full set of footnotes from TPL-001-5.1 Table 1 or clarify why TPL-008-1 contains only a limited subset of the footnotes to Table 1.

Drafting team response:

The Contingencies chosen for TPL-008-1 are different from TPL-001-5.1. TPL-008-1 standard is developed and organized to be independent from TPL-001-5.1. Based on this, not all footnotes were needed for TPL-008-1.

Violation Severity Levels (VSLs)

Some entities expressed concern regarding the severity level for the VSLs.

Drafting team response:

The team encourages entities to review the VSL Guidelines document. When a pass/fail requirement is drafted, any noncompliance with the requirement will have only one VSL – Severe. Link to guideline document: [VSL Guidelines (Revised) (nerc.com)](https://www.nerc.com).

Implementation Plan

Benchmark Events

Some entities request a date be established as to when the ERO will have the benchmark event library published.

Drafting team response:

An ERO Benchmark Event Process document has been published with the TPL-008-1 draft 2 posting. The ERO benchmark event library will be published and up and running by December 2024. This library will contain events for the first 5-year iteration of TPL-008-1. Additional time is essentially provided to entities as the benchmark events will be published and TPL-008-1 will be pending approval from the respective applicable governmental authorities. In addition, example benchmark event examples have been provided in a separate document for entities to see what they will be working with to meet the TPL-008-1 Reliability Standard. Please reference the process document for additional details on how the ERO plans to address preparing for the next 5-year iteration of benchmark events.

Requirement R1

Many entities disagreed with making Requirement R1 effective on the effective date of TPL-008-1 because this requirement includes the development of processes that currently do not exist.

Drafting team response:

Per FERC Order 896, Paragraph 7, *"we direct NERC to ensure that the proposed new or modified Reliability Standard becomes mandatory and enforceable beginning no later than 12 months from the effective date of Commission approval of the new or modified Reliability Standard."* To meet this FERC directive, Requirement R1 is the most reasonable requirement to meet the 12-month implementation directive. 1 months from the approval date of TPL-008-1 is adequate time to **identify** individual and joint responsibilities for completing the Extreme Temperature Assessment. Requirement R3 is when the process should be developed and implemented, which per the TPL-008-1 Implementation Plan has 36-months. In addition, there is nothing precluding entities from starting discussion with other PCs and TPs once the petition has been submitted for approval with the respective governmental authorities.

Requirement R9

Some entities expressed concern that if R9 is intended to include the construction of capital projects, there should be additional time allowed for construction of those projects after the completion of the first Extreme Temperature Assessment study.

Drafting team response:

The drafting team did not change the implementation plan; however, Requirement R9.3 was added to permit the use of Non-Consequential Load Loss as an interim solution, which normally is not permitted in Table 1, in situations that are beyond the control of the Planning Coordinator or Transmission Planner that prevent the implementation of a Corrective Action Plan in the required timeframe. The use of Non-Consequential Load Loss as an interim solution in this situation is permitted, provided that each responsible entity documents the situation causing the problem, alternatives evaluated, and takes actions to resolve the situation. Additionally, Requirement R9.4 was added to permit having revisions to the CAP in subsequent Extreme Temperature Assessments, provided that the planned BES continues to meet the performance requirements of Table 1.

Implementation Plan Diagram

One commenter pointed out that the diagram does not line up with the Implementation Plan Language and requested the team update it accordingly.

Drafting team response:

Please see the updated diagram in the Implementation Plan, which should provide clarity on any confusion.

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Reminder
Standards Announcement
Project 2023-07 Transmission Planning Performance Requirements for Extreme Weather

Initial Ballots and Non-binding Poll Open through May 3, 2024

Now Available

Initial ballots for draft one of **TPL-008-1 – Transmission System Planning Performance Requirements for Extreme Temperature Events** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels are open through **8 p.m. Eastern, Friday, May 3, 2024**.

Reminder Regarding Corporate RBB Memberships

Under the NERC Rules of Procedure, each entity and its affiliates is collectively permitted one voting membership per Registered Ballot Body Segment. Each entity that undergoes a change in corporate structure (such as a merger or acquisition) that results in the entity or affiliated entities having more than the one permitted representative in a particular Segment must withdraw the duplicate membership(s) prior to joining new ballot pools or voting on anything as part of an existing ballot pool. Contact ballotadmin@nerc.net to assist with the removal of any duplicate registrations.

Balloting

Members of the ballot pools associated with this project can log in and submit their votes by accessing the Standards Balloting and Commenting System (SBS) here.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will review all responses received during the comment period and determine the next steps of the project.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Jordan Mallory (via email) or at 404-479-7358. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2023-07 Transmission Planning Performance Requirements for Extreme Weather observer list” in the Description Box.

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Standards Announcement

Project 2023-07 Transmission Planning Performance Requirements for Extreme Weather

Formal Comment Period Open through May 3, 2024
Ballot Pools Forming through April 18, 2024

Now Available

A 45-day formal comment period for draft one of **TPL-008-1 – Transmission System Planning Performance Requirements for Extreme Temperature Events** is open through 8 p.m. Eastern, **Friday, May 3, 2024**.

Commenting
Use the Standards Balloting and Commenting System (SBS) to submit comments. An unofficial Word version of the comment form is posted on the project page.

Reminder Regarding Corporate RBB Memberships
Under the NERC Rules of Procedure, each entity and its affiliates is collectively permitted one voting membership per Registered Ballot Body Segment. Each entity that undergoes a change in corporate structure (such as a merger or acquisition) that results in the entity or affiliated entities having more than the one permitted representative in a particular Segment must withdraw the duplicate membership(s) prior to joining new ballot pools or voting on anything as part of an existing ballot pool. Contact ballotadmin@nerc.net to assist with the removal of any duplicate registrations.

Ballot Pools
Ballot pools are being formed through **8 p.m. Eastern, Thursday, April 18, 2024.** Registered Ballot Body members can join the ballot pools here.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
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Next Steps
Initial ballots for the standard and implementation plan, as well as a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **April 24 – May 3, 2024**.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Jordan Mallory (via email) or at 404-479-7358. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify "Project 2023-07 Transmission Planning Performance Requirements for Extreme Weather observer list" in the Description Box.

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BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/319)
Ballot Name: 2023-07 Transmission Planning Performance Requirements for Extreme Weather TPL-008-1 IN 1 ST
Voting Start Date: 4/24/2024 12:01:00 AM
Voting End Date: 5/3/2024 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 277
Total Ballot Pool: 314
Quorum: 88.22
Quorum Established Date: 5/3/2024 2:03:44 PM
Weighted Segment Value: 18.69

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	89	1	10	0.135	64	0.865	0	4	11
Segment: 2	8	0.6	0	0	6	0.6	0	1	1
Segment: 3	68	1	6	0.1	54	0.9	0	3	5
Segment: 4	18	1	3	0.231	10	0.769	0	1	4
Segment: 5	76	1	9	0.158	48	0.842	0	9	10
Segment: 6	47	1	5	0.135	32	0.865	0	4	6
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	1	0	0	0	0	0	0	1	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	7	0.6	4	0.4	2	0.2	0	1	0
Totals:	314	6.2	37	1.159	216	5.041	0	24	37

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Negative	Comments Submitted
1	Ameren - Ameren Services	Tamara Evey		Negative	Comments Submitted
1	American Transmission Company, LLC	Amy Wilke		Negative	Comments Submitted
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Negative	Comments Submitted
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Black Hills Corporation	Micah Runner		Negative	Comments Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
1	Central Electric Power Cooperative (Missouri)	Michael Bax		None	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Third-Party Comments
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	Third-Party Comments
1	Colorado Springs Utilities	Corey Walker		Negative	Third-Party Comments
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Third-Party Comments
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Negative	Comments Submitted
1	Duke Energy	Katherine Street		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Robert Blackney		None	N/A
1	Entergy	Brian Lindsey		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Evergy	Kevin Frick	Hayden Maples	Negative	Comments Submitted
1	Eversource Energy	Joshua London		Negative	Comments Submitted
1	Exelon	Daniel Gacek		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Negative	Comments Submitted
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
1	Great River Energy	Gordon Pietsch		None	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Lidija Efremova	Affirmative	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Negative	Comments Submitted
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
1	JEA	Joseph McClung		Negative	Comments Submitted
1	KAMO Electric Cooperative	Micah Breedlove		Negative	Third-Party Comments
1	Lakeland Electric	Larry Watt		Negative	Third-Party Comments
1	Lincoln Electric System	Josh Johnson		None	N/A
1	Long Island Power Authority	Isidoro Behar		Negative	Comments Submitted
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
1	LS Power Transmission, LLC	Jennifer Richardson		None	N/A
1	M and A Electric Power Cooperative	William Price		Negative	Third-Party Comments
1	Manitoba Hydro	Nazra Gladu		Negative	Comments Submitted
1	MEAG Power	David Weekley	Rebika Yitna	Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Negative	Comments Submitted
1	Muscatine Power and Water	Andrew Kurriger		Negative	Third-Party Comments
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Third-Party Comments
1	National Grid USA	Michael Jones		Negative	Third-Party Comments
1	NB Power Corporation	Jeffrey Streifling		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
1	New York Power Authority	Daniel Valle		Negative	Third-Party Comments
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Negative	Comments Submitted
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Negative	Third-Party Comments
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Negative	Comments Submitted
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Negative	Comments Submitted
1	Platte River Power Authority	Marissa Archie		Negative	Third-Party Comments
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
1	Portland General Electric Co.	Brooke Jockin		Abstain	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	Comments Submitted
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Negative	Third-Party Comments
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Negative	Comments Submitted
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Negative	Comments Submitted
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		None	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Matthew Jaramilla	Israel Perez	Negative	Comments Submitted
1	Santee Cooper	Chris Wagner		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	SaskPower	Wayne Guttormson		Negative	Comments Submitted
1	Seminole Electric Cooperative, Inc.	Kristine Ward		None	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Negative	Third-Party Comments
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Negative	Third-Party Comments
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	None	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		None	N/A
1	Tennessee Valley Authority	David Plumb		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel		Negative	Comments Submitted
1	VELCO -Vermont Electric Power Company, Inc.	Randall Buswell		Abstain	N/A
1	Western Area Power Administration	Ben Hammer		Negative	Comments Submitted
1	Xcel Energy, Inc.	Eric Barry		Negative	Third-Party Comments
2	California ISO	Darcy O'Connell		Abstain	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
2	Independent Electricity System Operator	Helen Lainis		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	ISO New England, Inc.	John Pearson	Keith Jonassen	Negative	Comments Submitted
2	Midcontinent ISO, Inc.	Bobbi Welch	Adrian Harris	Negative	Third-Party Comments
2	New York Independent System Operator	Gregory Campoli		Negative	Third-Party Comments
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Negative	Third-Party Comments
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Negative	Comments Submitted
3	AEP	Leshel Hutchings		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		None	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
3	Austin Energy	Lovita Griffin		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
3	BC Hydro and Power Authority	Ming Jiang		Negative	Comments Submitted
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs	Carly Miller	Negative	Comments Submitted
3	Bonneville Power Administration	Ron Sporseen		Negative	Comments Submitted
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Third-Party Comments
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Negative	Third-Party Comments
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Negative	Comments Submitted
3	Colorado Springs Utilities	Hillary Dobson		Negative	Third-Party Comments
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Bill Garvey		Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Abstain	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
3	Entergy	James Keele		Negative	Comments Submitted
3	Evergy	Marcus Moor	Hayden Maples	Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary		Negative	Comments Submitted
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		None	N/A
3	Great River Energy	Michael Brytowski		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
3	JEA	Marilyn Williams		Negative	Comments Submitted
3	Lakeland Electric	Steven Marshall		Negative	Comments Submitted
3	Lincoln Electric System	Sam Christensen		Negative	Comments Submitted
3	Los Angeles Department of Water and Power	Fausto Serratos		Abstain	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Negative	Third-Party Comments
3	Manitoba Hydro	Mike Smith		Negative	Comments Submitted
3	MEAG Power	Roger Brand	Rebika Yitna	Negative	Comments Submitted
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	Third-Party Comments
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
3	New York Power Authority	David Rivera		Negative	Third-Party Comments
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
3	Northern California Power Agency	Michael Whitney		Negative	Comments Submitted
3	NW Electric Power Cooperative, Inc.	Heath Henry		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
3	Omaha Public Power District	David Heins		Negative	Third-Party Comments
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party Comments
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Negative	Comments Submitted
3	Platte River Power Authority	Richard Kiess		Negative	Third-Party Comments
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted
3	Portland General Electric Co.	Mayra Franco		Abstain	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Negative	Third-Party Comments
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Negative	Comments Submitted
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Negative	Comments Submitted
3	Santee Cooper	Vicky Budreau		Negative	Comments Submitted
3	Seminole Electric Cooperative, Inc.	Marc Sedor		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Negative	Third-Party Comments
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Snohomish County PUD No. 1	Holly Chaney		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	None	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
3	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Negative	Third-Party Comments
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Third-Party Comments
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		None	N/A
4	Austin Energy	Tony Hua		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Third-Party Comments
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		Negative	Third-Party Comments
4	CMS Energy - Consumers Energy Company	Aric Root		Negative	Comments Submitted
4	DTE Energy	Patricia Ireland		None	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
4	Georgia System Operations Corporation	Katrina Lyons		Negative	Comments Submitted
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Northern California Power Agency	Marty Hostler		Negative	Comments Submitted
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Negative	Comments Submitted
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Ken Habgood		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	None	N/A
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
4	Western Power Pool	Kevin Conway		Negative	Comments Submitted
5	AEP	Thomas Foltz		Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Comments Submitted
5	APS - Arizona Public Service Co.	Andrew Smith		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Chuck Booth		Negative	Comments Submitted
5	Austin Energy	Michael Dillard		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Negative	Comments Submitted
5	BC Hydro and Power Authority	Quincy Wang		Negative	Comments Submitted
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Negative	Comments Submitted
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Bonneville Power Administration	Juergen Bermejo		Negative	Comments Submitted
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Negative	Third-Party Comments
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Negative	Comments Submitted
5	Colorado Springs Utilities	Jeffrey Icke		Negative	Third-Party Comments
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
5	Constellation	Alison MacKellar		Abstain	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Third-Party Comments
5	Dominion - Dominion Resources, Inc.	Anna Salmon		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Abstain	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Negative	Comments Submitted
5	Entergy - Entergy Services, Inc.	Gail Golden		Negative	Comments Submitted
5	Evergy	Jeremy Harris	Hayden Maples	Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	Abstain	N/A
5	Great River Energy	Jacalynn Bentz		None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Abstain	N/A
5	Grid Strategies LLC	Michael Goggin		Negative	Comments Submitted
5	Hydro-Quebec (HQ)	Junji Yamaguchi		Negative	Comments Submitted
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	Invenergy LLC	Rhonda Jones		None	N/A
5	JEA	John Babik		Negative	Comments Submitted
5	Lincoln Electric System	Brittany Millard		Negative	Comments Submitted
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
5	LS Power Development, LLC	C. A. Campbell		None	N/A
5	Manitoba Hydro	Kristy-Lee Young		Negative	Comments Submitted
5	Muscatine Power and Water	Neal Nelson		Negative	Third-Party Comments
5	National Grid USA	Robin Berry		None	N/A
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		Negative	Comments Submitted
5	Nebraska Public Power District	Ronald Bender		Negative	Third-Party Comments
5	New York Power Authority	Zahid Qayyum		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	NextEra Energy	Richard Vendetti		Negative	Comments Submitted
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Third-Party Comments
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Third-Party Comments
5	Oglethorpe Power Corporation	Donna Johnson		Negative	Third-Party Comments
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Third-Party Comments
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
5	Orlando Utilities Commission	Dania Colon		Affirmative	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	Third-Party Comments
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Negative	Comments Submitted
5	Pattern Operators LP	George E Brown		Negative	Third-Party Comments
5	Platte River Power Authority	Jon Osell		Negative	Third-Party Comments
5	Portland General Electric Co.	Ryan Olson		Abstain	N/A
5	PSEG Nuclear LLC	Tim Kucey		Negative	Third-Party Comments
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Public Utility District No. 2 of Grant County, Washington	Nikkee Hebdon		None	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Negative	Comments Submitted
5	Santee Cooper	Carey Salisbury		Negative	Comments Submitted
5	Seminole Electric Cooperative, Inc.	Melanie Wong		None	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Negative	Third-Party Comments
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Comments Submitted
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	None	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Abstain	N/A
5	Tennessee Valley Authority	Darren Boehm		Negative	Comments Submitted
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Negative	Third-Party Comments
6	AEP	Mathew Miller		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Comments Submitted
6	Austin Energy	Imane Mrini		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A
6	Black Hills Corporation	Rachel Schuldt		Negative	Comments Submitted
6	Bonneville Power Administration	Tanner Brier		Negative	Comments Submitted
6	Cleco Corporation	Robert Hirchak		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
6	Constellation	Kimberly Turco		Abstain	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Stephanie Kenny		Negative	Comments Submitted
6	Entergy	Julie Hall		Negative	Comments Submitted
6	Evergy	Tiffany Lake	Hayden Maples	Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted
6	Great River Energy	Brian Meloy		Negative	Third-Party Comments
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Lincoln Electric System	Eric Ruskamp		Negative	Comments Submitted
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Manitoba Hydro	Kelly Bertholet		Negative	Comments Submitted
6	Muscatine Power and Water	Nicholas Burns		Negative	Third-Party Comments
6	New York Power Authority	Shelly Dineen		Negative	Third-Party Comments
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
6	Northern California Power Agency	Dennis Sismaet		Negative	Comments Submitted
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Third-Party Comments
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments
6	Platte River Power Authority	Sabrina Martz		Negative	Third-Party Comments
6	Portland General Electric Co.	Stefanie Burke		Abstain	N/A
6	Powerex Corporation	Raj Hundal		Negative	Third-Party Comments
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie		Negative	Comments Submitted
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Negative	Comments Submitted
6	Santee Cooper	Marty Watson		Negative	Comments Submitted
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
6	Snohomish County PUD No. 1	John Liang		None	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
6	Southern Indiana Gas and Electric Co.	Kati Barr		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	None	N/A
6	Western Area Power Administration	Jennifer Neville		Negative	Comments Submitted
6	Xcel Energy, Inc.	Steve Szablya		Negative	Third-Party Comments
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Tyler Schwendiman		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Negative	Comments Submitted

Previous 1 Next

Showing 1 to 314 of 314 entries

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/319)
Ballot Name: 2023-07 Transmission Planning Performance Requirements for Extreme Weather Implementation Plan IN 1 OT
Voting Start Date: 4/24/2024 12:01:00 AM
Voting End Date: 5/3/2024 8:00:00 PM
Ballot Type: OT
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 276
Total Ballot Pool: 314
Quorum: 87.9
Quorum Established Date: 5/3/2024 2:21:51 PM
Weighted Segment Value: 30.03

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	89	1	20	0.274	53	0.726	0	5	11
Segment: 2	8	0.5	1	0.1	4	0.4	0	1	2
Segment: 3	68	1	13	0.217	47	0.783	0	3	5
Segment: 4	18	1	4	0.308	9	0.692	0	1	4
Segment: 5	76	1	15	0.263	42	0.737	0	9	10
Segment: 6	47	1	10	0.27	27	0.73	0	4	6
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	1	0	0	0	0	0	0	1	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	7	0.6	4	0.4	2	0.2	0	1	0
Totals:	314	6.1	67	1.832	184	4.268	0	25	38

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Negative	Comments Submitted
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
1	American Transmission Company, LLC	Amy Wilke		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Negative	Comments Submitted
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Black Hills Corporation	Micah Runner		Negative	Comments Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
1	Central Electric Power Cooperative (Missouri)	Michael Bax		None	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Third-Party Comments
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	Third-Party Comments
1	Colorado Springs Utilities	Corey Walker		Negative	Third-Party Comments
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Third-Party Comments
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Negative	Comments Submitted
1	Duke Energy	Katherine Street		Affirmative	N/A
1	Edison International - Southern California Edison Company	Robert Blackney		None	N/A
1	Entergy	Brian Lindsey		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Evergy	Kevin Frick	Hayden Maples	Negative	Comments Submitted
1	Eversource Energy	Joshua London		Negative	Comments Submitted
1	Exelon	Daniel Gacek		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
1	Great River Energy	Gordon Pietsch		None	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Lidija Efremova	Affirmative	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
1	JEA	Joseph McClung		Negative	Comments Submitted
1	KAMO Electric Cooperative	Micah Breedlove		Negative	Third-Party Comments
1	Lakeland Electric	Larry Watt		Negative	Third-Party Comments
1	Lincoln Electric System	Josh Johnson		None	N/A
1	Long Island Power Authority	Isidoro Behar		Negative	Comments Submitted
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
1	LS Power Transmission, LLC	Jennifer Richardson		None	N/A
1	M and A Electric Power Cooperative	William Price		Negative	Third-Party Comments
1	Manitoba Hydro	Nazra Gladu		Negative	Comments Submitted
1	MEAG Power	David Weekley	Rebika Yitna	Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Negative	Comments Submitted
1	Muscatine Power and Water	Andrew Kurriger		Negative	Third-Party Comments
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Third-Party Comments
1	National Grid USA	Michael Jones		Negative	Third-Party Comments
1	NB Power Corporation	Jeffrey Streifling		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
1	New York Power Authority	Daniel Valle		Negative	Third-Party Comments
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Negative	Comments Submitted
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Negative	Third-Party Comments
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Negative	Comments Submitted
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Negative	Comments Submitted
1	Platte River Power Authority	Marissa Archie		Negative	Third-Party Comments
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Abstain	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	Comments Submitted
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Abstain	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Negative	Comments Submitted
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		None	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Matthew Jaramilla	Israel Perez	Negative	Comments Submitted
1	Santee Cooper	Chris Wagner		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	SaskPower	Wayne Guttormson		Negative	Comments Submitted
1	Seminole Electric Cooperative, Inc.	Kristine Ward		None	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Negative	Third-Party Comments
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Negative	Third-Party Comments
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	None	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		None	N/A
1	Tennessee Valley Authority	David Plumb		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel		Negative	Comments Submitted
1	VELCO -Vermont Electric Power Company, Inc.	Randall Buswell		Abstain	N/A
1	Western Area Power Administration	Ben Hammer		Negative	Comments Submitted
1	Xcel Energy, Inc.	Eric Barry		Negative	Third-Party Comments
2	California ISO	Darcy O'Connell		Abstain	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A
2	Independent Electricity System Operator	Helen Lainis		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	ISO New England, Inc.	John Pearson	Keith Jonassen	Negative	Comments Submitted
2	Midcontinent ISO, Inc.	Bobbi Welch	Adrian Harris	None	N/A
2	New York Independent System Operator	Gregory Campoli		Negative	Third-Party Comments
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Negative	Third-Party Comments
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Negative	Comments Submitted
3	AEP	Leshel Hutchings		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		None	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
3	Austin Energy	Lovita Griffin		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
3	BC Hydro and Power Authority	Ming Jiang		Negative	Comments Submitted
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs	Carly Miller	Negative	Comments Submitted
3	Bonneville Power Administration	Ron Sporseen		Negative	Comments Submitted
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Negative	Third-Party Comments
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Negative	Third-Party Comments
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Negative	Comments Submitted
3	Colorado Springs Utilities	Hillary Dobson		Negative	Third-Party Comments
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Bill Garvey		Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Abstain	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
3	Entergy	James Keele		Negative	Comments Submitted
3	Evergy	Marcus Moor	Hayden Maples	Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary		Negative	Comments Submitted
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		None	N/A
3	Great River Energy	Michael Brytowski		Negative	Third-Party Comments
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	JEA	Marilyn Williams		Negative	Comments Submitted
3	Lakeland Electric	Steven Marshall		Negative	Comments Submitted
3	Lincoln Electric System	Sam Christensen		Negative	Comments Submitted
3	Los Angeles Department of Water and Power	Fausto Serratos		Abstain	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Negative	Third-Party Comments
3	Manitoba Hydro	Mike Smith		Negative	Comments Submitted
3	MEAG Power	Roger Brand	Rebika Yitna	Negative	Comments Submitted
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	Third-Party Comments
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
3	New York Power Authority	David Rivera		Negative	Third-Party Comments
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
3	Northern California Power Agency	Michael Whitney		Negative	Comments Submitted
3	NW Electric Power Cooperative, Inc.	Heath Henry		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
3	Omaha Public Power District	David Heins		Negative	Third-Party Comments
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party Comments
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Negative	Comments Submitted
3	Platte River Power Authority	Richard Kiess		Negative	Third-Party Comments
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
3	Portland General Electric Co.	Mayra Franco		Abstain	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Negative	Third-Party Comments
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Negative	Comments Submitted
3	Santee Cooper	Vicky Budreau		Negative	Comments Submitted
3	Seminole Electric Cooperative, Inc.	Marc Sedor		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Negative	Third-Party Comments
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Snohomish County PUD No. 1	Holly Chaney		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	None	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Negative	Third-Party Comments
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Third-Party Comments
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		None	N/A
4	Austin Energy	Tony Hua		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Third-Party Comments
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		Negative	Third-Party Comments
4	CMS Energy - Consumers Energy Company	Aric Root		Negative	Comments Submitted
4	DTE Energy	Patricia Ireland		None	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
4	Georgia System Operations Corporation	Katrina Lyons		Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Northern California Power Agency	Marty Hostler		Negative	Comments Submitted
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Negative	Comments Submitted
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Ken Habgood		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	None	N/A
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
4	Western Power Pool	Kevin Conway		Negative	Comments Submitted
5	AEP	Thomas Foltz		Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Negative	Comments Submitted
5	Austin Energy	Michael Dillard		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Negative	Comments Submitted
5	BC Hydro and Power Authority	Quincy Wang		Negative	Comments Submitted
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Negative	Comments Submitted
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Bonneville Power Administration	Juergen Bermejo		Negative	Comments Submitted
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Negative	Third-Party Comments
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Negative	Comments Submitted
5	Colorado Springs Utilities	Jeffrey Icke		Negative	Third-Party Comments
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
5	Constellation	Alison MacKellar		Abstain	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Third-Party Comments
5	Dominion - Dominion Resources, Inc.	Anna Salmon		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Abstain	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Negative	Comments Submitted
5	Entergy - Entergy Services, Inc.	Gail Golden		Negative	Comments Submitted
5	Evergy	Jeremy Harris	Hayden Maples	Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	Abstain	N/A
5	Great River Energy	Jacalynn Bentz		None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Abstain	N/A
5	Grid Strategies LLC	Michael Goggin		Negative	Comments Submitted
5	Hydro-Quebec (HQ)	Junji Yamaguchi		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	Invenergy LLC	Rhonda Jones		None	N/A
5	JEA	John Babik		Negative	Comments Submitted
5	Lincoln Electric System	Brittany Millard		Negative	Comments Submitted
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
5	LS Power Development, LLC	C. A. Campbell		None	N/A
5	Manitoba Hydro	Kristy-Lee Young		Negative	Comments Submitted
5	Muscatine Power and Water	Neal Nelson		Negative	Third-Party Comments
5	National Grid USA	Robin Berry		None	N/A
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		Negative	Comments Submitted
5	Nebraska Public Power District	Ronald Bender		Negative	Third-Party Comments
5	New York Power Authority	Zahid Qayyum		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	NextEra Energy	Richard Vendetti		Negative	Comments Submitted
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Third-Party Comments
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Third-Party Comments
5	Oglethorpe Power Corporation	Donna Johnson		Negative	Third-Party Comments
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Third-Party Comments
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
5	Orlando Utilities Commission	Dania Colon		Affirmative	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	Third-Party Comments
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Negative	Comments Submitted
5	Pattern Operators LP	George E Brown		Negative	Third-Party Comments
5	Platte River Power Authority	Jon Osell		Negative	Third-Party Comments
5	Portland General Electric Co.	Ryan Olson		Abstain	N/A
5	PSEG Nuclear LLC	Tim Kucey		Negative	Third-Party Comments
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Public Utility District No. 2 of Grant County, Washington	Nikkee Hebdon		None	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Negative	Comments Submitted
5	Santee Cooper	Carey Salisbury		Negative	Comments Submitted
5	Seminole Electric Cooperative, Inc.	Melanie Wong		None	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Negative	Third-Party Comments
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	None	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Abstain	N/A
5	Tennessee Valley Authority	Darren Boehm		Negative	Comments Submitted
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Negative	Third-Party Comments
6	AEP	Mathew Miller		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Comments Submitted
6	Austin Energy	Imane Mrini		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A
6	Black Hills Corporation	Rachel Schuldt		Negative	Comments Submitted
6	Bonneville Power Administration	Tanner Brier		Negative	Comments Submitted
6	Cleco Corporation	Robert Hirchak		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
6	Constellation	Kimberly Turco		Abstain	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	John Sturgeon		Affirmative	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Negative	Comments Submitted
6	Entergy	Julie Hall		Negative	Comments Submitted
6	Evergy	Tiffany Lake	Hayden Maples	Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted
6	Great River Energy	Brian Meloy		Negative	Third-Party Comments
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Lincoln Electric System	Eric Ruskamp		Negative	Comments Submitted
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Manitoba Hydro	Kelly Bertholet		Negative	Comments Submitted
6	Muscatine Power and Water	Nicholas Burns		Negative	Third-Party Comments
6	New York Power Authority	Shelly Dineen		Negative	Third-Party Comments
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
6	Northern California Power Agency	Dennis Sismaet		Negative	Comments Submitted
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Third-Party Comments
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments
6	Platte River Power Authority	Sabrina Martz		Negative	Third-Party Comments
6	Portland General Electric Co.	Stefanie Burke		Abstain	N/A
6	Powerex Corporation	Raj Hundal		Negative	Third-Party Comments
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Negative	Comments Submitted
6	Santee Cooper	Marty Watson		Negative	Comments Submitted
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
6	Snohomish County PUD No. 1	John Liang		None	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	None	N/A
6	Western Area Power Administration	Jennifer Neville		Negative	Comments Submitted
6	Xcel Energy, Inc.	Steve Szablya		Negative	Third-Party Comments
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Tyler Schwendiman		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Negative	Comments Submitted

Showing 1 to 314 of 314 entries

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BALLOT RESULTS

Ballot Name: 2023-07 Transmission Planning Performance Requirements for Extreme Weather TPL-008-1 | Non-binding Poll IN 1 NB
Voting Start Date: 4/24/2024 12:01:00 AM
Voting End Date: 5/3/2024 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 262
Total Ballot Pool: 297
Quorum: 88.22
Quorum Established Date: 5/3/2024 2:21:59 PM
Weighted Segment Value: 16.67

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	86	1	10	0.172	48	0.828	14	14
Segment: 2	7	0.5	0	0	5	0.5	1	1
Segment: 3	63	1	6	0.12	44	0.88	10	3
Segment: 4	18	1	1	0.083	11	0.917	2	4
Segment: 5	72	1	9	0.196	37	0.804	18	8
Segment: 6	44	1	5	0.172	24	0.828	10	5
Segment: 7	0	0	0	0	0	0	0	0
Segment: 8	1	0	0	0	0	0	1	0
Segment: 9	0	0	0	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 10	6	0.4	3	0.3	1	0.1	2	0
Totals:	297	5.9	34	1.044	170	4.856	58	35

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Negative	Comments Submitted
1	Ameren - Ameren Services	Tamara Evey		Abstain	N/A
1	American Transmission Company, LLC	Amy Wilke		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Negative	Comments Submitted
1	Austin Energy	Thomas Standifur		Abstain	N/A
1	Avista - Avista Corporation	Mike Magruder		Negative	Comments Submitted
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	BC Hydro and Power Authority	Adrian Andreoiu		Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Black Hills Corporation	Micah Runner		Abstain	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
1	Central Electric Power Cooperative (Missouri)	Michael Bax		None	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Comments Submitted
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	Comments Submitted
1	Colorado Springs Utilities	Corey Walker		Negative	Comments Submitted
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Negative	Comments Submitted
1	Duke Energy	Katherine Street		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Robert Blackney		None	N/A
1	Entergy	Brian Lindsey		Negative	Comments Submitted
1	Evergy	Kevin Frick	Hayden Maples	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Eversource Energy	Joshua London		Negative	Comments Submitted
1	Exelon	Daniel Gacek		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Negative	Comments Submitted
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Comments Submitted
1	Great River Energy	Gordon Pietsch		None	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Lidija Efremova	Affirmative	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Negative	Comments Submitted
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
1	JEA	Joseph McClung		Negative	Comments Submitted
1	KAMO Electric Cooperative	Micah Breedlove		Negative	Comments Submitted
1	Lakeland Electric	Larry Watt		Negative	Comments Submitted
1	Lincoln Electric System	Josh Johnson		None	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	LS Power Transmission, LLC	Jennifer Richardson		None	N/A
1	M and A Electric Power Cooperative	William Price		Negative	Comments Submitted
1	MEAG Power	David Weekley	Rebika Yitna	Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Negative	Comments Submitted
1	Muscatine Power and Water	Andrew Kurriger		Negative	Comments Submitted
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Comments Submitted
1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	NB Power Corporation	Jeffrey Streifling		Abstain	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Daniel Valle		Negative	Comments Submitted
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Negative	Comments Submitted
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	Omaha Public Power District	Doug Peterchuck		Negative	Comments Submitted
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Abstain	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Negative	Comments Submitted
1	Platte River Power Authority	Marissa Archie		Negative	Comments Submitted
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
1	Portland General Electric Co.	Brooke Jockin		Abstain	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		None	N/A
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Negative	Comments Submitted
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Negative	Comments Submitted
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Negative	Comments Submitted
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		None	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	Comments Submitted
1	Salt River Project	Matthew Jaramilla	Israel Perez	Negative	Comments Submitted
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	SaskPower	Wayne Guttormson		Negative	Comments Submitted
1	Seminole Electric Cooperative, Inc.	Kristine Ward		None	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Negative	Comments Submitted
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	None	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		None	N/A
1	Tennessee Valley Authority	David Plumb		Abstain	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel		Abstain	N/A
1	VELCO -Vermont Electric Power Company, Inc.	Randall Buswell		None	N/A
1	Western Area Power Administration	Ben Hammer		Negative	Comments Submitted
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
2	Independent Electricity System Operator	Helen Lainis		None	N/A
2	ISO New England, Inc.	John Pearson	Keith Jonassen	Negative	Comments Submitted
2	Midcontinent ISO, Inc.	Bobbi Welch	Adrian Harris	Negative	Comments Submitted
2	New York Independent System Operator	Gregory Campoli		Negative	Comments Submitted
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Abstain	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Negative	Comments Submitted
3	AEP	Leshel Hutchings		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Ameren - Ameren Services	David Jendras Sr		Abstain	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		None	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
3	Austin Energy	Lovita Griffin		Abstain	N/A
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
3	BC Hydro and Power Authority	Ming Jiang		Negative	Comments Submitted
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs	Carly Miller	Abstain	N/A
3	Bonneville Power Administration	Ron Sporseen		Negative	Comments Submitted
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Comments Submitted
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Negative	Comments Submitted
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Negative	Comments Submitted
3	Colorado Springs Utilities	Hillary Dobson		Negative	Comments Submitted
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Bill Garvey		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Abstain	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
3	Entergy	James Keele		Negative	Comments Submitted
3	Evergy	Marcus Moor	Hayden Maples	Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary		Negative	Comments Submitted
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Great River Energy	Michael Brytowski		Negative	Comments Submitted
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
3	JEA	Marilyn Williams		Negative	Comments Submitted
3	Lakeland Electric	Steven Marshall		Negative	Comments Submitted
3	Lincoln Electric System	Sam Christensen		Abstain	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Negative	Comments Submitted
3	MEAG Power	Roger Brand	Rebika Yitna	Negative	Comments Submitted
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Negative	Comments Submitted
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
3	Northern California Power Agency	Michael Whitney		Negative	Comments Submitted
3	NW Electric Power Cooperative, Inc.	Heath Henry		Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
3	Omaha Public Power District	David Heins		Negative	Comments Submitted
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Negative	Comments Submitted
3	Platte River Power Authority	Richard Kiess		Negative	Comments Submitted
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted
3	Portland General Electric Co.	Mayra Franco		Abstain	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Abstain	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Negative	Comments Submitted
3	Salt River Project	Mathew Weber	Israel Perez	Negative	Comments Submitted
3	Santee Cooper	Vicky Budreau		Abstain	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Negative	Comments Submitted
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Negative	Comments Submitted
3	Snohomish County PUD No. 1	Holly Chaney		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg		Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Comments Submitted
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		None	N/A
4	Austin Energy	Tony Hua		Abstain	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Comments Submitted
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		Negative	Comments Submitted
4	CMS Energy - Consumers Energy Company	Aric Root		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	DTE Energy	Patricia Ireland		None	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
4	Georgia System Operations Corporation	Katrina Lyons		Negative	Comments Submitted
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Comments Submitted
4	Northern California Power Agency	Marty Hostler		Negative	Comments Submitted
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Negative	Comments Submitted
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Comments Submitted
4	Seminole Electric Cooperative, Inc.	Ken Habgood		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	None	N/A
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
4	Western Power Pool	Kevin Conway		Negative	Comments Submitted
5	AEP	Thomas Foltz		Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Negative	Comments Submitted
5	Austin Energy	Michael Dillard		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Avista - Avista Corporation	Glen Farmer		Negative	Comments Submitted
5	BC Hydro and Power Authority	Quincy Wang		Negative	Comments Submitted
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Negative	Comments Submitted
5	Black Hills Corporation	Sheila Suurmeier		Abstain	N/A
5	Bonneville Power Administration	Juergen Bermejo		Negative	Comments Submitted
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Negative	Comments Submitted
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Negative	Comments Submitted
5	Colorado Springs Utilities	Jeffrey Icke		Negative	Comments Submitted
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
5	Constellation	Alison MacKellar		Abstain	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Anna Salmon		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Abstain	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Entergy - Entergy Services, Inc.	Gail Golden		Negative	Comments Submitted
5	Evergy	Jeremy Harris	Hayden Maples	Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	Abstain	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Abstain	N/A
5	Grid Strategies LLC	Michael Goggin		Negative	Comments Submitted
5	Hydro-Quebec (HQ)	Junji Yamaguchi		Negative	Comments Submitted
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	JEA	John Babik		Negative	Comments Submitted
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
5	LS Power Development, LLC	C. A. Campbell		None	N/A
5	Muscatine Power and Water	Neal Nelson		Negative	Comments Submitted
5	National Grid USA	Robin Berry		None	N/A
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender		Abstain	N/A
5	New York Power Authority	Zahid Qayyum		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	NextEra Energy	Richard Vendetti		Negative	Comments Submitted
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Comments Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Comments Submitted
5	Oglethorpe Power Corporation	Donna Johnson		Negative	Comments Submitted
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Comments Submitted
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
5	Orlando Utilities Commission	Dania Colon		Affirmative	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	Comments Submitted
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Negative	Comments Submitted
5	Pattern Operators LP	George E Brown		Negative	Comments Submitted
5	Platte River Power Authority	Jon Osell		Negative	Comments Submitted
5	Portland General Electric Co.	Ryan Olson		Abstain	N/A
5	PSEG Nuclear LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Public Utility District No. 2 of Grant County, Washington	Nikkee Hebdon		None	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	Comments Submitted
5	Salt River Project	Thomas Johnson	Israel Perez	Negative	Comments Submitted
5	Santee Cooper	Carey Salisbury		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		None	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Negative	Comments Submitted
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	None	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Abstain	N/A
5	Tennessee Valley Authority	Darren Boehm		None	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Abstain	N/A
6	AEP	Mathew Miller		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Comments Submitted
6	Austin Energy	Imane Mrini		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A
6	Black Hills Corporation	Rachel Schuldt		Abstain	N/A
6	Bonneville Power Administration	Tanner Brier		Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
6	Constellation	Kimberly Turco		Abstain	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Stephanie Kenny		Negative	Comments Submitted
6	Entergy	Julie Hall		Negative	Comments Submitted
6	Evergy	Tiffany Lake	Hayden Maples	Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted
6	Great River Energy	Brian Meloy		Negative	Comments Submitted
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Negative	Comments Submitted
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Muscatine Power and Water	Nicholas Burns		Negative	Comments Submitted
6	New York Power Authority	Shelly Dineen		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
6	Northern California Power Agency	Dennis Sismaet		Negative	Comments Submitted
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Comments Submitted
6	Omaha Public Power District	Shonda McCain		Negative	Comments Submitted
6	Platte River Power Authority	Sabrina Martz		Negative	Comments Submitted
6	Portland General Electric Co.	Stefanie Burke		Abstain	N/A
6	Powerex Corporation	Raj Hundal		Negative	Comments Submitted
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie		Negative	Comments Submitted
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	Comments Submitted
6	Salt River Project	Timothy Singh	Israel Perez	Negative	Comments Submitted
6	Santee Cooper	Marty Watson		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
6	Snohomish County PUD No. 1	John Liang		None	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	None	N/A
6	Western Area Power Administration	Jennifer Neville		Negative	Comments Submitted
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Tyler Schwendiman		Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A

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Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the second draft of the proposed standard posted for a 38-day formal comment period with additional ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	July 19, 2023
SAR posted for comment	August 8 – September 27, 2023
45-day formal comment period with initial ballot	March 20 – May 3, 2024

Anticipated Actions	Date
38-day formal comment period with additional ballot	July 16 – August 22, 2024
45-day formal comment period with additional ballot	September 2024
10-day final ballot	November 2024
Board adoption	December 2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

Extreme Temperature Assessment – Documented evaluation of future ~~Transmission~~Bulk Electric System performance for extreme heat and extreme cold temperature benchmark events.

A. Introduction

1. **Title:** Transmission System Planning Performance Requirements for Extreme Temperature Events

2. **Number:** TPL-008-1

3. **Purpose:** Establish ~~requirements for~~ Transmission system planning performance ~~for~~requirements to develop a Bulk Power System (BPS) that will operate reliably during extreme heat and extreme cold temperature events.

3. **Applicability:**

   3.1. Functional Entities:

   4.1.1. Transmission Planner

   4.1.2. Planning Coordinator

4. **Effective Date:** See Implementation Plan for Project 2023-07.

B. Requirements and Measures

R1. Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall ~~determine and~~ identify each entity's individual and joint responsibilities for ~~performing the studies needed to complete~~completing the Extreme Temperature Assessment. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M1. Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall provide documentation of each entity's individual and joint responsibilities, such as meeting minutes, agreements, copies of procedures or protocols in effect between entities or between departments of a vertically integrated system, or email correspondence that identifies an agreement has been reached on individual and joint responsibilities for ~~performing the studies needed to complete~~completing the Extreme Temperature Assessment.

R2. Each responsible entity, as identified in Requirement R1, shall select at least one extreme heat benchmark temperature event and at least one extreme cold benchmark temperature event, from the ~~approved~~ benchmark library, approved and maintained by the Electric Reliability Organization (ERO), for ~~performing~~completing the Extreme Temperature Assessment. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M2. Each responsible entity, as identified in Requirement R1, shall have evidence in either electronic or hard copy format of ~~its selected~~selecting at least one extreme heat benchmark event and at least one extreme cold benchmark temperature event for ~~performing~~completing the Extreme Temperature Assessment.

R3. Each Planning Coordinator shall develop and implement a process for coordinating the development of benchmark planning cases ~~among~~, using the selected benchmark temperature events identified in Requirement R2, among adjacent impacted Planning Coordinator(s), Transmission Planner(s), and other designated study entities ~~based on the selected benchmark events as identified in Requirement R2.~~, within an Interconnection. This process shall~~:~~ include seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers to represent the selected benchmark temperature events. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

~~**3.1.** Define the planning study area boundary based on the selected benchmark events.~~

~~**3.2.** Modify the benchmark planning cases to include seasonal and temperature dependent adjustment for Load, generation, Transmission, and transfers which represents the selected benchmark events.~~

M3. Each Planning Coordinator shall ~~provide~~have dated evidence ~~of~~that it developed and implemented a process for coordinating the development of benchmark planning cases ~~among impacted Planning Coordinators, and Transmission Planner(s)~~ as specified in Requirement R3~~. Acceptable evidence may include, but is not limited to,~~

~~the following dated documentation (electronic or hardcopy format): records defining the planning study area boundary based on the selected benchmark events and modifications to the benchmark planning cases~~ that ~~include~~includes seasonal and temperature dependent adjustment for Load, generation, Transmission, and transfers ~~which~~to represent the selected benchmark temperature events.

R4. Each responsible entity, as identified in Requirement R1, shall ~~develop and maintain System models within its planning area for performing the Extreme Temperature Assessment. The System models shall~~ use the coordination process developed in accordance with Requirement R3 and data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, ~~and shall represent projected System conditions based on the selected benchmark events as identified in Requirement R2.~~to develop and maintain the following: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

4.1. ~~Each responsible entity,~~Benchmark planning cases that include seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers to represent the System conditions of the selected benchmark temperature events as identified in Requirement R2 for one of the years in the Long-Term Transmission Planning Horizon. The rationale for the year selected for evaluation shall be available as supporting information. ~~R1,~~This establishes Category P0 as the normal System condition in Table 1.

4.2. Sensitivity cases to demonstrate the impact of changes to the basic assumptions used in the benchmark planning cases. To accomplish this, the sensitivity cases shall have changes to at least one of the following conditions:

- Generation;
- Real and reactive forecasted Load; or
- Transfers.

M4. Each responsible entity shall have dated evidence in either electronic or hard copy format that it developed and maintained ~~System models of the responsible entity's~~benchmark planning ~~area~~cases and sensitivity cases for ~~performing~~completing the Extreme Temperature Assessment.

R5. Each responsible entity, as identified in Requirement R1, shall have criteria for acceptable System steady state voltage limits ~~and~~, post-Contingency voltage deviations, and applicable Facility Ratings for ~~performing~~completing the Extreme Temperature Assessment ~~in accordance with Requirement R3~~. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M5. Each responsible entity, as identified in Requirement R1, shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits ~~and~~, post-Contingency voltage deviations, and applicable Facility Ratings for ~~performing~~completing the Extreme Temperature Assessment ~~in accordance with Requirement R5~~.

R6. Each responsible entity, as identified in Requirement R1, shall define and document the criteria or methodology used in the Extreme Temperature Assessment analysis to identify instability, uncontrolled separation, or Cascading~~.~~ within an Interconnection. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M6. Each responsible entity, as identified in Requirement R1, shall provide dated evidence such as electronic or hard copy documentation of the ~~defined and documented~~ criteria or methodology used to identify instability, uncontrolled separation, or Cascading ~~used in the Extreme Temperature Assessment analysis in accordance with Requirement R6~~within an Interconnection.

R7. Each responsible entity, as identified in Requirement R1, shall identify ~~Contingencies used in performing the Extreme Temperature Assessment~~the planning events for each ~~of the event categories~~category in Table 1 that are expected to produce more severe System impacts ~~within~~on its ~~planning area~~portion of the Bulk Electric System. The rationale for those Contingencies selected for evaluation shall be available as supporting information. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M7. Each responsible entity, as identified in Requirement R1, shall provide dated evidence such as electronic or hard copy documentation ~~that it has identified Contingencies for performing~~of the ~~Extreme Temperature Assessment~~ planning events for each ~~of the~~ event ~~categories~~category in Table 1 that are expected to produce more severe System impacts ~~within~~on its ~~planning area and the~~ portion of the Bulk Electric System along with supporting rationale~~, in accordance with Requirement R7, such as electronic or hard copies of documents identifying the Contingencies with supporting rationale.~~.

R8. Each responsible entity, as identified in Requirement R1, shall complete ~~an~~steady state and transient stability analyses in its Extreme Temperature Assessment ~~of the Long-Term Transmission Planning Horizon~~ at least once every five calendar years~~,~~ using the ~~benchmark planning cases~~ Contingencies identified in Requirement R7, and ~~the System models identified in Requirement R3 and R4, and the Contingencies identified in Requirement R7 for each of the event categories in Table 1, and~~ shall document the assumptions and results of the steady state and transient stability analyses. The Extreme Temperature Assessment shall include the following~~.~~: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

8.1. ~~Assessment~~Analysis of the benchmark planning cases developed ~~under~~ in accordance with Requirement R4~~, for one of the years in the Long-Term Transmission Planning Horizon. The rationale for the year selected for evaluation shall be available as supporting information.~~ Part 4.1.

~~**8.2.** Sensitivity analysis to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Extreme Temperature Assessment shall include, at a minimum, changes to one of the following conditions:~~

- ~~Generation;~~
- ~~Real and reactive forecasted Load; or~~
- ~~Transfers~~

8.2. Analysis of the sensitivity cases developed in accordance with Requirement R4 Part 4. 2.

M8. Each responsible entity, as identified in Requirement R1, shall provide dated evidence that it ~~performed an~~completed the steady state and transient stability analyses in its Extreme Temperature Assessment, such as electronic or hard copies of the ~~assessment~~analyses, meeting all the requirements in Requirement R8.

R9. Each responsible entity, as identified in Requirement R1, shall develop a Corrective Action Plan(s) (CAPs) when the assessment of a benchmark planning case ~~study results indicate the~~, in accordance with Requirement R8 Part 8.1, indicates its portion of the Bulk Electric System is unable to meet performance requirements for Table 1 P0 or P1 Contingencies. ~~The~~For each Corrective Action Plan, the responsible ~~entities~~entity shall ~~share~~: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

9.1. Make their ~~CAPs with,~~CAP available and solicit feedback from~~,~~ applicable regulatory authorities or governing bodies responsible for retail electric service issues. ~~In addition, where Load shed is allowed as an element of a CAP for the Table 1 P1 Contingency, the responsible entity shall document~~

~~**8.3.**~~**9.2.** Document the alternative(s) considered~~, as mentioned in Requirement R10~~, and notify the applicable regulatory authorities or governing bodies responsible for retail electric service issues~~. Revisions to the CAP(s) are allowed in subsequent Extreme Temperature Assessments, but the planned System shall continue to meet the performance requirements. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*~~ when Non-Consequential Load Loss is utilized as an element of a CAP for the Table 1 P1 Contingency.

9.3. Be permitted to utilize Non-Consequential Load Loss as an interim solution, which normally is not permitted in Table 1, in situations that are beyond the control of the Planning Coordinator or Transmission Planner that prevent the implementation of a Corrective Action Plan in the required timeframe. The use of Non-Consequential Load Loss as an interim solution in this situation is permitted, provided that each responsible entity documents the situation causing the problem, alternatives evaluated, and takes actions to resolve the situation.

9.4. Be allowed to have revisions to the CAP in subsequent Extreme Temperature Assessments, provided that the planned BES shall continue to meet the performance requirements of Table 1.

M9. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copy documentation, of each CAP developed for its Extreme Temperature Assessment, including any revision history, when the assessment of the benchmark planning cases indicate its portion of the BES is unable to meet performance requirements for Table 1 P0 or P1 Contingencies in accordance with Requirement R9.

R10. Each responsible entity, as identified in Requirement R1, shall evaluate and document possible actions for the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

10.1. Benchmark planning cases where possible actions are designed to mitigate the consequences and adverse impacts when the study results indicate the System could result in instability, uncontrolled separation, or Cascading for the Table 1 P2, P4, and P7 Contingencies.

10.2. Sensitivity cases where possible actions are designed to mitigate failures to meet the performance requirements in Table 1 for category P0, P1, P2, P4, and P7 Contingencies.

M10. Each responsible entity, as identified in Requirement R1, shall provide dated evidence such as electronic or hard copy documentation ~~of a CAP, including any revision history, when the benchmark planning case study results indicate the System is unable to meet performance requirements for the Table 1 P0 or P1 Contingencies in accordance with Requirement R9.~~ that it evaluated and ~~document~~documented possible actions designed to ~~reduce the likelihood or~~ mitigate the consequences and adverse impacts when the benchmark planning case study results indicate the System could result in instability, uncontrolled separation, or Cascading for the Table 1 P2, P4, ~~P5,~~ and P7 Contingencies. ~~*[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* Each responsible entity, as identified in Requirement R1, shall provide the dated evidence that it evaluated and documented possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts when the benchmark planning case study results indicate the System could result in instability, uncontrolled separation, or Cascading for the Table 1 P2, P4, P5, and P7 Contingencies in accordance with Requirement R10, such as electronic or hard copies of the assessment detailing such actions.~~

~~R9.~~R11. Each responsible entity, as identified in Requirement R1, shall provide its Extreme Temperature Assessment results within 60 calendar days of a request to any functional entity that has a reliability related need and submits a written request for the information. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M11. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient; or a demonstration of a public posting that it provided its Extreme Temperature Assessment to any functional entity who has a reliability need within 60 calendar days of a written request.

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. 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.

- Each responsible entity shall retain evidence of compliance with each requirement in this standard for five calendar years or one complete Extreme Temperature Assessment cycle, whichever is longer.

1.3. 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.

Table 1 1: Contingencies ~~and Performance Criteria~~Category See Footnote 2 for BES Level					
Category	**Initial Condition**	**Event**	~~P0~~Fault type		
~~Facility Voltage Level of Contingency~~			~~Applicable to:~~ • ~~BES level 200 kV and above~~ • ~~Any common structure that includes a Facility 200kV and above~~ ~~Reference Voltages:~~ • ~~Non-generator step up transformer outage events, the reference voltage applies to the low-side winding.~~ • ~~Generator and generator step-up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the step-up transformer).~~		
~~Steady State Performance Criteria~~			• ~~Applicable Facility Ratings shall not be exceeded.~~ • ~~System steady state voltages shall be within acceptable limits as defined in Requirement R5.~~	• ~~Applicable Facility ratings shall not be exceeded~~ • ~~System steady state voltages shall be within acceptable limits as defined in Requirement R5.~~	~~Evaluation for uncontrolled separation or Cascading, as defined in Requirement R6.~~
~~Stability Performance Criteria~~			~~Initialization without oscillation~~		~~Evaluation for instability, uncontrolled separation, or Cascading, as defined in Requirement R6.~~
~~Corrective Action Plan Required~~			~~Yes (See Requirement R9)~~	~~Yes (See Requirement R9)~~	~~No (See Requirement R10)~~

Table 1.~~1~~: Contingencies ~~and Performance Criteria~~Category See Footnote 2 for BES Level					
Category	Initial Condition	Event	~~P0~~Fault type		
~~Non-Consequential Load Loss Allowed~~			~~No (See Requirement R9)~~	~~Yes (See Requirement R9)~~	~~Yes~~

~~Table 1: Contingencies and Performance Criteria~~			
~~Category~~	~~Initial Condition~~	~~Event~~	~~Fault Type~~ [1]
P0 No Contingency	Normal System	None	N/A
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt ~~Device~~[2]Device[3]	3Ø
		5. Single Pole of a DC line	SLG
P2 Single Contingency	Normal System	1. Opening of a line section w/o a ~~fault~~ [3]Fault [4]	N/A
		2. Bus Section Fault	SLG
		3. Internal Breaker Fault[5] (non-Bus-tie Breaker)	SLG
		~~1.~~ Internal Breaker ~~Fault~~[4] 4. ~~(non-~~Fault (Bus-tie Breaker)[5]	SLG
P4 Multiple Contingency *(Fault plus stuck breaker[6])*	Normal System	Loss of multiple Elements caused by a stuck breaker[6](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device[3] 5. Bus Section	SLG

		6. Loss of multiple Elements caused by a stuck breaker[6] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	
P7 Multiple Contingency *(Common Structure)*	Normal System	~~Internal Breaker Fault (Bus-tie Breaker)[4]~~The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure ~~1.~~2. Loss of a bipolar DC line	SLG

~~Table 1: Contingencies and Performance Criteria~~			
~~Category~~	~~Initial Condition~~	~~Event~~	~~Fault Type~~ [1]
~~**P4**~~ ~~Multiple Contingency~~ ~~*(Fault plus stuck breaker*~~[10]~~*)*~~	~~Normal System~~	~~Loss of multiple elements caused by a stuck breaker~~[5]~~(non-Bus-tie Breaker) attempting to clear a Fault on one of the following:~~ ~~5. Generator~~ ~~6. Transmission Circuit~~ ~~7. Transformer~~ ~~8. Shunt Device~~[2] ~~9. Bus Section~~	~~SLG~~
		~~10. Loss of multiple elements caused by a stuck breaker~~[5] ~~(Bus-tie Breaker) attempting to clear a Fault on the associated bus~~	~~SLG~~
~~**P5**~~ ~~Multiple Contingency~~ ~~*(Fault plus non-redundant component of a Protection System failure to operate)*~~	~~Normal System~~	~~Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System~~[7] ~~protecting the Faulted element to operate as designed, for one of the following:~~ ~~1. Generator~~ ~~2. Transmission Circuit~~ ~~3. Transformer~~ ~~4. Shunt Device~~[2] ~~5. Bus Section~~	
~~**P7**~~ ~~Multiple Contingency~~ ~~*(Common Structure)*~~	~~Normal System~~	~~The loss of:~~ ~~1. Any two adjacent (vertically or horizontally) circuits on common structure~~ [6] ~~2. Loss of a bipolar DC line~~	~~SLG~~

Table 1~~—~~.2: Steady State & Stability Performance ~~Footnotes (Planning Events and Extreme Events)~~Requirements

	P0	P1	P2	P4	P7
Steady State Performance Requirements	• Applicable Facility Ratings shall not be exceeded. • System steady state voltages shall be within acceptable limits as defined in Requirement R5.	• Applicable Facility ratings shall not be exceeded. • System steady state voltages shall be within acceptable limits as defined in Requirement R5.	Instability, uncontrolled separation, or Cascading, as defined in Requirement R6, shall not occur.		
Stability Performance Requirements	~~1. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.~~ ~~2. Requirements which are applicable to shunt devices also~~	Instability, uncontrolled separation, or Cascading, as defined in Requirement R6, shall not occur.	Instability, uncontrolled separation, or Cascading, as defined in Requirement R6, shall not occur.		

Table 1~~—~~.2: Steady State & Stability Performance ~~Footnotes (Planning Events and Extreme Events)~~Requirements			
	~~apply to FACTS devices that are connected to ground.~~ ~~3. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.~~ ~~4. An internal breaker fault means a breaker failing internally, thus creating a~~The System ~~fault which must be cleared by protection on both sides of the breaker.~~ ~~5. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is~~		

Table 1~~—~~.2: Steady State & Stability Performance ~~Footnotes (Planning Events and Extreme Events)~~Requirements			
	~~assumed to~~shall remain ~~closed. A stuck breaker results in Delayed Fault Clearing.~~ ~~6. Excludes circuits that share a common structure (Planning event P7) for one mile or less.~~ ~~7. For purposes of this standard, non-redundant components of a Protection System to consider are~~stable. Instability, uncontrolled separation, or Cascading, as ~~follows:~~ ~~A single protective relay which responds to electrical quantities, without an alternative (which may or may~~defined in Requirement R6, shall not ~~respond to electrical quantities) that provides comparable Normal Clearing times;~~occur.		

Table 1~~—~~.2: Steady State & Stability Performance ~~Footnotes (Planning Events and Extreme Events)~~Requirements			
	~~a. A single communications system associated with protective functions, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing (an exception is a single communications system that is both monitored and reported at a Control Center);~~ ~~b. A single station dc supply associated with protective functions required for Normal Clearing (an exception is a single station dc supply that is both monitored and reported at a~~		

Table 1~~—~~.2: Steady State & Stability Performance ~~Footnotes (Planning Events and Extreme Events)~~Requirements			
	~~Control Center for both low voltage and open circuit);~~ ~~A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply through and including the trip coil(s) of the circuit breakers or other interrupting devices, required for Normal Clearing (the trip coil may be excluded if it is both monitored and reported at a Control Center).~~		
Requirements for Benchmark Planning Case Assessment Results			
Corrective Action Plan Required	Yes (See Requirement R9)	Yes (See Requirement R9)	No (See Requirement R10)
Non-Consequential Load Loss Allowed	No (See Requirement R9)	Yes (See Requirement R9)	Yes
Interruption of Firm Transmission Service Allowed	Yes	Yes	Yes
Requirements for Sensitivity Case Assessment Results			

Table 1~~—~~.2: Steady State & Stability Performance ~~Footnotes~~ ~~(Planning Events and Extreme Events)~~Requirements			
Corrective Action Plan Required	No (See Requirement R10)	No (See Requirement R10)	No (See Requirement R10)
Non-Consequential Load Loss Allowed	Yes	Yes	Yes
Interruption of Firm Transmission Service Allowed	Yes	Yes	Yes

Table 1.3 – Steady State & Stability Performance Footnotes

1. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
2. Facility voltage level of Contingency is applicable to:
    a. BES level 200 kV and above (referenced Contingency voltage)
    b. For P7 events include Contingencies that have at least one 200kV voltage and above Facilities on common structure that has more than one mile in length.
    c. For non-generator step up transformer outage events, the reference voltage, as used in footnote 2a, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
3. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
4. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
5. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
6. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	N/A	N/A	N/A	The Planning Coordinator, in conjunction with its Transmission Planner(s), failed to determine and identify individual and joint responsibilities for ~~performing the required studies for~~completing the Extreme Temperature Assessment.
R2.	N/A	N/A	The responsible entity did not select ~~an~~at least one extreme heat benchmark event or extreme cold benchmark temperature event from the ERO approved benchmark library for performing the Extreme Temperature Assessment.	The responsible entity did not select an extreme heat benchmark event and extreme cold benchmark temperature event from the ERO approved benchmark library for performing the Extreme Temperature Assessment.
R3.	N/A	N/A	N/A	The Planning Coordinator did not develop or implement a process for coordinating the development of benchmark planning cases among impacted adjacent Planning Coordinator(s), Transmission Planner(s), and other designated study entities,

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				within the same Interconnection. OR The Planning Coordinator developed and implemented a process for coordinating the development of benchmark planning cases among impacted adjacent Planning Coordinator(s), Transmission Planner(s), and other designated study entities~~, but this process did not define~~ within the ~~planning study area boundary based off the selected benchmark events.~~ ~~OR~~ ~~The Planning Coordinator developed and implemented a process for coordinating the development of benchmark planning cases among impacted Planning Coordinator(s), Transmission Planner(s), and other designated study entities~~same Interconnection, but this process did not modify the benchmark planning cases to

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
				include seasonal and temperature dependent adjustments load, generation, Transmission, and transfers.
R4.	N/A	N/A	N/A	The responsible entity did not develop or maintain ~~System models of the responsible entity's~~benchmark planning ~~area~~cases or sensitivity cases for performing the Extreme Temperature Assessment. OR The responsible entity developed and maintained ~~System models~~benchmark planning cases or sensitivity cases for performing the Extreme Temperature Assessment~~,~~ but ~~the System model~~ did not use data consistent with that provided in accordance with the MOD-032 standard ~~supplemented by other sources as needed~~.
R5.	N/A	N/A	N/A	The responsible entity, as determined in Requirement

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				R1, did not have criteria for acceptable System steady state voltage limits ~~and~~, post-Contingency voltage deviations, and applicable Facility Ratings for performing Extreme Temperature Assessment.
R6.	N/A	N/A	N/A	The responsible entity failed to define and document, the criteria or methodology used in the analysis to identify System instability, uncontrolled separation, or Cascading~~.~~ within an Interconnection.
R7.	N/A	N/A	The responsible entity, as determined in Requirement R1, identified Contingencies for performing Extreme Temperature Assessment for each of the ~~event categories~~planning events in Table 1 that are expected to produce more severe System impacts within its planning area, but did not include the rationale for those Contingencies selected for	The responsible entity, as determined in Requirement R1, did not identify Contingencies for performing Extreme Temperature Assessment for each of the ~~event categories~~planning events in Table 1 that are expected to produce more severe System impacts within its planning area.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			evaluation as supporting documentation.	
R8.	The responsible entity, as determined in Requirement R1, completed an Extreme Temperature Assessment, but it was ~~completed~~performed less than or equal to six months late.	The responsible entity, as determined in Requirement R1, completed an Extreme Temperature Assessment, but it was ~~completed~~performed more than six months but less than or equal to 12 months late.	The responsible entity, as determined in Requirement R1, completed an Extreme Temperature Assessment, but it was ~~completed~~performed more than 12 months but less than or equal to ~~than~~ 18 months late.	The responsible entity, as determined in Requirement R1, ~~completed~~performed an Extreme Temperature Assessment, but it was more than 18 months late. OR The responsible entity, as determined in Requirement R1, did not ~~complete~~perform an Extreme Temperature Assessment. OR The responsible entity, as determined in Requirement R1, ~~completed~~performed an Extreme Temperature Assessment, but it was missing one or more of the required elements in Requirement R8.
R9.	N/A	N/A	The responsible entity, as determined in Requirement R1, developed a ~~CAP~~Corrective	The responsible entity, as determined in Requirement R1, failed to develop a

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			Action Plan meeting each of the elements in Requirement R9, but failed to make their Corrective Action Plan available to, or solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.	Corrective Action Plan meeting each of the elements of Requirement R9 when the benchmark planning case study results indicate the System is unable to meet performance requirements for the Table 1 P0 or P1 Contingencies.
R10.	N/A	N/A	N/A	Each responsible entity, as determined in Requirement R1, failed to evaluate and document possible actions ~~designed to reduce the likelihood or~~, mitigate the consequences, and adverse impacts when the benchmark planning case study results indicate the System could result in instability, uncontrolled separation, or Cascading for the Table 1 P2, P4, ~~P5,~~ and P7 Contingencies.
R11.	The responsible entity, as determined in Requirement R1, distributed its Extreme Temperature Assessment	The responsible entity, as determined in Requirement R1, distributed its Extreme Temperature Assessment	The responsible entity, as determined in Requirement R1, distributed its Extreme Temperature Assessment	The responsible entity, as determined in Requirement R1, distributed its Extreme Temperature Assessment

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	results to functional entities having a reliability related need who requested the information in writing, but it was more than 60 days but less than or equal to 80 days following the request.	results to functional entities having a reliability related need who requested the information in writing, but it was more than 80 days but less than or equal to 100 days following the request.	results to functional entities having a reliability related need who requested the information in writing, but it was more than 100 days but less than or equal to 120 days following the request.	results to functional entities having a reliability related need who requested the information in writing, but it was more than 120 days following the request. OR The responsible entity, as determined in Requirement R1, did not distribute its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing.

D. Regional Variances

None.

E. Associated Documents

- Implementation Plan for 2023-07
- Technical Rationale Document
- Consideration of Issues and Directives for FERC Order 896.

Version History

Version	Date	Action	Change Tracking
1	TBD	Addressing FERC Order 896	New Standard

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the second draft of the proposed standard posted for a 38-day formal comment period with additional ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	July 19, 2023
SAR posted for comment	August 8 – September 27, 2023
45-day formal comment period with initial ballot	March 20 – May 3, 2024

Anticipated Actions	Date
38-day formal comment period with additional ballot	July 16 – August 22, 2024
45-day formal comment period with additional ballot	September 2024
10-day final ballot	November 2024
Board adoption	December 2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

Extreme Temperature Assessment – Documented evaluation of future ~~Transmission~~Bulk Electric System performance for extreme heat and extreme cold temperature benchmark events.

A. Introduction

1. **Title:** Transmission System Planning Performance Requirements for Extreme Temperature Events

2. **Number:** TPL-008-1

3. **Purpose:** Establish ~~requirements for~~ Transmission system planning performance ~~for~~requirements to develop a Bulk Power System (BPS) that will operate reliably during extreme heat and extreme cold temperature events.

3. **Applicability:**

   3.1. Functional Entities:

   4.1.1. Transmission Planner

   4.1.2. Planning Coordinator

4. **Effective Date:** See Implementation Plan for Project 2023-07.

B. Requirements and Measures

R1. Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall ~~determine and~~ identify each entity's individual and joint responsibilities for ~~performing the studies needed to complete~~completing the Extreme Temperature Assessment. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M1. Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall provide documentation of each entity's individual and joint responsibilities, such as meeting minutes, agreements, copies of procedures or protocols in effect between entities or between departments of a vertically integrated system, or email correspondence that identifies an agreement has been reached on individual and joint responsibilities for ~~performing the studies needed to complete~~completing the Extreme Temperature Assessment.

R2. Each responsible entity, as identified in Requirement R1, shall select at least one extreme heat benchmark temperature event and at least one extreme cold benchmark temperature event, from the ~~approved~~ benchmark library, approved and maintained by the Electric Reliability Organization (ERO), for ~~performing~~completing the Extreme Temperature Assessment. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M2. Each responsible entity, as identified in Requirement R1, shall have evidence in either electronic or hard copy format of ~~its selected~~selecting at least one extreme heat benchmark event and at least one extreme cold benchmark temperature event for ~~performing~~completing the Extreme Temperature Assessment.

R3. Each Planning Coordinator shall develop and implement a process for coordinating the development of benchmark planning cases ~~among~~, using the selected benchmark temperature events identified in Requirement R2, among adjacent impacted Planning Coordinator(s), Transmission Planner(s), and other designated study entities ~~based on the selected benchmark events as identified in Requirement R2.~~, within an Interconnection. This process shall~~:~~ include seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers to represent the selected benchmark temperature events. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

~~**3.1.** Define the planning study area boundary based on the selected benchmark events.~~

~~**3.2.** Modify the benchmark planning cases to include seasonal and temperature dependent adjustment for Load, generation, Transmission, and transfers which represents the selected benchmark events.~~

M3. Each Planning Coordinator shall ~~provide~~have dated evidence ~~of~~that it developed and implemented a process for coordinating the development of benchmark planning cases ~~among impacted Planning Coordinators, and Transmission Planner(s)~~ as specified in Requirement R3~~. Acceptable evidence may include, but is not limited to,~~

~~the following dated documentation (electronic or hardcopy format): records defining the planning study area boundary based on the selected benchmark events and modifications to the benchmark planning cases~~ that ~~include~~includes seasonal and temperature dependent adjustment for Load, generation, Transmission, and transfers ~~which~~to represent the selected benchmark temperature events.

R4. Each responsible entity, as identified in Requirement R1, shall ~~develop and maintain System models within its planning area for performing the Extreme Temperature Assessment. The System models shall~~ use the coordination process developed in accordance with Requirement R3 and data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, ~~and shall represent projected System conditions based on the selected benchmark events as identified in Requirement R2.~~to develop and maintain the following: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

4.1. ~~Each responsible entity,~~Benchmark planning cases that include seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers to represent the System conditions of the selected benchmark temperature events as identified in Requirement R2 for one of the years in the Long-Term Transmission Planning Horizon. The rationale for the year selected for evaluation shall be available as supporting information. ~~R1,~~This establishes Category P0 as the normal System condition in Table 1.

4.2. Sensitivity cases to demonstrate the impact of changes to the basic assumptions used in the benchmark planning cases. To accomplish this, the sensitivity cases shall have changes to at least one of the following conditions:

- Generation;
- Real and reactive forecasted Load; or
- Transfers.

M4. Each responsible entity shall have dated evidence in either electronic or hard copy format that it developed and maintained ~~System models of the responsible entity's~~benchmark planning ~~area~~cases and sensitivity cases for ~~performing~~completing the Extreme Temperature Assessment.

R5. Each responsible entity, as identified in Requirement R1, shall have criteria for acceptable System steady state voltage limits ~~and~~, post-Contingency voltage deviations, and applicable Facility Ratings for ~~performing~~completing the Extreme Temperature Assessment ~~in accordance with Requirement R3~~. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M5. Each responsible entity, as identified in Requirement R1, shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits ~~and~~, post-Contingency voltage deviations, and applicable Facility Ratings for ~~performing~~completing the Extreme Temperature Assessment~~ in accordance with Requirement R5~~.

R6. Each responsible entity, as identified in Requirement R1, shall define and document the criteria or methodology used in the Extreme Temperature Assessment analysis to identify instability, uncontrolled separation, or Cascading~~.~~ within an Interconnection. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M6. Each responsible entity, as identified in Requirement R1, shall provide dated evidence such as electronic or hard copy documentation of the ~~defined and documented~~ criteria or methodology used to identify instability, uncontrolled separation, or Cascading ~~used in the Extreme Temperature Assessment analysis in accordance with Requirement R6~~within an Interconnection.

R7. Each responsible entity, as identified in Requirement R1, shall identify ~~Contingencies used in performing the Extreme Temperature Assessment~~the planning events for each ~~of the event categories~~category in Table 1 that are expected to produce more severe System impacts ~~within~~on its ~~planning area~~portion of the Bulk Electric System. The rationale for those Contingencies selected for evaluation shall be available as supporting information. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M7. Each responsible entity, as identified in Requirement R1, shall provide dated evidence such as electronic or hard copy documentation ~~that it has identified Contingencies for performing~~of the ~~Extreme Temperature Assessment~~ planning events for each ~~of the~~ event ~~categories~~category in Table 1 that are expected to produce more severe System impacts ~~within~~on its ~~planning area and the~~ portion of the Bulk Electric System along with supporting rationale~~, in accordance with Requirement R7, such as electronic or hard copies of documents identifying the Contingencies with supporting rationale.~~.

R8. Each responsible entity, as identified in Requirement R1, shall complete ~~an~~steady state and transient stability analyses in its Extreme Temperature Assessment ~~of the Long-Term Transmission Planning Horizon~~ at least once every five calendar years~~,~~ using the ~~benchmark planning cases~~ Contingencies identified in Requirement R7, and ~~the System models identified in Requirement R3 and R4, and the Contingencies identified in Requirement R7 for each of the event categories in Table 1, and~~ shall document the assumptions and results of the steady state and transient stability analyses. The Extreme Temperature Assessment shall include the following~~.~~: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

8.1. ~~Assessment~~Analysis of the benchmark planning cases developed ~~under~~ in accordance with Requirement R4~~, for one of the years in the Long-Term Transmission Planning Horizon. The rationale for the year selected for evaluation shall be available as supporting information.~~ Part 4.1.

~~8.2. Sensitivity analysis to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Extreme Temperature Assessment shall include, at a minimum, changes to one of the following conditions:~~

- ~~Generation;~~
- ~~Real and reactive forecasted Load; or~~
- ~~Transfers~~

8.2. Analysis of the sensitivity cases developed in accordance with Requirement R4 Part 4. 2.

M8. Each responsible entity, as identified in Requirement R1, shall provide dated evidence that it ~~performed an~~completed the steady state and transient stability analyses in its Extreme Temperature Assessment, such as electronic or hard copies of the ~~assessment~~analyses, meeting all the requirements in Requirement R8.

R9. Each responsible entity, as identified in Requirement R1, shall develop a Corrective Action Plan(s) (CAPs) when the assessment of a benchmark planning case ~~study results indicate the~~, in accordance with Requirement R8 Part 8.1, indicates its portion of the Bulk Electric System is unable to meet performance requirements for Table 1 P0 or P1 Contingencies. ~~The~~For each Corrective Action Plan, the responsible ~~entities~~entity shall ~~share~~: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

9.1. Make their ~~CAPs with,~~CAP available and solicit feedback from~~,~~ applicable regulatory authorities or governing bodies responsible for retail electric service issues. ~~In addition, where Load shed is allowed as an element of a CAP for the Table 1 P1 Contingency, the responsible entity shall document~~

~~8.3.~~9.2. Document the alternative(s) considered~~, as mentioned in Requirement R10~~, and notify the applicable regulatory authorities or governing bodies responsible for retail electric service issues~~. Revisions to the CAP(s) are allowed in subsequent Extreme Temperature Assessments, but the planned System shall continue to meet the performance requirements. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*~~ when Non-Consequential Load Loss is utilized as an element of a CAP for the Table 1 P1 Contingency.

9.3. Be permitted to utilize Non-Consequential Load Loss as an interim solution, which normally is not permitted in Table 1, in situations that are beyond the control of the Planning Coordinator or Transmission Planner that prevent the implementation of a Corrective Action Plan in the required timeframe. The use of Non-Consequential Load Loss as an interim solution in this situation is permitted, provided that each responsible entity documents the situation causing the problem, alternatives evaluated, and takes actions to resolve the situation.

9.4. Be allowed to have revisions to the CAP in subsequent Extreme Temperature Assessments, provided that the planned BES shall continue to meet the performance requirements of Table 1.

M9. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copy documentation, of each CAP developed for its Extreme Temperature Assessment, including any revision history, when the assessment of the benchmark planning cases indicate its portion of the BES is unable to meet performance requirements for Table 1 P0 or P1 Contingencies in accordance with Requirement R9.

R10. Each responsible entity, as identified in Requirement R1, shall evaluate and document possible actions for the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

10.1. Benchmark planning cases where possible actions are designed to mitigate the consequences and adverse impacts when the study results indicate the System could result in instability, uncontrolled separation, or Cascading for the Table 1 P2, P4, and P7 Contingencies.

10.2. Sensitivity cases where possible actions are designed to mitigate failures to meet the performance requirements in Table 1 for category P0, P1, P2, P4, and P7 Contingencies.

M10. Each responsible entity, as identified in Requirement R1, shall provide dated evidence such as electronic or hard copy documentation ~~of a CAP, including any revision history, when the benchmark planning case study results indicate the System is unable to meet performance requirements for the Table 1 P0 or P1 Contingencies in accordance with Requirement R9.~~ that it evaluated and ~~document~~documented possible actions designed to ~~reduce the likelihood or~~ mitigate the consequences and adverse impacts when the benchmark planning case study results indicate the System could result in instability, uncontrolled separation, or Cascading for the Table 1 P2, P4, ~~P5,~~ and P7 Contingencies. ~~*[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* Each responsible entity, as identified in Requirement R1, shall provide the dated evidence that it evaluated and documented possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts when the benchmark planning case study results indicate the System could result in instability, uncontrolled separation, or Cascading for the Table 1 P2, P4, P5, and P7 Contingencies in accordance with Requirement R10, such as electronic or hard copies of the assessment detailing such actions.~~

~~R9.~~R11. Each responsible entity, as identified in Requirement R1, shall provide its Extreme Temperature Assessment results within 60 calendar days of a request to any functional entity that has a reliability related need and submits a written request for the information. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M11. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient; or a demonstration of a public posting that it provided its Extreme Temperature Assessment to any functional entity who has a reliability need within 60 calendar days of a written request.

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. **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.

   - Each responsible entity shall retain evidence of compliance with each requirement in this standard for five calendar years or one complete Extreme Temperature Assessment cycle, whichever is longer.

   1.3. **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.

Table 1 1: Contingencies ~~and Performance Criteria~~Category See Footnote 2 for BES Level					
Category	**Initial Condition**	**Event**	~~P0~~Fault type		
~~Facility Voltage Level of Contingency~~			~~Applicable to:~~ ~~• BES level 200 kV and above~~ ~~• Any common structure that includes a Facility 200kV and above~~ ~~Reference Voltages:~~ ~~• Non-generator step up transformer outage events, the reference voltage applies to the low-side winding.~~ ~~• Generator and generator step-up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the step-up transformer).~~		
~~Steady State Performance Criteria~~			~~• Applicable Facility Ratings shall not be exceeded.~~ ~~• System steady state voltages shall be within acceptable limits as defined in Requirement R5.~~	~~• Applicable Facility ratings shall not be exceeded~~ ~~• System steady state voltages shall be within acceptable limits as defined in Requirement R5.~~	~~Evaluation for uncontrolled separation or Cascading, as defined in Requirement R6.~~
~~Stability Performance Criteria~~			~~Initialization without oscillation~~		~~Evaluation for instability, uncontrolled separation, or Cascading, as defined in Requirement R6.~~
~~Corrective Action Plan Required~~			~~Yes (See Requirement R9)~~	~~Yes (See Requirement R9)~~	~~No (See Requirement R10)~~

Table 1.1: Contingencies ~~and Performance Criteria~~Category See Footnote 2 for BES Level					
Category	Initial Condition	Event	~~P0~~Fault type		
~~Non-Consequential Load Loss Allowed~~			~~No (See Requirement R9)~~	~~Yes (See Requirement R9)~~	~~Yes~~

~~Table 1: Contingencies and Performance Criteria~~			
~~Category~~	~~Initial Condition~~	~~Event~~	~~Fault Type~~ [1]
P0 No Contingency	Normal System	None	N/A
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt ~~Device~~[2]Device[3]	3Ø
		5. Single Pole of a DC line	SLG
P2 Single Contingency	Normal System	1. Opening of a line section w/o a ~~fault~~ [3]Fault [4]	N/A
		2. Bus Section Fault	SLG
		3. Internal Breaker Fault[5] (non-Bus-tie Breaker)	SLG
		~~1.~~ Internal Breaker ~~Fault~~[4] 4. ~~(non-~~Fault (Bus-tie Breaker)[5]	SLG
P4 Multiple Contingency *(Fault plus stuck breaker[6])*	Normal System	Loss of multiple Elements caused by a stuck breaker[6](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device[3] 5. Bus Section	SLG

		6. Loss of multiple Elements caused by a stuck breaker[6] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	
P7 Multiple Contingency *(Common Structure)*	Normal System	~~Internal Breaker Fault (Bus-tie Breaker)[4]~~The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure ~~1.~~2. Loss of a bipolar DC line	SLG

~~Table 1: Contingencies and Performance Criteria~~

~~Category~~	~~Initial Condition~~	~~Event~~	~~Fault Type [1]~~
~~**P4**~~ ~~Multiple Contingency~~ ~~*(Fault plus stuck breaker[10])*~~	~~Normal System~~	~~Loss of multiple elements caused by a stuck breaker[5](non-Bus-tie Breaker) attempting to clear a Fault on one of the following:~~ ~~5. Generator~~ ~~6. Transmission Circuit~~ ~~7. Transformer~~ ~~8. Shunt Device[2]~~ ~~9. Bus Section~~	~~SLG~~
		~~10. Loss of multiple elements caused by a stuck breaker[5] (Bus-tie Breaker) attempting to clear a Fault on the associated bus~~	~~SLG~~
~~**P5**~~ ~~Multiple Contingency~~ ~~*(Fault plus non-redundant component of a Protection System failure to operate)*~~	~~Normal System~~	~~Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System[7] protecting the Faulted element to operate as designed, for one of the following:~~ ~~1. Generator~~ ~~2. Transmission Circuit~~ ~~3. Transformer~~ ~~4. Shunt Device[2]~~ ~~5. Bus Section~~	
~~**P7**~~ ~~Multiple Contingency~~ ~~*(Common Structure)*~~	~~Normal System~~	~~The loss of:~~ ~~1. Any two adjacent (vertically or horizontally) circuits on common structure[6]~~ ~~2. Loss of a bipolar DC line~~	~~SLG~~

Table 1~~—~~.2: Steady State & Stability Performance ~~Footnotes (Planning Events and Extreme Events)~~Requirements					
	P0	P1	P2	P4	P7
Steady State Performance Requirements	• Applicable Facility Ratings shall not be exceeded. • System steady state voltages shall be within acceptable limits as defined in Requirement R5.	• Applicable Facility ratings shall not be exceeded. • System steady state voltages shall be within acceptable limits as defined in Requirement R5.	Instability, uncontrolled separation, or Cascading, as defined in Requirement R6, shall not occur.		
Stability Performance Requirements	~~1. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.~~ ~~2. Requirements which are applicable to shunt devices also~~	Instability, uncontrolled separation, or Cascading, as defined in Requirement R6, shall not occur.	Instability, uncontrolled separation, or Cascading, as defined in Requirement R6, shall not occur.		

Table 1~~—~~.2: Steady State & Stability Performance ~~Footnotes (Planning Events and Extreme Events)~~Requirements			
	~~apply to FACTS devices that are connected to ground.~~ ~~3. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.~~ ~~4. An internal breaker fault means a breaker failing internally, thus creating a~~The System ~~fault which must be cleared by protection on both sides of the breaker.~~ ~~5. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is~~		

Table 1~~—~~.2: Steady State & Stability Performance ~~Footnotes (Planning Events and Extreme Events)~~Requirements			
	~~assumed to~~shall remain ~~closed. A stuck breaker results in Delayed Fault Clearing.~~ ~~6. Excludes circuits that share a common structure (Planning event P7) for one mile or less.~~ ~~7. For purposes of this standard, non-redundant components of a Protection System to consider are~~stable. Instability, uncontrolled separation, or Cascading, as ~~follows:~~ ~~A single protective relay which responds to electrical quantities, without an alternative (which may or may~~defined in Requirement R6, shall not ~~respond to electrical quantities) that provides comparable Normal Clearing times;~~occur.		

Table 1~~—~~.2: Steady State & Stability Performance ~~Footnotes (Planning Events and Extreme Events)~~Requirements			
	~~a. A single communications system associated with protective functions, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing (an exception is a single communications system that is both monitored and reported at a Control Center);~~ ~~b. A single station dc supply associated with protective functions required for Normal Clearing (an exception is a single station dc supply that is both monitored and reported at a~~		

Table 1~~—~~.2: Steady State & Stability Performance ~~Footnotes (Planning Events and Extreme Events)~~Requirements			
	~~Control Center for both low voltage and open circuit);~~ ~~A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply through and including the trip coil(s) of the circuit breakers or other interrupting devices, required for Normal Clearing (the trip coil may be excluded if it is both monitored and reported at a Control Center).~~		
Requirements for Benchmark Planning Case Assessment Results			
Corrective Action Plan Required	Yes (See Requirement R9)	Yes (See Requirement R9)	No (See Requirement R10)
Non-Consequential Load Loss Allowed	No (See Requirement R9)	Yes (See Requirement R9)	Yes
Interruption of Firm Transmission Service Allowed	Yes	Yes	Yes
Requirements for Sensitivity Case Assessment Results			

Table 1~~—~~.2: Steady State & Stability Performance ~~Footnotes (Planning Events and Extreme Events)~~Requirements			
Corrective Action Plan Required	No (See Requirement R10)	No (See Requirement R10)	No (See Requirement R10)
Non-Consequential Load Loss Allowed	Yes	Yes	Yes
Interruption of Firm Transmission Service Allowed	Yes	Yes	Yes

Table 1.3 – Steady State & Stability Performance Footnotes
1. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria. 2. Facility voltage level of Contingency is applicable to: a. BES level 200 kV and above (referenced Contingency voltage) b. For P7 events include Contingencies that have at least one 200kV voltage and above Facilities on common structure that has more than one mile in length. c. For non-generator step up transformer outage events, the reference voltage, as used in footnote 2a, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers. 3. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground. 4. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point. 5. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker. 6. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	N/A	N/A	N/A	The Planning Coordinator, in conjunction with its Transmission Planner(s), failed to determine and identify individual and joint responsibilities for ~~performing the required studies for~~completing the Extreme Temperature Assessment.
R2.	N/A	N/A	The responsible entity did not select ~~an~~at least one extreme heat benchmark event or extreme cold benchmark temperature event from the ERO approved benchmark library for performing the Extreme Temperature Assessment.	The responsible entity did not select an extreme heat benchmark event and extreme cold benchmark temperature event from the ERO approved benchmark library for performing the Extreme Temperature Assessment.
R3.	N/A	N/A	N/A	The Planning Coordinator did not develop or implement a process for coordinating the development of benchmark planning cases among impacted adjacent Planning Coordinator(s), Transmission Planner(s), and other designated study entities,

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				within the same Interconnection. OR The Planning Coordinator developed and implemented a process for coordinating the development of benchmark planning cases among impacted adjacent Planning Coordinator(s), Transmission Planner(s), and other designated study entities~~, but this process did not define~~ within the ~~planning study area boundary based off the selected benchmark events.~~ ~~OR~~ ~~The Planning Coordinator developed and implemented a process for coordinating the development of benchmark planning cases among impacted Planning Coordinator(s), Transmission Planner(s), and other designated study entities~~same Interconnection, but this process did not modify the benchmark planning cases to

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
				include seasonal and temperature dependent adjustments load, generation, Transmission, and transfers.
R4.	N/A	N/A	N/A	The responsible entity did not develop or maintain ~~System models of the responsible entity's~~benchmark planning ~~area~~cases or sensitivity cases for performing the Extreme Temperature Assessment. OR The responsible entity developed and maintained ~~System models~~benchmark planning cases or sensitivity cases for performing the Extreme Temperature Assessment~~,~~ but ~~the System model~~ did not use data consistent with that provided in accordance with the MOD-032 standard ~~supplemented by other sources as needed~~.
R5.	N/A	N/A	N/A	The responsible entity, as determined in Requirement

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
				R1, did not have criteria for acceptable System steady state voltage limits ~~and~~, post-Contingency voltage deviations, and applicable Facility Ratings for performing Extreme Temperature Assessment.
R6.	N/A	N/A	N/A	The responsible entity failed to define and document, the criteria or methodology used in the analysis to identify System instability, uncontrolled separation, or Cascading~~.~~ within an Interconnection.
R7.	N/A	N/A	The responsible entity, as determined in Requirement R1, identified Contingencies for performing Extreme Temperature Assessment for each of the ~~event categories~~planning events in Table 1 that are expected to produce more severe System impacts within its planning area, but did not include the rationale for those Contingencies selected for	The responsible entity, as determined in Requirement R1, did not identify Contingencies for performing Extreme Temperature Assessment for each of the ~~event categories~~planning events in Table 1 that are expected to produce more severe System impacts within its planning area.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			evaluation as supporting documentation.	
R8.	The responsible entity, as determined in Requirement R1, completed an Extreme Temperature Assessment, but it was ~~completed~~performed less than or equal to six months late.	The responsible entity, as determined in Requirement R1, completed an Extreme Temperature Assessment, but it was ~~completed~~performed more than six months but less than or equal to 12 months late.	The responsible entity, as determined in Requirement R1, completed an Extreme Temperature Assessment, but it was ~~completed~~performed more than 12 months but less than or equal to ~~than~~ 18 months late.	The responsible entity, as determined in Requirement R1, ~~completed~~performed an Extreme Temperature Assessment, but it was more than 18 months late. OR The responsible entity, as determined in Requirement R1, did not ~~complete~~perform an Extreme Temperature Assessment. OR The responsible entity, as determined in Requirement R1, ~~completed~~performed an Extreme Temperature Assessment, but it was missing one or more of the required elements in Requirement R8.
R9.	N/A	N/A	The responsible entity, as determined in Requirement R1, developed a ~~CAP~~Corrective	The responsible entity, as determined in Requirement R1, failed to develop a

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			Action Plan meeting each of the elements in Requirement R9, but failed to make their Corrective Action Plan available to, or solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.	Corrective Action Plan meeting each of the elements of Requirement R9 when the benchmark planning case study results indicate the System is unable to meet performance requirements for the Table 1 P0 or P1 Contingencies.
R10.	N/A	N/A	N/A	Each responsible entity, as determined in Requirement R1, failed to evaluate and document possible actions ~~designed to reduce the likelihood or~~, mitigate the consequences, and adverse impacts when the benchmark planning case study results indicate the System could result in instability, uncontrolled separation, or Cascading for the Table 1 P2, P4, ~~P5,~~ and P7 Contingencies.
R11.	The responsible entity, as determined in Requirement R1, distributed its Extreme Temperature Assessment	The responsible entity, as determined in Requirement R1, distributed its Extreme Temperature Assessment	The responsible entity, as determined in Requirement R1, distributed its Extreme Temperature Assessment	The responsible entity, as determined in Requirement R1, distributed its Extreme Temperature Assessment

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	results to functional entities having a reliability related need who requested the information in writing, but it was more than 60 days but less than or equal to 80 days following the request.	results to functional entities having a reliability related need who requested the information in writing, but it was more than 80 days but less than or equal to 100 days following the request.	results to functional entities having a reliability related need who requested the information in writing, but it was more than 100 days but less than or equal to 120 days following the request.	results to functional entities having a reliability related need who requested the information in writing, but it was more than 120 days following the request. OR The responsible entity, as determined in Requirement R1, did not distribute its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing.

D. Regional Variances

None.

E. Associated Documents

- Implementation Plan for 2023-07
- Technical Rationale Document
- Consideration of Issues and Directives for FERC Order 896.

Version History

Version	Date	Action	Change Tracking
1	TBD	Addressing FERC Order 896	New Standard

Implementation Plan

Project 2023-07 Transmission System Planning Performance Requirements for Extreme Weather
Reliability Standard TPL-008-1

Applicable Standard

- TPL-008-1 – Transmission System Planning Performance Requirements for Extreme Temperature Events

Requested Retirement

- Not applicable

Prerequisite Standard

- Not applicable

Applicable Entities

- Planning Coordinators
- Transmission Planners

New Terms in the NERC Glossary of Terms

Proposed New Definition(s):

- Extreme Temperature Assessment - Documented evaluation of future Bulk Electric System performance for extreme heat and extreme cold temperature benchmark events.

Background

On June 15, 2023, FERC issued a Final Rulemaking directing NERC to develop a new or modified Reliability Standard to address the lack of a long-term planning requirement(s) for extreme heat and cold weather events. Specifically, FERC directed NERC to develop modifications to Reliability Standard TPL-001-5.1 or develop a new Reliability Standard that requires the following: (1) development of benchmark planning cases based on major prior extreme heat and cold weather events and/or meteorological projections; (2) planning for extreme heat and cold weather events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios including the expected resource mix's availability during extreme heat and cold weather conditions, and including the wide-area impacts of extreme heat and cold weather; and (3) development of Corrective Action Plans that mitigate any instances where performance requirements for extreme heat and cold weather events are not met.

Effective Date

The effective date for the proposed Reliability Standard is provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of the proposed Reliability Standard (e.g., an entire Requirement or a portion thereof), the additional time for compliance with that section is specified below. These phased-in compliance dates represent the dates that entities must begin to comply with that particular section of the Reliability Standard, even where the Reliability Standard goes into effect at an earlier date.

TPL-008-1

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Phased-In Compliance Dates

Compliance Date for TPL-008-1 Requirement R1

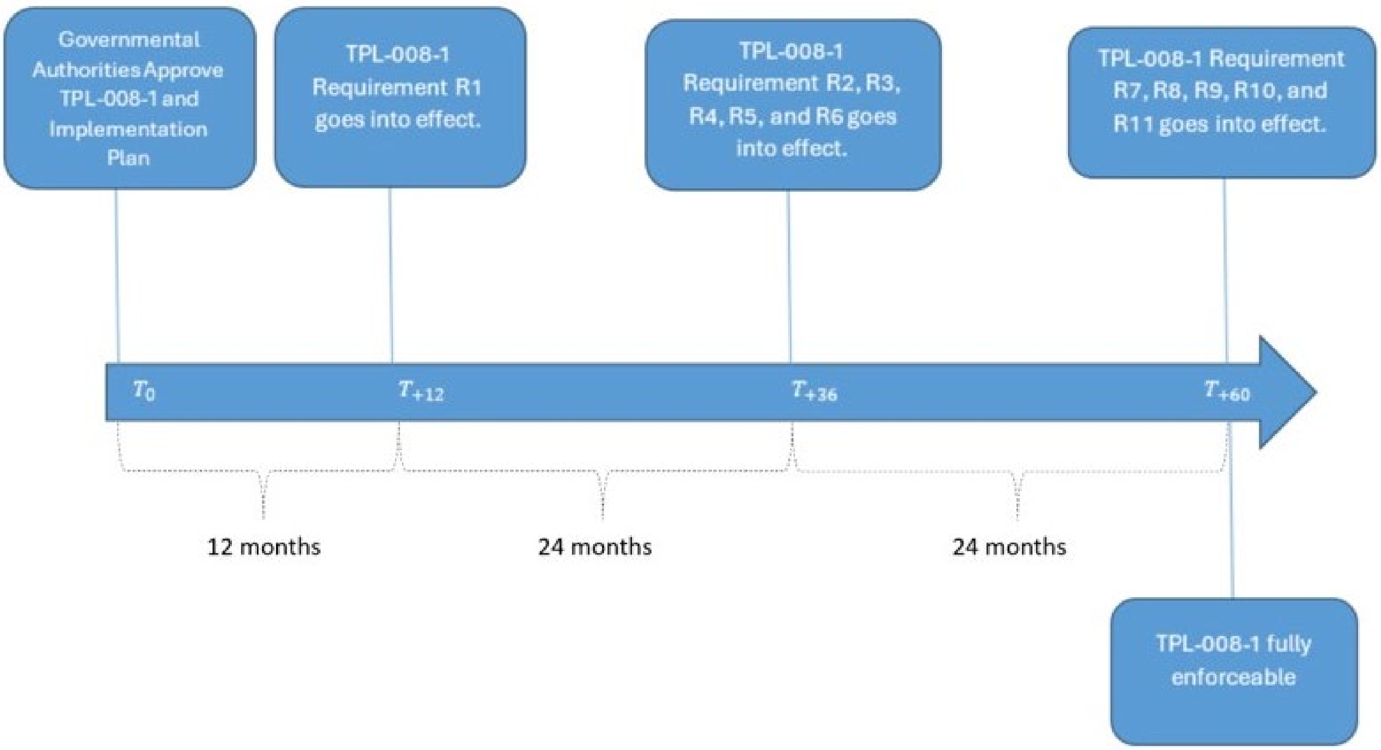
Entities shall be required to comply with Requirement R1 upon the effective date of Reliability Standard TPL-008-1.

Compliance Date for TPL-008-1 Requirements R2, R3, R4, R5, R6

Entities shall not be required to comply with Requirements R2, R3, R4, R5, and R6 until thirty-six (36) months after the effective date of Reliability Standard TPL-008-1.

Compliance Date for TPL-008-1 Requirements R7, R8, R9, R10, R11

Entities shall not be required to comply with Requirements R7, R8, R9, R10, R11 until sixty (60) months after the effective date of Reliability Standard TPL-008-1.


Governmental Authorities Approve TPL-008-1 and Implementation Plan
TPL-008-1 Requirement R1 goes into effect.
TPL-008-1 Requirement R2, R3, R4, R5, and R6 goes into effect.
TPL-008-1 Requirement R7, R8, R9, R10, and R11 goes into effect.
T_0
T_{+12}
T_{+36}
T_{+60}
12 months
24 months
24 months
TPL-008-1 fully enforceable

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Technical Rationale and Justification for TPL-008-1

Project 2023-07 Transmission Planning Performance Requirements for Extreme Weather

July 2024

RELIABILITY | RESILIENCE | SECURITY

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
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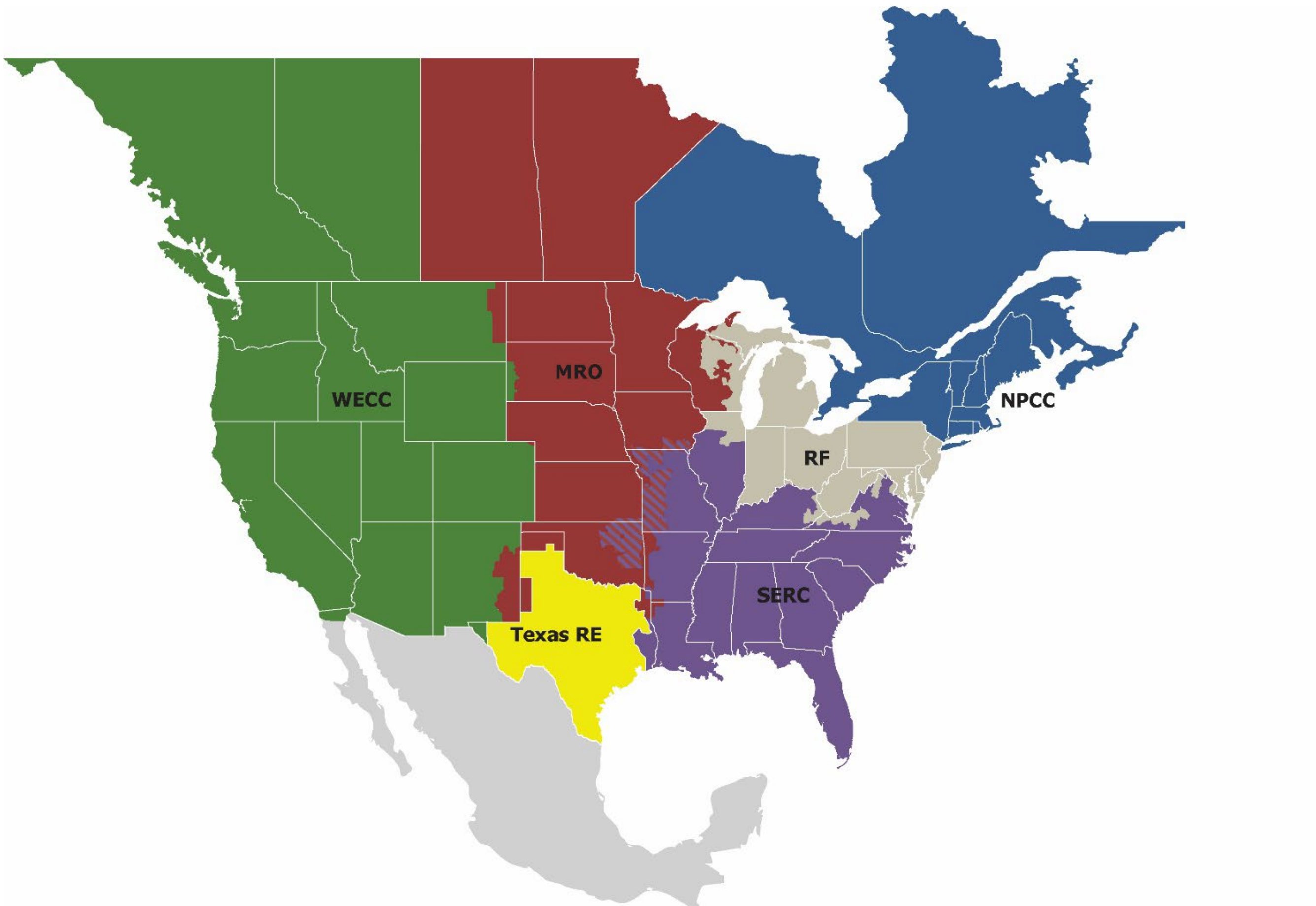
Table of Contents

Preface

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

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

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



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

Introduction

This document explains the technical rationale and justification for the proposed Reliability Standard TPL-008-1. It provides stakeholders and the ERO Enterprise with an understanding of the technology and technical requirements in the Reliability Standard. This Technical Rationale and Justification for TPL-008-1 is not a Reliability Standard and should not be considered mandatory and enforceable.

Background

On June 15, 2023, FERC issued FERC Order No. 896 that acknowledges the "challenges associated with planning for extreme heat and cold weather events, particularly those that occur during periods when the Bulk-Power System must meet unexpectedly high demand. Extreme heat and cold weather events have occurred with greater frequency in recent years and are projected to occur with even greater frequency in the future. These events have shown that load shed during extreme temperatures result in unacceptable risk to life and have extreme economic impact. As such, the impact of concurrent failures of Bulk-Power System generation and transmission equipment and the potential for cascading outages that may be caused by extreme heat and cold weather events should be studied and corrective actions should be identified and implemented."[1]

Therefore, the Commission directed in FERC Order No. 896 to develop a new or modified Reliability Standard to address a lack of long-term planning requirement(s) for extreme heat and cold weather events. Specifically, FERC directed NERC to develop modifications to Reliability Standard TPL-001-5.1 or a new Reliability Standard, to require the following: (1) development of benchmark planning cases based on major prior extreme heat and cold weather events and/or meteorological projections; (2) planning for extreme heat and cold weather events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios including the expected resource mix's availability during extreme heat and cold weather conditions, and including the wide-area impacts of extreme heat and cold weather; and (3) development of corrective action plans that mitigate any instances where performance requirements for extreme heat and cold weather events are not met.

[1] N. Am. Elec. Reliability Corp., 183 FERC ¶ 61,191 (2023) (FERC Order), Final Rule. eLibrary | File List (ferc.gov)

Defined Terms

The Standard Drafting Team (SDT) defined one term to be added to the NERC Glossary of Terms to make the requirements easier to read and understand.

Extreme Temperature Assessment
Documented evaluation of future Bulk Electric System performance for extreme heat and extreme cold temperature benchmark events.

The definition of Extreme Temperature Assessment was developed by the SDT to limit wordiness throughout the requirements.

TPL-008-1 Standard

The FERC Order No. 896 directed NERC to submit a new Reliability Standard or modifications to Reliability Standard TPL-001-5.1 to address the concerns pertaining to transmission system planning for extreme heat and cold weather events that impact the Reliable Operation of the Bulk-Power System.

The SDT developed TPL-008-1 to address the FERC directive and determined that a new Reliability Standard was the cleanest way to address all directives versus modifying Reliability Standard TPL-001-5.1. While the TPL-008-1 standard pulls in similar requirements, this allows industry to have one standard that focuses on extreme heat and extreme cold weather benchmark planning analysis requirements.

Requirement R1

Requirement R1 was drafted to allow Planning Coordinator(s) (PC) and its Transmission Planner(s) (TP) within the PC's footprint to coordinate each entity's individual and joint responsibilities when completing the Extreme Temperature Assessment. The purpose of this requirement is to have the PC and its TPs identify their individual and joint responsibilities for the following activities: selecting the extreme heat and cold benchmark temperature events, developing and maintaining modeling data, having acceptable criteria, identifying Contingencies, performing steady state and transient stability analyses, developing Corrective Action Plans (CAPs) for Table 1 P0 and P1 Contingencies, evaluating and documenting possible actions for Table 1 P2, P4, and P7 Contingencies, and providing study results to any functional entity who have a reliability related need.

Requirement R2

Requirement R2 describes the need to select foundational weather data necessary for the creation of benchmark planning cases. Specifically, extreme hot and cold temperatures experienced during benchmark events are assumed to be outside the ranges used as the basis of planning cases studied under Reliability Standard TPL-001-5.1. Since temperature levels and associated weather conditions affect load levels, generation performance, and transfer levels, the selection of benchmark events is critical to ensuring the Extreme Temperature Assessment appropriately evaluates probable System conditions.

The SDT determined that the extreme heat and extreme cold temperatures selected must have a verified statistical basis based on weather data from credible sources. However, because there are many factors to consider in selecting benchmark events (e.g., temperature magnitude, duration of the event, geographical area impacted, etc.) the SDT is not in a position to provide that statistical basis or determine the appropriateness of any specific event. Therefore, to ensure consistency across regions, it is necessary for the ERO to have the responsibility for determining the suitability of benchmark events to represent probable future conditions. The ERO will maintain a library of benchmark events and develop a process to incorporate additional events proposed by responsible entities. Responsible entities will then have access to vetted benchmark weather data in a format that can be incorporated into benchmark planning cases.

Since any region can experience temperatures that are higher or lower than normal, each responsible entity must select at least one case that includes hotter temperature assumptions and one case that includes colder temperature assumptions. While it is understood that, for example, one region may typically experience hotter summers and milder winters than another region, both a hotter than average summer and a colder than average winter could result in reliability concerns. Therefore, the requirement is for at least one case specific to extreme heat and at least one case specific to extreme cold conditions to be studied for the Extreme Temperature Assessment.

Requirement R3

Requirement R3 aligns with directives in FERC Order 896, emphasizing the importance of coordinating the development of benchmark planning cases amongst impacted responsible entities, where the scope of extreme temperature event studies will likely cover large geographical areas exceeding smaller individual planning areas. Rather than attempting to define study boundaries, the SDT instead focused on developing language that ensures Planning Coordinators establish a process that ensures coordination of temperature-dependent variables with other affected entities based upon the selected benchmark temperature events.

NERC already defines "Wide Area" as "The entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits." Reliability Coordinator Areas can be geographically very large – for example the Reliability Coordinator West (RCW) region extends from the Pacific Northwest to the southern borders of California and Arizona. Thus, defining coordination requirements based on these boundaries may not accurately capture weather events and system impacts at a sufficiently granular level. In addition, it is recognized that electrical boundaries such as those defining the Eastern/Western/ERCOT interconnections limit the potential for events in one area to affect reliability in another.

The SDT considered comments from the industry expressing concerns regarding the necessity to coordinate among all impacted Planning Coordinators in developing benchmark planning cases for various extreme temperature benchmark temperature events. Recognizing that coordination among all impacted Planning Coordinators may not be necessary to ensure reliability within an individual planning area, the SDT revised Requirement R3 to require each Planning Coordinator to develop and implement a process for coordinating the development of benchmark planning cases among adjacent impacted Planning Coordinator(s), Transmission Planner(s), and other designated study entities, within the same Interconnection. The SDT believes this change balances the need to ensure the planning cases capture impacts to/from entities affected by the same benchmark weather event, while recognizing that reliability will not be impacted by system changes far removed from the individual planning area.

Requirement R4

The SDT revised Requirement R4 to require the responsible entity to use data consistent with Reliability Standard MOD-032 for developing and maintaining benchmark planning cases that include seasonal and temperature dependent adjustment for Load, generation, Transmission and transfers representing System conditions based on selected benchmark events. This aligns with directives in FERC Order 896, paragraph 30, emphasizing the requirement of developing both benchmark planning cases and sensitivity study cases. Requirement R4 is consistent with how Reliability Standard TPL-001-5.1 cross-references Reliability Standard MOD-032, which establishes consistent modeling data requirements and reporting procedures for the development of planning horizon cases necessary to support analysis of the reliability of the interconnected System.

As per Order 896, paragraph 94, it is clarified that resource adequacy benchmarks are not within the scope of TPL-008-1. The intent of the standard is to evaluate benchmark events where sufficient generation is available to supply load. However, under an extreme heat or extreme cold temperature condition, there may be instances where the benchmark planning cases and/or sensitivity cases may not have sufficient available generation to supply the load. In these scenarios, it may be acceptable for the responsible entity to revise the model to reduce the projected load, or include reasonable projections of future resources, to achieve a solution for the benchmark planning case and evaluate future Bulk Electric System performance for extreme temperature events.

Requirement R5

Requirement R5 was drafted to require each responsible entity to set the criteria needed for limits that will be used to evaluate the steady-state voltage and thermal results from the Extreme Temperature Assessment. The establishment of these criteria allows auditors to compare the results of the assessment with the established criteria.

Requirement R6

Requirement R6 was drafted to require the responsible entity to have the criteria or methodology used in evaluating the Extreme Temperature Assessment analysis to identify instability, uncontrolled separation, or Cascading within an Interconnection. Adequate and thorough criteria should be built into the Extreme Temperature Assessment to help identify instability, uncontrolled separation, and Cascading conditions. The establishment of these criteria allows auditors to compare the results of the assessment with the established criteria.

Requirement R7

This requirement addresses directives in FERC Order No. 896 to define a set of Contingencies that responsible entities will be required to consider when conducting wide-area studies of extreme heat and cold weather events. FERC's preference to rely on established Contingency definitions, "[w]e believe that it is necessary to establish a set of common contingencies for all responsible entities to analyze. Required contingencies, such as those listed in Table 1 of Reliability Standard TPL-001-5.1 (i.e., category P1 through P7), establish common planning events that set the starting point for transmission system planning assessments," was also considered by the SDT. It is necessary to establish a set of common Contingencies for all responsible entities to analyze. Requiring the study of predefined Contingencies, such as those listed in Table 1, will ensure a level of uniformity across planning regions, considering that extreme heat and cold weather events often exceed the geographic boundaries of most existing planning footprints. Defining the Contingencies in Table 1 consistently with Table 1 of Reliability Standard TPL-001-5.1 meets FERC's preference for commonality.

If feasible, all Contingencies or Planning Events listed in Table 1 should be considered for evaluation by the responsible entity; however, the language affords flexibility in identifying the most appropriate Contingencies. As such, the responsible entity should implement a method and establish sufficient supporting rationale to ensure Contingencies that are expected to produce more severe System impacts within its planning area are adequately identified. It is noted that since the benchmark planning cases are developed from the extreme temperature benchmark events, they already represent extreme System conditions and thus not all Contingencies from Reliability Standard TPL-001-5.1 Table 1 are included in the TPL-008-1 Table 1 for assessment. The Events included in TPL-008-1 Table 1 represent the more likely Contingencies to occur.

The SDT finds it reasonable to exclude P3, P5 and P6 Contingencies from the Extreme Temperature Assessment. The following discusses the rationale for excluding these Contingencies for TPL-008-1:

1. Excluding P3 and P6 Contingencies:

   Part of the decision stems from the complexity of P3 and P6, which involve multiple element outages triggered by multiple Contingencies, with System adjustments allowed between them. Consequently, the occurrence likelihood of P3 and P6 could be even lower compared to P2, P4, and P7 Contingencies. Moreover, aligning with the directives set forth in FERC Order 896, which emphasizes the importance of incorporating derated generation, transmission capacity, and the availability of generation and transmission in the development of benchmark planning cases, it becomes imperative for responsible entities to consider potential concurrent or correlated generation and transmission outages and/or derates within relevant benchmark planning cases. This ensures that the benchmark planning case accurately reflects System conditions under extreme temperatures, with generation and transmission derates and/or outages already factored. Therefore, the SDT believes excluding P3 and P6 is justified, as generation and transmission derates and/or outages are already accounted for within the benchmark planning cases.

2. Excluding P5 Contingencies:

   After consideration of comments were received, the SDT removed P5 Contingency (Delayed Fault Clearing due to failure of non-redundant component of a Protection System). This is because while some categories of Contingencies may be assessed in a straightforward approach, category P5 events often require a significant level of engineering analysis (including protection and/or control analysis). These analyses are sensitive to the System topology and expected dispatch. As the planning benchmark cases are developed for TPL-008-1 that represent System conditions that are different than the typical summer or winter peak conditions, the development of category P5 events is expected to be a significant burden. Since these events only require evaluations of possible mitigations (and not CAPs), violations resulting from these events are unlikely to result in significant transmission System investment. Furthermore, any violations resulting from category P5 events may be mitigated by eliminating and addressing the single point of failure included in the event definition. Thus, the evaluation of possible actions is unlikely to result in further insight beyond the general reliability improvements associated with eliminating single points of failure.

Some, but not all, items to consider when developing the rationale for selecting Contingencies are:

- Past studies,
- Subject matter expert knowledge of the responsible entity's System (to be supplemented with data or analysis), and
- Historical data from past operating events.

Requirement R8

Requirement R8 was drafted to provide clarity on the following:

1. Frequency of the Extreme Temperature Assessment (Assessment):

   Due to significant level of data collection and coordination between the Planning Coordinator(s) and Transmission Planner(s) for the potential wide-area extreme cold or extreme heat benchmark events, as well as the need to document the assumptions and study results, the SDT opined that performing and completing of the Assessment once every five calendar years is a reasonable timeframe to allow responsible entities to coordinate, prepare, perform and document the Assessment study results. To the extent that responsible entities want to perform more than one set of Assessment for an extreme heat and extreme cold benchmark event, they can do so, but the minimum requirement is once every five calendar years to perform and complete one set of Assessment.

2. What planning study cases are required?

   The Requirement R8 includes the following minimum number of assessments to complete the Extreme Temperature Assessment and address FERC 896 directives per paragraph 111 that "direct NERC to require in the proposed new or modified Reliability Standard that responsible entities perform both steady state and transient stability (dynamic) analyses in the extreme heat and cold weather planning studies". In addition, Requirement R8 also addresses FERC 896 directives per paragraph 124 that "require the use of sensitivity cases to demonstrate the impact of changes to the assumptions used in the benchmark planning case". Requirement R8 also addresses FERC directives per paragraph 124 that sensitivity cases "should consider including conditions that vary with temperature such as load, generation, and system transfers." Since the benchmark planning case(s) already include System conditions under extreme heat or extreme cold events, the sensitivity analysis is to include, at a minimum, changes to one of the assumptions in generation, loads or transfers. Since the minimum requirement includes changes to one of these conditions, the PCs and the TPs can include further sensitivity assessments to change more conditions if they choose to do so.

   The following provides the minimum number of assessments required to complete the Extreme Temperature Assessment for the benchmark planning cases, as well as for sensitivity assessments.

Type of Extreme Temperature Assessment	Extreme Cold Temperature Event	Extreme Heat Temperature Event	Total
Benchmark Planning Case Analysis	A minimum of one extreme cold benchmark planning case assessment	A minimum of one extreme heat benchmark planning case assessment	Total Minimum: Two benchmark planning case assessments
Sensitivity Analysis	A minimum of one sensitivity study case for one of the following: 1. Changes in generation availability, or 2. Changes in load level (real and reactive), or	A minimum of one sensitivity study case for one of the following: 1. Changes in generation availability, or 2. Changes in load level (real and reactive), or	Total Minimum: Two sensitivity cases analysis

Type of Extreme Temperature Assessment	Extreme Cold Temperature Event	Extreme Heat Temperature Event	Total
	3. Changes in transfer level	3. Changes in transfer level	
Total			A minimum total of four assessments to complete the Extreme Temperature Assessment

3. What are the types of power flow related analyses?

There are two types of power flow related analyses: a steady-state and a stability analysis that are applied for the minimum of four planning study cases as identified in the above table. This requirement is to satisfy FERC Order 896 directive paragraph 111.

Requirement R9

FERC Order 896 identifies a deficiency in the existing Reliability Standard TPL-001-5.1 where “planning coordinators and transmission planners are required to evaluate possible actions to reduce the likelihood or mitigate the consequences of extreme temperature events but are not obligated to develop corrective action plans” (¶139).

Given potential severe consequences of extreme cold and extreme heat events, FERC Order 896 raises the bar and “directs NERC to require in the new or modified Reliability Standard the development of extreme weather corrective action plans for specified instances when performance standards are not met” (¶152).

Due to higher likelihood of P0 and P1 planning events, performance requirements for P0 and P1 Contingencies are held to a higher performance standard, and Corrective Action Plans (CAPs) are required to address performance deficiencies for P0 and P1 Contingencies in the Extreme Temperature Assessments.

Furthermore, having a CAP requirement for P0 and P1 contingencies aligns with ensuring resilience during future extreme cold and extreme heat events, when the transmission System is required to be P1-secure (using contingency analysis, voltage stability and transient stability).

Given that a P0 planning event represents a continuous System condition without any system disturbances, the SDT opined that load shedding should not be considered as a CAP. However, the SDT has determined that load curtailment may be considered for a P1 Contingency as a CAP where load shed is allowed to prevent system-wide failures and ensuring the continued operation of essential services under a critical P1 Contingency in the extreme heat and cold temperature events. The SDT also emphasizes that other alternative solutions, other than firm load curtailment, are evaluated in higher priorities. In the event that firm Load shed is included in the CAP for a P1 contingency, the responsible entity shall document the alternative(s) considered, as mentioned in Requirement R9, and notify the applicable regulatory authorities or governing bodies responsible for retail electric service issues.

Requirement R10

The requirement for responsible entities to assess and document possible actions designed to reduce the likelihood or mitigate the consequences of System instability, uncontrolled separation, or Cascading failures during P2, P4, and P7 Contingencies is in response to directives outlined in FERC Order 896.

The P2, P4, and P7 Contingencies involve multiple element outages resulting from a single event, making them relatively less likely to occur compared to P0 and P1 Contingencies but potentially causing more severe system impacts. Considering both the likelihood of these Contingencies and the fact that the Extreme Temperature Assessment already addresses low-probability System conditions, the SDT determined that no Corrective Action Plan is required for P2, P4, and P7 Contingencies. However, due to their potential severity resulting from single-Contingency multiple element outages, the SDT believes it is appropriate for responsible entities to at least evaluate and document possible mitigation actions to reduce the likelihood or mitigate the consequences and adverse impacts. The biggest benefit from the evaluation and documentation of the mitigating actions is it allows an entity to see where major problems exist that they may need to be addressed; and, if a project shows up on enough issues, it may encourage a fix to be implemented without it being strictly called for from the standard. Not requiring CAPs for these contingencies but requiring the evaluation is a compromise from having CAPs for all studied issues.

Requirement R11

The requirement for responsible entities to share Extreme Temperature Assessment results aligns with directives in FERC Order 896, emphasizing coordination and sharing of study findings. It ensures collaboration among stakeholders and timely dissemination of critical information to entities with reliability-related needs. This fosters a collective understanding of reliability concerns identified in wide-area studies, thereby enhancing overall grid reliability.

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Unofficial Comment Form

Project 2023-07 Transmission Planning Performance Requirements for Extreme Weather

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on draft two of **TPL-008-1 – Transmission System Planning Performance Requirements for Extreme Temperature Events** by **8 p.m. Eastern, Thursday, August 22, 2024.**

Additional information is available on the project page. If you have questions, contact Senior Standards Developer, Jordan Mallory (via email), or at 470-479-7538.

Background Information

On June 15, 2023, FERC issued FERC Order No. 896 that acknowledges the "challenges associated with planning for extreme heat and cold weather events, particularly those that occur during periods when the Bulk-Power System must meet unexpectedly high demand. Extreme heat and cold weather events have occurred with greater frequency in recent years, and are projected to occur with even greater frequency in the future. These events have shown that load shed during extreme temperature result in unacceptable risk to life and have extreme economic impact. As such, the impact of concurrent failures of Bulk-Power System generation and transmission equipment and the potential for cascading outages that may be caused by extreme heat and cold weather events should be studied and corrective actions should be identified and implemented."[1]

Therefore, the Commission directed in FERC Order No. 896 to develop a new or modified Reliability Standard to address a lack of long-term planning requirement(s) for extreme heat and cold weather events. Specifically, FERC directed NERC to develop modifications to Reliability Standard TPL-001-5.1 or a new Reliability Standard, to require the following: (1) development of benchmark planning cases based on major prior extreme heat and cold weather events and/or meteorological projections; (2) planning for extreme heat and cold weather events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios including the expected resource mix's availability during extreme heat and cold weather conditions, and including the wide-area impacts of extreme heat and cold weather; and (3) development of corrective action plans that mitigate any instances where performance requirements for extreme heat and cold weather events are not met.

[1] N. Am. Elec. Reliability Corp., 183 FERC ¶ 61,191 (2023) (FERC Order), Final Rule. eLibrary | File List (ferc.gov)

Questions

1. The drafting team (DT) updated the Requirements in chronological order. Do you agree with the proposed TPL-008-1 Reliability Standard Requirement layout? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.
   ☐ Yes
   ☐ No

   Comments:

2. The DT updated Requirements R1 – R2 based on comments received. Do you agree with the updated proposed TPL-008-1 Reliability Standard Requirements R1-R2? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.
   ☐ Yes
   ☐ No

   Comments:

3. The DT updated Requirements R3 – R5 based on comments received. Do you agree with the updated proposed TPL-008-1 Reliability Standard Requirements R3-R5? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.
   ☐ Yes
   ☐ No

   Comments:

4. The DT updated Requirements R6 – R8 based on comments received. Do you agree with the updated proposed TPL-008-1 Reliability Standard Requirements R6-R8? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.
   ☐ Yes
   ☐ No

   Comments:

5. The DT updated Requirement R9 based on comments received. Do you agree with the updated proposed TPL-008-1 Reliability Standard Requirement R9? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.
   ☐ Yes
   ☐ No

   Comments:

6. The DT updated Requirement R10 based on comments received. Do you agree with the updated proposed TPL-008-1 Reliability Standard Requirement R10? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.
   ☐ Yes
   ☐ No

   Comments:

7. The DT split out Table 1 into parts for better readability. Do you agree with the updated layout of Table 1? If you do not agree, please provide your recommendation and technical justification.
   ☐ Yes
   ☐ No

   Comments:

8. The DT believes proposed modifications in TPL-008-1 provide entities with flexibility to meet the reliability objectives in a cost-effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost-effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.
   ☐ Yes
   ☐ No

   Comments:

9. Provide any additional comments for the standard drafting team to consider, including the provided technical rationale document, if desired.

   Comments:

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Violation Risk Factor and Violation Severity Level Justifications

Project 2023-07 Transmission System Planning Performance Requirements for Extreme Weather

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Project 2023-07 Transmission System Planning Performance Requirements for Extreme Weather. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for TPL-008-1, Requirement R1	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to the fact that the Planning Coordinators, in conjunction with its Transmission Planner(s) will determine joint responsibilities for requirements throughout TPL-008-1.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Planning Coordinator, in conjunction with its Transmission Planner(s), failed to determine and identify individual and joint responsibilities for completing the Extreme Temperature Assessment.

VSL Justifications for TPL-008-1, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL has been assigned as a binary due to the Planning Coordinator and Transmission Planner to determine who completes the responsibilities throughout TPL-008-1. The responsibilities documentation will either be developed or not.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R2	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of high is appropriate due to the fact that selecting a benchmark event to perform an extreme temperature assessment can affect the grid based on planning analysis for future events.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The responsible entity did not select at least one extreme heat benchmark event or extreme cold benchmark temperature event from the ERO approved benchmark library for performing the Extreme Temperature Assessment.	The responsible entity did not select an extreme heat benchmark event and extreme cold benchmark temperature event from the ERO approved benchmark library for performing the Extreme Temperature Assessment.

VSL Justifications for TPL-008-1, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	This VSL has been assigned as a binary due to the benchmark event needing to be selected for benchmark planning cases to be completed. You either select a benchmark event or not.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R3	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of high is appropriate due to the fact that it is important to develop and maintain System models within an entity's planning area for performing Extreme Temperature Assessments. Connecting to MOD-032 to provide important data needed to assist entities with System models is also important for accurate information to be used.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Planning Coordinator did not develop or implement a process for coordinating the development of benchmark planning cases among impacted adjacent Planning Coordinator(s), Transmission Planner(s), and other designated study entities, within the same Interconnection. OR The Planning Coordinator developed and implemented a process for coordinating the development of benchmark planning cases among impacted adjacent Planning Coordinator(s), Transmission Planner(s), and other designated study entities within the same Interconnection, but this process did not modify the benchmark planning cases to include seasonal and temperature dependent adjustments load, generation, Transmission, and transfers.

VSL Justifications for TPL-008-1, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL has been assigned as a binary due to the responsible entity either develops and maintains the System models within its planning area or it does not develop and maintain the System models within its planning area.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R4	
Proposed VRF	**Medium**
NERC VRF Discussion	The VRF of Medium is appropriate because it could directly affect the electrical state or capability of the BPS if coordination is not completed for benchmark planning cases and sensitivity cases for the Extreme Temperature Assessment results.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity did not develop or maintain benchmark planning cases or sensitivity cases for performing the Extreme Temperature Assessment. OR The responsible entity developed and maintained benchmark planning cases or sensitivity cases for performing the Extreme Temperature Assessment but did not use data consistent with that provided in accordance with the MOD-032 standard.

VSL Justifications for TPL-008-1, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL has been assigned as a binary due to the Planning Coordinator to develop and implement a process for coordinating the development of benchmark planning cases. The benchmark planning cases will either be developed and implemented or not.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R5	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate due to the importance of having criteria for acceptable System steady state voltage limits of post-Contingency voltage deviations for performing Extreme Temperature Assessments.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity, as determined in Requirement R1, did not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and applicable Facility Ratings for performing Extreme Temperature Assessment.

VSL Justifications for TPL-008-1, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL has been assigned as a binary due to the responsible entity either having acceptable criteria for System steady state voltage limits and post-contingency voltage deviations or not.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R6	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate due to the importance of defining and documenting the criteria or methodology for System instability, uncontrolled separation, or Cascading.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity failed to define and document, the criteria or methodology used in the analysis to identify System instability, uncontrolled separation, or Cascading within an Interconnection.

VSL Justifications for TPL-008-1, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R7	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate for this requirement. Identifying Contingencies for performing Extreme Temperature Assessments for each of the event categories in Table 1 can directly impact the BES.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The responsible entity, as determined in Requirement R1, identified Contingencies for performing Extreme Temperature Assessment for each of the planning events in Table 1 that are expected to produce more severe System impacts within its planning area, but did not include the rationale for those Contingencies selected for evaluation as supporting documentation.	The responsible entity, as determined in Requirement R1, did not identify Contingencies for performing Extreme Temperature Assessment for each of the planning events in Table 1 that are expected to produce more severe System impacts within its planning area.

VSL Justifications for TPL-008-1, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R8	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate due to the importance of performing an Extreme Temperature Assessment every 5 years.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
The responsible entity, as determined in Requirement R1, completed an Extreme Temperature Assessment, but it was performed less than or equal to six months late.	The responsible entity, as determined in Requirement R1, completed an Extreme Temperature Assessment, but it was performed more than six months but less than or equal to 12 months late.	The responsible entity, as determined in Requirement R1, completed an Extreme Temperature Assessment, but it was performed more than 12 months but less than or equal to 18 months late.	The responsible entity, as determined in Requirement R1, performed an Extreme Temperature Assessment, but it was more than 18 months late. OR The responsible entity, as determined in Requirement R1, did not perform an Extreme Temperature Assessment. OR The responsible entity, as determined in Requirement R1, performed an Extreme Temperature Assessment, but it was missing one or more of the required elements in Requirement R8.

VSL Justifications for TPL-008-1, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R9	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate for this requirement. Developing a Corrective Action Plan is important to the BES as it assists entities when Systems are unable to meet performance requirements.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R9			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The responsible entity, as determined in Requirement R1, developed a Corrective Action Plan meeting each of the elements in Requirement R9, but failed to make their Corrective Action Plan available to, or solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.	The responsible entity, as determined in Requirement R1, failed to develop a Corrective Action Plan meeting each of the elements of Requirement R9 when the benchmark planning case study results indicate the System is unable to meet performance requirements for the Table 1 P0 or P1 Contingencies.

VSL Justifications for TPL-008-1, Requirement R9	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL has been assigned as a binary due to the responsible entity either having acceptable criteria for System steady state voltage limits and post-contingency voltage deviations or not.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R10	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of lower has been assigned to Requirement R10. Documenting possible actions to reduce the likelihood or mitigate the consequences and adverse impacts are administrative in nature.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R10			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	Each responsible entity, as determined in Requirement R1, failed to evaluate and document possible actions, mitigate the consequences, and adverse impacts when the benchmark planning case study results indicate the System could result in instability, uncontrolled separation, or Cascading for the Table 1 P2, P4, and P7 Contingencies.

VSL Justifications for TPL-008-1, Requirement R10	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL has been assigned as a binary due to the fact that the responsible entity ~~will~~ either have evaluated and documented possible actions to mitigate adverse impacts.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R11	
Proposed VRF	**Medium**
NERC VRF Discussion	The VRF of Medium is appropriate because it could directly affect the electrical state or capability of the BES if entities are not aware of the results from its Extreme Temperature Assessment results.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R11			
Lower	**Moderate**	**High**	**Severe**
The responsible entity, as determined in Requirement R1, distributed its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 60 days but less than or equal to 80 days following the request.	The responsible entity, as determined in Requirement R1, distributed its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 80 days but less than or equal to 100 days following the request.	The responsible entity, as determined in Requirement R1, distributed its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 100 days but less than or equal to 120 days following the request.	The responsible entity, as determined in Requirement R1, distributed its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 120 days following the request. OR The responsible entity, as determined in Requirement R1, did not distribute its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing.

VSL Justifications for TPL-008-1, Requirement R11	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

Consideration of FERC Order 896 Directives

Project 2023-07 Transmission System Planning Performance Requirements for Extreme Weather
July 2024

On June 15, 2023, FERC issued a Final Rule, Order No. 896, directing NERC to develop a new or modified Reliability Standard to address a lack of a long-term planning requirement(s) for extreme heat and cold weather events. Specifically, FERC directed NERC to develop modifications to Reliability Standard TPL-001-5.1 or to develop a new Reliability Standard to require the following: (1) development of benchmark planning cases based on major prior extreme heat and cold weather events and/or meteorological projections; (2) planning for extreme heat and cold weather events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios including the expected resource mix's availability during extreme heat and cold weather conditions, and including the wide-area impacts of extreme heat and cold weather; and (3) development of corrective action plans that mitigate any instances where performance requirements for extreme heat and cold weather events are not met. FERC directed NERC to submit a new or revised standard within 18 months, or by December 2024. The below provides the directives from FERC Order 896 along with the drafting team's consideration of the directives.

FERC Order 896 Directives	
Directive Language	**Consideration of Directives**
P35. "[W]e direct NERC to: (1) develop extreme heat and cold weather benchmark events, and (2) require the development of benchmark planning cases based on identified benchmark events." **P36**: "…As recommended by commenters, NERC should consider the examples of approaches for defining benchmark events identified in the NOPR (e.g., the use of projected frequency or probability distribution). NERC may also consider other approaches that achieve the objectives outlined in this final rule."	The ERO will work with respective subject matter experts, including climate experts, the six regions, etc., and develop extreme heat and extreme cold weather benchmark events. An ERO-maintained library will be created, and all developed extreme heat and extreme cold weather benchmark events will be retained. From this library, responsible entities will be able to review and select the appropriate benchmark events to assist with the development of its benchmark planning cases. NERC, in consultation with climate data subject matter expert consultants on the benchmark events, utilizes publicly available modeled data to inform TPL-008-1 data library and potentially augment it with historical

FERC Order 896 Directives	
Directive Language	**Consideration of Directives**
	observations as needed. Further information on the benchmark events will be posted by NERC in the July 2024 timeframe. The drafting team developed requirements within TPL-008-1 to require responsible entities to select one extreme heat benchmark event and extreme cold benchmark event from the approved ERO library (Requirement R2). After selecting its benchmark events, the responsible entity is required to develop and implement a process for coordinating the development of benchmark planning cases among the responsible entities (Requirement R3) and to develop and maintain benchmark planning cases and sensitivity cases (Requirement R4).
P38. "[I]n developing extreme heat and cold benchmark events, NERC shall ensure that benchmark events reflect regional differences in climate and weather patterns."	NERC, in consultation with climate data subject matter expert consultants on benchmark events, has utilized publicly available modeled data in the last forty-three years (1980-2022), as well as more than eighty years of projected hourly meteorology data from PNNL to ensure regional differences in climate and weather patterns are reflected within the developed benchmark events. Benchmark events are provided for eleven regions in the continental United States and provinces in Canada.
P39. "We also direct NERC to include in the Reliability Standard the framework and criteria that responsible entities shall use to develop from the relevant benchmark event planning cases to represent potential weather-related contingencies (e.g., concurrent/correlated generation and transmission outages, derates) and expected future conditions of the system such as changes in load, transfers, and generation resource mix, and impacts on generators sensitive to extreme heat or cold, due to the weather conditions indicated in the benchmark events. Developing such a framework would provide a common design basis for responsible entities to follow when creating benchmark planning cases. This would not only	The directive is addressed in proposed TPL-008-1 through Requirements R3, R4, and R8. Requirement R3 obligates the Planning Coordinator to develop and implement a process to coordinate the development of the benchmark planning cases. This process shall include seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers to represent the selected benchmark temperature events.

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Directive Language	**Consideration of Directives**
help establish a clear set of expectations for responsible entities to follow when developing benchmark planning events, but also facilitate auditing and enforcement of the Standard."	Requirement R4 obligates the responsible entity to develop and maintain benchmark planning cases and sensitivity cases for performing the Extreme Temperature Assessment which reflects System conditions from the selected benchmark events. Requirement R8 obligates the responsible entity to complete an Extreme Temperature Assessment for one of the years in the Long-Term Transmission Planning Horizon, for the benchmark planning cases, as well as sensitivity cases which include changes to one of these conditions: generation, real or reactive forecasted Load, or transfers.
P40. "We also direct NERC to ensure the reliability standard contains appropriate mechanisms for ensuring the benchmark event reflects up-to-date meteorological data."	The drafting team discussed a similar process to how BAL-003 gathers data. It was determined that the ERO, with the assistance from NERC's consultant, is in the best situation to provide a review with the respective subject matter experts, including climate experts, the six regions, etc., and update the benchmark events to reflect up-to-date meteorological data every five years via a NERC process document.
P50. "[W]e…direct NERC to require that transmission planning studies under the new or revised Reliability Standard consider the wide-area impacts of extreme heat and cold weather. We direct NERC to clearly describe the process that an entity must use to define the wide-area boundaries. While commenters provide various views in favor of both a geographical approach and electrical approach to defining wide-area boundaries, we do not adopt any one approach in this final rule…NERC should consider the comments in this proceeding when developing a new or modified reliability standard that considers the broad area impacts of extreme heat and cold weather."	The Standard Drafting Team (SDT) reviewed all the extreme weather events mentioned within the FERC Order 896. In addition, NERC in consultation with its climate data subject matter experts, utilized publicly available modeled data in the last forty-three years (1980-2022), as well as more than eighty years of projected hourly meteorology data from PNNL to develop the benchmark events for the ERO-maintained library. The benchmark events are provided and shown in a wide-area for various regions within the continental United States, as well as Canadian provinces. The drafting team addressed this directive by developing Requirement R2 and Requirement R3. Requirement R2 requires entities to, "select at least one extreme heat benchmark temperature event and at least one extreme cold benchmark temperature event, from the benchmark library, approved and maintained by the Electric Reliability Organization (ERO), for completing the Extreme Temperature Assessment."

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	Requirement R3 requires Planning Coordinators to "develop and implement a process for coordinating the development of benchmark planning cases, using the selected benchmark temperature events identified in Requirement R2, among adjacent impacted Planning Coordinator(s), Transmission Planner(s), and other designated study entities, within an Interconnection. This process shall include seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers to represent the selected benchmark temperature events."
P58. "[W]e…direct NERC to develop benchmark events for extreme heat and cold weather events through the Reliability Standards development process."	It was determined that the ERO, with the assistance from NERC's subject matter expert consultants, is in the best position to develop and update benchmark events through a fair and open process outside of the traditional standard development process. Such a process would allow maximum flexibility to update the benchmark events as climate conditions change or new science emerges. The ERO will initially work with its consultant, Telos Energy, to develop benchmark events for the first five-year assessment cycle. For the future Extreme Temperature Assessment (ETA) cycles, NERC will work with respective subject matter experts, including climate experts, the six regions, as well as its consultant, to develop future benchmark events. These events will be uploaded to an ERO library where responsible entities will then select their respective benchmark events from the ERO library to develop the benchmark planning cases. Requirement R2 obligates the responsible entity to select one extreme heat benchmark event and one extreme cold benchmark event from the approved benchmark library, that is approved and maintained by the ERO, for completing the Extreme Temperature Assessment.
P60. "[W]e…direct NERC to designate the type(s) of entities responsible for developing benchmark planning cases and conducting wide-area studies	The drafting team discussed that the Transmission Planner (TP) and/or Planning Coordinator (PC) would be the responsible entities to address TPL-

FERC Order 896 Directives	
Directive Language	**Consideration of Directives**
under the new or modified Reliability Standard…benchmark planning cases should be developed by registered entities such as large planning coordinators, or groups of planning coordinators, with the capability of planning on a regional scope." **P61**: "We believe the designated responsible entities should have certain characteristics, including having a wide-area view of the Bulk-Power System and the ability to conduct long-term planning studies across a wide geographic area. The responsible entities should also have the planning tools, expertise, processes, and procedures to develop benchmark planning cases and analyze extreme weather events in the long-term planning horizon." **P62**: "To comply with this directive, NERC may designate the tasks of developing benchmark planning cases and conducting wide-area studies to an existing functional entity or a group of functional entities (e.g., a group of planning coordinators). NERC may also establish a new functional entity registration to undertake these tasks. In the petition accompanying the proposed Reliability Standard NERC should explain how the applicable registered entity or entities meet the objectives outlined above."	008-1 Requirements. Requirement R1 obligates both the TP and PC to identify their individual and joint responsibilities. The drafting team reviewed all the extreme weather events mentioned within the FERC Order 896. In addition, NERC's consultant, Telos Energy, utilized publicly available modeled data in the last forty-three years (1980-2022), as well as more than eighty years of projected hourly meteorology data from PNNL to develop the benchmark events for the ERO-maintained library. The selected benchmark event will include the impacted wide-area for the regions in the continental United States, as well as Canadian provinces. Requirement R3 obligates each the responsible entity to develop and implement a process for coordinating the development of benchmark planning cases, using the selected benchmark temperature events identified in Requirement R2, among adjacent impacted Planning Coordinator(s), Transmission Planner(s), and other designated study entities, within an Interconnection. Requirement R4 obligates each responsible entity, as identified in Requirement R1, to use the coordination process developed in accordance with Requirement R3 and data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, to develop and maintain benchmark planning cases and sensitivity cases.
P72. "[W]e direct NERC to require functional entities to share with the entities responsible for developing benchmark planning cases and conducting wide-area studies the system information necessary to develop benchmark planning cases and conduct wide-area studies. Further, responsible entities must share the study results with affected transmission operators, transmission owners, generator owners, and other functional entities with a reliability need for the studies."	The directive is addressed in proposed TPL-008-1 through requirements R3, R4 and R11. Requirement R3 obligates each responsible entity to develop and implement a process for coordinating the development of benchmark planning cases, using the selected benchmark temperature events identified in Requirement R2, among adjacent impacted Planning

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	Coordinator(s), Transmission Planner(s), and other designated study entities, within an Interconnection. Requirement R4 obligates each responsible entity, as identified in Requirement R1, to use the coordination process developed in accordance with Requirement R3 and data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, to develop and maintain benchmark planning cases and sensitivity cases. Requirement R11 obligates each responsible entity, as identified in Requirement R1, to provide its Extreme Temperature Assessment results within 60 calendar days of a request to any functional entity that has a reliability related need and submits a written request for the information.
P73. "Because in this final rule we direct NERC to determine the responsible entities that will be developing benchmark planning cases and conducting wide-area studies, it is possible that the selected responsible entities under the new or modified Reliability Standard will not be able to request and receive needed data pursuant to MOD-032-1, absent modification to that Standard."	The drafting team discussed and determined that data needed to address the Extreme Temperature Assessment would still be appropriate to receive through MOD-032. MOD-032 ensures an adequate means of data collection for transmission planning and requires applicable registered entities to provide steady-state, dynamic, and short circuit modeling data to their transmission planner(s) and planning coordinator(s). As outlined in R1 and Attachment 1 of MOD-032, MOD-032 allows various data collection such as in-service status and capability associated with demand, generation, and transmission associated with various case types, scenarios, system operating states, or conditions for the long-term planning horizon. MOD-032 also requires applicable registered entities to provide "other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes" for each of the three types of data required. Because the drafting team determined the

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Directive Language	**Consideration of Directives**
	responsible entities that will be developing benchmark planning cases are limited to planning coordinators and transmission planners, they will be able to request and receive needed data pursuant to MOD-032. Thus, the drafting team believes that there is no need to update MOD-032 because it allows planning coordinators and transmission planners to request any specific data needed for developing and maintaining benchmark planning cases required in R4 of TPL-008-1. The directive is addressed in proposed TPL-008-1 through Requirements R1, R3, R4 and R8. Requirement R1 obligates the Planning Coordinator, in conjunction with its Transmission Planners(s), to identify each entity's individual and joint responsibilities for completing the Extreme Temperature Assessment. Requirement R3 obligates the Planning Coordinator to develop and implement a process for coordinating the development of benchmark planning cases among adjacent impacted Planning Coordinator(s), Transmission Planner(s), and other designated study entities, within an Interconnection. Requirement R4 obligates the responsible entity, as identified in Requirement R1, to develop and maintain benchmark planning cases and sensitivity cases in accordance with data consistent with the MOD-032 standard. Requirement R8 obligates the responsible entity, as identified in Requirement R1, to perform steady state and transient stability analyses of the benchmark planning and sensitivity cases developed in Requirement R4.
P76: "[W]e…direct NERC to address the requirement for wide-area coordination through the standards development process, giving due consideration to relevant factors identified by commenters in this proceeding."	The drafting team reviewed all the extreme weather events mentioned within the FERC Order 896. For this project, the drafting team focused the scope of Requirement R3 to require each Planning Coordinator to develop and implement a process for coordinating the development of benchmark planning cases, using the selected benchmark temperature events identified in Requirement R2, among adjacent impacted Planning

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	Coordinator(s), Transmission Planner(s), and other designated study entities, within an Interconnection. However, future modifications may be needed as extreme temperature events evolve that may result in the need for wider area impact of coordination between PCs.
P77. "[W]e direct NERC to require in the new or modified Reliability Standard that responsible entities share the results of their wide-area studies with other registered entities such as transmission operators, transmission owners, and generator owners that have a reliability related need for the studies."	This directive is addressed in proposed TPL-008-1 Requirement R11. Requirement R11 obligates each responsible entity to provide the wide-area study results within 60 calendar days of a request to any functional entity that has a reliability related need and has submitted a written request for the information.
P88. "[W]e direct NERC to require under the new or revised Reliability Standard the study of concurrent/correlated generator and transmission outages due to extreme heat and cold events in benchmark events as described in more detail below."	This directive is addressed in proposed TPL-008-1 through Requirement R4. Per Requirement R4 Part 4.1, the responsible entity is obligated to develop and maintain benchmark planning cases that include seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers to represent the System conditions of the selected benchmark temperature events for one of the years in the Long-Term Transmission Planning Horizon. Per Requirement R4 Part 4.2, the responsible entity is obligated to develop and maintain sensitivity cases by changing at least one of the following conditions in the benchmark planning cases: generation, real and reactive forecasted Load, or transfers.
P111. "[W]e direct NERC to require in the proposed new or modified Reliability Standard that responsible entities perform both steady state and transient stability (dynamic) analyses in the extreme heat and cold weather planning studies. In a steady state analysis, the system components are modeled as either in-service or out-of-service and the result is a single point-in-time snapshot of the system in a state of operating equilibrium. A transient stability (dynamic) analysis examines the system from the start to the end of a disturbance to determine if the system regains a state of operating equilibrium. Performing both analyses ensures that the system has been thoroughly assessed for instability, uncontrolled separation, and	This directive is addressed in proposed TPL-008-1 through Requirement R8 and Table 1. Requirement R8 requires the responsible entity to complete both steady state and transient stability analyses and document the assumptions and results. Table 1 obligates each responsible entity to perform both steady state and transient stability analyses and compare the study results against steady state and stability performance requirements.

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cascading failures in both the steady state and the transient stability realms." (internal citations omitted).	
P112. "[W]e direct NERC to define a set of contingencies that responsible entities will be required to consider when conducting wide-area studies of extreme heat and cold weather events under the new or modified Reliability Standard. We believe that it is necessary to establish a set of common contingencies for all responsible entities to analyze. Required contingencies, such as those listed in Table 1 of Reliability Standard TPL-001-5.1 (i.e., category P1 through P7), establish common planning events that set the starting point for transmission system planning assessments. Requiring the study of predefined contingencies will ensure a level of uniformity across planning regions—a feature that will be necessary in the new or revised Reliability Standard considering that extreme heat and cold weather events often exceed the geographic boundaries of most existing planning footprints." **P113:** "[T]he contingencies required in the new or revised Reliability Standards should reflect the complexities of transmission system planning studies for extreme heat and cold weather events."	This directive is addressed in proposed TPL-008-1 through Requirement R7 and Table 1. Requirement R7 requires the responsible entity to identify Contingencies for completing the Extreme Temperature Assessment. The rationale for those Contingencies selected for evaluation shall be available as supporting information. The planning events for each Contingency category in Table 1 of TPL-008-1 correspond to the well-established Contingencies defined in Reliability Standard TPL-001-5.1. Table 1 also establishes common planning events that set the starting point for transmission system planning assessments by requiring the study of predefined contingencies that will ensure a level of uniformity across planning regions.
P116. "[W]e direct NERC to require in the new or modified Reliability Standard that responsible entities model demand load response in their extreme weather event planning area. As indicated by several commenters, because demand load response is generally a mitigating action that involves reducing distribution load during periods of stress to stabilize the Bulk-Power System, its effect during an extreme weather event should be modeled." **P 117:** "[I]n addressing this directive, we expect NERC to determine whether responsible entities will need to take additional steps to ensure that the impacts of demand load response are accurately modeled in	TPL-008-1 Requirement R4 meets this directive by requiring each responsible entity to develop and maintain System models within its planning area consistent with that of the MOD-032 standard. Specifically, Attachment 1 of MOD-032 requires information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes.

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extreme weather studies, such as by analyzing demand load response as a sensitivity, as is currently the case under Reliability Standard TPL-001-5.1.”	
P124. “[W]e direct NERC to require the use of sensitivity cases to demonstrate the impact of changes to the assumptions used in the benchmark planning case. Sensitivity analyses help a transmission planner to determine if the results of the base case are sensitive to changes in the inputs. The use of sensitivity analyses is particularly necessary when studying extreme heat and cold events because some of the assumptions made when developing a base case may change if temperatures change – for example, during extreme cold events, load may increase as temperatures decrease, while a decrease in temperature may result in a decrease in generation. We… direct NERC to define during the Reliability Standard development process a baseline set of sensitivities for the new or modified Reliability Standard. While we do not require the inclusion of any specific sensitivity in this final rule, NERC should consider including conditions that vary with temperature such as load, generation, and system transfers.” **P125**. “We…believe that responsible entities should be free to study additional sensitivities relevant to their planning areas…cooperation will be necessary between responsible entities conducting extreme heat and extreme cold weather studies and other registered entities within their extreme weather study footprints to ensure the selection of appropriate sensitivities.”	This directive is addressed in proposed TPL-008-1 through Requirements R4 and R8. Per Requirement R4 Part 4.1, the responsible entity is obligated to develop and maintain benchmark planning cases that include seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers to represent the System conditions of the selected benchmark temperature events for one of the years in the Long-Term Transmission Planning Horizon. Per Requirement R4 Part 4.2, the responsible entity is obligated to develop and maintain sensitivity cases by changing at least one of the following conditions in the benchmark planning cases: generation, real and reactive forecasted Load, or transfers. In addition, the responsible entities are required to coordinate among adjacent impacted Planning Coordinators and Transmission Planners, and other designated study entities, which an Interconnection. (Requirement R3)
P134. “[W]e directs NERC to require in the new or modified Reliability Standard the use of planning methods that ensure adequate consideration of the broad characteristics of extreme heat and cold weather conditions. We further direct NERC to determine during the standard development process whether probabilistic elements can be incorporated into the new	The Standard Drafting Team discussed probabilistic elements and determined while probabilistic analysis would be a good step forward, it would be better suited for the future as the methodology, process, and tools mature.

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Directive Language	**Consideration of Directives**
or modified Reliability Standard and implemented presently by responsible entities. If NERC identifies probabilistic elements which responsible entities can feasibly implement and that would improve upon existing planning practices, we expect the inclusion of those methods in the proposed Reliability Standard." **P138.** "[W]e direct NERC to identify during the standard development process any probabilistic planning methods that would improve upon existing planning practices, but that NERC deems infeasible to include in the proposed Reliability Standard at this time. If any such methods are identified, NERC shall describe in its petition for approval of the proposed Reliability Standard the barriers preventing the implementation of those probabilistic elements. We intend to use this information to determine whether and what next steps may be warranted to facilitate the use of probabilistic methods in transmission system planning practices."	Probabilistic assessment of generation and transmission facilities for the benchmark planning cases was discussed during the process of drafting the TPL-008-1 standard. However, based on the actual extreme heat and extreme cold events that have occurred, outages for generation and transmission facilities were unique for each of these events. Thus, it was challenging to draw correlation for the outages that occurred for different extreme heat and cold events for different regions and different timeframes. In addition, the data that were available from these events were limited to perform an adequate probabilistic assessment. Due to these reasons, the Standard Drafting Team has decided not to pursue any probabilistic assessment for the current TPL-008-1 standard. This, however, does not preclude future development of probabilistic assessment when having additional data, as well as mature methodology, process and tools that can provide meaningful probabilistic assessment for generation and transmission outages under extreme temperature conditions.
P152. "[W]e direct NERC to require in the new or modified Reliability Standard the development of extreme weather corrective action plans for specified instances when performance standards are not met. In addition, as explained below, we direct NERC to develop certain processes to facilitate interaction and coordination with applicable regulatory authorities or governing bodies responsible for retail electric service as appropriate in implementing a corrective action plan." **P155**: "[T]he Commission is not directing any specific result or content of the corrective action plan."	The directive is addressed in the proposed TPL-008-1 Requirement R9. When the benchmark planning case study results indicate the System is unable to meet performance requirements for P0 and P1 Contingencies, Corrective Action Plans must be developed. Additionally, in accordance with Requirement R9.1, the responsible entities shall make their Corrective Action Plan (CAP) available and solicit feedback from applicable regulatory authorities or governing bodies responsible for retail electric service issues.
P157. "[W]e direct NERC to require in the new or modified Reliability Standard the development of corrective action plans that include mitigation for specified instances where performance requirements for extreme heat and cold events are not met—i.e., when certain studies	The directive is addressed in the proposed TPL-008-1 Requirement R9. When the benchmark planning case study results indicate the system is unable to meet performance requirements for P0 and P1 Contingencies, Corrective Action Plans must be developed.

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conducted under the Standard show that an extreme heat or cold event would result in cascading outages, uncontrolled separation, or instability." **P158**: "[W]e give NERC in this final rule the flexibility to specify the circumstances that require the development of a corrective action plan."	
P165. "[w]e direct NERC to require in the new or modified Reliability Standard that responsible entities share their corrective action plans with, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues."	The directive is addressed in the proposed TPL-008-1 Requirement R9. Requirement R9.1 requires the responsible entities to make their CAP available and solicit feedback from applicable regulatory authorities or governing bodies responsible for retail electric service issues.
P167. "Further, because an important goal of transmission planning is to avoid load shed, any responsible entity that includes non-consequential load loss in its corrective action plan should also identify and share with applicable regulatory authorities or governing bodies responsible for retail electric service alternative corrective actions that would, if approved and implemented, avoid the use of load shedding."	This directive is addressed in proposed TPL-008-1 Requirement R9. As stipulated in Requirement R9.2, when Non-Consequential Load Loss is utilized as an element of a CAP for the Table 1 P1 Contingency, the responsible entity must document the alternative(s) considered, and notify the applicable regulatory authorities or governing bodies responsible for retail electric service issues.
P188. "[W]e direct NERC to submit a new or modified Reliability Standard within 18 months of the date of publication of this final rule in the Federal Register. Further, we direct NERC to propose an implementation timeline for the new or modified Reliability Standard, with implementation beginning no later than 12 months after the effective date of a Commission order approving the proposed Reliability Standard."	The directive is addressed with the publication of TPL-008-1 and will be filed with the regulatory government no later than December 23, 2024, within 18 months of the date Order No. 896 was published in the *Federal Register*. The implementation plan addresses Requirement R1 becoming effective 12 months from the effective date of the Commission order approving the TPL-008-1. In addition, phased-in approaches have been provided for other Requirements needing additional time. See the TPL-008-1 Implementation Plan.
P193. "[W]e direct NERC to establish an implementation timeline for the proposed Reliability Standard. In complying with this directive, NERC will have discretion to develop a phased-in implementation timeline for the different requirements of the proposed Reliability Standard (i.e.,	The implementation plan addresses Requirement R1 becoming effective 12 months from the effective date of the Commission order approving the TPL-008-1. In addition, phased-in approaches have been provided for other

FERC Order 896 Directives	
Directive Language	**Consideration of Directives**
developing benchmark cases, conducting studies, developing corrective action plans). However, this phased-in implementation must begin within 12 months of the effective date of a Commission order approving the proposed Reliability Standard and must include a clear deadline for implementation of all requirements."	Requirements needing additional time. See the TPL-008-1 Implementation Plan.

DRAFT ERO Enterprise Process for TPL-008-1 Benchmark Weather Event Development and Maintenance

Standards Development and Engineering Process Document
July 2024

Background

This Electric Reliability Organization (ERO) Enterprise Process for TPL-008-1[1] Benchmark Weather Event Development and Maintenance addresses how ERO Enterprise staff will develop and maintain a library of benchmark weather events (herein as the Weather Event Library) to be used by Planning Coordinators and Transmission Planners for TPL-008-1 studies. Per Requirement R3 of TPL-008-1 and consistent with directives outlined in FERC Order No. 896[2], Planning Coordinators and Transmission Planners will select and use events from the Weather Event Library to develop their benchmark planning cases.

Purpose

The purpose of this process document is to formalize a repeatable approach to develop and maintain the Weather Event Library. While both the TPL-008-1 study requirements and this process are in the initial stages of development, it is essential that industry is informed of this process and how it will be designed and implemented following the completion of NERC Project 2023-07. This process document outlines an initial set of process objectives and approach but is not considered to be complete at this time. This document will be revised as needed throughout the development of NERC Project 2023-07.

Document Maintenance

NERC will maintain this document to assure it is consistent with acceptable practices and publicly available. This document will be reviewed as it is implemented. Updates will be made by NERC Standards Development and Engineering, as needed, to reflect lessons learned as the process matures. Any substantive changes to this process, supplemental/attached criteria, or other guidance to be used by NERC in developing additional benchmark events, archiving/removing benchmark events, or other modifications to the Weather Event Library, will be reviewed in consultation with NERC Legal, NERC Compliance Assurance, Regional Entity staff, and FERC. Approved substantive revisions to this document will be detailed in the Appendix, broadly communicated to industry, and included as part of informational filings to FERC.

[1] *Link pending final approval of TPL-008-1*
[2] FERC Docket No. RM22-10-000; Order No. 896; https://www.ferc.gov/media/e-1-rm22-10-000; June 15, 2023

Definitions

Refer to the NERC Glossary of Terms[3] for the below capitalized terms used in this process.

- Affected Regional Entity (ARE)
- Compliance Enforcement Authority (CEA)
- Coordinated Oversight
- Extreme Temperature Assessment (ETA)
- Lead Regional Entity (LRE)
- Multi-Region Registered Entity (MRRE)

Process Overview

The following is a five-year iterative process coinciding with Planning Coordinator and Transmission Planner implementation of TPL-008-1. As TPL-008-1 and associated benchmark event(s) will be submitted to FERC in December 2024, the first iteration of this process will cover five years (2025—2029).

- December 2024
  - Weather Event Library developed and ready to go live for industry.
  - Benchmark Events, for the first five-years required per the TPL-008-1 Reliability Standard, completed and uploaded to the Weather Event Library.
- Year One (2025):
  - ERO to provide Weather Event Library training and how to request approval for entity-created benchmark events.
  - ERO to engage with industry subject matter experts (SMEs), Planning Coordinators, research labs, and trade organizations, and NERC technical committees on additional and updated criteria for developing benchmark events.
- Year Two (2026):
  - ERO to initiate review of benchmark event criteria, identify any changes needed, and incorporate feedback from year one.
  - ERO to deliver a webinar on updated criteria for developing benchmark events.
- Year Three (2027):
  - ERO to develop new benchmark events[4] based on updated criteria in year two.
  - ERO to update the Weather Event Library with updated benchmark events.
  - ERO to review any PC submitted benchmark events and determine approval.

[3] NERC Glossary of Terms: Glossary_of_Terms.pdf (nerc.com)
[4] Note: This is for the second iteration of benchmark events being developed.

   - If approved, will be added to the Weather Event Library.
   - If not approved, a response will be submitted to the entity explaining how the submittal did not follow the process or sufficiently meet criteria as outlined in the process below.

- Year Four (2028):
  - ERO to review any PC submitted benchmark events and determine approval.
    - If approved, will be added to the Weather Event Library.
    - If not approved, a response will be submitted to the entity.
- Year Five (2029):
  - ERO to File informational filing with FERC.
  - ERO to conduct review of this process and make necessary revisions based on lessons-learned and feedback (e.g., CMEP feedback loops, FERC, SMEs)
  - ERO to provide training on benchmark event process and changes to the Weather Event Library.

Year 1
- Deliver Weather Event Library Training
- Develop training and guidance for planning case development

Year 2
- Review and modify benchmark event criteria
- Informational session on updated criteria

Year 3
- Update library with new/removed benchmark events
- (optional) Planning Coordinator due date to submit benchmark events based on different criteria for ERO approval

Year4
- Informational filing to FERC for any change to criteria and modifications to Weather Events Library

Year 5
- Review process and revise based on lessons learned and other feedback loops
- Update Weather Event Library training

Criteria in Attachment B

Criteria for benchmark events to be drafted.

Submittal Process for Entity-Created Benchmark Events

Step 1 – Registered Entity Submittal

If a Planning Coordinator or group of Planning Coordinators determine that a benchmark event, other than one provided in the Weather Event Library, would be a more accurate representation of extreme hot or extreme cold events, then the entity will contact the ERO to submit the necessary information.

The entity shall submit the data requested in Attachment A: Benchmark Event Entity Submittal Form to a secure site that will be established by the ERO. The ERO will acknowledge receipt of the submission in writing within 15 days and review that all information requested in the Entity Submittal Template is provided in the entity's submittal. If the submittal is incomplete, the ERO will inform the entity to resubmit, and the process will restart. The ERO will notify NERC Compliance Assurance when acknowledging receipt of the submission.

The entity submitting the request may withdraw the request any time prior to the ERO communicating the final determination.

Step 2 – ERO Enterprise Review

NERC will form an ERO Enterprise Review Panel (review panel) comprised of not less than four (4) total individuals from the applicable Regional Entity(s) and NERC. The review panel will perform a review of the submitted information and develop a preliminary determination of whether the submitted information is complete and that the usage of different, or differently applied, criteria does not conflict with the technical rationale provided. This review panel will complete the review within 90 days of its acknowledgement of the receipt of submission. During its review, the review panel may work through the ERO to request additional information from the entity submitting the request.

If the review panel determines it will be unable to complete its review within the established timeframe, the review panel, based on consultation with the managers of NERC Compliance Assurance and NERC Power System Analysis, will establish a revised timeline for completing its review. The revised timeline for review and determination will be provided to the entity by the ERO.

Step 3 – ERO Determination

The review panel will present to the NERC Vice President of Engineering and Standards for approval of the preliminary determination as the ERO determination. The review panel will communicate the ERO determination and rationale to NERC Compliance Assurance and the applicable Regional Entities.

The ERO will then communicate the ERO determination in writing to the PC(s) along with the rationale for the determination within 30 days of NERC's Vice President Engineering and Standards receiving the review panel's preliminary determination.

Step 1. (15-day process)

Entity submit Attachment A: Benchmark Event Entity Submittal Form To ERO via secure site.

ERO has 15 days to acknowledge receipt of submission .

Entity may withdraw request at anytime prior to ERO communicating final determination.

Step 2. (90-day process)

ERO review panel will perform a review of the submitted information and develop a preliminary determination of whether the submitted information is complete and that the usage of different, or differently applied, criteria does not conflict with the technical rationale provided

Step 3. (30-day process)

review panel will present to the NERC Vice President of Engineering and Standards for approval of the preliminary determination as the ERO determination.

communicate the ERO determination in writing to the entity along with the rationale for the determination.

Attachment A: Benchmark Event Entity Submittal Form

Per the process above, a registered Planning Coordinator, or group of Planning Coordinators, seeking to include additional extreme temperature weather events to the NERC Weather Event Library must provide the following information to NERC. Answers to questions should be narratives with summarized technical rationales that are supported through documentation. Submittal of this form does not guarantee approval of the weather event(s) to the Weather Event Library. Per the process above, NERC will review the submittal form and provide a response either approving the event(s), rejecting the event(s), or requesting additional information to be provided.

Entity Information	
Entity name(s):	
NCR#:	
Primary entity contact name and information:	
Request submittal date:	
Other Planning Coordinators impacted by the proposed extreme temperature weather event(s)	

Benchmark Event Information	
Development Criteria: **1. What criteria was applied** **2. What was different than posted NERC criteria, if any.** **3. Technically substantive rationale/study for why the event(s) are more appropriate**	

Coordination ▪ **If this event is submitted on behalf of more than one PC, please provide details on the coordination conducted. Otherwise, respond "N/A".**	
Additional information an entity wishes to provide regarding benchmark event being submitted.	

Attachment B: Criteria used to develop the benchmark events

Criteria

Criteria for benchmark events to be drafted.

TPL-008-1 ERO Enterprise Benchmark Weather Event Development and Maintenance Process Document Version History

Version	Date	Owner	Change tracking
1	TBD	Standards Staff	Initial Version

Extreme Heat and Cold Weather Benchmark Events Example

July 2024

Introduction

This extreme heat and cold weather benchmark events document provides industry with information regarding the project scope, high level criteria, and visual maps used to develop benchmark events. Historical meteorological data over the past 43 years (1980-2022) has been provided for the examples listed below.

Additional work is needed to develop planning cases from weather event data. NERC is only providing the weather event data within the ERO library and will continue to work with industry to develop guidance and promote training to developing planning cases.

This example is providing industry for awareness during the Standard Development process. Information herein is accurate to the date of this posting. Additional events will be developed to complete the initial Weather Event Library.

Project Scoping

The below table shows what is included and not included for the first iteration of the benchmark events.

	Included for First Iteration	Not Included for First Iteration
Scope of Weather Events	Extreme heat and cold temperature data	Other weather events (renewable lulls, hydro droughts, wildfires, hurricanes, etc.)
Temporal Coverage	Long historical record of weather data.	Only a few years of recent observations.
Geographic Coverage	Data for the entire continent, specifically the U.S. and Canada	Unique datasets for specific zones.
Data Consistency and Synchronization	Correlated, consistent, and time-synchronized data.	Stitched-together datasets comprising different events and/or datasets.
Future Projections	Historical weather data	Climate projections of future weather

Screening for Extreme Heat and Extreme Cold Events

Multi-day Weather Events

Calculated three-day rolling average temperatures for both extreme heat and extreme cold to identify multi-day periods of extreme heat/cold.

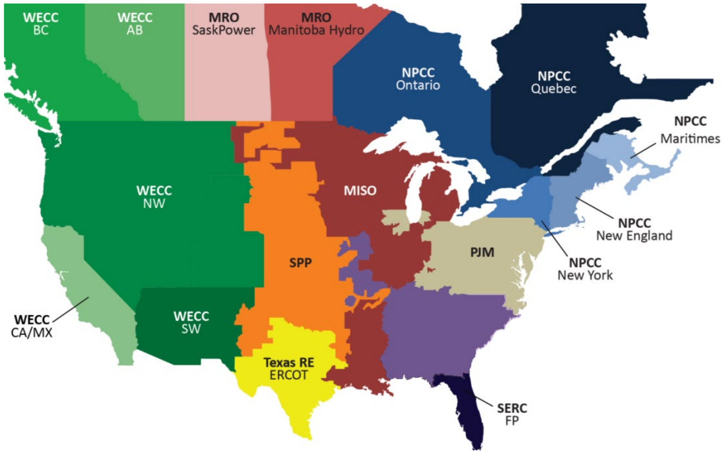
Wide-area Assessment

- Aggregated U.S. and Canada into 11 zones and evaluated average temperatures across wide-areas rather than smaller planning coordinators
- Evaluated the top 40 extreme heat and cold three-day periods for each zone and prioritized events that occurred across multiple zones during the same event
- Ensured each zone had at least its top two worst events covered

Wide-area Boundaries

Adapted from the NERC Assessment Areas[1]

- SERC: combined NERC Assessment areas of SERC-East, SERC-Central, and SERC-Southeast into a single zone based on climate similarities.
- Florida has significantly different weather patterns, which warrant separate treatment.
- WECC-NW, WECC-SW, SERC, and SERC-FP were aggregated



[1] NERC Assessment Areas.png (1590×661)

Extreme Cold Events

Rank of events by average three-day average min temperature, 1980-2022

Event Type	Year	Month	WECC NW	CA / MX	WECC SW	ERCOT	SPP	MISO	SERC	FRCC	PJM	NYISO	ISONE	LOWEST RANK	TOP 5 COUNT	SHORTLIST	PRIORITY EVENTS
Cold Event	1981	1							12	4	9	2	1	1	3	1	
Cold Event	1983	12	3			3	2	4	2	3	3			2	7	1	Widespread cold, worst case
Cold Event	1984	1	13			14	13	3	16		2	3		2	3	1	
Cold Event	1985	1				11	10	10	1	1	4			1	3	1	Widespread cold
Cold Event	1989	2	2	2			12			13				2	2	1	
Cold Event	1989	12				1	1	5	3	2	5			1	6	1	
Cold Event	1990	12	1	1	1		16							1	3	1	Western Cold
Cold Event	1994	1						2	7		1	1	3	1	4	1	Eastern Cold
Cold Event	1996	2	11			5	3	1	5		7	16		1	4	1	
Cold Event	2004	1	8									8	2	2	1	1	
Cold Event	2011	2			2	4	11	13						2	2	1	2011 Southwestern Event
Cold Event	2021	2				2	4	14						2	2	1	Winter Storm Uri
Cold Event	2022	12				8	9		6	11				6	0	1	Winter Storm Elliott
Total Cold Events Selected			**6**	**2**	**2**	**8**	**10**	**8**	**8**	**6**	**7**	**5**	**3**			**13**	

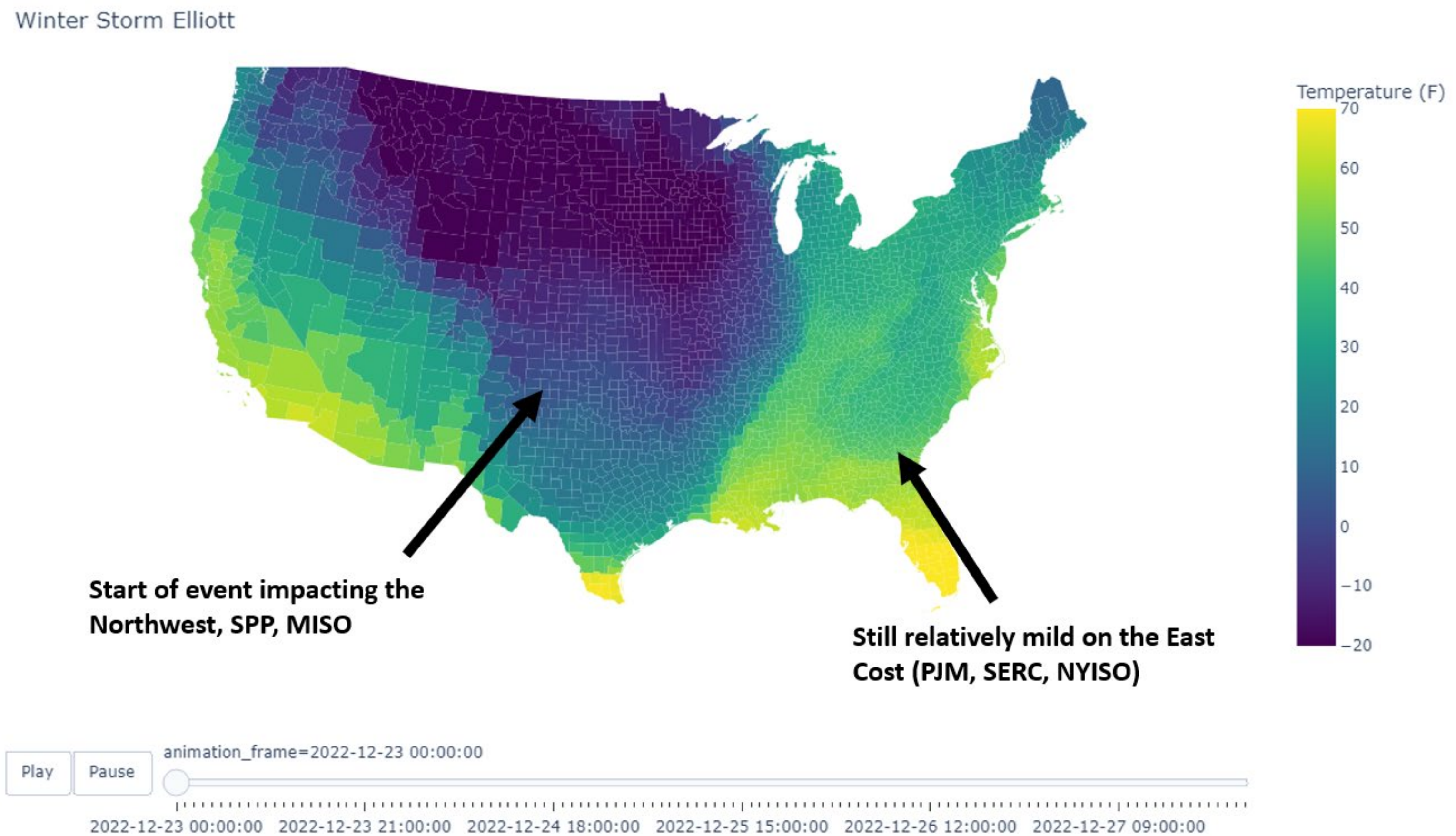
Extreme Heat Events

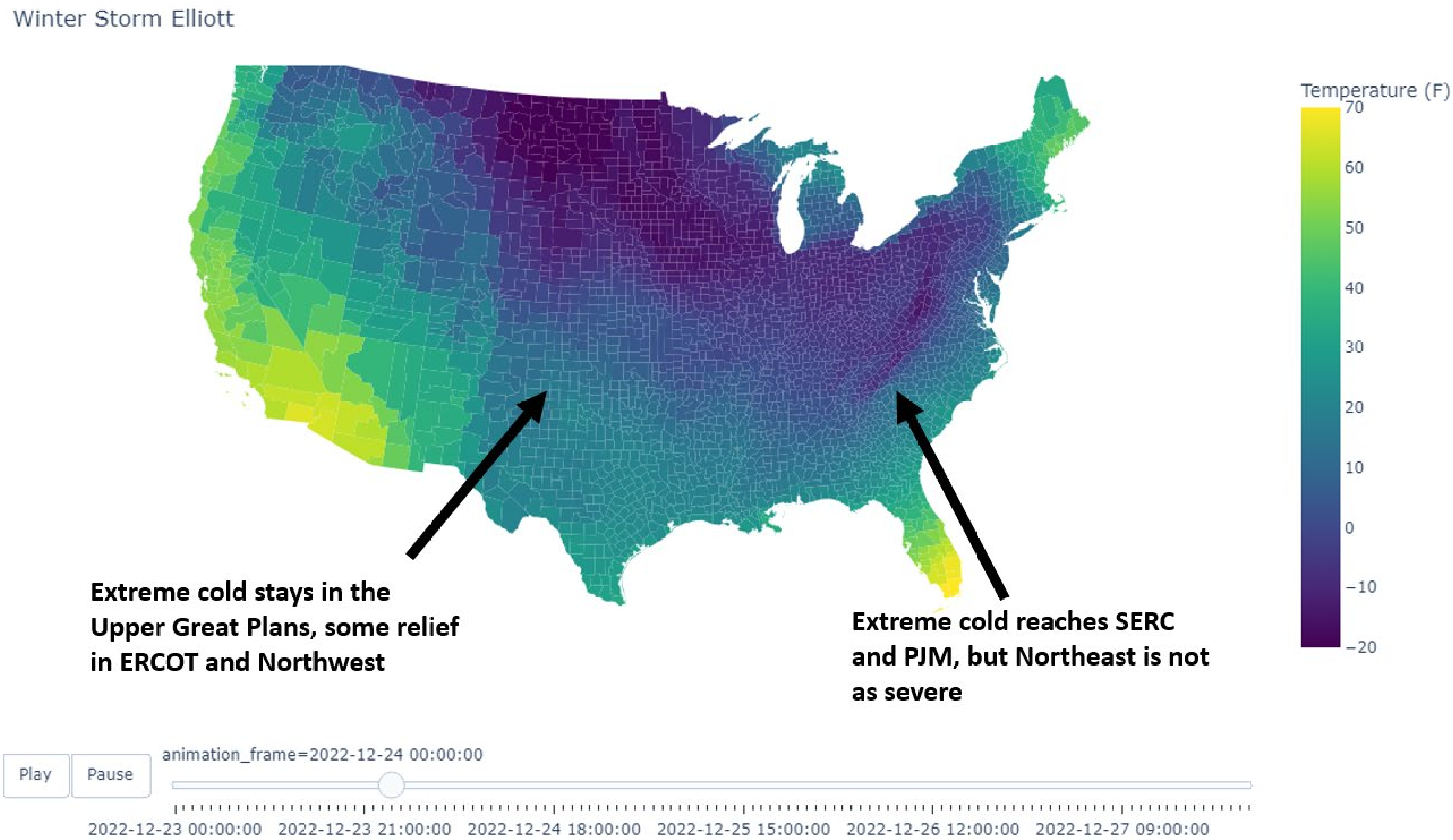
Rank of events by average three-day average min temperature, 1980-2022

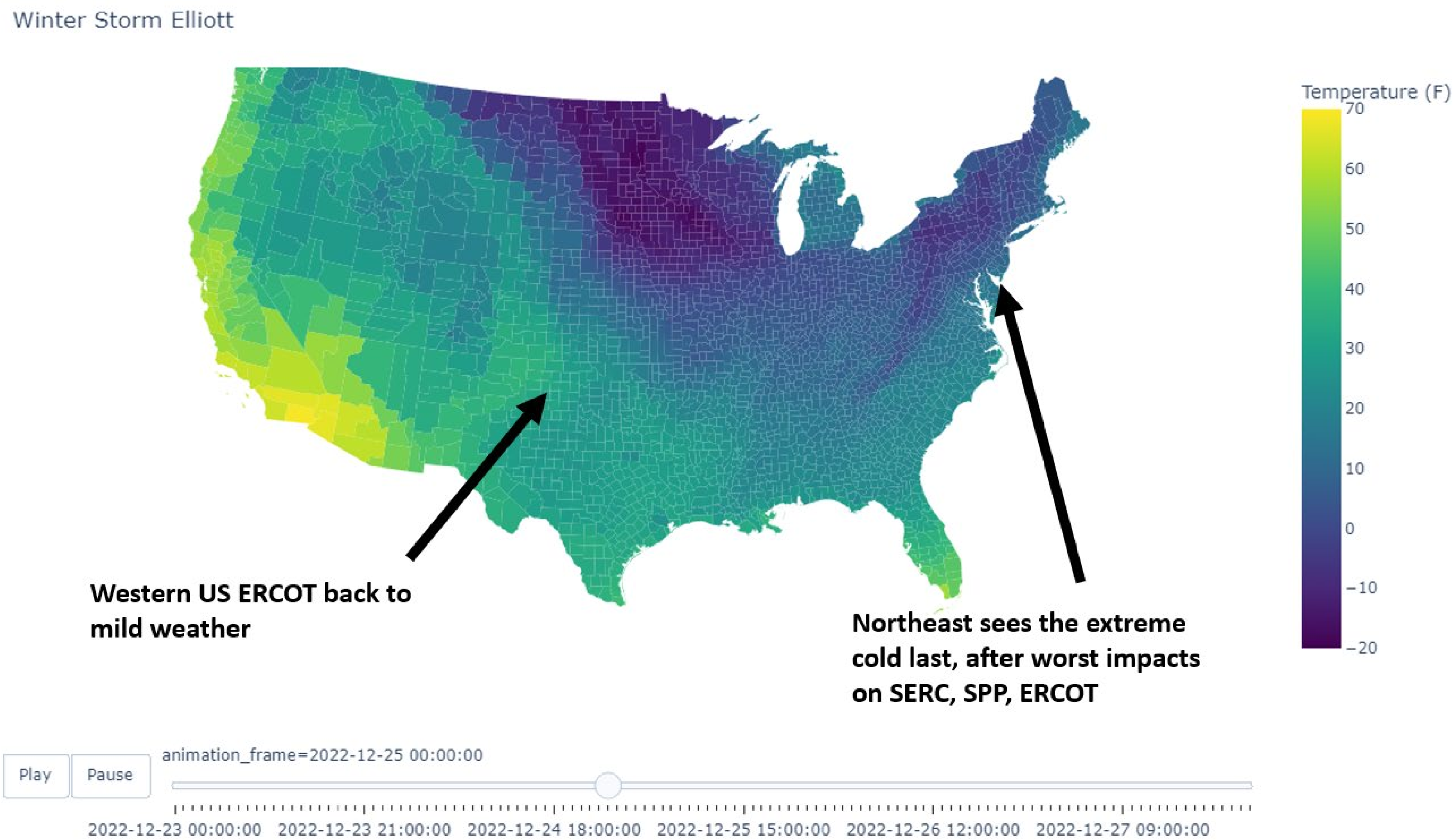
Event Type	Year	Month	WECC NW	CA / MX	WECC SW	ERCOT	SPP	MISO	SERC	FRCC	PJM	NYISO	ISONE	LOWEST RANK	TOP 5 COUNT	SHORTLIST	PRIORITY EVENTS
Heat Event	1980	6				2								2	1	1	
Heat Event	1981	6								3				3	1	1	
Heat Event	1988	8						1	15		4	7	16	1	2	1	
Heat Event	1991	7									12	9	1	1	1	1	
Heat Event	1995	7			1	8		9			3	8	13	1	2	1	Worst case Southwest
Heat Event	1998	6								1				1	1	1	
Heat Event	1999	7						4	6		2	1	6	1	3	1	
Heat Event	2000	9				1								1	1	1	
Heat Event	2002	7	7								15	13	2	2	1	1	
Heat Event	2006	7	2	3			3	7						2	3	1	
Heat Event	2006	8					12	3			5	4	4	3	4	1	Northeast Heatwave
Heat Event	2007	8							2					2	1	1	
Heat Event	2011	7					8	11	14		6	2	3	2	2	1	Eastern Interconnect Heatwave
Heat Event	2011	8				4	2		5					2	3	1	Central Plains
Heat Event	2012	7					4	2	1		1			1	4	1	Widespread heat event
Heat Event	2012	8					1	6						1	1	1	
Heat Event	2017	6			2									2	1	1	
Heat Event	2020	8	1	5	13									1	2	1	Western Heat Dome 2020
Heat Event	2022	9	10	2										2	1	1	Western Heat Dome 2022
Total Heat Events Selected			**4**	**3**	**3**	**4**	**6**	**8**	**6**	**2**	**8**	**7**	**7**			**19**	

Winter Storm Elliott Examples

Winter storm Elliott provides entities with an extreme event example showing hour by hour data. This will allow entities the ability to locate when their zone was most vulnerable and to gather data needed when building out its benchmark planning cases. The following figures represent various instances of winter storm Elliott's temperature.




Winter Storm Elliott
Temperature (F)
70
60
50
40
30
20
10
0
−10
−20
Extreme cold stays in the Upper Great Plans, some relief in ERCOT and Northwest
Extreme cold reaches SERC and PJM, but Northeast is not as severe
Play
Pause
animation_frame=2022-12-24 00:00:00
2022-12-23 00:00:00
2022-12-23 21:00:00
2022-12-24 18:00:00
2022-12-25 15:00:00
2022-12-26 12:00:00
2022-12-27 09:00:00


Winter Storm Elliott
Temperature (F)
70
60
50
40
30
20
10
0
−10
−20
Western US ERCOT back to mild weather
Northeast sees the extreme cold last, after worst impacts on SERC, SPP, ERCOT
Play
Pause
animation_frame=2022-12-25 00:00:00
2022-12-23 00:00:00
2022-12-23 21:00:00
2022-12-24 18:00:00
2022-12-25 15:00:00
2022-12-26 12:00:00
2022-12-27 09:00:00

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2023-07 Transmission Planning Performance Requirements for Extreme Weather

Formal Comment Period Open through August 22, 2024

Now Available

A 38-day formal comment period for draft two of **TPL-008-1 – Transmission System Planning Performance Requirements for Extreme Temperature Events** is open through **8 p.m. Eastern, Thursday, August 22, 2024**.

The standard drafting team's considerations of the responses received from the previous comment period are reflected in this draft of the standard.

Reminder Regarding Corporate RBB Memberships
Under the NERC Rules of Procedure, each entity and its affiliates is collectively permitted one voting membership per Registered Ballot Body Segment. Each entity that undergoes a change in corporate structure (such as a merger or acquisition) that results in the entity or affiliated entities having more than the one permitted representative in a particular Segment must withdraw the duplicate membership(s) prior to joining new ballot pools or voting on anything as part of an existing ballot pool. Contact ballotadmin@nerc.net to assist with the removal of any duplicate registrations.

Commenting
Use the Standards Balloting and Commenting System (SBS) to submit comments. An unofficial Word version of the comment form is posted on the project page.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps
Additional ballots for the standard and implementation plan, as well as a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **August 13-22, 2024**.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Jordan Mallory (via email) or at 404-479-7358. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify "Project 2023-07 Transmission Planning Performance Requirements for Extreme Weather observer list" in the Description Box.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comment Report

Project Name:	2023-07 Transmission Planning Performance Requirements for Extreme Weather | Draft 2
Comment Period Start Date:	7/16/2024
Comment Period End Date:	8/22/2024
Associated Ballots:	2023-07 Transmission Planning Performance Requirements for Extreme Weather Implementation Plan AB 2 OT 2023-07 Transmission Planning Performance Requirements for Extreme Weather TPL-008-1 AB 2 ST

There were 74 sets of responses, including comments from approximately 191 different people from approximately 118 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. The drafting team (DT) updated the Requirements in chronological order. Do you agree with the proposed TPL-008-1 Reliability Standard Requirement layout? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

2. The DT updated Requirements R1 – R2 based on comments received. Do you agree with the updated proposed TPL-008-1 Reliability Standard Requirements R1-R2? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

3. The DT updated Requirements R3 – R5 based on comments received. Do you agree with the updated proposed TPL-008-1 Reliability Standard Requirements R3-R5? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

4. The DT updated Requirements R6 – R8 based on comments received. Do you agree with the updated proposed TPL-008-1 Reliability Standard Requirements R6-R8? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

5. The DT updated Requirement R9 based on comments received. Do you agree with the updated proposed TPL-008-1 Reliability Standard Requirement R9? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

6. The DT updated Requirement R10 based on comments received. Do you agree with the updated proposed TPL-008-1 Reliability Standard Requirement R10? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

7. The DT split out Table 1 into parts for better readability. Do you agree with the updated layout of Table 1? If you do not agree, please provide your recommendation and technical justification.

8. The DT believes proposed modifications in TPL-008-1 provide entities with flexibility to meet the reliability objectives in a cost-effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost-effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

9. Provide any additional comments for the standard drafting team to consider, including the provided technical rationale document, if desired.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
MRO	Anna Martinson	1,2,3,4,5,6	MRO	MRO Group	Shonda McCain	Omaha Public Power District (OPPD)	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jamison Cawley	Nebraska Public Power District	1,3,5	MRO
					Jay Sethi	Manitoba Hydro (MH)	1,3,5,6	MRO
					Husam Al-Hadidi	Manitoba Hydro (System Preformance)	1,3,5,6	MRO
					Kimberly Bentley	Western Area Power Adminstration	1,6	MRO
					Jaimin Patal	Saskatchewan Power Coporation (SPC)	1	MRO
					George Brown	Pattern Operators LP	5	MRO
					Larry Heckert	Alliant Energy (ALTE)	4	MRO
					Terry Harbour	MidAmerican Energy Company (MEC)	1,3	MRO
					Dane Rogers	Oklahoma Gas and Electric (OG&E)	1,3,5,6	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Ayotte	ITC Holdings	1	MRO
					Andrew Coffelt	Board of Public Utilities-Kansas (BPU)	1,3,5,6	MRO
					Peter Brown	Invenergy	5,6	MRO

					Angela Wheat	Southwestern Power Administration	1	MRO
					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Joshua Phillips	Southwest Power Pool	2	MRO
					Patrick Tuttle	Oklahoma Municipal Power Authority	4,5	MRO
Dominion - Dominion Resources, Inc.	Barbara Marion	5		Dominion	Victoria Crider	Dominion	3	NA - Not Applicable
					Barbara Marion	Dominion	5	NA - Not Applicable
					Sean Bodkin	Dominion	6	NA - Not Applicable
					Steven Belle	Dominion	1	NA - Not Applicable
Midcontinent ISO, Inc.	Bobbi Welch	2	MRO,RF,SERC	ISO/RTO Council Standards Review Committee (SRC) Project 2023-07 TPL-008-1 Draft #2	Ali Miremadi	CAISO	2	WECC
					Kennedy Meier	Electric Reliability Council of Texas, Inc.	2	Texas RE
					Helen Lainis	IESO	2	NPCC
					Keith Jonassen	ISO-NE	2	NPCC
					Bobbi Welch	MISO	2	RF
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Charles Yeung	SPP	2	MRO
					Elizabeth Davis	PJM	2	RF
Western Power Pool	Chelsea Loomis	NA - Not Applicable	WECC	WPP Consortium of Engineers	Guiha Wang	BC Hydro	NA - Not Applicable	WECC
					Berhanu Tesema	BPA	NA - Not Applicable	WECC
					Christopher Lamb	CHPD	NA - Not Applicable	WECC
					Laryn Brinkman	CHPD	NA - Not Applicable	WECC
					Zach Zornes	CHPD	NA - Not Applicable	WECC

					Stephen Longmuir	IPCO	NA - Not Applicable	WECC
					Jessica Boatwright	NWMT	NA - Not Applicable	WECC
					Daniel Baye	PAC	NA - Not Applicable	WECC
					Rachit Aurora	PSE	NA - Not Applicable	WECC
					Nima Miri	SCL	NA - Not Applicable	WECC
					Rob Jones	SCL	NA - Not Applicable	WECC
					Ken Che	SNPD	NA - Not Applicable	WECC
					Tuan Dang	SNPD	NA - Not Applicable	WECC
					Ben Hutchins	WPP	NA - Not Applicable	WECC
Santee Cooper	Chris Wagner	1		Santee Cooper	Rene' Free	Santee Cooper	1,3,5,6	SERC
					Christie Pope	Santee Cooper	1,3,5,6	SERC
Public Utility District No. 1 of Chelan County	Joyce Gundry	3		CHPD	Rebecca Zahler	Public Utility District No. 1 of Chelan County	5	WECC
					Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC
					Diane Landry	Public Utility District No. 1 of Chelan County	1	WECC
					Robert Witham	Public Utility District No. 1 of Chelan County	6	WECC
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF

					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	RF
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
					Leslie Burke	Southern Company - Southern Company Generation	5	SERC
Black Hills Corporation	Rachel Schuldt	6		Black Hills Corporation - All Segments	Micah Runner	Black Hills Corporation	1	WECC
					Josh Combs	Black Hills Corporation	3	WECC
					Rachel Schuldt	Black Hills Corporation	6	WECC
					Carly Miller	Black Hills Corporation	5	WECC
					Sheila Suurmeier	Black Hills Corporation	5	WECC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC

					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
					Randy Buswell	Vermont Electric Power Company	1	NPCC
					James Grant	NYISO	2	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					David Burke	Orange and Rockland	3	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
					David Kwan	Ontario Power Generation	4	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
					Sean Cavote	PSEG	4	NPCC
					Jason Chandler	Con Edison	5	NPCC
					Tracy MacNicoll	Utility Services	5	NPCC
					Shivaz Chopra	New York Power Authority	6	NPCC
					Vijay Puran	New York State Department of Public Service	6	NPCC
					David Kiguel	Independent	7	NPCC
					Joel Charlebois	AESI	7	NPCC

					Joshua London	Eversource Energy	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC
					Joel Charlebois	AESI	7	NPCC
					John Hastings	National Grid	1	NPCC
					Erin Wilson	NB Power	1	NPCC
					James Grant	NYISO	2	NPCC
					Michael Couchesne	ISO-NE	2	NPCC
					Kurtis Chong	IESO	2	NPCC
					Michele Pagano	Con Edison	4	NPCC
					Bendong Sun	Bruce Power	4	NPCC
					Carvers Powers	Utility Services	5	NPCC
					Wes Yeomans	NYSRC	7	NPCC
					Chantal Mazza	Hydro Quebec	1	NPCC
					Nicolas Turcotte	Hydro Quebec	2	NPCC
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Victoria Crider	Dominion Energy	3	NA - Not Applicable
					Sean Bodkin	Dominion Energy	6	NA - Not Applicable
					Steven Belle	Dominion Energy	1	NA - Not Applicable
					Barbara Marion	Dominion Energy	5	NA - Not Applicable
Shannon Mickens	Shannon Mickens		MRO,SPP RE,WECC	SPP RTO	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Mia Wilson	Southwest Power Pool Inc.	2	MRO
					Eddie Watson	Southwest Power Pool Inc.	2	MRO
					Erin Cullum	Southwest Power Pool Inc.	2	MRO
					Jonathan Hayes	Southwest Power Pool Inc.	2	MRO

					Jeff McDiarmid	Southwest Power Pool Inc.	2	MRO
					Scott Jordan	Southwest Power Pool Inc	2	MRO
					Lottie Jones	Southwest Power Pool Inc.	2	MRO
					Sherri Maxey	Southwest Power Pool Inc.	2	MRO
					Josh Phillips	Southwest Power Pool Inc.	2	MRO
Western Electricity Coordinating Council	Steven Rueckert	10		WECC	Steve Rueckert	WECC	10	WECC
					Curtis Crews	WECC	10	WECC
Tim Kelley	Tim Kelley		WECC	SMUD and BANC	Nicole Looney	Sacramento Municipal Utility District	3	WECC
					Charles Norton	Sacramento Municipal Utility District	6	WECC
					Wei Shao	Sacramento Municipal Utility District	1	WECC
					Foung Mua	Sacramento Municipal Utility District	4	WECC
					Nicole Goi	Sacramento Municipal Utility District	5	WECC
					Kevin Smith	Balancing Authority of Northern California	1	WECC

1. The drafting team (DT) updated the Requirements in chronological order. Do you agree with the proposed TPL-008-1 Reliability Standard Requirement layout? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Long Island Power Authority	
Answer	Yes
Document Name	(if an attachment is provided by submitter)
Comment	
Submitter's comments	
Likes 0	# of other submitters who agree with these comments
Dislikes 0	# of other submitters who disagree with these comments
Response	
(Drafting team's response to submitter's comments)	

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	
The MRO NERC Standards Review Forum (NSRF) recommends the following changes to the order of the requirements: · R8 should be moved up. The standard needing to be met once every five years should be right up front. · R2 and R4 need to be together as they describe the cases. They should also clearly denote both power flow and dynamics benchmark and sensitivity cases need to be constructed. Please see the process flow proposed in Attachment A to these comments which illustrates a logical flow.	
Likes 1	Scott Brame, N/A, Brame Scott
Dislikes 0	
Response	

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	No
Document Name	
Comment	

Evergy supports and incorporates by reference the comments of the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 1	
Likes 0	
Dislikes 0	
Response	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
ATC supports the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Tri-State supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO	
Answer	No
Document Name	
Comment	

It's unclear to SPP how the "chronological order" helps the success of the proposed standard to move forward. Industry has identified too many unresolved issues with the proposed requirements to make any type of determination. For example, the drafting team has not provided any resolution or vision on how the industry will use the NERC (ERO) approved library since it has not been created at this time.

Moreover, the drafting team has not provided any tangible solutions/details in reference to joint coordination with neighboring entities as well as appropriate data collection via MOD-032 to build quality models to conduct this assessment and produce quality results.

SPP recommends that the drafting team provides clarity/tangible solutions via technical documentation to help industry get a better understanding on NERC's expectations for this standard.

Likes 0	
Dislikes 0	

Response

Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford

Answer	No
Document Name	

Comment

The chronological order is immaterial at this time. The issues outlined in the subsequent comments need to be addressed before the chronological order of requirements can be determined.

Likes 0	
Dislikes 0	

Response

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	

Comment

CenterPoint Energy Houston Electric, LLC (CEHE) disagrees with the proposed standard overall and definition of an "Extreme Temperature Assessment". Clarification on what "extreme heat" and "extreme cold temperature" and details on the meaning of benchmark events are needed.

CEHE has identified a few issues related to the Electric Reliability Organization (ERO) library. First, there is little information on the overall reliability benefit of the standard and details of exactly what the library will contain, how it will get populated, or which forms of data will be kept. Second, there is no requirement that authorizes the upkeep and ongoing maintenance of said library. Third, using one extreme heat benchmark, and one extreme cold benchmark, as approved by the ERO, ignores local extreme temperature events, and may exclude entities who may experience micro weather events. Extreme Temperature Assessments should include regional and significant local events. It is not clear who in the ERO approves and maintains a library of benchmarked events, or how this process is done for transparency. It is difficult to support or agree with the proposed language if the ERO has not made the library available and defined "Extreme Temperature Assessment" criteria or defined benchmark event criteria. CEHE would like clarification on the benchmark events, and further clarification on criteria to determine this responsibility. CEHE believes the PC should assume the responsibility to provide these system wide studies, since TPs already provide BPS data to the PC. The approved library of benchmark events is currently not available to Transmission Planners (TPs), therefore, CEHE cannot support any of the proposed requirements as written.

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	Yes
Document Name	

Comment

None.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	Yes
Document Name	

Comment

FirstEnergy has no concerns with the order of the requirements.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	Yes
Document Name	

Comment

Exelon agrees with the proposed TPL-008-1 Reliability Standard Requirement layout.	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation has no concerns with the updated chronological order of the requirements.	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	Yes
Document Name	
Comment	
NextEra is not concerned with the order of the requirements.	

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	Yes
Document Name	

Comment

EEI is not concerned with the order of the requirements.

Likes 0	
Dislikes 0	

Response

Selene Willis - Edison International - Southern California Edison Company - 5

Answer	Yes
Document Name	

Comment

Please see comments from EEI

Likes 0	
Dislikes 0	

Response

Greg Sorenson - Greg Sorenson On Behalf of: Tyler Schwendiman, ReliabilityFirst , 10; - Greg Sorenson

Answer	Yes
Document Name	

Comment

Our comments still haven’t been addressed. “Extreme heat and extreme cold temperatures hasn’t been defined.” We would prefer to see some percentile-based definition or other quantifiable requirement.

Likes 0	
Dislikes 0	

Response	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon agrees with the proposed TPL-008-1 Reliability Standard Requirement layout.	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
While ISO-NE believes that the Standard as written includes the requirements needed, there are areas in which the Standard Requirements could be combined or moved around, such as moving R8 earlier as a requirement describing how often a process should be completed is typically included as early as possible within the Standard. Recommendation: Make R8, R2, and adjusting the rest accordingly. ISO-NE recommends that the SDT review areas where Requirements could be combined to simplify or clarify the flow of requirements. TPL-007 is an example of how out of order requirements can confuse the industry, which required a flowchart in the technical rationale to illustrate the order in which requirements are performed.	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	

ITC does not have any concerns with the order of the requirements.

Likes 0	
Dislikes 0	

Response

Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle

Answer	Yes
Document Name	

Comment

PGAE agrees with the chronological order of the proposed TPL-008-1.

Likes 0	
Dislikes 0	

Response

Robert Blackney - Edison International - Southern California Edison Company - 1

Answer	Yes
Document Name	

Comment

See comments submitted by Edison Electric Institute

Likes 0	
Dislikes 0	

Response

Chantal Mazza - Chantal Mazza On Behalf of: Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza

Answer	Yes
Document Name	

Comment

Likes 0	

Dislikes 0	
Response	
Jeffrey Streifling - NB Power Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
Likes 1	Snohomish County PUD No. 1, 3, Chaney Holly
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chelsea Loomis - Western Power Pool - NA - Not Applicable - WECC, Group Name WPP Consortium of Engineers	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Srikanth Chennupati - Entergy - Entergy Services, Inc. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lidija Efremova - Lidija Efremova On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Lidija Efremova	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Fon Hiew - NB Power Corporation - New Brunswick Power Transmission Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Zahid Qayyum - New York Power Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Broc Bruton - Broc Bruton On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Broc Bruton	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Jones - Seattle City Light - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Barbara Marion - Dominion - Dominion Resources, Inc. - 5, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Junji Yamaguchi - Hydro-Quebec (HQ) - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Helen Lainis - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michele Tondalo - United Illuminating Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Matt Lewis - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michele Shafer - New York State Electric & Gas (NYSEG) - 6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Rebika Yitna - Rebika Yitna On Behalf of: David Weekley, MEAG Power, 3, 1; Roger Brand, MEAG Power, 3, 1; - Rebika Yitna	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC) Project 2023-07 TPL-008-1 Draft #2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Apollonia Gonzales - PNM Resources - Public Service Company of New Mexico - 1,3,5 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

John Brewer - National Energy Technology Laboratory - 9 - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Usama Tahir - Seminole Electric Cooperative, Inc. - 3

Answer	
Document Name	

Comment

No comment

Likes 0	
Dislikes 0	

Response

Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis

Answer	
Document Name	

Comment

PJM recommends the following changes to the order of the requirements:

R8 should be moved up. The standard needing to be met once every five years should be right up front.

R2 and R4 need to be together as they describe the cases. They should also clearly denote that both power flow and dynamics benchmark and sensitivity cases need to be constructed.

Likes 0	
Dislikes 0	

Response

2. The DT updated Requirements R1 – R2 based on comments received. Do you agree with the updated proposed TPL-008-1 Reliability Standard Requirements R1-R2? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Long Island Power Authority	
Answer	No
Document Name	(if an attachment is provided by submitter)
Comment	

The text of Requirement #2 mentions "benchmark library, approved and maintained by the Electric Reliability Organization (ERO)".

Similar to Attachment 1 of TPL-007-4, we recommend that the final version of the standard include an attachment that contains details of the extreme heat and extreme cold benchmark events, or at least some mention of the public facing library (site) to be created by Q4 2024 (as mentioned in the TPL-008 webinar in July 2024) and maintained by NERC. Ideally, stakeholders should have the opportunity to review the list of events and understand how they apply to their region, and what assessments they would need to conduct ahead of being asked to approve this standard.

Likes 0	# of other submitters who agree with these comments
Dislikes 0	# of other submitters who disagree with these comments
Response	
(Drafting team's response to submitter's comments)	

John Brewer - National Energy Technology Laboratory - 9 - NA - Not Applicable

Answer	No
Document Name	
Comment	

(R1) No issue.

(R2) R2 requirements refer to the benchmark library, approved and maintained by the ERO. However, Draft of ERO Enterprise Process for TPL-008-1 Benchmark Weather Event Development and Maintenance (July 2004) states "ERO Enterprise staff will develop and maintain a library of benchmark weather events (herein as the Weather Event Library) to be used by Planning Coordinators and Transmission Planners for TPL-008-1 studies." Consider aligning nomenclature "benchmark library" and "Weather Event Library" in these two documents so there is no confusion as documents advance.

(R2) R2 states that each responsible entity shell select extreme events from the library; however, it does not specify should they choose from the benchmark events(s) that NERC will submit to FERC in December 2024 (and every five years after that, e.g., 2029, 2034), or any event from the NERC's "live" Weather Event

Library that will go through updated from 2025 – 2029 as described in the Draft ERO Enterprise Process for TPL-008-1 Benchmark Weather Event Development and Maintenance.

(R2) R2 states that selection should be from “the benchmark library, approved and maintained by the ERO.” NERC should be more specific about who will approve the library in the ERO. Draft ERO Enterprise Process for TPL-008-1 Benchmark Weather Event Development and Maintenance states that “NERC will form an ERO Enterprise Review Panel (review panel) comprised of not less than four (4) total individuals from the applicable Regional Entities and NERC” to review entity-created benchmark events. Should the same review panel review all benchmark temperature event(s) from the library, including those developed by ERO? We suggest to replacing the text “approved and maintained by the Electric Reliability Organization (ERO)” with “approved and maintained by the Electric Reliability Organization (ERO) Enterprise Review Panel”.

Likes 0	
Dislikes 0	

Response

Robert Blackney - Edison International - Southern California Edison Company - 1

Answer	No
Document Name	

Comment

See comments submitted by Edison Electric Institute

Likes 0	
Dislikes 0	

Response

Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle

Answer	No
Document Name	

Comment

NERC entities operate transmission and generation assets across an enormous service territory and a variety of weather conditions. Every entity has its own unique “extreme weather condition(s)” to manage. PGAE would like to better understand the benefits of using a centralized benchmark library (still under development) over localized weather condition assessments.

Likes 0	
Dislikes 0	

Response

Usama Tahir - Seminole Electric Cooperative, Inc. - 3	
Answer	No
Document Name	
Comment	
The SDT should choose either the PC or TP to be responsible for R1. By allowing the responsible party to be either the TP or PC, the two parties may not agree on all terms or there may result a reliability gap. Seminole would like clarification on which responsibilities will belong to the Planning Coordinator and Transmission Planner. Seminole would like a longer implementation timeline of R2,R3,R4,R5,R6, R7, R8, R9, R10, R11	
Likes 0	
Dislikes 0	
Response	

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CEHE agrees with EEI comments, we continue to have concerns with Requirement R2 because this requirement relies on an ERO developed benchmark library that is being developed without industry review and approval, and as of this draft we continue to only have only superficial insights into this library. Moreover, the ERO was directed to set a framework with this Reliability Standard that included specific bounds by which the industry could conduct their extreme weather assessments. Yet, TPL-008-1 still does not contain any specific boundary limits that could guide responsible entities in their Extreme Weather Assessments or otherwise limit what might be contained or added to the Extreme Weather Event Library, now or in the future. For these reasons we ask that the DT set clear bounds that guide these Extreme Weather Assessments and set boundaries for any future changes to the Extreme Weather Event Library.	
Likes 0	
Dislikes 0	
Response	

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
• ITC believes R2 should be assigned to the Planning Coordinator within the standard. To ITC the assignment of R2 to the Planning Coordinator would seem to make the work of the standard flow in a more cohesive manner. To ITC the events should be chosen by the PC and such that they fit within the process being developed by the PC in R3.	

- The standard has the ERO identifying the weather events in the benchmark library. Is the ERO the correct entity to perform this work?
  - The ERO is not an entity that is auditable. What happens if their work product is completed late? Also, will the entity identified to develop the benchmark weather events provide entities the opportunity to comment on the identified events?

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	No
Document Name	

Comment

OPG supports NPCC Regional Standards Committee's comments:

Like Attachment 1 of TPL-007-4, we suggest that the standard includes an attachment that contains the extreme heat and extreme cold benchmark events. This is needed because stakeholders should have the opportunity to review the list of events and understand how they apply to their region, and what assessments they would need to conduct ahead of being asked to approve this standard.

Are the benchmark events considering regional-specific extremes? We are interested in seeing how Canadian, provincial attributes are considered within the ERO benchmark library. It is extremely important that Canadian benchmarks are adequately reflected and/or provide flexibility for Canadian entities to make appropriate changes to the ERO benchmark library.

Likes 0	
Dislikes 0	

Response

Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford

Answer	No
Document Name	

Comment

Comments provided to the previous draft suggested adding the "maintaining models" to the wording for R1 as that is an important joint responsibility for the PC and TP to do in support of the assessment. The modifications in draft 2 do not address this concern.

The modifications to R2 in this draft did not improve the overall requirement from draft 1. It is understood the ERO is tasked with developing and maintaining a benchmark events library for use by the responsible entity in the required assessment. It is not clear what the events will ultimately be and how the benchmark events library is to be maintained and updated. The SDT should define and clarify the process for maintaining the benchmark library. GTC also recommends that the PC & TP be involved in the development and/or approval of the benchmark events.

Likes 0	
Dislikes 0	

Response

Kinte Whitehead - Exelon - 3

Answer	No
Document Name	

Comment

R1 – Exelon does not have any objections to the proposed language for Requirement R1.

R2 – Exelon believes it is not appropriate to assign the Electric Reliability Organization (ERO) responsibility within the standard requirement that directly impacts the compliance to the standard requirement. There is a compliance risk to the directly assigned entity if the ERO fails to uphold its responsibility to maintain the database. We suggest coordinating this the way MMWG is coordinated through ERAG in the Eastern Interconnection.

Additionally, Exelon supports the comments submitted by the EEI for this question.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO

Answer	No
Document Name	

Comment

SPP has several concerns in reference to Requirement R2. The first concern focuses on the timing horizon of the study. As we reviewed draft 2, it was unclear if the assessment was intended for a near-term or long-term (six to ten year) horizon. In our review of TPL-001-5, Requirement R2 addresses both near and long-term assessments. Can we make the same assumption for TPL-008?

We recommend that the drafting team provide some clarity on the time horizon of the study for TPL-008. In the case the drafting team has the same intention for this standard as that of TPL-001-5, we recommend that they structure language like TPL-001-5 (i.e. 2.1, and 2.5).

As for the second concern, it is unclear in TPL-008 how the steady state and stability models (base case R4) will translate the benchmarked events (R2) into the models. At this point, there is no guidance on how to accomplish this goal of developing this type of models as well as conducting an assessment to produce quality results.

SPP recommends the drafting team takes into consideration coordinating with the NERC RSTC and their liaisons to help develop a guideline that will address uncharted territory applicable to the model build of this process.

The third and final concern relates to the expectations for the responsible entities to conduct an assessment from a library that does not currently exist.

We understand that EPRI is working with NERC to construct the library to support the requirement's effort. However, we will find it difficult for the responsible entities to support this requirement while there is no data to review. At this point, there is no official library data available for the responsible entities to conduct an assessment as well as compare those results with other entities to ensure quality results have been produced.

SPP recommends that the drafting team coordinate with NERC staff and ensure that the library has been finalized before moving forward with this requirement. It will be difficult to convince industry to support this effort when there are still too many unresolved issues at this point.

Likes 0	
Dislikes 0	

Response

Rebika Yitna - Rebika Yitna On Behalf of: David Weekley, MEAG Power, 3, 1; Roger Brand, MEAG Power, 3, 1; - Rebika Yitna

Answer	No
Document Name	

Comment

Benchmark library that is used for the Assessment may be better maintained at a Regional level.

Likes 0	
Dislikes 0	

Response

Donna Wood - Tri-State G and T Association, Inc. - 1

Answer	No
Document Name	

Comment

Tri-State supports the comments submitted by the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Matt Lewis - Lower Colorado River Authority - 1

Answer	No
Document Name	

Comment	
LCRA TSC agrees with other comments in that we would like to see the PCs maintain the benchmark event data for the applicable region rather than the data and library being entirely at one location under NERC control.	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	No
Document Name	
Comment	
LCRA agrees with other comments in that we would like to see the PCs maintain the benchmark event data for the applicable region rather than the data and library being entirely at one location under NERC control.	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	No
Document Name	
Comment	

Based on the sample benchmark information and assumed footprints of TPs/PCs, there could be situations where multiple Extreme Temperature Assessments may be needed to fully cover the risks posed. With the re-assessments required “at least once every five calendar years” should it be expected that identification of individual and joint responsibilities should occur for each Extreme Temperature Assessment and re-assessment? Would suggest removing the “or between departments of a vertically integrated system” as that would seem extremely limited in terms of actions needed to perform an Extreme Temperature Assessment. If Company A is a PC and a TP the individual and joint responsibilities are assigned to Company A from a compliance perspective. Requirement R2, as written, allows flexibility for PCs and TPs to select events best fitting their profile. The PCs will have to use some judgement in Requirement R3 to coordinate individual TP events with the event selected by the PC.

Likes 0	
Dislikes 0	

Response

Selene Willis - Edison International - Southern California Edison Company - 5

Answer	No
Document Name	

Comment

Please see comments from EEI

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment

EEI has no concerns with the updated Requirement R1. However, we continue to have concerns with Requirement R2 because this requirement relies on an ERO developed benchmark library that is being developed without industry review and approval, and as of this draft we continue to only have superficial insights into this library. Moreover, the ERO was directed to set a framework with this Reliability Standard that included specific bounds by which the industry could conduct their extreme weather assessments. Yet, TPL-008-1 still does not contain any specific boundary limits that could guide responsible entities in their Extreme Weather Assessments or otherwise limit what might be contained or added to the Extreme Weather Event Library, now or in the future. For these reasons we ask that the DT set clear bounds that guide these Extreme Weather Assessments and set boundaries for any future changes to the Extreme Weather Event Library. To address this concern, we suggest the following change in boldface below, but have intentionally left the specific boundaries to be set by the DT:

R.2 Each responsible entity, as identified in Requirement R1, shall select at least one extreme heat benchmark temperature event and at least one extreme cold benchmark temperature event for completing the Extreme Temperature Assessment. [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

2.1 Utilize metrological data that includes at least 20 years of historical data (*or as determined by the DT*), up to no less than two years prior to the year the Extreme Temperature Assessment is started.

2.2 Reflect extreme temperature conditions with a specified probability of (*As determined by the DT*) within the responsible entity's area.

2.3 Align extreme weather temperatures with those specified by all adjacent Planning Coordinators and Transmission Planners areas.

Likes 0	
Dislikes 0	
Response	
Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop	
Answer	No
Document Name	
Comment	
Ameren agrees with and supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	TPL-008 Q2 Response.docx
Comment	
PPL NERC Registered Affiliates agree with the general feedback provided by EEI. Throughout our responses we have provided additional, specific feedback in an effort to assist the DT's work. We appreciate the work of the DT to address feedback received for R1-R2. We recommend changes in the attached document to improve upon the revisions.	
Likes 0	
Dislikes 0	
Response	

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Southern Company agrees with EEI's comment. Additionally, the R2 and M2 language should be revised to extreme heat/cold temperature benchmark event for consistency with other mentions of 'temperature benchmark events', as opposed to 'benchmark temperature events'. This verbiage should be propagated consistently through the standard.	
Likes 0	
Dislikes 0	
Response	
Junji Yamaguchi - Hydro-Quebec (HQ) - 5	
Answer	No
Document Name	
Comment	
1. Similar to Attachment 1 of TPL-007-4, we suggest that the standard includes an attachment that contains the extreme heat and extreme cold benchmark events. This is needed because stakeholders should have the opportunity to review the list of events and understand how they apply to their region, and what assessments they would need to conduct ahead of being asked to approve this standard. 2. Are the benchmark events considering regional-specific extremes? We are interested in seeing how Canadian, provincial attributes are considered within the ERO benchmark library. It is extremely important that Canadian benchmarks are adequately reflected and/or provide flexibility for Canadian entities to make appropriate changes to the ERO benchmark library.	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	
NextEra supports EEI's comments	

EEI has no concerns with the updated Requirement R1. However, we continue to have concerns with Requirement R2 because this requirement relies on an ERO developed benchmark library that is being developed without industry review and approval, and as of this draft we continue to only have only superficial insights into this library. Moreover, the ERO was directed to set a framework with this Reliability Standard that included specific bounds by which the industry could conduct their extreme weather assessments. Yet, TPL-008-1 still does not contain any specific boundary limits that could guide responsible entities in their Extreme Weather Assessments or otherwise limit what might be contained or added to the Extreme Weather Event Library, now or in the future. For these reasons we ask that the DT set clear bounds that guide these Extreme Weather Assessments and set boundaries for any future changes to the Extreme Weather Event Library. To address this concern, we suggest the following change in boldface below, but have intentionally left the specific boundaries to be set by the DT:

R.2 Each responsible entity, as identified in Requirement R1, shall select at least one extreme heat benchmark temperature event and at least one extreme cold benchmark temperature event**, from the benchmark library, approved and maintained by the Electric Reliability Organization (ERO)**, for completing the Extreme Temperature Assessment. [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

2.1 Utilize metrological data that includes at least 20 years of historical data (*or as determined by the DT*), up to no less than two years prior to the year the Extreme Temperature Assessment is started.

1.2 Reflect extreme temperature conditions with a specified probability of (*As determined by the DT*) within the responsible entity's area.

1.3 Align extreme weather temperatures with those specified by all adjacent Planning Coordinators and Transmission Planners areas.

Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	No
Document Name	
Comment	
Would like to see a more concrete Benchmark Event Library functioning.	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	No
Document Name	

Comment	
For R2, Santee Cooper is concerned with the extreme heat and cold benchmark temperature being selected from a benchmark library that is approved and maintained by the Electric Reliability Organization (ERO). This may be better coordinated, assessed and planned at the Regional level. Being able to access and review the library before approving the requirement would be helpful.	
Likes 0	
Dislikes 0	
Response	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
ATC supports the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 2	
Likes 0	
Dislikes 0	
Response	
Barbara Marion - Dominion - Dominion Resources, Inc. - 5, Group Name Dominion	
Answer	No
Document Name	

Comment	
There are concerns over the CAP as well as ambiguity in R2.	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
Focusing exclusively on temperature will not get the job done; combinations of weather threats must be studied. What made Winter Storm Uri so destructive was that it began with an ice storm, taking-out the wind fleet of northern Texas, followed by a deep freeze with high winds, then a wind drought. The Polar Vortex of 2014 was preceded by drenching rain, which soaked insulation and made generation units vulnerable to the combination of low temperatures and high winds that followed.	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	No
Document Name	
Comment	
SMUD supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	No

Document Name	
Comment	

Black Hills Corporation has no concerns with the updated requirement R1 language. However, Black Hills Corporation has concerns with requirement R2 and echoes the comments developed by EEI, which are in italics below. Black Hills Corporation is concerned with the limited visibility and subsequent review by industry of the benchmark library being developed by the ERO.

'[W]e continue to have concerns with Requirement R2 because this requirement relies on an ERO developed benchmark library that is being developed without industry review and approval, and as of this draft we continue to only have only superficial insights into this library. Moreover, the ERO was directed to set a framework with this Reliability Standard that included specific bounds by which the industry could conduct their extreme weather assessments. Yet, TPL-008-1 still does not contain any specific boundary limits that could guide responsible entities in their Extreme Weather Assessments or otherwise limit what might be contained or added to the Extreme Weather Event Library, now or in the future. For these reasons we ask that the DT set clear bounds that guide these Extreme Weather Assessments and set boundaries for any future changes to the Extreme Weather Event Library. To address this concern, we suggest the following change in boldface below, but have intentionally left the specific boundaries to be set by the DT:

*R.2 Each responsible entity, as identified in Requirement R1, shall select at least one extreme heat benchmark temperature event and at least one extreme cold benchmark temperature event (remove:**, from the benchmark library, approved and maintained by the Electric Reliability Organization (ERO))**, for completing the Extreme Temperature Assessment. [Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1 Utilize metrological data that includes at least 20 years of historical data (or as determined by the DT), up to no less than two years prior to the year the Extreme Temperature Assessment is started.

2.1. Reflect extreme temperature conditions with a specified probability of (As determined by the DT) within the responsible entity's area.

2.2. Align extreme weather temperatures with those specified by all adjacent Planning Coordinators and Transmission Planners areas.'

Likes 0	
Dislikes 0	
Response	
Robert Jones - Seattle City Light - 1,3,4,5,6	
Answer	No
Document Name	
Comment	

It is difficult to evaluate this requirement without a functioning Benchmark Event Library or a far more explicit description of what will be included in the library.

Likes 0	
Dislikes 0	
Response	

Broc Bruton - Broc Bruton On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Broc Bruton	
Answer	No
Document Name	
Comment	
Oncor would like to ensure transparency in how the benchmark events are developed, chosen, calculated, and maintained. We agree with other's comments in that we would like to see the PCs maintain the benchmark event data for the applicable region rather than the data and library being entirely at one location under NERC control. This approach would likely make the data more transparent and accessible to the affected utilities than having a sole central repository at NERC for all regions of the country. In addition, the PC is likely to have more specific knowledge about effective methods of tuning and modifying the cases than NERC staff.	
Likes 0	
Dislikes 0	
Response	

Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
R1 – Exelon does not have any objections to the proposed language for Requirement R1. R2 – Exelon believes it is not appropriate to assign the Electric Reliability Organization (ERO) responsibility within the standard requirement that directly impacts the compliance to the standard requirement. There is a compliance risk to the directly assigned entity if the ERO fails to uphold its responsibility to maintain the database. We suggest coordinating this the way MMWG is coordinated through ERAG in the Eastern Interconnection. Additionally, Exelon supports the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	No
Document Name	
Comment	

Like Attachment 1 of TPL-007-4, we suggest that the standard includes an attachment that contains the extreme heat and extreme cold benchmark events. This is needed because stakeholders should have the opportunity to review the list of events and understand how they apply to their region, and what assessments they would need to conduct ahead of being asked to approve this standard.

Are the benchmark events considering regional-specific extremes? We are interested in seeing how Canadian, provincial attributes are considered within the ERO benchmark library. It is extremely important that Canadian benchmarks are adequately reflected and/or provide flexibility for Canadian entities to make appropriate changes to the ERO benchmark library.

Likes 0	
Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	No
Document Name	

Comment

The MRO NSRF supports some of the revisions and proposes modifications to others as detailed below.

R1. The MRO NSRF supports the SDT's decision to shorten the language to "completing."

R2. R2 and R4 need to be adjacent to each other as they both describe necessary cases. One should not have to read through R6 to know dynamic cases are also required.

Likes 1	Scott Brame, N/A, Brame Scott
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	No
Document Name	

Comment

Dominion Energy supports EEI comments

Likes 0	
Dislikes 0	

Response

Zahid Qayyum - New York Power Authority - 5	
Answer	No
Document Name	
Comment	

• NYPA Disagrees with R2 stating ‘benchmark library, approved and maintained by the Electric Reliability Organization (ERO)’. We believe that for greater effectiveness and suitability, the responsibility for maintaining and updating the library should be emphasized at the regional entity level rather than the ERO to better incorporate regional variability.

• Is the use of “category P0” to describe normal system condition in R1 appropriate, given that it includes both benchmark and extreme events, which are not typically considered normal operating conditions?

Likes 0	
Dislikes 0	
Response	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	

FirstEnergy supports EEI’s comments which state:

EEI has no concerns with the updated Requirement R1. However, we continue to have concerns with Requirement R2 because this requirement relies on an ERO developed benchmark library that is being developed without industry review and approval, and as of this draft we continue to only have superficial insights into this library. We also do not agree that ERO responsibilities and obligations need to be stated in the Requirement. To address this concern, we suggest the following change in boldface below:

R.2 Each responsible entity, as identified in Requirement R1, shall select at least one extreme heat benchmark temperature event and at least one extreme cold benchmark temperature event, from the **Extreme Weather Event L**ibrary, for completing the Extreme Temperature Assessment. [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

2.1 Utilize metrological data that includes at least 20 years of historical data (or as determined by the DT), up to no less than two years prior to the year the Extreme Temperature Assessment is started.

2.2 Reflect extreme temperature conditions with a specified probability of (As determined by the DT) within the responsible entity’s area.

2.3 Align extreme weather temperatures with those specified by all adjacent Planning Coordinators and Transmission Planners areas.

Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
Duke Energy agrees with and recommends implementation of EEI comments. Additionally, the standard language ERO developed benchmark library should be deleted and the concept of an entity standardized benchmark library should be developed, maintained, and remain with local or regional responsible entities (e.g., TP/PC).	
Likes 0	
Dislikes 0	
Response	
Fon Hiew - NB Power Corporation - New Brunswick Power Transmission Corporation - 5	
Answer	No
Document Name	
Comment	
Like Attachment 1 of TPL-007-4, we suggest that the standard includes an attachment that contains the extreme heat and extreme cold benchmark events. This is needed because stakeholders should have the opportunity to review the list of events and understand how they apply to their region, and what assessments they would need to conduct ahead of being asked to approve this standard. Are the benchmark events considering regional-specific extremes? We are interested in seeing how Canadian, provincial attributes are considered within the ERO benchmark library. It is extremely important that Canadian benchmarks are adequately reflected and/or provide flexibility for Canadian entities to make appropriate changes to the ERO benchmark library.	
Likes 0	
Dislikes 0	
Response	
Lidija Efremova - Lidija Efremova On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Lidija Efremova	
Answer	No

Document Name	
Comment	

Comments:

1. Similar to Attachment 1 of TPL-007-4, we suggest that the standard includes an Attachment 1 that contains a list or examples of the extreme heat and extreme cold benchmark events. This is required to avoid confusion because stakeholders need to know how and what assessments they need to ensure applicability to their region when the standard is posted for approval.

2. Are the benchmark events considering regional-specific extremes? We are interested in seeing how Canadian, provincial attributes are considered within the ERO benchmark library. It is extremely important that Canadian benchmarks are adequately reflected and provide flexibility for Canadian jurisdictions to make appropriate changes to the ERO benchmark library.

Likes 0	
Dislikes 0	
Response	

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	No
Document Name	
Comment	

(R1) No issues.

(R2) Due to R2 referencing a benchmark library that is not currently accessible, and therefore not fully understood, we are unable to express support for this requirement. We recommend making accessible the benchmark temperature event library prior to seeking concurrence on a dependent requirement.

Likes 0	
Dislikes 0	
Response	

Srikanth Chennupati - Entergy - Entergy Services, Inc. - 1,3,5,6 - SERC

Answer	No
Document Name	
Comment	

For R2: Technical Rationale states that “The ERO will maintain a library of benchmark events and develop a process to incorporate additional events proposed by responsible entities.” The standard does not provide any mechanism for responsible entities to propose events or collaborate on the review or approval process. As we commented before, this gives the ERO the ability to change compliance requirements at will (by changing or removing approved benchmark events) without going through any of the usual industry collaboration process. This standard should have a requirement for the

ERO to coordinate with Planning Coordinators to identify the benchmark events, or require the Planning Coordinators to collectively identify benchmark events in collaboration with the ERO and have the ERO simply provide a place to host the information.

Likes 0	
Dislikes 0	
Response	
Chelsea Loomis - Western Power Pool - NA - Not Applicable - WECC, Group Name WPP Consortium of Engineers	
Answer	No
Document Name	
Comment	
Would like to see a more concrete Benchmark Event Library functioning.	
Likes 0	
Dislikes 0	
Response	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	No
Document Name	
Comment	
While the drafting team made adjustments in an attempt to address concerns with the proposed benchmark library, R2 continues to leave this standard and the extreme temperature events open to broad adjustment without guaranteed stakeholder input. NERC has outlined a draft weather event development and maintenance process; however, this is a draft, and there is currently no process outlined for stakeholders to challenge the validity of benchmark events. Stakeholders cannot vote to approve R2 to TPL-008 because this will create an undefined, unchecked path for changes to the extreme temperature events, that are required to be assessed and planned for, without guaranteed stakeholder input and opportunity to challenge changes to benchmark events.	
Likes 0	
Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	No
Document Name	

Comment	
There should be an emphasis on Regional, not ERO. Not required for ERO to maintain this library, such libraries are better maintained at the Regional level. For smaller utilities, not sure how they are using the same criteria for Extrement Temperature Assessment.	
Likes 2	Snohomish County PUD No. 1, 3, Chaney Holly; Jennie Wike, N/A, Wike Jennie
Dislikes 0	
Response	

Jeffrey Streifling - NB Power Corporation - 1	
Answer	No
Document Name	
Comment	
Like Attachment 1 of TPL-007-4, we suggest that the standard includes an attachment that contains the extreme heat and extreme cold benchmark events. This is needed because stakeholders should have the opportunity to review the list of events and understand how they apply to their region, and what assessments they would need to conduct ahead of being asked to approve this standard. Are the benchmark events considering regional-specific extremes? We are interested in seeing how Canadian, provincial attributes are considered within the ERO benchmark library. It is extremely important that Canadian benchmarks are adequately reflected and/or provide flexibility for Canadian entities to make appropriate changes to the ERO benchmark library.	
Likes 0	
Dislikes 0	
Response	

Chantal Mazza - Chantal Mazza On Behalf of: Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	No
Document Name	
Comment	
1. Similar to Attachment 1 of TPL-007-4, we suggest that the standard includes an attachment that contains the extreme heat and extreme cold benchmark events. This is needed because stakeholders should have the opportunity to review the list of events and understand how they apply to their region, and what assessments they would need to conduct ahead of being asked to approve this standard. 2. Are the benchmark events considering regional-specific extremes? We are interested in seeing how Canadian, provincial attributes are considered within the ERO benchmark library. It is extremely important that Canadian benchmarks are adequately reflected and/or provide flexibility for Canadian entities to make appropriate changes to the ERO benchmark library.	
Likes 0	

Dislikes 0	
Response	
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
Answer	Yes
Document Name	
Comment	
PJM supports the IRC SRC comments.	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC) Project 2023-07 TPL-008-1 Draft #2	
Answer	Yes
Document Name	
Comment	
R1. The ISO/RTO Council Standards Review Committee (SRC)[1] supports the SDT's decision to shorten the language to "completing." [1] For purposes of these comments, the IRC SRC includes the following entities: CAISO (except for our response re: Part 9.2 to question 5), ERCOT, IESO (except for our response to question 5 in its entirety), ISO-NE, MISO, NYISO, PJM and SPP.	
Likes 0	

Dislikes 0	
Response	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	

ISO-NE recommends that the SDT review areas where Requirements could be combined to simplify or clarify the flow of requirements. TPL-007 is an example of how out of order requirements can confuse the industry, which required a flowchart in the technical rationale to illustrate the order in which requirements are performed.

While ISO-NE appreciates the Benchmark Event Example, many concerns that the industry has regarding this standard and the studies that would be required could be alleviated by the SDT/NERC providing a list of the Benchmark Temperature Events that would be available to choose from and what parameters are included for each event. It is difficult for areas to determine what would be required and to agree to perform studies on specific events without the list of events to choose from for the studies.

In the specific Benchmark Event Example, ISO-NE did not experience a cold weather event so there is no value in studying that particular event.

ISO-NE requests that a list of Benchmark Events be provided prior to any final Ballot on the TPL-008 Standard.

In addition, the requirements to coordinate between PCs could cause a burden on PCs if their neighbors choose to study a different Benchmark Event. For example, the Benchmark Event Example of Winter Storm Elliot would not be an event ISO-NE would choose as it did not have a significant impact on the ISO-NE area; However, PJM as the PC may choose to study it. If ISO-NE chooses the January 1998 Ice Storm, what effect would that have on NYISO which is adjacent to both ISO-NE and PJM? Do they now have to coordinate with both for the separate studies? What if NYISO chooses to study Polar Vortex in 2014?

Or, are we required to agree on a singular event to be studied? A line would need to be drawn somewhere. As in the case above, PJM wouldn't benefit from studying the 1998 Ice Storm and ISO-NE wouldn't benefit from studying Winter Storm Elliot. If so, some PCs may need to create model data for multiple Benchmark Events. In addition to possibly having to address multiple Events, some PCs may choose a different year (Year 6 through Year 10) within the Long-Term Planning Horizon, which further increases the burden associated with coordinating studies between the PCs.

Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	

We understand the urgency of these modifications directed by FERC in Order No. 896 and agree to the proposed modifications made by the standard drafting team. However, it is challenging to agree due to not knowing the benchmarks to be set by NERC.	
Likes 0	
Dislikes 0	
Response	
Helen Lainis - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
We understand from the SDT that the ERO is currently working on Canadian benchmarks. It is very important that Canadian benchmarks are considered within the ERO benchmark library so that we can appropriately assess.	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
We don't see any extreme temperature events identified for Canadian provinces. We assume NERC will reach out to applicable PCs/TPs to get the initial list of benchmark events prior to December 2024 to prepare the benchmark list for the first five years (according to the draft ERO Enterprise Process document for TPl-008-1).	
Likes 0	
Dislikes 0	
Response	
Apollonia Gonzales - PNM Resources - Public Service Company of New Mexico - 1,3,5 - WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michele Shafer - New York State Electric & Gas (NYSEG) - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Sorenson - Greg Sorenson On Behalf of: Tyler Schwendiman, ReliabilityFirst , 10; - Greg Sorenson	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michele Tondalo - United Illuminating Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
As there are still unknowns regarding the Benchmark Event Library, BPA cannot make a determination on R2 at this time. Once BPA can review the library, and attend the planned NERC training, BPA can review and provide more meaningful comments/feedback.	
Likes 0	
Dislikes 0	
Response	

Gary Trezza - Long Island Power Authority - 1 - NPCC	
Answer	
Document Name	
Comment	
The text of Requirement #2 mentions “benchmark library, approved and maintained by the Electric Reliability Organization (ERO)”. Similar to Attachment 1 of TPL-007-4, we recommend that the final version of the standard include an attachment that contains details of the extreme heat and extreme cold benchmark events, or at least some mention of the public facing library (site) to be created by Q4 2024 (as mentioned in the TPL-008 webinar in July 2024) and maintained by NERC. Ideally, stakeholders should have the opportunity to review the list of events and understand how they apply to their region, and what assessments they would need to conduct ahead of being asked to approve this standard.	
Likes 0	
Dislikes 0	
Response	

3. The DT updated Requirements R3 – R5 based on comments received. Do you agree with the updated proposed TPL-008-1 Reliability Standard Requirements R3-R5? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Long Island Power Authority	
Answer	Yes
Document Name	(if an attachment is provided by submitter)
Comment	
Requirement #5 mentions having criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and applicable Facility Ratings. Is it the intent that entities will also have to have (and document) applicable thermal criteria for completing the Extreme Temperature Assessment? For example, allowing for the possible use of STE facility ratings post-contingency? In certain jurisdiction, extreme temperature ratings have been established, but that is not necessarily the case in all jurisdictions. Will facility owners be required to establish extreme cold or warm temperature ratings for this standard?	
Likes 0	# of other submitters who agree with these comments
Dislikes 0	# of other submitters who disagree with these comments
Response	
(Drafting team's response to submitter's comments)	

Chantal Mazza - Chantal Mazza On Behalf of: Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza

Answer	No
Document Name	
Comment	
We are concerned that the R3-R4 requirements may necessitate a significant coordination effort by each PC similar to the MMWG base case development for the Eastern Interconnection for each of the extreme weather events. Was this the intent of R3-R4? If so, it does not seem feasible to develop consistent wide-area cases when each PC can select unique events. We note that R4.1 gives the freedom for individual adjacent entities to choose a different year for the long-term horizon, which could result in the requirement to develop even more cases. However, we agree with R5.	
Likes 0	
Dislikes 0	
Response	

Jeffrey Streifling - NB Power Corporation - 1	
Answer	No
Document Name	
Comment	
We are concerned that the R3-R4 requirements may necessitate a significant coordination effort by each PC like the MMWG base case development for the Eastern Interconnection for each of the extreme weather events. Was this the intent of R3-R4? If so, it does not seem feasible to develop consistent wide-area cases when each PC can select unique events. We note that R4.1 gives the freedom for individual adjacent entities to choose a different year for the long-term horizon, which could result in the requirement to develop even more cases. However, we agree with R5.	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
AEP is concerned by the phrase "at least one of the following conditions" within R4.2, as temperature would conceivably impact all three conditions specified: "Generation", "Real and reactive forecasted Load", and "Transfers." It follows then that using only one of these conditions could result in an analysis that might not capture all potential reliability issues. AEP believes the Technical Rationale could benefit from additional insight regarding the recommended conditions that might be considered for ensuring a high-quality analysis. AEP recommends revising the Technical Rationale document accordingly. AEP recommends to the SDT that care be taken to ensure that the obligations related to sensitivity cases align with the directives issued in FERC Order 1920.	
Likes 0	
Dislikes 0	
Response	

Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	No
Document Name	
Comment	

Need to define "other designated study entities" listed in R3. "Other designated study entities" is an unclear term. R5 Risk factor should be Medium to match TPL 001-5. The significant level of coordination needed for the standard will be a concern, particularly for small utilities.	
Likes 2	Snohomish County PUD No. 1, 3, Chaney Holly; Jennie Wike, N/A, Wike Jennie
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	No
Document Name	
Comment	
R3: Base Case should include known outages.	
Likes 0	
Dislikes 0	
Response	
Chelsea Loomis - Western Power Pool - NA - Not Applicable - WECC, Group Name WPP Consortium of Engineers	
Answer	No
Document Name	
Comment	
“other designated study entities” is unclear. R5 Risk factor should be Medium to match TPL 001-5. Concern that level of coordination needed to effect the standard will be significant, particularly for “smaller” entities.	
Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	

(R3) We recommend that R3 be updated to suggest that “designated study entities” are to be identified as part of the PC developed coordination process and only required to be coordinated with if included in the PC developed process. Otherwise, the term “designation” may suggest (1) the benchmark cases will designate entities, (2) entities other than the PC may designate a study entity, or (3) they may self-identify. It is unclear how the designation process will occur and the scale of entities to be possibly included.

(R4.2) We do not agree that R4.2, which requires an increasingly more extreme scenario for purposes of a sensitivity analysis, is credible. This is especially true for longer term planning horizons when generation additions and retirements, along with transmission configuration changes and new technologies to be deployed are less detailed.

(R5) No issues.

Likes 0	
Dislikes 0	

Response

Lidija Efremova - Lidija Efremova On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Lidija Efremova

Answer	No
Document Name	

Comment

Comments:

We are concerned that the R3-R4 requirements necessitate a coordination effort by each PC very similar to the MMWG base case development for the Eastern Interconnection for each of the extreme weather events. Was this the intent of R3-R4? Please clarify. If so, it does not seem feasible to develop consistent wide-area cases by each PC when a PC can select its own unique events. We note that R4.1 also gives the flexibility for adjacent entities to choose a different year for the long-term horizon, which could result in the requirement to develop even more cases. This undertaking must be simple and straightforward.

Likes 0	
Dislikes 0	

Response

Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD

Answer	No
Document Name	

Comment

CHPD believes the updates made to R3 through R5 were very good, with a couple concerns remaining. The statement ‘and other designated study entities’, is unclear. What is a study entity? Who is doing the designating? Due to non-clarity, it is recommended NERC provide clarity here or remove this language.

In addition, an R5 concern is the VRF for the limits criteria is 'High' as proposed in TPL-008, while the same type of limits requirement has a VRF of 'Medium' in TPL-001-5 R5. It is requested the VRF for TPL-008 R5 be similarly set as 'Medium' for consistency.	
Likes 1	Jennie Wike, N/A, Wike Jennie
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
Manitoba Hydro does not think there is a need to perform additional sensitivity studies as per R 4.2. We think R4.1 is sufficient to develop base cases capturing the sensitivity of generation, load, and transfers for extreme temperature events.	
Likes 0	
Dislikes 0	
Response	
Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA believes "other designated study entities" in R3 is unclear. R4.1 – BPA recommends deleting the sentence "The rationale for the year selected for evaluation shall be available as supporting information" as it is unclear what type(s) of rationale would be required. BPA views this as a potential for undue compliance burden on industry and will create difficulty when providing compliance evidence artifacts." BPA recommends the R5 Risk Factor should be set to Medium to match TPL 001-5. BPA is concerned that the level of coordination needed is not well defined and will be very difficult for smaller entities.	
Likes 0	
Dislikes 0	
Response	

Fon Hiew - NB Power Corporation - New Brunswick Power Transmission Corporation - 5	
Answer	No
Document Name	
Comment	

We are concerned that the R3-R4 requirements may necessitate a significant coordination effort by each PC like the MMWG base case development for the Eastern Interconnection for each of the extreme weather events. Was this the intent of R3-R4? If so, it does not seem feasible to develop consistent wide-area cases when each PC can select unique events. We note that R4.1 gives the freedom for individual adjacent entities to choose a different year for the long-term horizon, which could result in the requirement to develop even more cases. However, we agree with R5.

Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	

FirstEnergy supports EEI's comments which state:

EEI no concerns with the updated Requirement R1. However, we continue to have concerns with Requirement R2 because this requirement relies on an ERO developed benchmark library that is being developed without industry review and approval, including the deadlines for the review of the Extreme Temperature Assessments by adjacent PCs and TPs. To address our concerns, we offer the following in boldface for consideration:

R3. Each Planning Coordinator shall develop and implement a process for **developing** benchmark planning cases, using the selected benchmark temperature events identified in Requirement R2. **The process shall include:** [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

3.1. Seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers in the responsibility entity's area based on the extreme temperature conditions identified in Requirement R2.

3.2.1 Processes for requesting seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers from the adjacent entity's area based on the extreme temperature conditions identified in Requirement R2 that obligate the adjacent PC & TP to respond within 6 months of the request.

3.2.2 Obligation to respond to notify any affected Planning Coordinators and Transmission Planners of any concerns within 120 days of receipt of the data supplied.

3.2.3 An additional 60 shall also be allotted to the responsible Planning Coordinator to resolve any issues or concerns cited by the adjacent Planning Coordinator or Transmission Planner.

Likes 0	
Dislikes 0	
Response	

Zahid Qayyum - New York Power Authority - 5	
Answer	No
Document Name	
Comment	

NYPA believes the term used in R3 “other designated study entities" is vague and requires clarification from the SDT for better understanding. The significant level of coordination is needed for this Standard may be a concern, particularly for small utilities.

Likes 0	
Dislikes 0	
Response	

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	

The MRO NSRF’s most significant concerns involve requirements R3 and R4 as detailed below.

The Coordination Effort Required for Consistent, Wide-Area Cases Negates the Benefit of Choosing a Unique Benchmark Event

R3. While the MRO NSRF agrees the proposed language, “*among adjacent* impacted Planning Coordinator(s), Transmission Planner(s), and other designated study entities,” is an improvement over the prior language because it clarifies how far an entity must reach beyond its footprint to satisfy the requirement.

That said, the MRO NSRF still has significant concerns regarding the number of studies which must be performed, particularly when a Planning Coordinator (PC) selects a benchmark temperature event that is different from that of its adjacent PC(s). In that situation, each benchmark temperature event may necessitate a significant coordination effort, similar to what is done to develop the MMWG base case for the Eastern Interconnection.

If that’s the case, it doesn’t seem feasible to develop consistent, wide-area cases when each PC can select unique events. We also note that R4.1 gives each entity the freedom to choose a different year for the long-term horizon, which could further exacerbate the number of cases that must be developed to comply with the coordination process under R3.

To address this concern, the MRO NSRF recommends a governing body identify the scenarios. Extreme temperature events will typically extend beyond the footprint of a single Planning Coordinator. To avoid putting the PCs in a position where they are required to agree on a scenario, a year and the sensitivity to be studied, NERC or other (e.g. ERAG) should identify the extreme heat and extreme cold temperature events to be studied. This is necessary for consistent modeling results across adjacent planning entities. Also, as a benchmark temperature event may extend across several planning areas, the governing body must take this into consideration when determining which extreme heat and extreme cold temperature events are to be studied so that no planning entity is assigned more than one of each.

R4. MRO NSRF supports the proposed language (“data consistent with that provided in accordance with the MOD-032 standard”) and does not see a need to update MOD-032 at this time; however, depending upon what data the benchmark temperature event requires to perform the study, this may need to be revisited.

Part 4.1 MRO NSRF supports Part 4.1 and views the benchmark temperature event as a “base case sensitivity” to that performed under TPL-001.

Part 4.2 Is there an opportunity to “bake” sensitivities into the benchmark temperature event?

R5. MRO NSRF supports the addition of “*and applicable Facility Ratings*” considering the need to comply with FERC Order 881 and Ambient Adjusted Ratings in the near future. MRO NSRF is also exploring this further with its member TOs.

Likes 1	Scott Brame, N/A, Brame Scott
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC

Answer	No
Document Name	

Comment

We are concerned that the R3-R4 requirements may necessitate a significant coordination effort by each PC like the MMWG base case development for the Eastern Interconnection for each of the extreme weather events. Was this the intent of R3-R4? If so, it does not seem feasible to develop consistent wide-area cases when each PC can select unique events. We note that R4.1 gives the freedom for individual adjacent entities to choose a different year for the long-term horizon, which could result in the requirement to develop even more cases. However, we agree with R5.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	No
Document Name	

Comment	
There is nothing in the standard enforcing that PCs and TPs need to coordinate and share data between themselves to build the cases in R4. This may need to be a stand-alone requirement. "Each responsible entity shall coordinate and cooperate with other responsible entities to create the benchmark planning Cases." R3 – The last sentence needs clarification. Propose to change it to "This process shall include documentation of assumptions that consider seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers to represent the selected benchmark temperature events." R4 – No concerns from Exelon. R5 – No concerns from Exelon. Additionally, Exelon supports the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Broc Bruton - Broc Bruton On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Broc Bruton	
Answer	No
Document Name	
Comment	
For R3, Oncor agrees with the idea that the PC should have the responsibility for coordinating and developing benchmark planning cases. For R4, "Each responsible entity…" could be replaced with language that is similar to R3, and it would instead read "Each Planning Coordinator…." Oncor also asks whether language can be added to ensure that entities can take credit for studies that are run as part of the Sensitivity analysis, rather than running those studies again as part of the assessment to be conducted under TPL-001? For example, the Extreme Temperature Assessment could take the place of the sensitivity analysis required within the TPL-001 assessment for both the steady state and stability analyses.Moreover, if the Extreme Temperature Assessment is essentially a type of sensitivity analysis already, Oncor would advise removing R4.2 because this would create a sensitivity case based on a sensitivity case. For R5, Oncor urges its comment from R4, particularly because the PC would develop and maintain the criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations.	
Likes 0	
Dislikes 0	
Response	
Robert Jones - Seattle City Light - 1,3,4,5,6	
Answer	No
Document Name	

Comment	
The term "other designated study entities" is unclear. R5 Risk factor should be Medium to match TPL-001-5. The level of coordination needed to comply with the standard will be significant, particularly for "smaller" entities.	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	No
Document Name	
Comment	
Black Hills Corporation has no concerns with the updated language for requirements R4 and R5. Black Hills Corporation has concerns with R3 and aligns with the comments (below in italics) made by EEI with regards to requirement R3. *'Requirement R3 does not provide sufficient clarity for the processes or expectations for coordination between adjacent Planning Coordinators and Transmission Planners, including the deadlines for the review of the Extreme Temperature Assessments by adjacent PCs and TPs. To address our concerns, we offer the following in boldface for consideration:* *R3. Each Planning Coordinator shall develop and implement a process for **developing** (remove: **coordinating the development of)** benchmark planning cases, using the selected benchmark temperature events identified in Requirement R2. **The process shall include:** (remove: **, among adjacent impacted Planning Coordinator(s). Transmission Planner(s), and other designated study entities, within an Interconnection. This process shall include seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers to represent the selected benchmark temperature events.**) [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]* ***3.1. Seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers in the responsibility entity's area based on the extreme temperature conditions identified in Requirement R2.*** ***3.2.1 Processes for requesting seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers from the adjacent entity's area based on the extreme temperature conditions identified in Requirement R2 that obligate the adjacent PC & TP to respond within 6 months of the request.*** ***3.2.2 Obligation to respond to notify any affected Planning Coordinators and Transmission Planners of any concerns within 120 days of receipt of the data supplied.*** ***3.2.3 An additional 60 shall also be allotted to the responsible Planning Coordinator to resolve any issues or concerns cited by the adjacent Planning Coordinator or Transmission Planner.'***	
Likes 0	
Dislikes 0	
Response	

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC

Answer	No
Document Name	

Comment

SMUD supports the comments submitted by the MRO NSRF regarding Requirement R4, Part 4.2 and recommends that Part 4.2 be removed in its entirety.

Likes 0	
Dislikes 0	

Response

Donald Lock - Talen Generation, LLC - 5

Answer	No
Document Name	

Comment

PCs can model benchmark events only if having valid sensitivity factors for temperature, wind speed and precipitation. They do not presently have this information, and TPL-008-1 makes no suggestions in this respect other than that they refer to, “other sources as needed.” These sources are non-existent.

Likes 0	
Dislikes 0	

Response

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples

Answer	No
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 3

Likes 0	

Dislikes 0	
Response	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
ATC appreciates the additional clarity added to the relationship between R3 and R4. ATC supports the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	No
Document Name	
Comment	
“other designated study entities” is unclear. R5 Risk factor should be Medium to match TPL 001-5. Concern that level of coordination needed to effect the standard will be significant, particularly for “smaller” entities.	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	
NextEra supports EEI's comments EEI does not have concerns with the updated proposed Requirements for R4 and R5, however, Requirement R3 does not provide sufficient clarity for the processes or expectations for coordination between adjacent Planning Coordinators and Transmission Planners, including the deadlines for the	

review of the Extreme Temperature Assessments by adjacent PCs and TPs. To address our concerns, we offer the following in boldface for consideration:

R3. Each Planning Coordinator shall develop and implement a process for **developing coordinating the development of** benchmark planning cases, using the selected benchmark temperature events identified in Requirement R2. **The process shall include: , among adjacent impacted Planning Coordinator(s). Transmission Planner(s), and other designated study entities, within an Interconnection. This process shall include seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers to represent the selected benchmark temperature events.** [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

3.1. Seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers in the responsibility entity's area based on the extreme temperature conditions identified in Requirement R2.

3.2.1 Processes for requesting seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers from the adjacent entity's area based on the extreme temperature conditions identified in Requirement R2 that obligate the adjacent PC & TP to respond within 6 months of the request.

3.2.2 Obligation to respond to notify any affected Planning Coordinators and Transmission Planners of any concerns within 120 days of receipt of the data supplied.

3.2.3 An additional 60 shall also be allotted to the responsible Planning Coordinator to resolve any issues or concerns cited by the adjacent Planning Coordinator or Transmission Planner.

Likes 0	
Dislikes 0	

Response

Junji Yamaguchi - Hydro-Quebec (HQ) - 5

Answer	No
Document Name	

Comment

We are concerned that the R3-R4 requirements may necessitate a significant coordination effort by each PC similar to the MMWG base case development for the Eastern Interconnection for each of the extreme weather events. Was this the intent of R3-R4? If so, it does not seem feasible to develop consistent wide-area cases when each PC can select unique events. We note that R4.1 gives the freedom for individual adjacent entities to choose a different year for the long-term horizon, which could result in the requirement to develop even more cases. However, we agree with R5.

Likes 0	
Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	
Comment	

Southern Company appreciates the inclusion of 'among adjacent' as well as the clarification of what impacts will be considered in the development of benchmark planning cases in R3; however, the expectations of coordination need further definition along with clarifying the timeline of coordination with adjacent entities to prevent other entities from causing compliance risk.

Likes 0	
Dislikes 0	
Response	

Helen Lainis - Independent Electricity System Operator - 2

Answer	No
Document Name	
Comment	

We support NPCC TFCP comments. We are concerned that the coordination effort required for consistent, wide-area cases negates the benefit of choosing a unique benchmark event. Specifically, we are concerned regarding the number of studies which must be performed, particularly when a Planning Coordinator (PC) selects a benchmark temperature event that is different from that of its adjacent PC(s). In that situation, each benchmark temperature event may necessitate a significant coordination effort, similar to what is done to develop the MMWG base case for the Eastern Interconnection. It does not seem feasible to develop consistent, wide-area cases when each PC can select unique events.

Consequently, we recommend that NERC/Regional Entities/ERAG to identify the scenarios, and the extreme heat and extreme cold temperature events to be studied so that no planning entity is assigned more than one of each.

Likes 0	
Dislikes 0	
Response	

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF

Answer	No
Document Name	
Comment	

Regarding Requirement R3, the DT has made improvements in this Requirement, but the language still fails to provide the flexibility necessary for a responsible entity to get the required cases built in a timely and practical manner. There are two primary issues for which we provide recommendations to provide more flexibility.

First, there is no specification or bounds on the type of data that represents the benchmark event. Is it a single temperature for the adjacent entity's entire region? Is it sub-zip-code level temperature data? Again, the DT must include more specifics in the standard about the framework and criteria of benchmark temperature events.

Second, there is no flexibility to make technically justified assumptions. These will be necessary for this process to be completed effectively. Consider a case with a local cold front. The responsible entity and all adjacent entities are experiencing increased load and potentially some lost generation. Thus, they have a collective power deficit. How is this model going to solve? The power must be imported from somewhere. The DT should solve these issues by allowing the responsible entity to make technically justified assumptions for non-adjacent areas. To continue the example above, if the entity is in the northeast United States, it may reasonably assume power will be imported from the southern United States. It is not necessary to coordinate with all entities to determine what imports will be available. As noted above, the impact of adjusting specific assets is diluted relative to electrical distance.

The two issues above would be appropriately addressed in the Requirement R2 and R3 proposed in the last question. Requirement R3 is repeated here:

R3. Each responsible entity, as identified in Requirement R1, shall develop a process for developing benchmark planning cases to represent the benchmark temperature events selected in Requirement R2. The process shall include:

3.1. Seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers in the responsibility entity's area based on the temperature conditions identified in Requirement R2 Part 2.2.

3.2. Coordination with adjacent Planning Coordinators and Transmission Planners to make seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers and in their areas based on the temperature conditions identified in Requirement R2 Part 2.3.

3.3. Technical rationale and methods for approximating seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers in other areas of the Interconnection.

Finally, it is not clear who "other designated study entities" are. This should be removed or clarified by the DT (this phrase was removed in the suggested language above).

Regarding Requirement R4, this format is improved from the first draft. However, it is recommended that the DT clarify in Part 4.2 that only one sensitivity case is required for each benchmark temperature event. Suggested modification to the first sentence: "**At least one s**[S]ensitivity case[s] **for each benchmark planning case developed in Requirement R4 Part 4.1** to demonstrate the impact…"

The DT should also add a requirement specifying how much time adjacent entities have to submit data to a requestor. Suppose an entity starts its Extreme Temperature Assessment six months before its due date. They request data from a neighbor and the neighbor does not provide the requested data until 9 months later. Is the responsible entity to blame for not providing enough time? Or did the adjacent entity take too long?

Likes 0	
Dislikes 0	

Response

Michele Tondalo - United Illuminating Co. - 1

Answer	No
Document Name	

Comment	
In R3 it is not clear what this coordination between PCs is expected to result in, in particular how are adjacent regions that select different extreme events expected to reconcile differences? In R4.1, it is unclear what is establishing Category P0 as the normal System Condition in Table 1.	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez	
Answer	No
Document Name	
Comment	
Define Table 1 for requirement 4.1. Recommend clarifying on case selection for requirement R4.	
Likes 0	
Dislikes 0	
Response	
Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop	
Answer	No
Document Name	
Comment	
Ameren would like clarity on why R4.2 does not include Transmission. In addition, Ameren agrees with and supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	

Comment	
EEI does not have concerns with the updated proposed Requirements for R4 and R5, however, Requirement R3 does not provide sufficient clarity for the processes or expectations for coordination between adjacent Planning Coordinators and Transmission Planners, including the deadlines for the review of the Extreme Temperature Assessments by adjacent PCs and TPs. To address our concerns, we offer the following in boldface for consideration: R3. Each Planning Coordinator shall develop and implement a process for **developing** benchmark planning cases, using the selected benchmark temperature events identified in Requirement R2. **The process shall include:** [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] **3.1. Seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers in the responsibility entity's area based on the extreme temperature conditions identified in Requirement R2.** **3.2.1 Processes for requesting seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers from the adjacent entity's area based on the extreme temperature conditions identified in Requirement R2 that obligate the adjacent PC & TP to respond within 6 months of the request.** **3.2.2 Obligation to respond to notify any affected Planning Coordinators and Transmission Planners of any concerns within 120 days of receipt of the data supplied.** **3.2.3 An additional 60 shall also be allotted to the responsible Planning Coordinator to resolve any issues or concerns cited by the adjacent Planning Coordinator or Transmission Planner.**	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	No
Document Name	
Comment	
Please see comments from EEI	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	No
Document Name	

Comment	
Is the coordination process expected to call out which year of "one of the years in the Long-Term Transmission Planning Horizon" is to be used? Or is every year in the Long-Term Planning Horizon a coordinated effort? Or does each TP and PC select their own year (which would likely lead to possible misleading overall results)?	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Greg Sorenson - Greg Sorenson On Behalf of: Tyler Schwendiman, ReliabilityFirst , 10; - Greg Sorenson	
Answer	No
Document Name	
Comment	
R4, states that the sensitivity analysis shall include, at a minimum, changes to one of the following conditions: Generation; Real and reactive forecasted Load; or Transfers. RF believes that the assessment should consider all of the listed conditions as opposed to only one. In the Feb 2021 Southwest event, the load was higher and the generation lower than expected(https://www.ercot.com/news/february2021). Likewise, in the Dec 2022 Elliott event, PJM load was significantly higher (10,000MW) while generation outages were significantly above baseline (https://www.pjm.com/-/media/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.ashx).	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No

Document Name	
Comment	
Tri-State supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Michele Shafer - New York State Electric & Gas (NYSEG) - 6	
Answer	No
Document Name	
Comment	
In R4.1, it is unclear what is establishing Category P0 as the normal System Condition in Table 1.	
Likes 0	
Dislikes 0	
Response	
Rebika Yitna - Rebika Yitna On Behalf of: David Weekley, MEAG Power, 3, 1; Roger Brand, MEAG Power, 3, 1; - Rebika Yitna	
Answer	No
Document Name	
Comment	
The "other designated study entities" mentioned in R3 need to be defined. The phrase "other designated study entities" is unclear.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO	
Answer	No
Document Name	
Comment	

SPP raises concerns regarding the coordination among neighboring entities impacted by Requirement R3. We understand that this coordination extends to all Planning Coordinators, including those outside the event area, potentially leading to unnecessary administrative burdens. Moreover, there is the concern of including/translating the seasonal and temperature dependent adjustments in the models. As we state in the previous question, there is no guidance on how to accomplish this goal of developing this type of models as well as conducting an assessment to produce quality results.

SPP recommends the drafting team takes into consideration coordinating with the NERC RSTC and their liaisons to help develop a guideline that will address uncharted territory applicable to the neighbor coordinating and model building process.

Regarding Requirement R4 and the use of the MOD-032 Standard for data collection, SPP questions its suitability for assessing Inverter-Based, Distributed Energy, and Energy Storage Resources, given unresolved project directives.

At this point, SPP recommends that the drafting team coordinates with the drafting team Project 2022-02 (which includes MOD-032 efforts). This coordination will ensure that the appropriate data request requirements are addressed as this will contribute the quality results from all associated assessments.

Likes 0	
Dislikes 0	

Response

Kinte Whitehead - Exelon - 3

Answer	No
Document Name	

Comment

There is nothing in the standard enforcing that PCs and TPs need to coordinate and share data between themselves to build the cases in R4. This may need to be a stand-alone requirement. “Each responsible entity shall coordinate and cooperate with other responsible entities to create the benchmark planning Cases.”

R3 – The last sentence needs clarification. Propose to change it to “This process shall include documentation of assumptions that consider seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers to represent the selected benchmark temperature events.”

R4 – No concerns from Exelon.

R5 – No concerns from Exelon.

Additionally, Exelon supports the comments submitted by the EEI for this question.

Likes 0	
Dislikes 0	

Response

Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford

Answer	No
Document Name	
Comment	

R3:

- Replace "Each Planning Coordinator shall" with "Each responsible entity, as identified in Requirement R1, shall". This may require supplemental wording edits in the requirement.
- The inclusion of "other designated study entities" is not clear.
- The SDT should consider combining this requirement with R4.
- Requiring each PC to coordinate the development of benchmark planning cases among "adjacent impacted" entities "within an Interconnection" is potentially a massive amount of workload as benchmark events may be significantly different between these entities. It is not reasonable for the PC or TP to have responsibility for coordinating models outside of their respective planning areas.

R4:

- The SDT should consider combining this requirement with R3.

R5:

- The recently adopted NERC Glossary term, System Voltage Limits, should be referenced in this requirement instead of the outdated wording "System steady state voltage limits". "…shall have criteria for acceptable System Voltage Limits for performing the Extreme Temperature Assessment…"
- Since this requirement appears to refer to steady-state voltage, the post contingency voltage deviation portion of the existing requirement should be removed. The resultant steady-state voltage level being outside of acceptable high and low limits is the point of concern. For example, if a low voltage criterion is 0.92 p.u., then voltages below this limit would violate this particular criterion regardless of whether the beginning voltage was 0.95 p.u., 0.98 p.u., or any other voltage level.
- The inclusion of Facility Ratings in the requirement is not clear and does not offer an improvement over the previous draft. Since this standard is modeling so much of its wording and the attached table after TPL-001, the performance criteria regarding ratings, voltage, & stability should be similarly referenced in this standard. Note that "Performance Requirements" is more generally referred to in this draft's R9 which could easily refer to the suggested inclusion in the table. As it stands, "Performance Requirements" referred to in this draft is not clearly defined.

Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	

OPG supports NPCC Regional Standards Committee's comments:

We are concerned that the R3-R4 requirements may necessitate a significant coordination effort by each PC like the MMWG base case development for the Eastern Interconnection for each of the extreme weather events. Was this the intent of R3-R4? If so, it does not seem feasible to develop consistent wide-area cases when each PC can select unique events. We note that R4.1 gives the freedom for individual adjacent entities to choose a different year for the long-term horizon, which could result in the requirement to develop even more cases. However, we agree with R5.

Likes 0	
Dislikes 0	

Response

Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen

Answer	No
Document Name	

Comment

The requirements to coordinate between PCs could cause a burden on PCs if their neighbors choose to study a different Benchmark Event. For example, the Benchmark Event Example of Winter Storm Elliot would not be an event ISO-NE would choose as it did not have a significant impact on the ISO-NE area; However, PJM as the PC may choose to study it. If ISO-NE chooses the January 1998 Ice Storm, what effect would that have on NYISO which is adjacent to both ISO-NE and PJM? Do they now have to coordinate with both for the separate studies? What if NYISO chooses to study Polar Vortex in 2014?

Or, are we required to agree on a singular event to be studied? A line would need to be drawn somewhere. As in the case above, PJM wouldn't benefit from studying the 1998 Ice Storm and ISO-NE wouldn't benefit from studying Winter Storm Elliot. If so, some PCs may need to create model data for multiple Benchmark Events. In addition to possibly having to address multiple Events, some PCs may choose a different year (Year 6 through Year 10) within the Long-Term Planning Horizon, which further increases the burden associated with coordinating studies between the PCs.

Likes 0	
Dislikes 0	

Response

Ben Hammer - Western Area Power Administration - 1

Answer	No
Document Name	

Comment

WAPA has concerns regarding the number of studies which must be performed, particularly when a Planning Coordinator (PC) selects a benchmark temperature event that is different from that of its adjacent PC(s). In that situation, each benchmark temperature event may necessitate a significant coordination effort.

WAPA recommends a governing body identify the scenarios. Extreme temperature events will typically extend beyond the footprint of a single Planning Coordinator. To avoid putting the PCs in a position where they are required to agree on a scenario, a year and the sensitivity to be studied, NERC or other (e.g. ERAG) should identify the extreme heat and extreme cold temperature events to be studied. This is necessary for consistent modeling results across adjacent planning entities. Also, as a benchmark temperature event may extend across several planning areas, the governing body must take this into consideration when determining which extreme heat and extreme cold temperature events are to be studied so that no planning entity is assigned more than one of each.

Likes 0	
Dislikes 0	

Response

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	No
Document Name	

Comment

Does the DT believe the existing MOD-032 includes the ability for both the TP and PCs to be able to obtain the information necessary from generators? ITC understands the FERC requirement to perform a sensitivity study. ITC does believe the scope of work required for the sensitivity study should be revised to make it more meaningful and so that it does provide a reliability benefit.

Likes 0	
Dislikes 0	

Response

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	

Comment

CEHE agrees with EEI comments, requirement R3 does not provide sufficient clarity for the processes or expectations for coordination between adjacent Planning Coordinators and Transmission Planners, including the deadlines for the review of the Extreme Temperature Assessments by adjacent PCs and TPs.

Likes 0	
Dislikes 0	

Response

Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC) Project 2023-07 TPL-008-1 Draft #2

Answer	No
Document Name	

Comment

The SRC's most significant concerns involve requirement R3 as detailed below.

The Coordination Effort Required for Consistent, Wide-Area Cases Negates the Benefit of Choosing a Unique Benchmark Event

R3. The SRC agrees the proposed language, "***among adjacent*** impacted Planning Coordinator(s), Transmission Planner(s), and other designated study entities, within an Interconnection" is an improvement over the prior language because it clarifies how far an entity must reach beyond its footprint to satisfy the requirement.

That said, the SRC still has significant concerns regarding the number of studies that must be performed, particularly when a Planning Coordinator (PC) selects a benchmark temperature event that is different from that of its adjacent PC(s). In that situation, each benchmark temperature event may necessitate a significant coordination effort, similar to what is done to develop the MMWG base case for the Eastern Interconnection.

If that's the case, it doesn't seem feasible to develop consistent, wide-area cases when each PC can select unique events. We also note that R4.1 gives each entity the freedom to choose a different year for the long-term horizon, which could further exacerbate the number of cases that must be developed to comply with the coordination process under R3.

To address this concern, the SRC recommends a neutral third party identify the scenarios for Interconnections with more than one PC. Extreme temperature events in such Interconnections will typically extend beyond the footprint of a single Planning Coordinator. To avoid putting the PCs in a position where they are required to agree on a scenario, a year and the sensitivity to be studied, NERC or some other entity (e.g. Eastern Interconnection Reliability Assessment Group, ERAG) should identify the extreme heat and extreme cold temperature events to be studied. This is necessary to ensure consistent modeling results across adjacent planning entities within an Interconnection. Also, as a benchmark temperature event may extend across several planning areas, the neutral third party must take this into consideration when determining which extreme heat and extreme cold temperature events are to be studied so that no planning entity is assigned more than one of each.

R4. SRC supports the proposed language ("data consistent with that provided in accordance with the MOD-032 standard") and does not see a need to update MOD-032 at this time; however, depending upon what data the benchmark temperature event requires to perform the study, this may need to be revisited.

R5. SRC supports the addition of "***and applicable Facility Ratings***" considering the need to comply with FERC Order 881 and Ambient Adjusted Ratings in the near future. SRC members are also exploring this further with their member TOs.

Likes 0	
Dislikes 0	

Response

Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle

Answer	No
Document Name	

Comment

PGAE agrees with R5 and R6 but does not agree with R4. Extreme Temperature Events are already a "sensitivity" to normal long-term planning cases and are be built with Gen/Load/Transfer based on the extreme weather conditions of an entity's territory. Additional, mandatory "sensitivity cases" seems redundant in nature.

Likes 0	

Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	

ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.

In addition, ERCOT is concerned that Requirement R4, Part 4.1 unnecessarily and inadvertently limits the ability of entities to properly develop their benchmark planning cases. Specifically, ERCOT is concerned that Part 4.1 could be understood to mean that entities are limited to making the adjustments specifically described in Part 4.1 and are prevented from making adjustments necessary to update the planning cases to reflect the expected future state of the system or to ensure that the generation necessary to serve load is available so that the case can solve. Adjusting the case to ensure that it contains enough generation to serve the modeled load is essential to ensure that the standard does not address resource adequacy issues and fully complies with paragraph 94 of FERC Order No. 896, which states that resource adequacy is not in scope for this project.

ERCOT is also concerned that Part 4.1 could be understood to require entities to model facility derates and outages that were actually observed during the selected benchmark temperature event rather than requiring entities to model impacts of the temperatures observed during that event on the system as it is expected to exist in the year being evaluated. To address these concerns, ERCOT recommends that Part 4.1 be revised to read as follows:

4.1 Benchmark planning cases that ***reflect the expected future state of the System and*** include seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers ***based on the weather*** conditions ***described in*** the selected benchmark temperature events as identified in Requirement R2 for one of the years in the Long-Term Transmission Planning Horizon. ***The responsible entity may adjust the total modeled generation or Load in each case as necessary to allow the total modeled generation to serve the total modeled System Load.*** The rationale for the year selected for evaluation shall be available as supporting information. This establishes Category P0 as the normal System condition in Table 1.

ERCOT also recommends that Requirement R3 be revised as needed to align with any revisions made to Requirement R4.

Likes 0	
Dislikes 0	
Response	
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
Answer	No
Document Name	

Comment	
PJM supports the IRC SRC comments.	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1	
Answer	No
Document Name	
Comment	
See comments submitted by Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
John Brewer - National Energy Technology Laboratory - 9 - NA - Not Applicable	
Answer	No
Document Name	
Comment	

(R3) It is unclear who the "other designated study entities" are and who defines them.

(R3) R2 Requirement allows each responsible entity to select different benchmark temperature event(s). R3 should be revised to clarify how conflicts will be resolved if different Planning Coordinators within the same Interconnection select different events.

(R4.1) In Order 896 paragraph 88, FERC directs "NERC to require under the new or revised Reliability Standard the study of concurrent/correlated generator and transmission outages due to extreme heat and cold events in benchmark events," explaining in paragraph 89 that "it is necessary that responsible entities evaluate the risk of correlated or concurrent outages and derates of all types of generation resources and transmission facilities as a result of extreme heat and cold events." We suggest modifying "Benchmark planning cases that include seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers" to include "concurrent/correlated generator and transmission outages."

Allowing benchmark planning cases for “one of the years in the Long-Term Transmission Planning Horizon” will burden each responsible entity with developing necessary adjustments for a different year than the adjacent responsible entity selected if they do not select the same year.

(R4.2) If sensitivity analysis allows the selection of only one condition, R4.2 should be revised to (1) provide a ranking of what conditions should be selected first, or (2) provide a process that each responsible entity should follow for the sensitivity analysis with the three listed conditions, or (3) requires all conditions to be changed during the sensitivity analysis.

(R5) No issue.

Likes 0	
Dislikes 0	

Response

Usama Tahir - Seminole Electric Cooperative, Inc. - 3

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF

Answer	Yes
Document Name	

Comment

M4 should state “Each responsible entity, as identified in Requirement R1,…” to remain consistent with other Measures

Likes 0	
Dislikes 0	

Response

Gary Trezza - Long Island Power Authority - 1 - NPCC

Answer	Yes
Document Name	
Comment	

Comments/ Questions:

Requirement #5 mentions having criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and applicable Facility Ratings.

Is it the intent that entities will also have to have (and document) applicable thermal criteria for completing the Extreme Temperature Assessment? For example, allowing for the possible use of STE facility ratings post-contingency?

In certain jurisdiction, extreme temperature ratings have been established, but that is not necessarily the case in all jurisdictions. Will facility owners be required to establish extreme cold or warm temperature ratings for this standard?

Likes 0	
Dislikes 0	
Response	

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	Yes
Document Name	
Comment	

Duke Energy supports proposed language but requires clarification of the phrase “other designated study entities”.

Likes 0	
Dislikes 0	
Response	

Daniela Atanasovski - APS - Arizona Public Service Co. - 1

Answer	Yes
Document Name	
Comment	

AZPS generally supports the updates made by the STD to R3 – R5. AZPS also supports the comments that were submitted by EEI on behalf of its members that R3 does not provide sufficient clarity for the processes or expectations for coordination between adjacent Planning Coordinators and

Transmission Planners, including the deadlines for the review of the Extreme Temperature Assessments by adjacent PCs and TPs. Please see EEI comments regarding recommended changes to the requirement.	
Likes 0	
Dislikes 0	
Response	
Apollonia Gonzales - PNM Resources - Public Service Company of New Mexico - 1,3,5 - WECC	
Answer	Yes
Document Name	
Comment	
R3 and R4.4 should include facility ratings since FERC Order 881 establish AAR. Seasonal rating typically used in planning studies would not be appropriate for the extreme weather assessment. … include seasonal and temperature dependent adjustment for Load, generation, Transmission, facility ratings, and transformers… The SDT should consider making the definition of Extreme Temperature Assessment align better with the definition of Planning Assessment.	
Likes 0	
Dislikes 0	
Response	
Srikanth Chennupati - Entergy - Entergy Services, Inc. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Barbara Marion - Dominion - Dominion Resources, Inc. - 5, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Matt Lewis - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE has the following recommendations for Requirement R3:

- Provide clarification around "adjacent impacted Planning Coordinators, Transmission Planners, and other designated study entities". If the Planning Coordinator (PC) determines an adjacent PC or Transmission Planner (TP) is not impacted, justification should be provided.
- The goal for Requirement R3, is for the PC to have a process which describes the methodology used to define temperature dependent adjustments to the overall load, generation, transmission ratings, and transfers to match the benchmark temperature level compared to the seasonal ratings in order for consistent temperature dependent adjustments to be utilized by all the impacted entities within the interconnection. Texas RE recommends the following revision to Requirement R3 (in bold):

R3. Each Planning Coordinator shall develop and implement a process for coordinating the development of benchmark planning cases, using the selected benchmark temperature events identified in Requirement R2, among adjacent impacted Planning Coordinator(s), Transmission Planner(s), and other designated study entities, within an Interconnection. This process shall include the methodologies used to generate seasonal and the temperature dependent adjustments for the data inputs such as Load, generation, Transmission, and transfers to represent the selected benchmark temperature events.

Texas RE has the following recommendations for Requirement R4:

- Requirements R3 and R4 are currently written in such a way that if an entity fails to meet one of the standards, it will fail to meet the other one. Texas RE recommends bifurcating both requirements so R3 focuses on developing a process for coordination the development of benchmark cases, and R4 focuses on implementing the process in Requirement R3 for coordinating the development of the benchmark case. The term "implement" rather than the term "use" is consistent with other NERC Reliability Standards. Texas RE recommends the following verbiage:

R3. Each Planning Coordinator **shall develop** a process for coordinating the development of benchmark planning cases, using the selected benchmark temperature events…

R4. Each responsible entity, as identified in Requirement R1, shall **implement** the coordination process developed in accordance with Requirement R3…

- Texas RE is concerned that Requirement R4 states the selected benchmark temperature events should be for one of the years in the Long-Term Transmission Planning Horizon. Given the number of variables, the Transmission System could be significantly different 6-10 years in the future. Texas RE recommends selecting benchmark events for the Near-Term Planning Horizon as there are more known variables.

- Requirement 4.1 states the “Benchmark planning cases that include seasonal and temperature dependent adjustments for Load, generation…” This could create some confusion whether a seasonal base case should be developed first and then make the temperature dependent adjustments for the data points listed. Texas RE recommends removing the word ‘seasonal’ from this requirement.

4.1. Benchmark planning cases that include temperature dependent adjustments for Load, generation, Transmission, and transfers to represent the System conditions of the selected benchmark temperature events as identified in Requirement R2 for one of the years in the Long-Term Transmission Planning Horizon. The rationale for the year selected for evaluation shall be available as supporting information. This establishes Category P0 as the normal System condition in Table 1

For consistency with other Requirement language, Texas RE recommends the following revision for Requirement R5 (in bold):

R5. Each responsible entity, as identified in Requirement R1, **shall define** and document the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and applicable Facility Ratings for **evaluating** the Extreme Temperature Assessment results.

Likes 0	
Dislikes 0	

Response

4. The DT updated Requirements R6 – R8 based on comments received. Do you agree with the updated proposed TPL-008-1 Reliability Standard Requirements R6-R8? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Long Island Power Authority	
Answer	No
Document Name	(if an attachment is provided by submitter)

Comment

Requirement # 7 states:

“Each responsible entity, as identified in Requirement R1, shall identify the planning events for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System. The rationale for those Contingencies selected for evaluation shall be available as supporting information.”

We observe that the above language is slightly different from TPL-001-5.1 Req # 3.4, which states:

“Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES shall be identified, and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.”

In summary, we observe that TPL-008-1 Req #7 requires the identification of planning events for each category in Table 1 (i.e., P0, P1, P2, P4, P7), while TPL-001-5.1 Req #3.4 does not explicitly require the identification of planning events for each category in Table 1.

We are not certain if this distinction (added burden for TPL-008-1 as compared to TPL-001-5.1) was intended by the SDT, as so we wanted to point this out.

We would also like the SDT to clarify if the intent is that the entity must identify contingencies for each “Category” (P2 for example) AND each “Event” (P2.1 for example). Without clarification, this requirement could be interpreted differently by auditors.

Likes 0	# of other submitters who agree with these comments
Dislikes 0	# of other submitters who disagree with these comments

Response

(Drafting team’s response to submitter’s comments)

John Brewer - National Energy Technology Laboratory - 9 - NA - Not Applicable	
Answer	No
Document Name	
Comment	

(R6) No issue.

(R7) No issue.

(R8) It is not clear if steady state and transient stability analysis using the identified contingencies from R7 should be included in every 8.1 (the benchmark planning cases developed in accordance with Requirement R4 Part 4.1.) and 8.2 (the sensitivity cases developed in accordance with Requirement R4 Part 4. 2.) analysis.

The Technical Rationale for R8 Requirements specifies the minimum number of assessments (a minimum of one benchmark planning case analysis for extreme cold, a minimum of one for extreme heat, a minimum of one sensitivity study case for one condition for extreme cold, and a minimum of one sensitivity study case for one condition for extreme heat). We suggest clarifying this in 4.1. and 4.2.

Likes 0	
Dislikes 0	
Response	
Apollonia Gonzales - PNM Resources - Public Service Company of New Mexico - 1,3,5 - WECC	
Answer	No
Document Name	
Comment	

PNM agrees with EEI's comments and feedback for this question.

Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1	
Answer	No
Document Name	
Comment	

See comments submitted by Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
Answer	No
Document Name	
Comment	
PJM supports the IRC SRC comments.	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	No
Document Name	
Comment	

PGAE has no comment on R6 or R7, however, we disagree with the proposed R8. *See above comments for Question 3 related to R4, as R8 is in reference to R4.*	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC) Project 2023-07 TPL-008-1 Draft #2	
Answer	No
Document Name	
Comment	
The SRC supports some of the revisions and proposes modifications to others as detailed below. R6 needs better wording to indicate instability, uncontrolled separation and cascading must all be monitored for. The "or" makes it seem like only one of the three must be addressed. **R7.** SRC supports the SDT's decision to modify the language from "Contingencies" to "planning events;" however, we believe a similar change should be made to the second reference to "Contingencies" later in the paragraph (*see* sentence 2). SRC proposes the edit below. **R7.** Each responsible entity, as identified in Requirement R1, shall identify the planning events for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System. The rationale for those ***planning events*** selected for evaluation shall be available as supporting information.	
Likes 0	
Dislikes 0	
Response	
Usama Tahir - Seminole Electric Cooperative, Inc. - 3	
Answer	No
Document Name	
Comment	
Seminole would like a longer implementation timeline for R7 of 72 months to determine which planning events produce more severe planning events.	
Likes 0	
Dislikes 0	
Response	

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
Please refer to Question 1 comments.	
Likes 0	
Dislikes 0	
Response	

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
In R7, ITC has concerns with the term planning event and believes that this should be changed to contingencies. To ITC, the term planning event should be used to describe the benchmark event, not the outage of a portion of the grid. The DT needs to identify which system this standard is applicable to analyze. ITC believes it should remain the Bulk Electric System (BES) rather than being applicable to the Bulk Power System (BPS). NERC standards do not typically apply to the BPS. Entities that own the BES system in an area can identify any concerns for the BES. If an entity does not own the BPS also, applying it to the BPS would expose them to issues outside of their control.	
Likes 0	
Dislikes 0	
Response	

Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	No
Document Name	
Comment	
R6 could be moved to the beginning of the R2-R5 section or be included as part of the Operating Plan as described in our response to Question 1. R7 requires testing of all the events listed in Table 1, however R9 only requires the development of CAPs for the P0 and P1 contingencies. ISO-NE recommends modifying Table 1 to only include P0 and P1 events in accordance with the FERC Order 896 Paragraph 113 Commission Determination that *"NERC may determine whether contingencies P1 through P7 should also apply to the new or modified Reliability Standard, or*	

whether a new set of contingencies should be developed." Paragraph 113 of the Commission Determination does not require the inclusion of events other than P0. ISO-NE believes P0 and P1 events are acceptable for this Standard, however, P2, P4, and P7 events are not.

The technical Rationale for R10 should be modified to remove *"However, due to their potential severity resulting from single Contingency multiple element outages, the SDT believes it is appropriate for responsible entities to at least evaluate and document possible mitigation actions to reduce the likelihood or mitigate the consequences and adverse impacts. The biggest benefit from the evaluation and documentation of the mitigating actions is it allows an entity to see where major problems exist that they may need to be addressed; and, if a project shows up on enough issues, it may encourage a fix to be implemented without it being strictly called for from the standard. Not requiring CAPs for these contingencies but requiring the evaluation is a compromise from having CAPs for all studied issues."*

Likes 0	
Dislikes 0	

Response

Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford

Answer	No
Document Name	

Comment

R6:

- The inclusion of "within an Interconnection" is not appropriate as the PC or TP should not be required to assess outside of its applicable area. Note the inclusion of more appropriate language referring to the PC's or TP's planning area (its portion of the Bulk Electric System) in this draft so it is not clear why some requirements refer to an Interconnection while others, more correctly, refer to the area of actual responsibility for the PC or TP.
- The following bullet contains a wording addition to clarify the applicability of this requirement to System-wide impacts. This is also consistent with wording in other Reliability Standards when referencing these types of impacts.
- "Each responsible entity, as identified in Requirement R1, shall define and document the criteria or methodology used in the Extreme Temperature Assessment analysis to identify instability, uncontrolled separation, or Cascading of the Bulk Electric System."

R7 & R8:

- It does not appear likely that P0 & P1 events would be "expected to produce more severe System impacts" in typical planning studies. However, with an extreme weather scenario as the baseline, a P0 or P1 may produce more severe impacts due to the anomalous starting point. It would make more sense to allow the PC/TP to develop the appropriate study methodology (and document it) to appropriately analyze the required benchmark. Focusing on traditional P-event definitions and recycling language from TPL-001 is not appropriate since the analysis/assessments between the two standards is drastically different.
- The standard does not clearly and specifically state whether steady-state and/or stability analysis is to be performed for the identified events as TPL-001 does for instance. The SDT should consider modifying R7 to allow the responsible entity to develop a methodology or rationale in the performance of a benchmark event to appropriately assess it for that entity's planning area, otherwise, additional clarity in the analysis expectations is needed. Different weather events would require a different consideration of applicable contingencies and analysis approaches.
- Adding "transient" to qualify stability may result in more confusion in interpretation between planning entities, auditors, and the referenced ERO. There is a requirement to document stability criteria so this should be clear based on that documentation. Adding "transient" therefore is more detrimental than helpful to this standard.
- Some of the lack of clarity may be related to the lack of clarity around the composition of the benchmark events to be determined. If these benchmark events are limited to temperature profiles versus temperature profiles and potential resultant generation unavailability (for example), the responsible entity's analysis approach will potentially vary.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO

Answer	No
Document Name	

Comment

SPP has concerns in reference to Requirement R7 and the applicability of Table 1 creating issues for industry by applying the extreme weather event matrix to this standard as it creates issues with the base case and scenario results.

At this point, it is unclear how the base case will translate the benchmarked events into the models. Moreover, it is unclear on the expectations of handling the events in the Table 1. For example, our initial assessment would lead us to believe that we will need to evaluate a P1 event like a P6 event.

Finally, there is a concern about the validity of the issues that maybe found dearing in this assessment and resulting dollars for CAPs.

SPP recommends that the drafting team provide clarity around their expectations for Table 1 by using the current events information from TPL-001 or revisioning those events to align appropriate with the requirements of the assessment for the TPL-008.

Likes 0	
Dislikes 0	

Response

Rebika Yitna - Rebika Yitna On Behalf of: David Weekley, MEAG Power, 3, 1; Roger Brand, MEAG Power, 3, 1; - Rebika Yitna

Answer	No
Document Name	

Comment

The phrase “within an Interconnection” may need to be clarified or defined.

Likes 0	
Dislikes 0	

Response

Donna Wood - Tri-State G and T Association, Inc. - 1

Answer	No

Document Name	
Comment	

Tri-State supports the comments submitted by the MRO NSRF.

Likes 0	
Dislikes 0	
Response	

Greg Sorenson - Greg Sorenson On Behalf of: Tyler Schwendiman, ReliabilityFirst , 10; - Greg Sorenson

Answer	No
Document Name	
Comment	

Similar to the CIP-014 project, R6 includes “instability, uncontrolled separation, or Cascading". This is similar to, yet slightly different from, the defined term Interconnection Reliability Operating Limit (IROLs).

Likes 0	
Dislikes 0	
Response	

Hillary Creurer - Allete - Minnesota Power, Inc. - 1

Answer	No
Document Name	
Comment	

Minnesota Power supports MRO’s NERC Standards Review Forum’s (NSRF) comments.

Likes 0	
Dislikes 0	
Response	

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC

Answer	No
Document Name	
Comment	

Requirement R7 struck “Contingencies” and replaced that with “the planning events” in the first sentence but did not strike “Contingencies” in the second sentence. It is not clear as to why the change was made as “Contingency” is defined while “planning event” is not. Requirement R8 uses the phrase “Contingencies identified in Requirement 7” which is not supported by the proposed language of Requirement R7. The Technical Rational supports and reiterates the use of Contingency. FERC Order 896 stated (and is listed in the Technical Rationale): “[w]e believe that it is necessary to establish a set of common contingencies for all responsible entities to analyze. Required contingencies, such as those listed in Table 1 of Reliability Standard TPL-001-5.1 (i.e., category P1 through P7), establish common planning events that set the starting point for transmission system planning assessments,”.

Likes 0	
Dislikes 0	

Response

Selene Willis - Edison International - Southern California Edison Company - 5

Answer	No
Document Name	

Comment

Please see comments from EEI

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment

EEI does not have concerns with Requirement R6 or Requirement R8, however, we do suggest some non-substantive changes to Requirement R7. Specifically, we suggest changing “planning event” to “contingency event” to align with Table 1.1 more clearly. Our suggested changes are indicated below in boldface.

R7. Each responsible entity, as identified in Requirement R1, shall identify the **contingency** events for each category in Table 1**.1** that are expected to produce more severe System impacts on its portion of the Bulk Electric System. The rationale for those Contingencies selected for evaluation shall be available as supporting information. [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

Likes 0	
Dislikes 0	

Response	
Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop	
Answer	No
Document Name	
Comment	
In R7, Ameren recommends changing "Contingencies" to "planning events" in the last sentence. This would align with the revision made in the first part of R7. In addition, Ameren agrees with and supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez	
Answer	No
Document Name	
Comment	
Define Table 1 for requirement R7. We also request increased clarity on the case selection & building process required in R4.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
The Requirement R7 language is not clear whether the responsible entity should evaluate the impact of each of the Contingencies listed in Table 1.1 or the responsible entity is to guess (or select based on some rationale criteria) which contingency event will produce more severe System impacts on its portion of the BPS. Additionally, while the requirement language states there should be rationale for those Contingencies selected, there is no language saying there should be rationale for the Contingencies not selected. Texas RE recommends language to require rationale for both why certain Contingencies are selected and why others are not selected.	
Likes 0	

Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	

Comment

Southern Company requests that the phrase “within an Interconnection” be clarified or defined. Southern Company would like clarification on why transient stability is specified in R8, but not other portions of the standard.

Likes 0	
Dislikes 0	

Response

Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	

Comment

NextEra supports EEI's comments

EEI does not have concerns with Requirement R6 or Requirement R8, however, we do suggest some non-substantive changes to Requirement R7. Specifically, we suggest changing “planning event” to “contingency event” to align with Table 1.1 more clearly. Our suggested changes are indicated below in boldface.

R7. Each responsible entity, as identified in Requirement R1, shall identify the **contingency** events for each category in Table 1**.1** that are expected to produce more severe System impacts on its portion of the Bulk Electric System. The rationale for those Contingencies selected for evaluation shall be available as supporting information. [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

Likes 0	
Dislikes 0	

Response

Kevin Conway - Western Power Pool - 4	
Answer	No
Document Name	

Comment	
R6 and R7 Risk factors should be Medium to match TPL 001-5.	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
For R6 & R7, Santee Cooper suggests the VRF's be Medium to match TPL-001-5. We also feel like the additional sensitivity studies required in R8.2 would add a significant administrative burden without more clarification to how it benefits the long term planning horizon.	
Likes 0	
Dislikes 0	
Response	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
ATC supports the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	No
Document Name	
Comment	

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 4	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	No
Document Name	
Comment	
The Violation Risk Factor (VRF) for Requirements R7 and R8 are designated as High, however, the VRF for similar requirements in TPL-001-5 are designated as Medium. The VRF for Requirements R7 and R8 in TPL-008-1 should be set to Medium to match TPL-001-5.	
Likes 0	
Dislikes 0	
Response	
Robert Jones - Seattle City Light - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
R6 and R7 Risk factors should be Medium to match TPL-001-5.	
Likes 0	
Dislikes 0	
Response	
Broc Bruton - Broc Bruton On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Broc Bruton	
Answer	No
Document Name	

Comment	

For R6, Oncor urges its comment from R5. The PC would need to ensure that all entities use the same methodology and criteria for instability, uncontrolled separation, or Cascading.

For R8, Oncor asks whether language can be added to ensure that entities can take credit for studies that are run as part of the Extreme Temperature Assessment, rather than running those studies again as part of the assessment to be conducted under TPL-001? For example, the Extreme Temperature Assessment could take the place of the sensitivity analysis required within the TPL-001 assessment for both the steady state and stability analyses.

Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	

MRO NSRF supports some of the revisions and proposes modifications to others as detailed below.

R6 needs better wording to indicate instability, uncontrolled separation and cascading must all be monitored for. The “or” makes it seem optional.

R7. MRO NSRF supports the SDT’s decision to modify the language from “Contingencies” to “*planning events*;” however, we believe a similar change should be made to the second reference to “Contingencies” later in the paragraph (*see* sentence 2). MRO NSRF proposes the edit below.

R7. Each responsible entity, as identified in Requirement R1, shall identify the *planning events* for each *category* in Table 1 that are expected to produce more severe System impacts *on* its *portion of the Bulk Electric System*. The rationale for those Contingencies *planning events* selected for evaluation shall be available as supporting information.

Part 8.1 MRO NSRF supports Part 8.1 and the analysis of the benchmark planning cases developed pursuant to Requirement 4, Part 4.1. As noted above, MRO NSRF views the benchmark temperature event as a “base case sensitivity” to that performed under TPL-001 and asks whether all sensitivities can be “baked into” the benchmark temperature event.

Likes 1	Scott Brame, N/A, Brame Scott
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	

Dominion Energy supports EEI comments. In addition, Dominion Energy is concerned over the ambiguity in the CAP process and would appreciate additional clarity on the role of the ERO in the CAP process.	
Likes 0	
Dislikes 0	
Response	
Zahid Qayyum - New York Power Authority - 5	
Answer	No
Document Name	
Comment	
The Violation Risk Factor for R6 and R7 is currently 'high' and should be lowered to 'medium' to align with TPL 001-5.1	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FirstEnergy supports EEI's comments which state: EEI does not have concerns with Requirement R6 or Requirement R8, however, we do suggest some non-substantive changes to Requirement R7. Specifically, we suggest changing "planning event" to "contingency event" to more clearly align with Table 1.1. We also note that Bulk Power System was incorrectly identified as Bulk Electric System. Our suggested changes are indicated below in boldface: R7. Each responsible entity, as identified in Requirement R1, shall identify the **contingency** events for each category in Table 1**.1** that are expected to produce more severe System impacts on its portion of the Bulk **Electric Power** System. The rationale for those Contingencies selected for evaluation shall be available as supporting information. [Violation Risk Factor: High] [Time Horizon: Long-term Planning]	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	

Answer	No
Document Name	
Comment	

Duke Energy agrees with and recommends implementation of EEI comments.

Likes 0	
Dislikes 0	
Response	

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO

Answer	No
Document Name	
Comment	

The standard practice is to first identify the base-case planning scenarios to perform the extreme temperature assessment and then identify the applicable contingencies. The revised wording in R7 is confusing and does not convey the correct message. Please refer to the specific table when referring to contingencies and performance requirements, for example, refer to Table 1.1 the contingencies to be studies and Table 1.2 for the performance requirements. It is expected that the SDT will revise R7 to make this clarification.

Manitoba Hydro does not think there is a need to perform additional sensitivity studies as per R 8.2 (see our response to R 4.2 under comment -3).

Likes 0	
Dislikes 0	
Response	

Gary Trezza - Long Island Power Authority - 1 - NPCC

Answer	No
Document Name	
Comment	

Requirement # 7 states:

"*Each responsible entity, as identified in Requirement R1, shall identify the planning events for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System. The rationale for those Contingencies selected for evaluation shall be available as supporting information.*"

We observe that the above language is slightly different from TPL-001-5.1 Req # 3.4, which states:

"Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES shall be identified, and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information."

In summary, we observe that TPL-008-1 Req #7 requires the identification of planning events for each category in Table 1 (i.e., P0, P1, P2, P4, P7), while TPL-001-5.1 Req #3.4 does not explicitly require the identification of planning events for each category in Table 1.

We are not certain if this distinction (added burden for TPL-008-1 as compared to TPL-001-5.1) was intended by the SDT, as so we wanted to point this out.

We would also like the SDT to clarify if the intent is that the entity must identify contingencies for each "Category" (P2 for example) AND each "Event" (P2.1 for example). Without clarification, this requirement could be interpreted differently by auditors.

Likes 0	
Dislikes 0	

Response

Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD

Answer	No
Document Name	

Comment

CHPD believes the updates made to R6 through R8 were very good, with one concern for R6 and R7 remaining. The VRF for the 'Bad 3' criteria and contingencies/rational are both set as 'High' as proposed in TPL-008, while the same type of limits requirement has a VRF of 'Medium' in TPL-001-5 R6 and R3.4/R4.4 respectively. It is requested the VRF for TPL-008 R6 and R7 be similarly set as 'Medium' for consistency.

Likes 1	Jennie Wike, N/A, Wike Jennie
Dislikes 0	

Response

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

(R6) No issues.

(R7) No issues.

(R8.2) We do not agree that R8.2, which requires an increasingly more extreme scenario for purposes of a sensitivity analysis, is credible. This is especially true for longer term planning horizons when generation additions and retirements, along with transmission configuration changes and new technologies to be deployed are less detailed.	
Likes 0	
Dislikes 0	
Response	
Chelsea Loomis - Western Power Pool - NA - Not Applicable - WECC, Group Name WPP Consortium of Engineers	
Answer	No
Document Name	
Comment	
R6 and R7 Risk factors should be Medium to match TPL 001-5.	
Likes 0	
Dislikes 0	
Response	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	No
Document Name	
Comment	
If R8 refers to Contingencies identified in requirement R7, why was the use of "contingencies" in R7 changed to "planning events". Recommend changing R7 back to contingencies for consistency. When referring to contingencies in table 1, suggest updating to table "1.1".	
Likes 0	
Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	No
Document Name	
Comment	

R6, and R7 VRFs are 'high', but they should be Medium to match TPL 001-5.	
Likes 2	Snohomish County PUD No. 1, 3, Chaney Holly; Jennie Wike, N/A, Wike Jennie
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
R6. Each responsible entity, as identified in Requirement R1, shall define and document the criteria or methodology used in the Extreme Temperature Assessment analysis to identify instability, uncontrolled separation, ***and*** Cascading. within an Interconnection.	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Helen Lainis - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	

We support the SDT's decision to modify the language from "Contingencies" to "planning events;" however, we believe a similar change should be made throughout the proposed standard.	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation has no concerns with the updated language for requirements R6, R7, and R8.	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question.	

Likes 0	
Dislikes 0	
Response	
Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA recommends R6 and R7 Risk factors should be set to Medium to match TPL 001-5. For R7, BPA recommends adding “and create a list of Contingencies to be evaluated”. *Each responsible entity, as identified in Requirement R1, shall identify the planning events for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System and create a list of Contingencies to be evaluated. The rationale for those Contingencies selected for evaluation shall be available as supporting information.*	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michele Shafer - New York State Electric & Gas (NYSEG) - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Matt Lewis - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michele Tondalo - United Illuminating Co. - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Junji Yamaguchi - Hydro-Quebec (HQ) - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Barbara Marion - Dominion - Dominion Resources, Inc. - 5, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Fon Hiew - NB Power Corporation - New Brunswick Power Transmission Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lidija Efremova - Lidija Efremova On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Lidija Efremova	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Srikanth Chennupati - Entergy - Entergy Services, Inc. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Streifling - NB Power Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Chantal Mazza On Behalf of: Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	

5. The DT updated Requirement R9 based on comments received. Do you agree with the updated proposed TPL-008-1 Reliability Standard Requirement R9? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Long Island Power Authority	
Answer	No
Document Name	(if an attachment is provided by submitter)
Comment	

Requirement #9.3 states:

"Be permitted to utilize Non-Consequential Load Loss as an interim solution, which normally is not permitted in Table 1, in situations that are beyond the control of the Planning Coordinator or Transmission Planner that prevent the implementation of a Corrective Action Plan in the required timeframe."

The Extreme Temperature Assessment would have to be performed at least once every 5 years, assessing one year in the Long Term Planning Horizon.

It is recognized that the details of the extreme heat/cold benchmark temperature events may change over time, and that the underlying assumptions utilized in the Extreme Temperature Assessment for one of the years in the Long Term Planning Horizon may change over time. CAPs identified in one Assessment may not be needed in a future Assessment. It may be difficult to pursue expensive CAPs understanding that assumptions may change.

With this in mind, we find it difficult from a compliance perspective to clearly identify what is meant by "in the required timeframe". This language, while allowing for flexibility, seems very ambiguous. The Technical Rationale does not elaborate on this point.

We recommend that the SDT clarify what is intended by "in the required timeframe."

Likes 0	# of other submitters who agree with these comments
Dislikes 0	# of other submitters who disagree with these comments
Response	
(Drafting team's response to submitter's comments)	

Chantal Mazza - Chantal Mazza On Behalf of: Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza

Answer	No
Document Name	

Comment	
There are already existing processes for interactions with applicable regulatory authorities and governing bodies regarding CAP for many other issues and items. Extreme weather CAPs are not exceptions and do not need a new way to solicit feedback. R9.1 should be removed because it also creates a compliance requirement without any benefit to reliability and would be confusing.	
Likes 0	
Dislikes 0	
Response	
Jeffrey Streifling - NB Power Corporation - 1	
Answer	No
Document Name	
Comment	
There are already existing processes for interactions with applicable regulatory authorities and governing bodies regarding CAP for many other issues and items. Extreme weather CAPs are not exceptions and do not need a new way to solicit feedback. R9.1 should be removed because it also creates a compliance requirement without any benefit to reliability and would be confusing.	
Likes 0	
Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	No
Document Name	
Comment	
The "applicable regulatory authorities... electric service" needs better clarification - what does this look like for Jurisdisctionals vs non-Jurisdictionals - is this not applicable to non-Jurisdictionals? Ask of SDT to provide better guidance & examples. Could NERC provide some examples for both jurisdictional entities and non-jurisdictional entities for what is intended for this standard. It is highly recommended using operation procedures instead of CAPs since operation procedures have more flexibility to respond to a system’s needs and adapt proactively.	
Likes 2	Snohomish County PUD No. 1, 3, Chaney Holly; Jennie Wike, N/A, Wike Jennie
Dislikes 0	
Response	
Chelsea Loomis - Western Power Pool - NA - Not Applicable - WECC, Group Name WPP Consortium of Engineers	

Answer	No
Document Name	

Comment

Language unclear pertaining to non-jurisdictionals, could NERC provide some examples for both jurisdictionals and non-jurisdictionals for what is intended for this standard? applicable regulatory authorities or governing bodies responsible for retail electric service" needs better clarification - what does this look like for Jurisdisctionals vs non-Jurisdictionals - is this not applicable to non-Jurisdictionals? Ask of SDT to provide better guidance and examples here.

Could operational procedures be used in lieu of a CAP as an acceptable mitigation?

Likes 0	
Dislikes 0	

Response

Srikanth Chennupati - Entergy - Entergy Services, Inc. - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

R9.3 The phrase "required timeframe" is unclear and should be more thoroughly defined.

Likes 0	
Dislikes 0	

Response

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

(R9.1) We cannot agree with R9.1 without further clarification of how “applicable” entities are determined. We recommend that the reference to “applicable” entities in R9.1 should be integrated into R3, suggesting that “applicable” entities shall be identified as part of R3 coordination process developed by the PC.

(R9.2) We cannot agree with R9.2 due to the lack of understanding of the value for “alternative considerations”. The analysis process to determine how best to meet performance requirements is quite complex and comprehensive. We believe attempting to document, notify, and discuss alternatives that were deemed less reliable, less economical, and therefore less impactful to ensure system performance would be an inefficient and ineffective task, and likely to cause more confusion that clarity.

(R9.3) No issues.

(R9.4) No issues.

Likes 0	
Dislikes 0	

Response

Lidija Efremova - Lidija Efremova On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Lidija Efremova

Answer	No
Document Name	

Comment

Comments:

We think R9.1 should be removed because it creates a compliance requirement without any incremental benefit to reliability. It further conflicts with existing planning requirements and processes.

Please see comment on R10.

Likes 0	
Dislikes 0	

Response

Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD

Answer	No
Document Name	

Comment

CHPD believes the updates made to R9 were very good, with a couple concerns remaining. The first concern is to the statement ‘make their CAP available’ in R9.1. CHPD suggests this be changed to ‘make available on request’, to align with a similar request-based mechanism under R11. We’ve found the general ‘make available’ is murky language for compliance.

The second concern is the expectation in 9.1 and 9.2 for soliciting feedback and notifications to ‘regulatory authorities or governing bodies responsible for retail electric service issues. The intent here is not clear. Could the SDT provide some examples of what is intended here, both for Jurisdictional and

non-Jurisdictional entities? Furthermore, it is noted that the Measures for R9 do not appear to include the solicitation and notification as part of the measures for compliance with R9.	
Likes 1	Jennie Wike, N/A, Wike Jennie
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
R9 and Table 1 requires the development of Corrective Action Plans for P1 events where applicable facility ratings are exceeded and steady state voltages are not within limits. This requirement goes beyond the directives in FERC Order 896. The FERC Order is concerned with cascading, instability, and uncontrolled islanding but not with facility overloads.	
Likes 0	
Dislikes 0	
Response	
Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA views this as an extreme event that doesn't occur often. BPA recommends these issues be resolved in the operational time horizon through operating plans. BPA believes an operating plan would provide acceptable performance for an extreme event. BPA believes an operating plan could be used in lieu of a Corrective Action Plan.	
Likes 0	
Dislikes 0	
Response	
Fon Hiew - NB Power Corporation - New Brunswick Power Transmission Corporation - 5	
Answer	No
Document Name	
Comment	

There are already existing processes for interactions with applicable regulatory authorities and governing bodies regarding CAP for many other issues and items. Extreme weather CAPs are not exceptions and do not need a new way to solicit feedback. R9.1 should be removed because it also creates a compliance requirement without any benefit to reliability and would be confusing.

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	No
Document Name	

Comment

Duke Energy agrees with and recommends implementation of EEI comments.

Additionally: (a) Define authorities and governing bodies listed in proposed Requirement 9.1.: "Make their CAP available and solicit feedback from applicable regulatory authorities or governing bodies responsible for retail electric service issues" and

(b) Modify R9.2. to read 'Document "any" alternative(s) considered', since scenarios may only have one option and prove unrealistic for all scenarios.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	No
Document Name	

Comment

FirstEnergy requests the DT to clarify intent providing feedback toward CAP – timeframe of soliciting feedback and what actions would result from providing feedback. Clarify who applicable "regulatory authorities or governing bodies for retail service" would be.

FirstEnergy also supports EEI's comments which state:

EEI offers non-substantive edits in boldface below to Requirement R9.

R9. Each responsible entity, as identified in Requirement R1, shall develop a Corrective Action Plan(s) (CAPs) when the assessment of a benchmark planning case, in accordance with Requirement R8 Part 8.1, indicates its portion of the Bulk **Electric Power** System is unable to meet performance requirements for Table **1.1** P0 or P1 Contingencies. For each Corrective Action Plan, the responsible entity shall: [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

Likes 0	
Dislikes 0	

Response

Zahid Qayyum - New York Power Authority - 5

Answer	No
Document Name	

Comment

Regarding R9.1 NYPA request standard drafting team to clarify the term "applicable regulatory authorities...electric service" for better clarification and understanding.

Likes 0	
Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	No
Document Name	

Comment

The MRO NSRF recommends the SDT adopt one of the two options (below) and clarify the requirements for each.:

Option #1:

- R9 should focus solely on either benchmark cases for power flow and stability and
- R10 should focus solely on sensitivity cases for each

Option #2:

- R9 should focus on power flow for both benchmark and stability and
- R10 focus on sensitivity study requirements for both power flow and dynamic stability.

MRO NSRF observes that **R9** addresses Load Loss under TPL-008 whereas this is addressed under TPL-001 in TPL-001-5.1, Table 1. The first sentence of Part 9.3 should be stricken from the standard as illustrated below because it is explanatory in nature and adds no value to the standard. MRO NSRF recommends this be migrated to the Technical Rationale if the SDT feels it is important to retain.

9.3. The use of Non-Consequential Load Loss as an interim solution in this situation is permitted, provided that each responsible entity documents the situation causing the problem, alternatives evaluated, and takes actions to resolve the situation.

(Please review the attached document, question 1).	
Likes 1	Scott Brame, N/A, Brame Scott
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	No
Document Name	
Comment	
There are already existing processes for interactions with applicable regulatory authorities and governing bodies regarding CAP for many other issues and items. Extreme weather CAPs are not exceptions and do not need a new way to solicit feedback. R9.1 should be removed because it also creates a compliance requirement without any benefit to reliability and would be confusing.	
Likes 0	
Dislikes 0	
Response	
Broc Bruton - Broc Bruton On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Broc Bruton	
Answer	No
Document Name	
Comment	
Oncor strongly disagrees with the following statement in R9.1: “Make their CAP available and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.” We propose that “applicable regulatory authorities or governing bodies” be defined and limited. For example, a TP should only need to provide their PC with CAP information. In addition, we disagree with the following phrase “and notify the applicable regulatory authorities or governing bodies responsible for retail electric service issues” as it relates to Load Shed. The intended regulatory audience needs to be clearly defined.	
Likes 0	
Dislikes 0	
Response	
Robert Jones - Seattle City Light - 1,3,4,5,6	
Answer	No
Document Name	

Comment	
The language unclear pertaining to non-jurisdictionals. "Applicable regulatory authorities or governing bodies responsible for retail electric service" needs better clarification - what does this look like for Jurisdisctionals vs non-Jurisdictionals. Is this not applicable to non-Jurisdictionals? Please provide better guidance and examples here. Could operational procedures be used in lieu of a CAP as an acceptable mitigation?	
Likes 0	
Dislikes 0	
Response	

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC

Answer	No
Document Name	
Comment	
SMUD supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	

Donald Lock - Talen Generation, LLC - 5

Answer	No
Document Name	
Comment	
The term, “Non-Consequential Load Loss,” is an oxymoron.	
Likes 0	
Dislikes 0	
Response	

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples

Answer	No
Document Name	
Comment	

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 5

Likes 0	
Dislikes 0	
Response	

Amy Wilke - American Transmission Company, LLC - 1

Answer	No
Document Name	
Comment	

ATC supports the MRO NSRF comments.

Likes 0	
Dislikes 0	
Response	

Robert Follini - Avista - Avista Corporation - 3

Answer	No
Document Name	
Comment	

Avista offers the following suggested comments for consideration:

Avista suggests clarifying that operational procedures may be acceptable mitigation.

Avista suggests NERC does not need to require interactions with regulatory authorities and governing bodies.

Likes 0	
Dislikes 0	
Response	

Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
Santee Cooper supports other entity comments for defining regulatory authorities and governing bodies proposed in R9.1. We also suggest modifying R9.2. to read 'Document "any" alternative(s) considered', since scenarios may only have one option and prove unrealistic for all scenarios.	
Likes 0	
Dislikes 0	
Response	

Kevin Conway - Western Power Pool - 4	
Answer	No
Document Name	
Comment	
Language unclear pertaining to non-jurisdictionals, could NERC provide some examples for both jurisdictionals and non-jurisdictionals for what is intended for this standard? applicable regulatory authorities or governing bodies responsible for retail electric service" needs better clarification - what does this look like for Jurisdisctionals vs non-Jurisdictionals - is this not applicable to non-Jurisdictionals? Ask of SDT to provide better guidance and examples here. Could operational procedures be used in lieu of a CAP as an acceptable mitigation?	
Likes 0	
Dislikes 0	
Response	

Junji Yamaguchi - Hydro-Quebec (HQ) - 5	
Answer	No
Document Name	
Comment	
There are already existing processes for interactions with applicable regulatory authorities and governing bodies regarding CAP for many other issues and items. Extreme weather CAPs are not exceptions and do not need a new way to solicit feedback. R9.1 should be removed because it also creates a compliance requirement without any benefit to reliability and would be confusing.	
Likes 0	
Dislikes 0	
Response	

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	

It is Southern Company's recommendation that the language requiring entities to solicit feedback from regulatory authorities and governing bodies, in R9.1, should be removed from the standard.

The action of soliciting regulatory feedback/approval does not comport with a risk-based action and only serves as an administrative burden that could delay reliability improvements to the BES. It is beyond the purview of a reliability standard to mandate a regulatory strategy for the implementation of projects. The precedent set by TPL-001-5 pertaining to notifying regulatory authorities and governing bodies is specific to the review of non-consequential load loss and does not support mandating regulatory authority and governing body feedback solicitation as outlined in R9.1.

Further clarification of the recipients and intention for making CAP details available is also required for R9.1 since not all entities fall under the jurisdiction of a Public Service Commission and considerations need to be made for the sharing of CEII information.

Southern appreciates the inclusion of R9.3 and R9.4 as clarification for CAP development.

Likes 0	
Dislikes 0	
Response	

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	

The DT replaced "assessment" with "analysis" in Requirement R8 Part 8.1. It is suggested that the same replacement be made in Requirement R9 for consistency.

Soliciting feedback from applicable regulatory authorities or governing bodies responsible for retail electric service should not be required for CAPs that do not include Non-Consequential Load Loss. There is no need to add the administrative burden or introduce the opportunity for disagreements and delays when the responsible entity is doing something straightforward like reconductoring a transmission line.

This type of solicitation is only required in TPL-001 when Non-Consequential Load Loss is being used as an emergency mitigation option, which is appropriate. The DT has done the reverse. Normal CAPs require feedback per Parts 9.1 and 9.2. However, the use of Non-Consequential Load Loss as an emergency mitigation option does not require feedback per Part 9.3. It is recommended that the DT remove Part 9.1 and add the feedback solicitation to Part 9.3. In this way, any use of Non-Consequential Load Loss (whether planned or emergency alternative) will receive feedback. CAPs including only standard System upgrades can proceed without the additional coordination.

Likes 0	
Dislikes 0	

Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
Suggest clarifying that operational procedures may be acceptable mitigation. Suggest NERC does not need to require interactions with regulatory authorities and governing bodies.	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez	
Answer	No
Document Name	
Comment	
Define Table 1 for requirement R9. Define who are the regulatory authorities or governing bodies.	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	No
Document Name	
Comment	
Requirement R9 should say “Extreme Temperature Assessment” Or “analysis” versus simply “assessment”. It is not clear where and when prevention of a Corrective Action Plan implementation would occur. Broadly allowing the use of Non-Consequential Load Loss could be detrimental to reliability. Calling it an “interim solution” with no CAP deadlines set and allowances for “revisions to the CAP in subsequent Extreme Temperature Assessments” (“subsequent” equals once every five (5) calendar years as a minimum based on a simple compliance approach) essentially creates an environment where Non-Consequential Load is a compliant result that does not appear to support reliability. Requirement R9 Part 9.4 is unclear. Who	

is allowing this to occur? Sounds more like a statement but unsure of who the statement should be for as there is no process for the “permitted” use on Non-Consequential Load Loss.

Likes 0	
Dislikes 0	

Response

Teresa Krabe - Lower Colorado River Authority - 5

Answer	No
Document Name	

Comment

LCRA agrees with other comments that we strongly disagrees with the following statement in R9.1: “Make their CAP available and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.” We propose that “applicable regulatory authorities or governing bodies” be defined and limited.

Likes 0	
Dislikes 0	

Response

Hillary Creurer - Allete - Minnesota Power, Inc. - 1

Answer	No
Document Name	

Comment

Minnesota Power supports MRO’s NERC Standards Review Forum’s (NSRF) comments.

Likes 0	
Dislikes 0	

Response

Matt Lewis - Lower Colorado River Authority - 1

Answer	No
Document Name	

Comment

LCRA TSC agrees with other comments that we strongly disagrees with the following statement in R9.1: “Make their CAP available and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.” We propose that “applicable regulatory authorities or governing bodies” be defined and limited.

Likes 0	
Dislikes 0	

Response

Donna Wood - Tri-State G and T Association, Inc. - 1

Answer	No
Document Name	

Comment

Tri-State supports the comments submitted by the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Rebika Yitna - Rebika Yitna On Behalf of: David Weekley, MEAG Power, 3, 1; Roger Brand, MEAG Power, 3, 1; - Rebika Yitna

Answer	No
Document Name	

Comment

The language requiring entities to solicit feedback from regulatory authorities and governing bodies, in R9.1, should be clarified.

Likes 0	
Dislikes 0	

Response

Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford

Answer	No
Document Name	

Comment

- As it stands, “Performance Requirements” referred to in this draft is not clearly defined. Refer to the comment for R5.

- Note the inclusion of language referring to the PC's or TP's planning area (its portion of the Bulk Electric System) in this draft so it is not clear why some requirements refer to an Interconnection while others, more correctly, refer to the area of actual responsibility for the PC or TP.
- Refer to previous comments for question 4 regarding referencing specific P events instead of a methodology developed by the PC/TP to appropriately assess the studied benchmark event.
- R9.4 refers to "performance requirements of Table 1". There are no performance requirements (stable system, loading within Facility Ratings…) in this draft of Table 1.
- The purpose and required response actions related to the sharing of CAPs and solicitation of feedback is not clear.
- Documentation of alternatives is an additional administrative burden and provides little benefit to reliability. It is also unclear if there is some type of expectation these alternatives are reviewed or potentially challenged as invalid.
- R9.3 would be better captured in Table 1 similar to TPL-001 Table 1.
- The role of the TO and/or GO in implementing or otherwise responding to CAPs that may require additions or modifications to their systems/facilities is not captured in these requirements.
- There appears to be a significant amount of outside review required but no clear actions the responsible entity is required to take, particularly if there is a dispute. What is the purpose of the review and the expected response? This potentially produces an undue burden on the PC/TP and adds subjectivity in requiring a review with no documented guidelines for conducting the review.

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	No
Document Name	

Comment

OPG supports NPCC Regional Standards Committee's comments:

There are already existing processes for interactions with applicable regulatory authorities and governing bodies regarding CAP for many other issues and items. Extreme weather CAPs are not exceptions and do not need a new way to solicit feedback. R9.1 should be removed because it also creates a compliance requirement without any benefit to reliability and would be confusing.

Likes 0	
Dislikes 0	

Response

Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen

Answer	No
Document Name	

Comment

See SRC Comments

Likes 0	
Dislikes 0	

Response

Ben Hammer - Western Area Power Administration - 1

Answer	No
Document Name	

Comment

9.3. The use of Non-Consequential Load Loss as an interim solution in this situation is permitted, provided that each responsible entity documents the situation causing the problem, alternatives evaluated, and takes actions to resolve the situation.

Likes 0	
Dislikes 0	

Response

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	No
Document Name	

Comment

- R9.2 ITC believes the requirement for the notification to an applicable regulatory entity should also include a threshold. As written, an entity would need to make a notification if a proposal tripped 0.1 MW of non-consequential load. Recommend the DT add a threshold in a similar way as is included in TPL-001 Attachment 1.
- R9.3 Delete the first sentence of this sub-requirement. It is explanatory and does not add anything to the intent of R9.
- ITC also has a recommended change to Table 1 which therefore would require a change to R9 at a minimum.

Likes 0	
Dislikes 0	

Response

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	

Comment

Please refer to Question 1 comments.

Likes 0	
Dislikes 0	

Response

Usama Tahir - Seminole Electric Cooperative, Inc. - 3

Answer	No
Document Name	

Comment

NERC, under R9.1, should not add in requirements for other regulatory authorities or governing bodies. Those entities may have approval requirements that are not clearly laid out here which could cause an undue burden onto NERC entities. Other regulatory entities, if they have been given such authority, can develop regulations on their own, to achieve what the SDT has written in R9.1.

Likes 0	
Dislikes 0	

Response

Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC) Project 2023-07 TPL-008-1 Draft #2

Answer	No
Document Name	

Comment

The SRC[1] observes that Load Loss is addressed in TPL-008, requirement R9 whereas Load Loss is addressed in TPL-001-5.1, Table 1. The SRC recommends the first sentence of Part 9.3 be stricken from the standard as illustrated below because it is explanatory in nature and adds no value to the standard. The SRC recommends the first sentence be migrated to the Technical Rationale if the SDT feels it is important to retain.

9.3. The use of Non-Consequential Load Loss as an interim solution in this situation is permitted, provided that each responsible entity documents the situation causing the problem, alternatives evaluated and takes actions to resolve the situation.

The SRC also expresses concern with Part 9.2, concerning notification to local public service commissions, and proposes this *only* be required when Non-Consequential Load Loss is utilized as an element of a corrective action plan (CAP) for the Table P1 contingency. The SRC believes this would be consistent with existing reporting requirements in TPL-001 and FERC Order 896. See proposed language below:

9.2 Document the alternatives considered and notify the applicable regulatory authorities or governing bodies responsible for retail electric service issues ***only*** when Non-Consequential Load Loss is utilized as an element of a CAP for the Table 1 P1 Contingency.

[1] For purposes of question 5, the IRC SRC includes the following entities: CAISO (only in support of our recommendation regarding Part 9.3), ERCOT, ISO-NE, MISO, NYISO, PJM and SPP.

Likes 0	

Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
Answer	No
Document Name	
Comment	
PJM supports the IRC SRC comments.	
Likes 0	
Dislikes 0	
Response	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Recommend updating table references to 1.2.	
Likes 0	
Dislikes 0	
Response	

Gary Trezza - Long Island Power Authority - 1 - NPCC	
Answer	Yes
Document Name	
Comment	

Requirement #9.3 states:

"Be permitted to utilize Non-Consequential Load Loss as an interim solution, which normally is not permitted in Table 1, in situations that are beyond the control of the Planning Coordinator or Transmission Planner that prevent the implementation of a Corrective Action Plan in the required timeframe."

The Extreme Temperature Assessment would have to be performed at least once every 5 years, assessing one year in the Long Term Planning Horizon.

It is recognized that the details of the extreme heat/cold benchmark temperature events may change over time, and that the underlying assumptions utilized in the Extreme Temperature Assessment for one of the years in the Long Term Planning Horizon may change over time. CAPs identified in one Assessment may not be needed in a future Assessment. It may be difficult to pursue expensive CAPs understanding that assumptions may change.

With this in mind, we find it difficult from a compliance perspective to clearly identify what is meant by "in the required timeframe". This language, while allowing for flexibility, seems very ambiguous. The Technical Rationale does not elaborate on this point.

We recommend that the SDT clarify what is intended by "*in the required timeframe."*

Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	

Exelon supports the comments submitted by the EEI for this question.

Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes

Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation has no concerns with the updated language for requirement R9.	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	Yes
Document Name	
Comment	

NextEra supports EEI's comments

: EEI offers non-substantive edits in boldface below to Requirement R9.

R9. Each responsible entity, as identified in Requirement R1, shall develop a Corrective Action Plan(s) (CAPs) when the assessment of a benchmark planning case, in accordance with Requirement R8 Part 8.1, indicates its portion of the Bulk Electric System is unable to meet performance requirements for Table **1.1** P0 or P1 Contingencies. For each Corrective Action Plan, the responsible entity shall: [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

9.1. Make their CAP available and solicit feedback from applicable regulatory authorities or governing bodies responsible for retail electric service issues.

9.2. Document the alternative(s) considered and notify the applicable regulatory authorities or governing bodies responsible for retail electric service issues when Non-Consequential Load Loss is utilized as an element of a CAP for the Table **1.1** P1 Contingency.

9.3. Be permitted to utilize Non-Consequential Load Loss as an interim solution, which normally is not permitted in Table 1, in situations that are beyond the control of the Planning Coordinator or Transmission Planner that prevent the implementation of a Corrective Action Plan in the required timeframe. The use of Non-Consequential Load Loss as an interim solution in this situation is permitted, provided that each responsible entity documents the situation causing the problem, alternatives evaluated, and takes actions to resolve the situation.

Likes 0	
Dislikes 0	

Response

Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop

Answer	Yes
Document Name	

Comment

In R9.1, Ameren suggests inserting the phrase "and Planning Coordinators" after "governing bodies." Ameren CAPs are typically approved by the Planning Coordinator through a stakeholder process.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	Yes
Document Name	

Comment

EEI offers non-substantive edits in boldface below to Requirement R9.

R9. Each responsible entity, as identified in Requirement R1, shall develop a Corrective Action Plan(s) (CAPs) when the assessment of a benchmark planning case, in accordance with Requirement R8 Part 8.1, indicates its portion of the Bulk Electric System is unable to meet performance requirements for Table **1.1** P0 or P1 Contingencies. For each Corrective Action Plan, the responsible entity shall: [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

9.1. Make their CAP available and solicit feedback from applicable regulatory authorities or governing bodies responsible for retail electric service issues.

9.2. Document the alternative(s) considered and notify the applicable regulatory authorities or governing bodies responsible for retail electric service issues when Non-Consequential Load Loss is utilized as an element of a CAP for the Table **1.1** P1 Contingency.

9.3. Be permitted to utilize Non-Consequential Load Loss as an interim solution, which normally is not permitted in Table 1, in situations that are beyond the control of the Planning Coordinator or Transmission Planner that prevent the implementation of a Corrective Action Plan in the required timeframe. The use of Non-Consequential Load Loss as an interim solution in this situation is permitted, provided that each responsible entity documents the situation causing the problem, alternatives evaluated, and takes actions to resolve the situation.

Likes 0	
Dislikes 0	

Response

Selene Willis - Edison International - Southern California Edison Company - 5

Answer	Yes
Document Name	

Comment

Please see comments from EEI

Likes 0	
Dislikes 0	

Response

Carver Powers - Utility Services, Inc. - 4

Answer	Yes
Document Name	

Comment

It is challenging to agree due to not knowing the benchmarks to be set by NERC and the number of CAPs that may exist. The benchmarks identified may not actually be realistic for certain entities depending on locations and could complicate the ability to apply CAPS for unrealistic benchmarks. We must assume that the process for developing the benchmarks will recognize the complexities that microclimates play on certain locations across the ERO footprint.

Based on other projects that include developing and implementing CAPs, USV would feel more confident with the proposed modifications if there were timelines set for the CAPs. Perhaps not in the standard itself, but guidance on timelines could be explained in the technical rationale and include timelines for implementing CAPs and when entities can utilize backup action plans such as Non-Consequential Load Loss.

Likes 0	
Dislikes 0	

Response	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	Yes
Document Name	
Comment	
PGAE has no comment on the updated R9 Corrective Action Plan.	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1	
Answer	Yes
Document Name	
Comment	
See comments submitted by Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Barbara Marion - Dominion - Dominion Resources, Inc. - 5, Group Name Dominion	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Helen Lainis - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michele Tondalo - United Illuminating Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Sorenson - Greg Sorenson On Behalf of: Tyler Schwendiman, ReliabilityFirst , 10; - Greg Sorenson	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michele Shafer - New York State Electric & Gas (NYSEG) - 6	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Apollonia Gonzales - PNM Resources - Public Service Company of New Mexico - 1,3,5 - WECC

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

John Brewer - National Energy Technology Laboratory - 9 - NA - Not Applicable

Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE continues to recommend including a timeframe for which the CAPs need to be developed and submitted for review once the benchmark planning case study results indicate the System is unable to meet performance requirements.

Texas RE likewise continues to have concerns about the submission of CAPs solely to "applicable regulatory authorities…responsible for retail electric service." As an initial matter, it is unclear how this requirement will work in practice and how the ERO could maintain visibility into the CAP review process. More broadly, since the Reliability Coordinator (RC) is the functional entity responsible for the Reliable Operation of the Bulk Electric System within the NERC jurisdictional model, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations, the CAP should at least be submitted to the RC in addition to applicable regulatory authorities.

Consistent with this approach, Texas RE recommends the following revision:

9.1 Make their CAPs available and solicit feedback from their Reliability Coordinator and applicable regulatory authorities or governing bodies responsible for retail electric service issues within 60 days of developing the CAPs.

Likes 0	
Dislikes 0	
Response	

6. The DT updated Requirement R10 based on comments received. Do you agree with the updated proposed TPL-008-1 Reliability Standard Requirement R10? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Long Island Power Authority	
Answer	Yes
Document Name	(if an attachment is provided by submitter)
Comment	
Submitter's comments	
Likes 0	# of other submitters who agree with these comments
Dislikes 0	# of other submitters who disagree with these comments
Response	
(Drafting team's response to submitter's comments)	

John Brewer - National Energy Technology Laboratory - 9 - NA - Not Applicable

Answer	No
Document Name	
Comment	
(R10) Previous requirements allowed for alternative(s) to be considered. We are suggesting replacing all "possible actions" with "possible action(s)" to allow a single action to mitigate the consequences and adverse impacts.	
Likes 0	
Dislikes 0	
Response	

Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle

Answer	No
Document Name	
Comment	
The decision to include the escalating phrase "instability, uncontrolled separation, or Cascading" in R10.1, but not 10.2 is confusing. This would indicate that the benchmark planning cases only require entities to "evaluate and document possible actions" if they rise to the level of significant BES impact. At a minimum, the DT should provide a clarifying statement to explain this rationale.	

Likes 0	
Dislikes 0	
Response	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
Please refer to Question 1 comments.	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
ITC understands the need for both steady-state and stability studies for the required contingencies. However, ITC makes the following recommendation for the sensitivity event being evaluated. R10 should be modified to only require P0 and P1 contingencies be analyzed as part of the standard for the sensitivity event. The remaining contingencies identified should be left as an option for entities. R10.2 should only be applicable for steady state studies of P0 and P1 for the sensitivity case. Additionally Table 1 should be modified so that system issues identified during steady state reviews for P0 and P1 be addressed with a CAP. As currently drafted, completion of the sensitivity case studies are purely an administrative burden on entities completing the studies.	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	No
Document Name	
Comment	

FERC Order 896 Paragraph 113 as part of the Commission Determination states that *"NERC may determine whether contingencies P1 through P7 should also apply to the new or modified Reliability Standard, or whether a new set of contingencies should be developed."*

ISO-NE recommends that R10 be removed from the Standard as the FERC Order does not require the inclusion of P2, P4, or P7 contingency events. The P0 and P1 contingency events have a higher likelihood of occurrence and should remain within the Standard.

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	No
Document Name	

Comment

OPG supports NPCC Regional Standards Committee's comments:

We see that R10 requires a significant amount of work without providing additional system reliability.

Likes 0	
Dislikes 0	

Response

Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford

Answer	No
Document Name	

Comment

- The purpose and reliability benefit of R10 is ambiguous. It is understood that P2, P4, P5, & P7 events tend to be lower probability but documenting possible mitigations every 5 years for these low-probability events in an extreme weather condition appears more administrative than reliability-based as the requirement is currently written. Reliability Standards should be performance based and impact reliability. Developing possible actions where mitigation is not required just adds more administrative burden to the PC/TP with no benefit to reliability as the result.
- The exclusion of the P3 & P6 events from these requirements is appropriate. The SDT should consider if specific P2, P4, P5, & P7 events should likewise be excluded so the standard only addresses those events that must be evaluated and mitigated. A better option would be to pursue a methodology developed by the PC/TP that is relevant to the benchmark event they are studying as opposed to rigidly referring to specific P events that may or may not be applicable to the analysis to be performed

Likes 0	
Dislikes 0	

Response

Rebika Yitna - Rebika Yitna On Behalf of: David Weekley, MEAG Power, 3, 1; Roger Brand, MEAG Power, 3, 1; - Rebika Yitna	
Answer	No
Document Name	
Comment	
Technical rationale should be assessed for justifying the removal of P2, P4, and especially P7 as well.	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Tri-State supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Matt Lewis - Lower Colorado River Authority - 1	
Answer	No
Document Name	
Comment	
LCRA TSC would like see more clarification on the difference between R9 and R10. How is “evaluate and document possible actions” different then developing CAPs?	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	

Answer	No
Document Name	
Comment	
Minnesota Power supports MRO’s NERC Standards Review Forum’s (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	No
Document Name	
Comment	
LCRA would like see more clarification on the difference between R9 and R10. How is “evaluate and document possible actions” different then developing CAPs?	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	No
Document Name	
Comment	
WECC suggests the DT consider "CAP development" versus “document possible actions”. Possible actions could include “do nothing” which does not appear to support reliability.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No

Document Name	

Comment

EEI does not object to the intent of Requirement 10, but we do not agree that entities should be made accountable for developing actions for categories P2 through P7 because no corrective actions are required under this Reliability Standard beyond categories P0 and P1. It is sufficient for the responsible entity to conduct the assessments but developing and retaining documentation for mitigations for categories P2 through P7 represents an unnecessary administrative burden and provides no reliability benefit.

R10. Each responsible entity, as identified in Requirement R1, shall evaluate **the Contingency Categories identified in Table 1.1** and document possible actions for **Categories P0 and P1. For Categories P2 through P7, document these categories were analyzed but it is not required to develop mitigations or retain records of those assessments. Assessments shall be as follows:** [Violation Risk Factor: Lower] [Time Horizon: Longterm Planning]

10.1. Benchmark planning cases where possible actions are designed to mitigate the consequences and adverse impacts when the study results indicate the System could result in instability, uncontrolled separation, or Cascading for the Table 1 P2, P4, and P7 Contingencies.

10.2. Sensitivity cases where possible actions are designed to mitigate failures to meet the performance requirements in Table 1 for category P0, P1, Contingencies

Likes 0	
Dislikes 0	

Response

Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez

Answer	No
Document Name	

Comment

Define Table 1 in requirement R10.1 and R10.2. Need to clarify or re write what needs to be done for requirement R10.

Likes 0	
Dislikes 0	

Response

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF

Answer	No
Document Name	

Comment

The analysis requirements of Requirement R10 pose a significant burden and produce no significant reliability benefit. Most of the contingencies analyzed do not require CAPs. It is suggested to remove P2, P4, and P7 from Part 10.2. This lessens the analysis burden while still ensuring sensitivity cases are analyzed for the Contingencies that require CAPs in the benchmark planning cases. This still accomplishes the FERC directives requiring the analysis of sensitivity cases.

Likes 0	
Dislikes 0	

Response

Helen Lainis - Independent Electricity System Operator - 2

Answer	No
Document Name	

Comment

We support NPCC TFCP comment

Likes 0	
Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

Southern Company appreciates the removal of P5. Technical rationale should be assessed for justifying the removal of P2, P4, and especially P7 as well.

Likes 0	
Dislikes 0	

Response

Junji Yamaguchi - Hydro-Quebec (HQ) - 5

Answer	No
Document Name	

Comment

We see that R10 requires a significant amount of work without providing additional system reliability. We suggest that this requirement be removed.	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	No
Document Name	
Comment	
Add in language that had been removed from previous version “reduce the likelihood or mitigate the consequences” to align with TPL-001.	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
Santee Cooper would like to see the language align more with TPL-001-5 and is concerned about the additional work and the benefit of the analysis to long term planning horizon.	
Likes 0	
Dislikes 0	
Response	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	

ATC supports the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 6	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
Documenting possible actions is insufficient; responsible entities must do something.	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	No
Document Name	

Comment	
SMUD supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Robert Jones - Seattle City Light - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
Add in language that had been removed from previous version “reduce the likelihood or mitigate the consequences” to align with TPL-001.	
Likes 0	
Dislikes 0	
Response	
Broc Bruton - Broc Bruton On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Broc Bruton	
Answer	No
Document Name	
Comment	
Oncor disagrees with R10 as well. The requirement does not give TPs the ability to create CAPs for the listed contingencies.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	No
Document Name	
Comment	

We see that R10 requires a significant amount of work without providing additional system reliability.

Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	

Part 10.1. MRO NSRF requests clarification regarding the objective of TPL-008-1, Part 10.1. What results are to be achieved pursuant to TPL-008-1, Requirement 10, Part 10.1 that are above and beyond the results achieved pursuant to TPL-001-5.1, Requirement 2, Parts 2.1, 2.2 and 2.7? The two provisions seem to be very similar and duplicative.

10.1. Benchmark planning cases where possible actions are designed to mitigate the consequences and adverse impacts when the study results indicate the System could result in instability, uncontrolled separation, or Cascading for the Table 1 P2, P4, and P7 Contingencies.

See also our response to Question #5.

Likes 0	
Dislikes 0	
Response	
Zahid Qayyum - New York Power Authority - 5	
Answer	No
Document Name	
Comment	

NYPA suggest SDT should consider align the language in R10 with that of TPL 001 5.1 for consistency. For instance, SDT can consider retaining the term “reduce the likelihood” as used in TPL 001-5.1

Likes 0	
Dislikes 0	
Response	

Fon Hiew - NB Power Corporation - New Brunswick Power Transmission Corporation - 5	
Answer	No
Document Name	
Comment	
We see that R10 requires a significant amount of work without providing additional system reliability.	
Likes 0	
Dislikes 0	
Response	
Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA recommends that R10.1 and R10.2 be modified to include “to reduce the likelihood or mitigate the consequences” to align with TPL-001. R10.1. Benchmark planning cases where possible actions are designed to **reduce the likelihood or mitigate the consequences** and adverse impacts when the study results indicate the System could result in instability, uncontrolled separation, or Cascading for the Table 1 P2, P4, and P7 Contingencies. R10.2. Sensitivity cases where possible actions are designed to **reduce the likelihood or mitigate** failures to meet the performance requirements in Table 1 for category P0, P1, P2, P4, and P7 Contingencies.	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
Please refer to our response for comments 3 and 4.	
Likes 0	

Dislikes 0	

Response

Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD

Answer	No
Document Name	

Comment

CHPD agrees with Western Power Pool's (WPP) comment.

Likes 1	Jennie Wike, N/A, Wike Jennie
Dislikes 0	

Response

Lidija Efremova - Lidija Efremova On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Lidija Efremova

Answer	No
Document Name	

Comment

Comments:

We see that R10 requires a significant amount of effort and work without any assurance of providing additional system reliability. We suggest that this requirement and associated testing requirements in R9 be removed.

Likes 0	
Dislikes 0	

Response

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

(R10 and R10.1) It is recommended that the requirement for documenting "possible actions" should preserve the right to identify only a single action (i.e., "possible action(s)") that would best mitigate the consequence or adverse impact based on the analysis. Otherwise, due to the complex and comprehensive nature of the analysis and mitigation option review, we believe attempting to document less reliable or less effective solutions in a way that is clear, so as to avoid any confusion, would be an inefficient and ineffective task.

(R10.2) As noted in the comments associated with R4.2, we do not agree that an increasingly more extreme scenario for purposes of a sensitivity analysis, is credible. This is especially true for longer term planning horizons when generation additions and retirements, along with transmission configuration changes and new technologies to be deployed are less detailed.

Likes 0	
Dislikes 0	

Response

Chelsea Loomis - Western Power Pool - NA - Not Applicable - WECC, Group Name WPP Consortium of Engineers	
Answer	No
Document Name	
Comment	
Add in language that had been removed from previous version "reduce the likelihood or mitigate the consequences" to align with TPL-001.	
Likes 0	
Dislikes 0	
Response	

Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	No
Document Name	
Comment	
Add in language that was removed from previous verson 'reduce the likelihood or mitigate the consequences" to align with TPL-001-5.	
Likes 2	Snohomish County PUD No. 1, 3, Chaney Holly; Jennie Wike, N/A, Wike Jennie
Dislikes 0	
Response	

Jeffrey Streifling - NB Power Corporation - 1	
Answer	No
Document Name	
Comment	
We see that R10 requires a significant amount of work without providing additional system reliability.	

Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Chantal Mazza On Behalf of: Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	No
Document Name	
Comment	
We see that R10 requires a significant amount of work without providing additional system reliability. We suggest that this requirement be removed.	
Likes 0	
Dislikes 0	
Response	
Usama Tahir - Seminole Electric Cooperative, Inc. - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gary Trezza - Long Island Power Authority - 1 - NPCC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Robert Blackney - Edison International - Southern California Edison Company - 1	
Answer	Yes
Document Name	
Comment	
See comments submitted by Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	
Please see comments from EEI	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	Yes

Document Name	

Comment
NextEra supports EEI's comments EEI does not object to the intent of Requirement 10, but we do not agree that entities should be made accountable for developing actions for categories P2 through P7 because no corrective actions are required under this Reliability Standard beyond categories P0 and P1. It is sufficient for the responsible entity to conduct the assessments but developing and retaining documentation for mitigations for categories P2 through P7 represents an unnecessary administrative burden and provides no reliability benefit. R10. Each responsible entity, as identified in Requirement R1, shall evaluate **the Contingency Categories identified in Table 1.1** and document possible actions for **Categories P0 and P1. For Categories P2 through P7, document these categories were analyzed but it is not required to develop mitigations or retain records of those assessments. Assessments shall be as follows the following:** [Violation Risk Factor: Lower] [Time Horizon: Longterm Planning] 10.1. Benchmark planning cases where possible actions are designed to mitigate the consequences and adverse impacts when the study results indicate the System could result in instability, uncontrolled separation, or Cascading for the Table 1 P2, P4, and P7 Contingencies. 10.2. Sensitivity cases where possible actions are designed to mitigate failures to meet the performance requirements in Table 1 for category P0, P1, **P2, P4, and P7** Contingencies

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	

Comment
Black Hills Corporation is aligned with the comments made by EEI, which are in italics below. *'EEI does not object to the intent of Requirement 10, but we do not agree that entities should be made accountable for developing actions for categories P2 through P7 because no corrective actions are required under this Reliability Standard beyond categories P0 and P1. It is sufficient for the responsible entity to conduct the assessments but developing and retaining documentation for mitigations for categories P2 through P7 represents an unnecessary administrative burden and provides no reliability benefit.* *R10. Each responsible entity, as identified in Requirement R1, shall evaluate **the Contingency Categories identified in Table 1.1** and document possible actions for **Categories P0 and P1. For Categories P2 through P7, document these categories were analyzed but it is not required to develop mitigations or retain records of those assessments. Assessments shall be as follows*** (remove: ***the following**): [Violation Risk Factor: Lower] [Time Horizon: Longterm Planning]*

10.1. Benchmark planning cases where possible actions are designed to mitigate the consequences and adverse impacts when the study results indicate the System could result in instability, uncontrolled separation, or Cascading for the Table 1 P2, P4, and P7 Contingencies.

10.2. Sensitivity cases where possible actions are designed to mitigate failures to meet the performance requirements in Table 1 for category P0 and P1 Contingencies'

Likes 0	
Dislikes 0	

Response

Daniela Atanasovski - APS - Arizona Public Service Co. - 1

Answer	Yes
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	Yes
Document Name	

Comment

Exelon supports the comments submitted by the EEI for this question.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	Yes
Document Name	

Comment

FirstEnergy supports EEI's comments which state:

EEI does not object to the intent of Requirement 10, but we do not agree that entities should be made accountable for developing actions for categories P2 through P7 because no corrective actions are required under this Reliability Standard beyond categories P0 and P1. It is sufficient for the responsible entity to conduct the assessments but developing and retaining documentation for mitigations for categories P2 through P7 represents an unnecessary administrative burden and provides no reliability benefit.

R10. Each responsible entity, as identified in Requirement R1, shall evaluate **the Contingency Categories identified in Table 1.1** and document possible actions for **Categories P0 and P1. For Categories P2 through P7, document these categories were analyzed but it is not required to develop mitigations or retain records of those assessments. Assessments shall be as follows the following:** [Violation Risk Factor: Lower] [Time Horizon: Long term Planning]

10.1. Benchmark planning cases where possible actions are designed to mitigate the consequences and adverse impacts when the study results indicate the System could result in instability, uncontrolled separation, or Cascading for the Table 1 P2, P4, and P7 Contingencies.

10.2. Sensitivity cases where possible actions are designed to mitigate failures to meet the performance requirements in Table 1 for category P0, P1, P2, P4, and P7 Contingencies

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	Yes
Document Name	

Comment

Duke Energy agrees with and recommends implementation of EEI comments.

Likes 0	
Dislikes 0	

Response

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF

Answer	Yes
Document Name	

Comment

Recommend updating table references to 1.2.

Likes 0	
Dislikes 0	
Response	
Apollonia Gonzales - PNM Resources - Public Service Company of New Mexico - 1,3,5 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC) Project 2023-07 TPL-008-1 Draft #2	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michele Shafer - New York State Electric & Gas (NYSEG) - 6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Greg Sorenson - Greg Sorenson On Behalf of: Tyler Schwendiman, ReliabilityFirst , 10; - Greg Sorenson

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Carver Powers - Utility Services, Inc. - 4

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Michele Tondalo - United Illuminating Co. - 1

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Barbara Marion - Dominion - Dominion Resources, Inc. - 5, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Srikanth Chennupati - Entergy - Entergy Services, Inc. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

7. The DT split out Table 1 into parts for better readability. Do you agree with the updated layout of Table 1? If you do not agree, please provide your recommendation and technical justification.

Long Island Power Authority	
Answer	No
Document Name	(if an attachment is provided by submitter)
Comment	

a) The updated layout of Table 1 is helpful. Note however, that the text of applicable requirements which reference "Table 1" should be modified to reflect reference to either "Table 1.1", "Table 1.2" or "Table 1.3".

b) We observe that Table 1.1 (Contingency Category) references a Footnote 2. Footnote 2 states applicable contingencies would be Facilities 200 kV and above.

This is an important distinction, and we recommend that that this detail be included within the actual text of Requirement #7.

c) Regarding Footnote 2b, the wording of the text is confusing.

We would recommend to edit the wording of Footnote 2b to be more consistent with TPL-001-5.1, footnote 11, such as:

"For P7 planning events that have at least one 200 kV voltage and above Facility that shares a common structure for at least 1 mile."

d) Additionally, Footnote 2b should be referenced within Table 1.1, next to the P7 category Event item 1 (similar to TPL-001-5.1 Table 1 for P7 events).

e) Questions Regarding footnote 2:

We interpret that footnote 2 is meant to be a filter (>200kV) or screening for identifying events that would have a more severe impact on the BES. We also interpret that as part of the Extreme Temperature Assessment, an entity is responsible for monitoring their entire BES.

Is this interpretation correct? Some elaboration within the Technical Rationale would be helpful.

Likes 0	# of other submitters who agree with these comments
Dislikes 0	# of other submitters who disagree with these comments

Response
(Drafting team's response to submitter's comments)

Chantal Mazza - Chantal Mazza On Behalf of: Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	No
Document Name	
Comment	
Consistent with comments above, Table 1 should be updated to remove P2, P4, and P7 Contingencies.	
Likes 0	
Dislikes 0	
Response	

Jeffrey Streifling - NB Power Corporation - 1	
Answer	No
Document Name	
Comment	
Consistent with comments above, Table 1 should be updated to remove P2, P4, and P7 Contingencies.	
Likes 0	
Dislikes 0	
Response	

Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	No
Document Name	
Comment	
The new table approach was confusing. Matching the formatting to Table 1 in TPL-001-5.1 would make good sense here.	
Likes 2	Snohomish County PUD No. 1, 3, Chaney Holly; Jennie Wike, N/A, Wike Jennie
Dislikes 0	

Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	No
Document Name	
Comment	
List all Planning Events from Table 1 of TPL-001-5 but identify N/A events for TPL-008 rather than including incomplete table.	
Likes 0	
Dislikes 0	
Response	
Chelsea Loomis - Western Power Pool - NA - Not Applicable - WECC, Group Name WPP Consortium of Engineers	
Answer	No
Document Name	
Comment	
Matching formatting to TPL 001-5 makes good sense here. Please see attached PNG for suggestion.	
Likes 0	
Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	No
Document Name	Proposed Table 1.pdf
Comment	
CHPD does not agree with the updated layout of Table 1. CHPD recommends combining Table 1.1 and Table 1.2 to keep things more in the flavor of TPL-001-5 Table 1. See the "Proposed Table 1" attachment for the direction of what CHPD would recommend. Additionally: 1) Footnote 1 in Table 1.3 (related to faults) does not appear to have an item referencing it in the current Table 1.1 or 1.2 and; 2) for the stability performance requirement, there is an additional line "The System shall remain stable" for the P0 event; this line does not appear to be coming from any	

requirements and does not appear to be discussed elsewhere. It is recommended this line be removed and the P0 requirement for stability is the same as the P1-P7 language set “Instability, uncontrolled separation, or Cascading, as defined in Requirement R6, shall not occur.”.

Likes 1	Jennie Wike, N/A, Wike Jennie
Dislikes 0	

Response

Gary Trezza - Long Island Power Authority - 1 - NPCC

Answer	No
Document Name	

Comment

a) The updated layout of Table 1 is helpful. Note however, that the text of applicable requirements which reference “Table 1” should be modified to reflect reference to either “Table 1.1”, “Table 1.2” or “Table 1.3”.

b) We observe that Table 1.1 (Contingency Category) references a Footnote 2. Footnote 2 states applicable contingencies would be Facilities 200 kV and above.

This is an important distinction, and we recommend that that this detail be included within the actual text of Requirement #7.

c) Regarding Footnote 2b, the wording of the text is confusing.

We would recommend to edit the wording of Footnote 2b to be more consistent with TPL-001-5.1, footnote 11, such as:

“For P7 planning events that have at least one 200 kV voltage and above Facility that shares a common structure for at least 1 mile.”

d) Additionally, Footnote 2b should be referenced within Table 1.1, next to the P7 category Event item 1 (similar to TPL-001-5.1 Table 1 for P7 events).

e) Questions Regarding footnote 2:

We interpret that footnote 2 is meant to be a filter (>200kV) or screening for identifying events that would have a more severe impact on the BES. We also interpret that as part of the Extreme Temperature Assessment, an entity is responsible for monitoring their entire BES.

Is this interpretation correct? Some elaboration within the Technical Rationale would be helpful.

Likes 0	
Dislikes 0	

Response

Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	WPP TPL-008 Table 1 Reference.pdf

Comment

BPA agrees with WPP Consortium of Engineers comments to match the format to TPL-001-5. BPA has attached a copy of the table referenced by WPP.

Likes 0	
Dislikes 0	

Response

Fon Hiew - NB Power Corporation - New Brunswick Power Transmission Corporation - 5

Answer	No
Document Name	

Comment

Consistent with comments above, Table 1 should be updated to remove P2, P4, and P7 Contingencies.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC

Answer	No
Document Name	

Comment

Consistent with comments above, Table 1 should be updated to remove P2, P4, and P7 Contingencies.

Likes 0	
Dislikes 0	

Response

Broc Bruton - Broc Bruton On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Broc Bruton

Answer	No
Document Name	

Comment

Table 1 should be updated to remove P2, P4, and P7 Contingencies. Oncor also agrees that matching the formatting of Table 1 to TPL 001-5 is appropriate.	
Likes 0	
Dislikes 0	
Response	
Robert Jones - Seattle City Light - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
The table should match formatting to TPL 001-5.	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	No
Document Name	
Comment	
SMUD supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	No
Document Name	2023-07 comment7.png
Comment	

Avista offers the following suggested comment for consideration: Given the intended scope of the project and the technical differences between TPL-001-5, we suggest maintaining consistency between these standards wherever possible to reduce confusion. To reduce confusion and create consistency, match formatting to TPL-001-5 using suggested table formatting below.	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	No
Document Name	
Comment	
Matching formatting to TPL 001-5 makes good sense here.	
Likes 0	
Dislikes 0	
Response	
Junji Yamaguchi - Hydro-Quebec (HQ) - 5	
Answer	No
Document Name	
Comment	
Comments: Consistent with comments above, Table 1 should be updated to remove P2, P4, and P7 Contingencies.	
Likes 0	
Dislikes 0	
Response	
Helen Lainis - Independent Electricity System Operator - 2	

Answer	No
Document Name	
Comment	
We support NPCC TFCP comment	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	TPL-008-1-proposed-Table-1.docx
Comment	
We appreciate the work of the DT to increase readability of Table 1. We recommend changes in the attached document to improve upon the revisions.	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	Table Example.png
Comment	
Given the intended scope of the project and the technical differences between TPL-001-5, we suggest maintaining consistency between these standards wherever possible to reduce confusion. To reduce confusion and create consistency, match formatting to TPL-001-5 using suggested table formatting attached.	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	

Answer	No
Document Name	
Comment	

Performance criteria should be included in the table.

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	No
Document Name	

Comment

OPG supports NPCC Regional Standards Committee's comments:

Consistent with comments above, Table 1 should be updated to remove P2, P4, and P7 Contingencies.

Likes 0	
Dislikes 0	

Response

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	

Comment

Please refer to Question 1 comments.

Likes 0	
Dislikes 0	

Response

John Brewer - National Energy Technology Laboratory - 9 - NA - Not Applicable

Answer	No

Document Name	
Comment	
By splitting out Table 1, the footnotes became Table 1.3. If the Table 1 split is selected for the final version of the standard, please move the footnotes after Table 1.1 because that is the only table with footnotes. Furthermore, check the footnote numbers. Footnote #1 is missing as a reference in the tables 1.1 and 1.2.	
Likes 0	
Dislikes 0	
Response	
Usama Tahir - Seminole Electric Cooperative, Inc. - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
references in requirements should reference table 1.1 or 1.2 instead of only table 1	
Likes 0	
Dislikes 0	
Response	
Srikanth Chennupati - Entergy - Entergy Services, Inc. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	

Footnote 1 is missing from table 1.1 & 1.2 and is defined in table 1.3.

Likes 0	
Dislikes 0	

Response

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO

Answer	Yes
Document Name	

Comment

Please refer to appropriate table number either Table 1.1 or Table 1.2 in the requirements.

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	Yes
Document Name	

Comment

Duke Energy agrees with and recommends implementation of EEI comments.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	Yes
Document Name	

Comment

No additional comments.

Likes 0	
Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	Yes
Document Name	

Comment

MRO NSRF supports the format for Table 1; however, has the following questions and comments.

Does Footnote 2 in Table 1.3 (200kV and greater) apply everywhere? The MRO NSRF requests the SDT clarify this in the standard.

Steady state performance requirements have stability requirements for P2, P4, P7. Voltage collapse (cascading) can be identified, but not instability or uncontrolled separation. This would require a dynamic study.

The MRO NSRF disagrees with the Table 1 reference to extreme conditions in a base model.

Is there an opportunity for TPL-008-1, Table 1.1 to reference TPL-001-5.1 instead? Only TPL-008-1, Table 1.2 shows information specific and unique to TPL-008.

Likes 1	Scott Brame, N/A, Brame Scott
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	Yes
Document Name	

Comment

Exelon agrees with the updated layout of Table 1. However, in Table 1.2, we believe the sentence “The System shall remain stable.” should either be removed or added to P1 Stability Performance Requirements so both P0 and P1 are consistent. Additionally, we noticed that footnote 1 in Table 1.3 is not referenced in any of the tables.

Additionally, Exelon supports the comments submitted by the EEI for this question.

Likes 0	
Dislikes 0	

Response

Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation has no concerns with the updated layout of Table 1.	
Likes 0	
Dislikes 0	
Response	

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	Yes
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 7	
Likes 0	
Dislikes 0	
Response	

Amy Wilke - American Transmission Company, LLC - 1

Answer	Yes
Document Name	
Comment	

Footnote 1 does not appear to be linked to 'Fault Type' in Table 1.1.

ATC supports the MRO NSRF comments.

Likes 0	
Dislikes 0	
Response	

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	Yes
Document Name	
Comment	

Table 1.2 provides much better visualization and clarification of expectations.

Please clarify the meaning of "The System shall remain stable", as well as the distinction between the use of "System" and "within an Interconnection".

Likes 0	
Dislikes 0	
Response	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	Yes
Document Name	
Comment	

EEI does not have any concerns with the revised labelling of the Tables but references to the tables should also be updated for clarity.

Likes 0	
Dislikes 0	
Response	

Kinte Whitehead - Exelon - 3

Answer	Yes
Document Name	

Comment

Exelon agrees with the updated layout of Table 1. However, in Table 1.2, we believe the sentence “The System shall remain stable.” should either be removed or added to P1 Stability Performance Requirements so both P0 and P1 are consistent. Additionally, we noticed that footnote 1 in Table 1.3 is not referenced in any of the tables.

Additionally, Exelon supports the comments submitted by the EEI for this question.

Likes 0	
Dislikes 0	

Response

Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen

Answer	Yes
Document Name	

Comment

ISO-NE is satisfied with the format of Table 1 with the recommendation of removing P2 and greater contingencies as FERC Order 896 Paragraph 113 as part of the Commission Determination states that *“NERC may determine whether contingencies P1 through P7 should also apply to the new or modified Reliability Standard, or whether a new set of contingencies should be developed.”*.

The FERC Order does not require the inclusion of P2, P4, or P7 contingency events. The P0 and P1 contingency events have a higher likelihood of occurrence and should remain within the Standard.

ISO-NE recommends removing the P2, P4 and P7 events from the Table or eliminating the need to perform analysis on those events from the Requirements.

Likes 0	
Dislikes 0	

Response

Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC) Project 2023-07 TPL-008-1 Draft #2

Answer	Yes
Document Name	

Comment

The SRC supports the Table 1 format. Is there an opportunity for TPL-008-1, Table 1.1 to reference TPL-001-5.1 instead? Only TPL-008-1, Table 1.2 shows information specific and unique to TPL-008.

Steady state performance requirements have stability requirements for P2, P4, P7. Voltage collapse (cascading) can be identified, but not instability or uncontrolled separation. This would require a dynamic study.

How does the SDT define how to determine stability performance requirements for P0 events? Currently it says that the system shall remain stable, and that instability, uncontrolled separation and cascading shall not occur, but how would those things occur for a P0 event?

Likes 0	
Dislikes 0	

Response

Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle

Answer	Yes
Document Name	

Comment

PGAE agrees with the updated layout of Table 1.

Likes 0	
Dislikes 0	

Response

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2

Answer	Yes
Document Name	

Comment

ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.

Likes 0	
Dislikes 0	

Response

Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis

Answer	Yes

Document Name	
Comment	
PJM supports the IRC SRC comments.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lidija Efremova - Lidija Efremova On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Lidija Efremova	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Zahid Qayyum - New York Power Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Barbara Marion - Dominion - Dominion Resources, Inc. - 5, Group Name Dominion	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michele Tondalo - United Illuminating Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Sorenson - Greg Sorenson On Behalf of: Tyler Schwendiman, ReliabilityFirst , 10; - Greg Sorenson	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Matt Lewis - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Michele Shafer - New York State Electric & Gas (NYSEG) - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rebika Yitna - Rebika Yitna On Behalf of: David Weekley, MEAG Power, 3, 1; Roger Brand, MEAG Power, 3, 1; - Rebika Yitna	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Apollonia Gonzales - PNM Resources - Public Service Company of New Mexico - 1,3,5 - WECC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	
Document Name	
Comment	
NetEra supports EEI's comments EEI does not have any concerns with the revised labelling of the Tables but references to the tables should also be updated for clarity.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE noticed multiple requirements in the standard refers to Table 1 and it is not clear which table is referenced (Table 1.1, Table 1.2 or Table 1.3)? Texas RE recommends the SDT consider making changes to reference the appropriate Table in each of the requirements. Texas RE also recommends that the column headers be carried over onto each page of the tables.	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	

Please see comments from EEI

Likes 0	
Dislikes 0	

Response
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC

Answer	
Document Name	

Comment
N/C

Likes 0	
Dislikes 0	

Response
Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO

Answer	
Document Name	

Comment
N/A

Likes 0	
Dislikes 0	

Response
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	
Document Name	

Comment
ITC does not have concerns with the layout of Table 1.

Likes 0	
Dislikes 0	
Response	

8. The DT believes proposed modifications in TPL-008-1 provide entities with flexibility to meet the reliability objectives in a cost-effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost-effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

Long Island Power Authority	
Answer	Yes
Document Name	(if an attachment is provided by submitter)
Comment	
Submitter's comments	
Likes 0	# of other submitters who agree with these comments
Dislikes 0	# of other submitters who disagree with these comments
Response	
(Drafting team's response to submitter's comments)	

John Brewer - National Energy Technology Laboratory - 9 - NA - Not Applicable	
Answer	No
Document Name	
Comment	
In general, the modifications in TPL-008-1 are a step in the right direction to provide entities with the flexibility to meet the reliability objectives cost-effectively. However, some concerns remain.	
Likes 0	
Dislikes 0	
Response	

Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
Answer	No
Document Name	
Comment	
PJM supports the IRC SRC comments.	
Likes 0	

Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	No
Document Name	
Comment	
Benchmarking extreme events should be considered a “sensitivity” case to normal Transmission Planning long-term cases. PGAE agrees that additional sensitivity cases to alter Gen/Load/Transfer may be prudent, however, a discrete Requirement for assessing sensitivity cases on top of the “sensitivity” cases of extreme weather conditions do not seem cost-effective.	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC) Project 2023-07 TPL-008-1 Draft #2	
Answer	No
Document Name	
Comment	
The SRC believes TPL-008 will require four additional cases be added to the case build process: 1. Summer benchmark planning case	

2. Summer sensitivity case

3. Winter benchmark planning case

4. Winter sensitivity case

The **Eastern Interconnection Reliability Assessment Group (ERAG) Multi-Regional Modeling Working Group (MMWG)** is likely the group that will coordinate interregional case builds for entities in the Eastern Interconnection, so these cases will be IN ADDITION TO existing case requirements. Also, extreme temperature sets will require additional data collection from generator owners through MOD-032. Once the temperature sets are known, PCs will need to issue a data request to generators requesting they provide:

1) the unit's ability to operate at that extreme temperature, and

2) if able, the machine's capability.

Further, the interchange coordination through the ERAG MMWG process only considers transactions that have confirmed annual firm transmission service along the entire path from source to sink and have a firm energy contract for the resource. As these transactions do not currently include temperature, that adds an additional layer of complexity to the development of these cases.

These are all non-trivial workload additions. For the Eastern Interconnection, the current funding of ERAG may be insufficient to accommodate model building for all the scenarios listed above. Therefore, ERAG will likely need to increase its fees to accomplish this work. In addition, PCs will likely need to hire more people to perform the studies.

Finding an effective and efficient process to meet the requirements of Order 896 is paramount to the success of this standard. The drafting team must be cognizant of the implications of workload on industry to ensure there is value-added for investing in these additional resources.

Likes 0	
Dislikes 0	

Response

Usama Tahir - Seminole Electric Cooperative, Inc. - 3

Answer	No
Document Name	

Comment

The TPL-001 studies are performed every year. The TPL-008 study will be performed at a minimum every 5 years. The DT should look at an approach that will reduce redundancy and overlap in testing between the TPL-008 and TPL-001 studies in order to save costs to customers.

Likes 0	
Dislikes 0	

Response

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	
Comment	

There is an associated cost impact with increasing experienced Transmission Planning resources for the additional work this new standard will require.

Likes 0	
Dislikes 0	
Response	

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	No
Document Name	
Comment	

ITC has concerns with the study scope for the sensitivity event. While ITC agrees that information can be gained from these studies, ITC believes that in most areas they will not result in any reliability benefit for the grid. ITC recommends a reduction in the required studies for the sensitivity event to only requiring steady state P0 and P1 studies. ITC also recommends that a CAP is also required when the system is unable to meet performance expectations. With these changes, less overall study work is required and additional reliability benefit will be obtained.

ITC also requests clarification be added in terms of footnote 1. The footnote identifies normal fault clearing. Is this what is intended for the study? Should this footnote be modified to consider the actual expected performance of the system to faults based on the weather event being studied.

Likes 0	
Dislikes 0	
Response	

Ben Hammer - Western Area Power Administration - 1

Answer	No
Document Name	
Comment	

WAPA believes the TPL-008 changes will require additional cases be added to the case build process. Also, extreme temperature sets will require additional data collection from generator owners through MOD-032. Once the temperature sets are known, PCs will need to issue a data request to generators to provide:

1) the unit's ability to operate at that extreme temperature, and

2) if able, the machine's capability.

Likes 0	
Dislikes 0	
Response	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	No
Document Name	
Comment	

ISO-NE does not agree with the requirements to perform Sensitivity Case studies in 4.2, 8.2 and 10.2. The results of Sensitivity Case studies are not required to be used per the current Standard language. This seems to be strictly an administrative action, which would burden the PCs with cost of time and resources to conduct the studies and does not provide reliability benefit for the BES.

R7 requires testing of all the events listed in Table 1, however R9 only requires the development of CAPs for the P0 and P1 contingencies. ISO-NE recommends modifying Table 1 to only include P0 and P1 events.

Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	

See comments providded by NPCC Regional Standards Committee.

Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	No
Document Name	
Comment	

- The attempt for flexibility is appreciated but this standard falls significantly short of something that is clear and allows the PC/TP to appropriately plan to meet reliability goals. The inclusion of outside entity reviews of CAPs offers the reviewer flexibility as there are no bounds provided to them. The PC/TP, however is potentially subjected to subjective reviews that have no framework with which the PC/TP can effectively respond.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO

Answer	No
Document Name	

Comment

SPP has a concern about the cost-effectiveness for this project.

From our perspective, it’s unclear on how the proposed modifications provides entities the flexibility to meet the reliability objectives in a cost effective manner. .

SPP recommends that the drafting team work with NERC staff revise the SAR development to include cost effective language to help industry get a better understanding of the cost effectiveness on implementing this standard.

Likes 0	
Dislikes 0	

Response

Rebika Yitna - Rebika Yitna On Behalf of: David Weekley, MEAG Power, 3, 1; Roger Brand, MEAG Power, 3, 1; - Rebika Yitna

Answer	No
Document Name	

Comment

The language requiring entities to solicit feedback from regulatory authorities and governing bodies, in R9.1, may be removed from the standard to make it cost-effective. Requiring CAP and installation of equipment is likely not as cost effective as implementing operational procedures

Likes 0	
Dislikes 0	

Response

Donna Wood - Tri-State G and T Association, Inc. - 1

Answer	No
Document Name	
Comment	
Tri-State supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO’s NERC Standards Review Forum’s (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
Suggest clarification that operational procedures may constitute an appropriate CAP.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	

Comment	
The requirement to solicit CAP feedback from regulatory authorities and governing bodies raises concern about how flexibility might otherwise be limited outside of the direct influence of the standard. It is Southern Company’s recommendation that the language requiring entities to solicit feedback from regulatory authorities and governing bodies, in R9.1, should be removed from the standard.	
Likes 0	
Dislikes 0	
Response	
Junji Yamaguchi - Hydro-Quebec (HQ) - 5	
Answer	No
Document Name	
Comment	
see comments in other sections.	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	No
Document Name	
Comment	
Requiring CAP and installation of equipment based off NERC TPL 008 is likely not as cost-effective as implementing operational procedures	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	No
Document Name	
Comment	

Avista offers the following suggested comments for consideration: Avista suggests clarification that operational procedures may constitute an appropriate CAP.	
Likes 0	
Dislikes 0	
Response	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
ATC supports the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 8	
Likes 0	
Dislikes 0	
Response	
Barbara Marion - Dominion - Dominion Resources, Inc. - 5, Group Name Dominion	
Answer	No
Document Name	
Comment	

There are concerns over the CAP as well as ambiguity in R2.

Likes 0	
Dislikes 0	

Response

Donald Lock - Talen Generation, LLC - 5

Answer	No
Document Name	

Comment

See our comments above

Likes 0	
Dislikes 0	

Response

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC

Answer	No
Document Name	

Comment

SMUD does not believe it is cost effective. The additional costs to maintain the necessary base cases and perform sensitivity studies of rare events that require no corrective actions is unnecessary and provides no reliability gains.

Likes 0	
Dislikes 0	

Response

Robert Jones - Seattle City Light - 1,3,4,5,6

Answer	No
Document Name	

Comment

Requiring a CAP is likely not as cost-effective as implementing operational procedures.

Likes 0	
Dislikes 0	

Response

Broc Bruton - Broc Bruton On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Broc Bruton

Answer	No
Document Name	

Comment

The timeline should not start until the ERO has developed and shared the benchmark event library. Because of the complexity of the required study, the proposed standard is written to employ a five-year process. Final implementation of the proposed standard should be five years after the ERO has developed the benchmark event library.

Likes 0	
Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	No
Document Name	

Comment

The MRO NSRF believes TPL-008 will require eight additional cases be added to the case build process:

1. Summer benchmark power flow
2. Summer sensitivity power flow
3. Summer benchmark dynamics
4. Summer sensitivity dynamics
5. Winter benchmark power flow
6. Winter sensitivity power flow
7. Winter benchmark dynamics
8. Winter sensitivity dynamics

MMWG is likely going to be the group to coordinate interregional case builds, so these cases will be IN ADDITION TO existing case requirements. Also, extreme temperature sets will require additional data collection from generator owners through MOD-032. Once the temperature sets are known, PCs will need to issue a data request to generators to provide:

1) the unit's ability to operate at that extreme temperature, and

2) if able, the machine's capability.

These are all non-trivial workload additions. Current funding of ERAG may be insufficient to accommodate model building for all the scenarios listed above. Therefore, ERAG will likely need to increase its fees to accomplish this work. In addition, PCs will likely need to hire more people to perform the studies.

Likes 1	Scott Brame, N/A, Brame Scott
Dislikes 0	

Response

Zahid Qayyum - New York Power Authority - 5

Answer	No
Document Name	

Comment

• NYPA will need more information to adequately assess the cost effectiveness of the proposed approach.

Likes 0	
Dislikes 0	

Response

Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

BPA does not believe it is cost effective. It is cost prohibitive to make capital investments for multiple contingency events during extreme temperatures. BPA believes it is more appropriate to deal with such scenarios in operating horizon through operating plans

Likes 0	
Dislikes 0	

Response

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
We believe performing sensitivity studies is unnecessary for the benchmarked extreme temperature scenarios. It is purely administrative and adds no value to the reliability since nothing expected to do with the the study results other than documenting the possible actions.	
Likes 0	
Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	No
Document Name	
Comment	
CHPD agrees with WPP's comment.	
Likes 1	Jennie Wike, N/A, Wike Jennie
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
At this time, due to the number of requirements that we do not agree with, we are unable to fully agree that this standard provides the necessary flexibility to meet the reliability objectives in a cost-effective manner.	
Likes 0	
Dislikes 0	
Response	

Chelsea Loomis - Western Power Pool - NA - Not Applicable - WECC, Group Name WPP Consortium of Engineers	
Answer	No
Document Name	
Comment	
Requiring CAP and installation of equipment based off NERC TPL 008 is likely not as cost-effective as implementing operational procedures	
Likes 0	
Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	No
Document Name	
Comment	
Requiring CAP and installation of equipment is likely not as cost effective as implementing operational procedures.	
Likes 2	Snohomish County PUD No. 1, 3, Chaney Holly; Jennie Wike, N/A, Wike Jennie
Dislikes 0	
Response	
Jeffrey Streifling - NB Power Corporation - 1	
Answer	No
Document Name	
Comment	
See other answers.	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Chantal Mazza On Behalf of: Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	No

Document Name	
Comment	
see comments in other sections	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Fon Hiew - NB Power Corporation - New Brunswick Power Transmission Corporation - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
None	

Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FE has no comment toward the cost-effectiveness of this proposal	
Likes 0	
Dislikes 0	
Response	
Apollonia Gonzales - PNM Resources - Public Service Company of New Mexico - 1,3,5 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michele Shafer - New York State Electric & Gas (NYSEG) - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Matt Lewis - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michele Tondalo - United Illuminating Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Gary Trezza - Long Island Power Authority - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Lidija Efremova - Lidija Efremova On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Lidija Efremova	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Srikanth Chennupati - Entergy - Entergy Services, Inc. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	
Document Name	
Comment	
N/C	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
Please see comments from EEI	
Likes 0	
Dislikes 0	
Response	

Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop

Answer	
Document Name	

Comment

Ameren has no comments on the cost effectiveness of the project.

Likes 0	
Dislikes 0	

Response

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF

Answer	
Document Name	

Comment

Without including the framework and criteria for benchmark events in the standard, it is impossible to assess the cost-effectiveness or the reliability objectives. While the DT does not need to include detailed weather data in the standard, it must include parameters such as: the duration of historical meteorological data to use, the likelihood/probability of the events to be studied, the granularity of data required, etc.

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments

Answer	
Document Name	

Comment

Black Hills Corporation will not comment on cost effectiveness.

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
Duke Energy does not comment on costs.	
Likes 0	
Dislikes 0	
Response	

9. Provide any additional comments for the standard drafting team to consider, including the provided technical rationale document, if desired.

Long Island Power Authority	
Answer	
Document Name	
Comment	

Comment on the Implementation Plan:

From the Implementation Plan (IP), the graphic on page 3 of the IP does not match the text on page 2. In the graphic, it appears that the timeline is based on governmental authority approval, and not on when TPL-008-1 goes into effect.

Page 2 of the IP states:

Phased-In Compliance Dates

Compliance Date for TPL-008-1 Requirement R1

Entities shall be required to comply with Requirement R1 upon the effective date of Reliability Standard TPL-008-1.

Compliance Date for TPL-008-1 Requirements R2, R3, R4, R5, R6

Entities shall not be required to comply with Requirements R2, R3, R4, R5, and R6 until thirty-six (36) months after the effective date of Reliability Standard TPL-008-1.

Compliance Date for TPL-008-1 Requirements R7, R8, R9, R10, R11

Entities shall not be required to comply with Requirements R7, R8, R9, R10, R11 until sixty (60) months after the effective date of Reliability Standard TPL-008-1.

To match the text on page 2, our interpretation is that the graphic on page 3 should be modified as shown below.

Comment on Requirement #11

Requirement #11 states:

“Each responsible entity, as identified in Requirement R1, shall provide its Extreme Temperature Assessment results within 60 calendar days of a request to any functional entity that has a reliability related need and submits a written request for the information.”

This could be interpreted in different ways.

We would recommend the SDT consider modifying the wording (see TPL-001-5.1 Req #8 for reference) and timeframe to be more consistent with TPL-001-5.1 Req #, 8 as follows:

“Each responsible entity, as identified in Requirement R1, shall provide its latest completed Extreme Temperature Assessment results within 90 calendar days of a request to any functional entity that has a reliability related need and submits a written request for the information.”

Likes 0	# of other submitters who agree with these comments
Dislikes 0	# of other submitters who disagree with these comments

Response
(Drafting team's response to submitter's comments)

Chantal Mazza - Chantal Mazza On Behalf of: Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza

Answer	
Document Name	

Comment

1. Facility Owners (FOs) have an important role in developing and implement corrective action plans. The document does not acknowledge the role of the FO explicitly. The FO ultimately has the accountability to present CAP and associated investments and cost to its regulatory body for retail service. We suggest the standard make this explicitly clear.

2. In certain jurisdiction, extreme temperature ratings have been established, but that is not necessarily the case in all jurisdictions. Will facility owners be required to establish extreme cold or warm temperature ratings for this standard?

Likes 0	
Dislikes 0	

Response

Jeffrey Streifling - NB Power Corporation - 1

Answer	
Document Name	

Comment

Facility Owners (FOs) have an important role in developing and implement corrective action plans. The document does not acknowledge the role of the FO explicitly. The FO ultimately has the accountability to present CAP and associated investments and cost to its regulatory body for retail service. We suggest the standard make this explicitly clear.

In certain jurisdiction, extreme temperature ratings have been established, but that is not necessarily the case in all jurisdictions. Will facility owners be required to establish extreme cold or warm temperature ratings for this standard?

Likes 0	
Dislikes 0	

Response

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF

Answer	
Document Name	

Comment

To remain consistent with TPL-001 and the definition of the Extreme Temperature Assessment, “Bulk Power System” should be refined to “Bulk Electric System” in the purpose statement of this standard.

Likes 0	
Dislikes 0	

Response

Srikanth Chennupati - Entergy - Entergy Services, Inc. - 1,3,5,6 - SERC

Answer	
Document Name	

Comment

The implementation plan should allow additional time beyond the five-year assessment schedule for the first assessment to be completed. This will allow time for benchmark temperature events to be identified and developed by the ERO & industry. This will also provide leeway for any issues that may arise in implementing this large-scale and complex model building and study process that will require new collaboration processes between Planning Coordinators.

Likes 0	
Dislikes 0	

Response

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	
Document Name	

Comment

(R11) We do not agree with R11. Although the comment document does not appear to request input for R11, we recommend that the “results” only include the assessments as contemplated in R9, for which Corrective Action Plans will be developed. Since the “possible actions” in R10 are suggested to be useful for reference only, per the Technical Rationale document, and are not required to have Corrective Action Plans, we believe sharing this reference information would be an inefficient and ineffective task, and likely to cause more confusion that clarity.

Likes 0	
Dislikes 0	

Response

Lidija Efremova - Lidija Efremova On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Lidija Efremova

Answer	

Document Name	
Comment	

Comments:

1. The document does not acknowledge the role of the facility owner explicitly. Facility Owners (FO) have an important role in developing and implement corrective action plans. PC cannot and should NOT come up with requirements without involving the FO. As an example, the IESO should not be allowed to come up for requirements for extreme weather without full alignment with HONI, that needs to spend the money and provision for emergency response and replacement for every event. In some jurisdictions, the FO ultimately has the accountability to present CAP and associated investments and cost to its regulatory body for retail service. We suggest the standard make this explicitly clear.

2. NERC and/or FERC should only direct coordination and alignment and not specific actions. The local PC/TO/BA can determine what the local needs and responses should be based on a consistent framework for the control area.

3. In Ontario, we have updated and derated equipment ratings by taking extreme temperatures into account; for example, for transmission line we have gone from 30C to 35C based on regional temperatures. In addition, we also consider extreme weather correction factors both for winter and summer. For this exercise/standard, would facility owner need to establish further extreme ratings such as 40C or 45C? This will be unmanageable and provide skewed results and double counting.

4. Are the benchmark events considering regional-specific extremes? We are interested in seeing how Canadian, provincial attributes are considered within the ERO benchmark library. It is extremely important that Canadian benchmarks are adequately reflected and/or provide flexibility for Canadian to make changes to the ERO benchmark library.

5. We appreciate and agree with the draft standard for assessment of extreme weather conditions using normal contingencies. However, we would not support an assessment with required CAP using any type of extreme contingencies.

6. The benchmarking and baselining of the events that one should consider is a necessary step as some jurisdictions/utilities may not want to take any risk and ask for a lot of funding and others may be more balanced and ask for less funding. Assessing to a reasonable risk level needs to be consistent.

Likes 0	
Dislikes 0	
Response	

Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD

Answer	
Document Name	
Comment	

Industry have not been provided NERC’s proposed set of benchmark events so that we may provide meaningful feedback during this standard development process. We continue to have concerns about the benchmark library and the process to include and update events.

On a positive note, while we have not seen such materials included in this standard development process, CHPD appreciates members of the SDT have reached out to our region regarding the benchmark library, and we have been able to provide dialogue to the SDT via this outreach. This outreach by the SDT members is appreciated and commendable.

Regarding outages – we see the SDT's comment and response to "All lines in Service", but we do not see clarification in the standard itself along these lines. CHPD requests clarity from the SDT on whether this is the expectation (in which case this should be specifically called out in requirements) or if this is more a N-0 all lines in service instance, in which case the baseline scenario would not have outages.

The approach in TPL-001-5 R2.1.4. regarding planned outages has precedence in the transmission planning realm.

TPL-001-5.1 R2.1.4 Language:

When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P0 and P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. This assessment shall include, at a minimum known outages expected to produce more severe System impacts on the Planning Coordinator or Transmission Planner's portion of the BES. Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and TPL-001-5.1 — Transmission System Planning Performance Requirements Page 3 of 32 configuration such as those following P3 or P6 category events in Table 1.

If planned outages instead of weather-related historic outages are the intent, a proposed language selection for TPL-008, based on TPL-001-5.1 R2.1.4 could be:

When known outage(s) of generation or Transmission Facility(ies) are planned in the Long-Term Transmission Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P0 and P1 categories identified in Table 1 for under Benchmark Planning Case Assessment conditions that the System is expected to experience when the known outage(s) are planned. This assessment shall include, at a minimum known outages expected to produce more severe System impacts on the Planning Coordinator or Transmission Planner's portion of the BES.

CHPD would also like to note, that we support and agree with WPP's submitted comments.

Likes 1	Jennie Wike, N/A, Wike Jennie
Dislikes 0	

Response

Gary Trezza - Long Island Power Authority - 1 - NPCC

Answer	
Document Name	2023-07_Unofficial_Comment_Form Draft 2_071624_LIPA comments_08-15-2024 (002).pdf

Comment

Comment on the Implementation Plan:

From the Implementation Plan (IP), the graphic on page 3 of the IP does not match the text on page 2.

In the graphic, it appears that the timeline is based on governmental authority approval, and not on when TPL-008-1 goes into effect.

Page 2 of the IP states:

Phased-In Compliance Dates

Compliance Date for TPL-008-1 Requirement R1

Entities shall be required to comply with Requirement R1 upon the effective date of Reliability Standard TPL-008-1.

Compliance Date for TPL-008-1 Requirements R2, R3, R4, R5, R6

Entities shall not be required to comply with Requirements R2, R3, R4, R5, and R6 **until thirty-six (36) months after the effective date of Reliability Standard TPL-008-1.**

Compliance Date for TPL-008-1 Requirements R7, R8, R9, R10, R11

Entities shall not be required to comply with Requirements R7, R8, R9, R10, R11 until **sixty (60) months after the effective date of Reliability Standard TPL-008-1.**

To match the text on page 2, our interpretation is that the graphic on page 3 should be MODIFIED as shown on on page 7 of 7 of the UPLOADED / ATTACHED file named *"2023-07_Unofficial_Comment_Form Draft 2_071624_LIPA comments_08-15-2024 (002).pdf".*

Comment on Requirement #11

Requirement #11 states:
"Each responsible entity, as identified in Requirement R1, shall provide its Extreme Temperature Assessment results within 60 calendar days of a request to any functional entity that has a reliability related need and submits a written request for the information."
This could be interpreted in different ways.
We would recommend the SDT consider modifying the wording (see TPL-001-5.1 Req #8 for reference) and timeframe to be more consistent with TPL-001-5.1 Req #, 8 as follows:
*"Each responsible entity, as identified in Requirement R1, shall provide its **latest completed** Extreme Temperature Assessment results within **90** calendar days of a request to any functional entity that has a reliability related need and submits a written request for the information."*

Likes 0	
Dislikes 0	

Response

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO

Answer	
Document Name	

Comment

Please correct the wording "min" to "max" in the table heading on page-4 of the "Extreme Heat and Cold Weather Benchmark Events Example" document.

Likes 0	
Dislikes 0	

Response

Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

BPA recommends adding "or to its designee" to all references of "ERO" in R2. BPA believes this will add flexibility to the requirement for scenarios such as large geographical footprints, where benchmark temperatures could be extremely variable"

BPA currently has the following concerns:

R2 - Uncertainty about the events in the NERC library and the process.

R3/R4 - Need a clearly defined scope regarding coordination with the other entities.

R9 Corrective Action Plans, use of Operating Plans could be a cost effective alternative to a CAP and result in acceptable system performance.

Likes 0	
Dislikes 0	

Response

Fon Hiew - NB Power Corporation - New Brunswick Power Transmission Corporation - 5

Answer	
Document Name	

Comment

Facility Owners (FOs) have an important role in developing and implement corrective action plans. The document does not acknowledge the role of the FO explicitly. The FO ultimately has the accountability to present CAP and associated investments and cost to its regulatory body for retail service. We suggest the standard make this explicitly clear.

In certain jurisdiction, extreme temperature ratings have been established, but that is not necessarily the case in all jurisdictions. Will facility owners be required to establish extreme cold or warm temperature ratings for this standard?

Likes 0	

Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
Modify R11 to match TPL-001-5.1 R8 except change 90 calendar-days to "180 calendar-days" in R8.1 due to the five-year time period between studies.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Zahid Qayyum - New York Power Authority - 5	
Answer	
Document Name	
Comment	
• It's unclear whether the responsible entity will do an annual reconciliation of cases using actual recorded data? NYPA appreciates if the SDT can provide clarity on this • Table 1 in the requirement language should be replaced with Table 1.1, table 1.2 appropriately.	
Likes 0	

Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	
Document Name	
Comment	

Footnote 1 from Table 1.3 is not reflected in Table 1.1 (it should be up by 'Fault Type' column header).

ETA Definition and Purpose: MRO NSRF notes that the definition for Extreme Temperature Assessment uses BES and the purpose of TPL-001-8 uses BPS. The two should align and MRO NSRF supports the use of “BES” to align with existing standard, TPL-001-5.1. Alternatively, the SDT needs to justify the reason for the difference.

DRAFT ERO Enterprise Process for TPL-008-1 Benchmark Weather Event Development and Maintenance

The process document says,” Refer to the NERC **Glossary of Terms** for the below capitalized terms used in this process.” While NERC may have defined these terms, those highlighted in yellow (below) are ***not*** in the NERC Glossary of Terms.

• Affected Regional Entity (ARE)

• Compliance Enforcement Authority (CEA)

• Coordinated Oversight

• Extreme Temperature Assessment (ETA) – New! In TPL-008-1 standard

• Lead Regional Entity (LRE)

• Multi-Region Registered Entity (MRRE)

Absence of the Benchmark Library

The MRO NSRF has concerns with finalizing the TPL-008 standard with the benchmark event library unseen as this may have significant impact as to how the standard should be structured and how it is interpreted and applied.

Relevance to Canada

The MRO NSRF requests that Canadian provinces be considered within the ERO benchmark library.

MRO NSRF requests clarification regarding the following. Is an entity required to use the same benchmark event across its entire footprint or can an entity use different events for different areas of its footprint? For example, if an MRO NSRF member selects a benchmark event that has high impacts concentrated in its Southern Region for its first iteration, could the next 5-year iteration use a benchmark event that has high impacts concentrated in its Central Region?

Depending on how far into the future these requests are made, there may great uncertainty for the resources. Many states have firm policies driving unit deactivations, but replacement resource location and size is not going to be able to be known. This may lead to these future cases being un-solvable without large reactive or replacement power assumptions.	
Likes 1	Scott Brame, N/A, Brame Scott
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	
Document Name	
Comment	
Facility Owners (FOs) have an important role in developing and implement corrective action plans. The document does not acknowledge the role of the FO explicitly. The FO ultimately has the accountability to present CAP and associated investments and cost to its regulatory body for retail service. We suggest the standard make this explicitly clear. In certain jurisdiction, extreme temperature ratings have been established, but that is not necessarily the case in all jurisdictions. Will facility owners be required to establish extreme cold or warm temperature ratings for this standard?	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	
Document Name	
Comment	
Overall, Exelon would like to see additional details of events in the benchmark library included in the associated standard requirements. Specifically, seeking clarity on exactly what data will be included in selected events as well as how event selection will inform coordination.	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	

Answer	
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC

Answer	
Document Name	

Comment

SMUD supports the comments submitted by the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Barbara Marion - Dominion - Dominion Resources, Inc. - 5, Group Name Dominion

Answer	
Document Name	

Comment

There are concerns over the CAP as well as ambiguity in R2.

Likes 0	
Dislikes 0	

Response

Michael Jones - National Grid USA - 1

Answer	
Document Name	

Comment

National Grid supports EEI's comments. In addition, please thoroughly review TPL-008-1 Table 1 to ensure consistency with TPL-001-5.1 Table 1, where applicable, to ensure nothing has been unintentionally missed. For example and consideration:

Table 1 - General comments:

Footnote 1 (in TPL-001) in header of Event column is 'missing,' i.e., not included in TPL-008.

Footnote 1 (in TPL-008), which is Footnote 2 (in TPL-001), is missing(?) from the header of Table 1

Footnote 2 (in TPL-001) in header of BES Level column is 'missing,' i.e., not included in TPL-008, while Facility voltage level of Contingency is listed in new Footnote 2 (in TPL-008) it is still 'inconsistent.'

Footnote 5 (in TPL-001) related to transformers is 'missing,' i.e., not included in TPL-008.

Footnote 9 (in TPL-001) for interruption of firm transmission is 'missing,' i.e., not included in TPL-008.

Footnote 11 (in TPL-001) related to DCTs is 'missing,' i.e., not included in TPL-008.

Footnote 12 (in TPL-001) on non-consequential load loss is 'missing,' i.e., not included in TPL-008.

Table 1.2 – Performance Requirements

P0: "The System shall remain stable" is only listed for P0– Suggest removing since not 'defined.' Similar to EEI comment, but recommending deleting since reference to 'remain stable' is unclear.

Allowance for non-Consequential Load Loss as an interim solution seems more stringent than TPL-001.

Requirement to "Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event" (TPL-001) has no matching counterpart in Table 1.

Event to "Simulate Normal Clearing unless otherwise specified" (TPL-001) has no counterpart in Table 1.

Minor issues: Table 1.2 (in TPL-008) is structured differently than in TPL-001 and placed after the 'main' Table 1., The ordering of Non-Consequential Load Loss and Interruption of Firm Transmission reversed (vs. TPL-001).

Likes 0	
Dislikes 0	

Response

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples

Answer	
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 9

Likes 0	
Dislikes 0	

Response

Amy Wilke - American Transmission Company, LLC - 1

Answer	
Document Name	

Comment

ATC supports the MRO NSRF comments.

Likes 0	
Dislikes 0	

Response

Junji Yamaguchi - Hydro-Quebec (HQ) - 5

Answer	
Document Name	

Comment

1. Facility Owners (FOs) have an important role in developing and implement corrective action plans. The document does not acknowledge the role of the FO explicitly. The FO ultimately has the accountability to present CAP and associated investments and cost to its regulatory body for retail service. We suggest the standard make this explicitly clear.

2. In certain jurisdiction, extreme temperature ratings have been established, but that is not necessarily the case in all jurisdictions. Will facility owners be required to establish extreme cold or warm temperature ratings for this standard?

Likes 0	
Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	
Document Name	
Comment	

- Key responsibilities and deadline details from the "ERO Enterprise Process for TPL-008-1 Benchmark Weather Event Development and Maintenance" should be included in the TPL-008-1 reliability standard to define the ERO's responsibilities as they pertain to the development and maintenance of the Weather Event Library. At minimum, the suggested language and footnote proposed by EEI in response to survey question 2 should be included.
- Page 3, A.3, the Introduction Purpose should change "Bulk Power System (BPS)" to "Bulk Electric System (BES)" for consistency.
- Reference to the benchmark events as either 'temperature benchmark events' or 'benchmark temperature events' should be made consistent throughout the document. Slight preference for 'temperature benchmark events'.

Likes 0	
Dislikes 0	
Response	

Helen Lainis - Independent Electricity System Operator - 2

Answer	
Document Name	
Comment	

We support NPCC TFCP comment regarding whether facility owners will be required to establish extreme cold or warm temperature ratings for this standard?

Likes 0	
Dislikes 0	
Response	

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF

Answer	
Document Name	
Comment	

The DT should consider whether the use of "The responsible entity" is appropriate instead of "Each responsible entity". Use of "each" seems to read that the PC and all TPs must each do the requirements, whereas the intention is that the PC and TPs decide who is going to be *the* responsible entity for each step.

Likes 0	

Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE has identified two issues with the proposed Implementation Plan. First, the Implementation Plan timeline and narrative do not consistently use the same start date for all applicable compliance dates. In particular, the compliance dates for Requirement R1 appear tied to the Standard Effective Date, but the compliance dates in the proposed timeline appear tied to the date of the government order. Second, Texas RE notes that no initial performance date is specified for Requirement R8.

Phased Implementation Dates

Texas RE requests again that the implementation plan descriptions and diagram be aligned to a consistent start date for all applicable requirements. Texas RE notes that in the narrative description, compliance activities appear to be linked to the Standard Effective Date, which is 12 months following the first calendar quarter after the order of the applicable governing authority approving the standard. For instance, the proposed Implementation Plan provides that entities shall be required to comply with Requirement R1 upon the effective date of the Reliability Standard TPL-008-1. Similarly, compliance dates for Requirements R2 through R6 are occur 36 months after the effective date of standard.

The table then provides that the enforcement date for Requirement R1 is 12 months following the applicable governing authority's order – that is, the Effective Date of the Standard. In contrast, however, the implementation timeline then appears to link the various staggered implementation dates for R2 through R6 and R7 through R11 to the date of the order approving the standard, not the Effective Date of the Standard itself. That is, entities in effect have only 24 months from the Effective Date of the Standard to comply with R2 though R6 under the timeline, not 36 months from the Effective Date of Reliability Standard TPL-008-1 as set forth in the Implementation Plan narrative.

Texas RE recommends that the SDT either revise the timeline chart to consistently link all required compliance dates to the Effective Date of the Standard or, alternatively, revise the narrative description to reference the date of the order approving the standard for all required compliance dates to avoid confusion.

The following table summarizes the Implementation Plan and chart as currently drafted:

Phased In Compliance Dates

Effective Date of the Standard = The first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governing authority's order.

R1 = Effective Date of TPL-008-1 (12 months after the government order)

R2, R3, R4, R5, R6 = Effective Date + 36 months

R7, R8, R9, R10, R11 = Effective Date + 60 months

The diagram in the implementation plan shows the following:

R1 = Effective Date of TPL-008-1 (12 months after the government order date)

R2, R3, R4, R5, R6 = Effective Date for TPL-008-1 + 24 months (36 months after the government order date)

R7, R8, R9, R10, R11 = Effective Date for TPL-008-1 + 48 months (60 months after the government order date)

Initial Performance Date

Additionally, Requirement R8 states that the Extreme Temperature Assessment shall be done once every five calendar years. Since there is no initial performance date specified, Texas RE understands that the entity would not need to perform its initial Extreme Temperature Assessment until 5 years after the effective date of Requirement R8 (that is, 10 years after the Effective Date of Requirement R8). Texas RE generally recommends establishing an explicit initial performance date upon the effective date of the requirement to avoid delaying compliance obligations an additional five years.

Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez	
Answer	
Document Name	
Comment	
The standard as written is inconsistent in all references to the attached tables. "Table 1" should be removed from the requirement language and table 1.1 and 1.2 used appropriately.	
Likes 0	
Dislikes 0	
Response	
Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop	
Answer	
Document Name	

Comment	
Ameren supports EEI's comments on this project.	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	
Document Name	
Comment	

Purpose statement includes use of BPS but new definition is limited to BES. Was that intentional? R11-Who determines "reliability related need"?

There are no defined actions to address deficiencies recognized by an Extreme Temperature Assessment. Only CAPs are called out, is that the expectation?

Extreme weather may not cover all of a responsible entity's area. Is it the DT's assumption that it would and therefore no partial footprint Extreme Temperature Assessments would meet the Requirements? Or are partial footprint Extreme Temperature Assessments allowable? Based on the additional materials provided it appears that boundaries have been set.

Table Issues- Where is Footnote 1 within the Table used?

Steady State P1- Capitalize "Facility ratings"

Requirement R5 Severe VSL should say "completing" not "performing".

Requirement R7 VSLs need rewritten to match language of the Standard unless language gets changed back to "Contingencies".

Requirement R8 VSLs indicate completion of an Extreme Temperature Assessment but do not reflect completion of "steady state and transient stability analyses". If one of those is not done, effectively an Extreme Temperature Assessment has not been performed. Is that correct?

Benchmark Weather Event Development and Maintenance Document

There are several terms noted as being in the Glossary of Terms but are not used in the process nor are they in the Glossary. Many deal with the Coordinated Oversight Program that has its own set of definitions. The sample benchmark event materials for the Weather Event Library provide some clarity on what materials will be included. Still looks like additional information may be needed for registered entities approach in using the events in the Extreme Temperature Assessments.

Likes 0	
Dislikes 0	
Response	

Teresa Krabe - Lower Colorado River Authority - 5

Answer	
Document Name	

Comment

The Technical Rationale for R7 mentions that the benchmark planning cases will factor generation and transmission outages. LCRA does not believe its clear on how the benchmark cases will account for generation and transmission outages prior to running the specified contingencies and how outages factor into CAP development.

Likes 0	
Dislikes 0	

Response

Hillary Creurer - Allete - Minnesota Power, Inc. - 1

Answer	
Document Name	

Comment

Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.

Likes 0	
Dislikes 0	

Response

Matt Lewis - Lower Colorado River Authority - 1

Answer	
Document Name	

Comment

The Technical Rationale for R7 mentions that the benchmark planning cases will factor generation and transmission outages. LCRA TSC does not believe its clear on how the benchmark cases will account for generation and transmission outages prior to running the specified contingencies and how outages factor into CAP development.

Likes 0	
Dislikes 0	

Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
Tri-State supports the comments submitted by the MRO NSRF referencing the absence of the Benchmark Library. "MRO NSRF has concerns with finalizing the TPL-008 standard with the benchmark event library unseen as this may have significant impact as to how the standard should be structured and how it is interpreted and applied."	
Likes 0	
Dislikes 0	
Response	
Romel Aquino - Edison International - Southern California Edison Company - 3	
Answer	
Document Name	Near Final EEI Comments P2023-07_ TPL-008 Draft 2 _ Rev. 0g 8_21_2024.docx
Comment	
See comments submitted by the Edison Electric Institute, attached.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO	
Answer	
Document Name	
Comment	
SPP recommends that the drafting team coordinate with other drafting teams like the Energy Reliability Assessment (ERA) to ensure that these assessments doesn't create overlap for each other's processes and efforts.	
Likes 0	

Dislikes 0	

Response

Kinte Whitehead - Exelon - 3	
Answer	
Document Name	

Comment
Overall, Exelon would like to see additional details of events in the benchmark library included in the associated standard requirements. Specifically, seeking clarity on exactly what data will be included in selected events as well as how event selection will inform coordination.

Likes 0	
Dislikes 0	

Response

Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	
Document Name	

Comment
• In general, the development of an extreme weather benchmark event is reasonable. The difficulty in properly assessing this draft Reliability Standard is the unknowns around the benchmark events. Whether these events are solely temperature-based or if there is a related electrical system or resource availability embedded needs to be clarified in the standard language. Also, there are numerous inconsistencies, ambiguities, and significant burdens being placed on the PC/TP in this standard that will result in problematic assessments, issues with coordination, competing CAPS within Interconnections, and cost for more staff to support the significant burden this standard poses.

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	
Document Name	

Comment
OPG supports NPCC Regional Standards Committee’s comments:

Facility Owners (FOs) have an important role in developing and implement corrective action plans. The document does not acknowledge the role of the FO explicitly. The FO ultimately has the accountability to present CAP and associated investments and cost to its regulatory body for retail service. We suggest the standard make this explicitly clear.

In certain jurisdiction, extreme temperature ratings have been established, but that is not necessarily the case in all jurisdictions. Will facility owners be required to establish extreme cold or warm temperature ratings for this standard?

Likes 0	
Dislikes 0	

Response

Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen

Answer	
Document Name	

Comment

While ISO-NE appreciates the Benchmark Event Example, many concerns that the industry has regarding this standard and the studies that would be required, could be alleviated by the SDT/NERC providing a list of the Benchmark Temperature Events that would be available to choose from. It is difficult for areas to determine what would be required and to agree to perform studies on specific events without the list of events to choose from for the studies.

In the specific Benchmark Event Example, ISO-NE did not experience a cold weather event so there is no value to ISO-NE in studying that particular event.

ISO-NE requests that a list of Benchmark Events and applicable parameters be provided **prior** to any final Ballot on the TPL-008 Standard.

Likes 0	
Dislikes 0	

Response

Ben Hammer - Western Area Power Administration - 1

Answer	
Document Name	

Comment

Absence of the Benchmark Library

WAPA has concerns with finalizing the TPL-008 standard with the benchmark event library unseen as this may have significant impact as to how the standard should be structured and how it is interpreted and applied.

Likes 0	

Dislikes	0

Response

Michael Goggin - Grid Strategies LLC - 5

Answer	
Document Name	

Comment

First, to comply with FERC Order 896, the standard should specify that benchmark events and Extreme Temperature Assessments will account for concurrent/correlated outages of generators during extreme heat and cold events. In Order 896 paragraph 88, FERC directs “NERC to require under the new or revised Reliability Standard the study of concurrent/correlated generator and transmission outages due to extreme heat and cold events in benchmark events,” explaining in paragraph 89 that “it is necessary that responsible entities evaluate the risk of correlated or concurrent outages and derates of all types of generation resources and transmission facilities as a result of extreme heat and cold events.”

The drafts of TPL-008 and the associated “Consideration of FERC Order 896 Directives” document appear to put the burden on responsible entities and not NERC for accounting for correlated outages: “This directive is addressed in proposed TPL-008-1 through Requirement R3 Part 3.2. The responsible entity is obligated to modify the benchmark planning cases to include seasonal and temperature dependent adjustment for Load, generation, Transmission, and transfers which represent the selected benchmark events.”[1]

Having responsible entities and not NERC conduct this adjustment increases the risk that different regions will use inconsistent methods for doing so, and at worst responsible entities that want to avoid addressing reliability concerns through a Corrective Action Plan will use unrealistically low assumptions for the rate of correlated generator outages or other input assumptions like load and transfers. This assumption can have such a large impact on results it cannot be left to responsible entities, and should be made by NERC. The drafting team’s Technical Rationale used similar logic in deciding that NERC (the Electric Reliability Organization or ERO) should assemble the benchmark planning cases: “to ensure consistency across regions, it is necessary for the ERO to have the responsibility for determining the suitability of benchmark events to represent probable future conditions.”

Given the significant variation in the rates at which different fuel types experience correlated outages,[2] and rapid changes in the generation mix that may cause the future power system to have greater or lesser exposure to correlated outage risk, it is particularly important for the benchmark events and Extreme Temperature Assessments to account for the concurrent/correlated outage risk of each fuel type in the future generation mix. In recent cold snap events, gas generator outages due to equipment failures and fuel supply interruptions have accounted for the majority of outages. NERC GADS data can be used to assess the rate of correlated outages and derates of generators by fuel type.{C}[3]

Second, the benchmark cases and Extreme Temperature Assessments should account for changes to generation, demand, and transmission resulting from climate change, electrification of heating, and other factors that are affecting the risk posed by extreme heat and cold. Accounting for how climate change is increasing the frequency and magnitude of extreme heat and cold events is consistent with FERC’s Order 896 directive in paragraph 40: “We also direct NERC to ensure the reliability standard contains appropriate mechanisms for ensuring the benchmark event reflects up-to-date meteorological data. The increasing intensity, frequency, and unpredictability of extreme weather conditions requires that key aspects of the benchmark events be reviewed, and if necessary, updated periodically to ensure the corresponding benchmark planning cases reflect updated meteorological data.” Electrification of heating is also increasing the sensitivity of electricity demand to extreme cold conditions, which should be accounted for in the benchmark cases and Extreme Temperature Assessments.

Third, due to the impact of climate change, electrification, and rapid changes in the generation mix, requirement R8 should require responsible entities to complete an Extreme Temperature Assessment more frequently than at least once every five calendar years. As noted above, FERC Order 896 specifies that the meteorology underlying benchmark cases should be updated at least every five years, but the generation mix and other grid conditions can change more rapidly than that. TPL-001 requirement R2 requires Planning Assessments to be conducted annually, and a similar annual requirement for Extreme Temperature Assessments is appropriate given that extreme heat and cold events are the largest threat to electric reliability.

Finally, the requirement in Section 4.1 under R4 is unclear and may be inadequate. That section states that the Extreme Temperature Assessment shall evaluate "one of the years in the Long-Term Transmission Planning Horizon. The rationale for the year selected for evaluation shall be available as supporting information." At minimum, that section of R4 should be modified to provide responsible entities with greater direction on which year or years to assess. Because extreme heat and cold risks can evolve over time due to changes in the generation mix, load, and the impact of climate change, R4 should require the responsible entity to document that the year selected is likely to pose the greatest reliability risk. If it cannot be determined which year is likely to pose the greatest risk, then the responsible entity should be required to conduct the assessment for all years that may pose the greatest risk. This is important because of the long and ambiguous timeframe covered by the Long-Term Transmission Planning Horizon, which the NERC Glossary indicates is the "Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete." Planning for multiple years is consistent with the requirement in Section 2.1.1. of requirement R2 for TPL-001, which requires Planning Assessments to examine multiple years by incorporating "System peak Load for either Year One or year two, and for year five."[4]

Requirement R9

a. Requirement R9 should be modified to specify that the expected impact of extreme heat and cold should be accounted for when designing and measuring the impact of the solutions proposed in a Corrective Action Plan (CAP). Many potential solutions in a CAP can have greater or lesser impact under extreme heat or cold conditions. For example, a CAP that relies on adding gas generation can be less effective under extreme heat due to output reductions due to ambient temperature derates, and under extreme cold due to correlated gas generator outages. Gas generator outages due to equipment failures and fuel supply interruptions have accounted for the majority of outages during recent cold snap events.{C}[5] As noted above in response to question 4, FERC's directive in paragraph 89 of Order 896 states that "it is necessary that responsible entities evaluate the risk of correlated or concurrent outages and derates of all types of generation resources and transmission facilities as a result of extreme heat and cold events." On the other hand, CAPs that include demand response and energy efficiency programs related to building HVAC systems can offer contributions that are larger than expected during extreme heat or cold because load associated with cooling or heating is higher during such events.

During extreme cold events, expanded transmission ties with neighboring grid operators can also exceed the benefits they offer under normal conditions because transmission line thermal limits are higher during extreme cold and wind chill conditions. Transmission ties also tend to offer large benefits during extreme heat and cold, as severe weather events tend to be at their most extreme in geographically confined areas, ensuring at least some nearby grid operators are not experiencing shortfalls in generation.[6] The benefits of interregional transmission are even greater at higher renewable penetrations.[7] The value of transmission ties during extreme heat and cold events should be accounted for when assessing baseline performance during benchmark events as well as quantifying the value of expanding these ties as part of a CAP.

The higher transfer capacity of advanced conductors under extreme heat and cold conditions should also be accounted for, as carbon and composite core conductors sag roughly half as much as comparable ACSR conductors. Finally, Grid-Enhancing Technologies like dynamic line ratings, topology optimization, and power flow control devices offer significant benefits when the grid may be congested due to extreme temperatures. Dynamic line ratings are particularly valuable for enabling operators to safely use transmission lines' higher thermal limits during extreme cold and wind chill conditions.

Accounting for how a CAP will fare under the extreme heat or cold conditions it is designed to solve is essential for ensuring reliability. Without accounting for the reduced effectiveness of some CAP elements under extreme heat or cold, planners will be blind to potential reliability risks. In other cases, failing to account for the effectiveness of specific CAP measures under extreme heat or cold will result in a suboptimal selection of solutions. Extreme heat and cold must not only be accounted for in identifying reliability risks, but also designing solutions to those risks.

b. The draft of R9 also includes a potential loophole that a responsible entity could use to avoid implementing a CAP that is needed to address reliability concerns.

First, allowing load curtailment for a P1 contingency under TPL-008 is a major departure from the requirements of TPL-001, which do not allow load shedding for a P1 contingency.{C}[8] Allowing responsible entities plans' to include load shed when they experience a single P1 contingency under extreme heat or cold conditions is contrary to FERC's intent in Order 896 that NERC enact a standard that will ensure reliable operations under extreme heat and cold conditions.

More generally, a major concern with the draft standard is that there is no compliance mechanism to ensure CAPs are implemented. If implementing some CAP solutions requires action by an entity other than the transmission planner or planning coordinator responsible entities, the draft standard should be revised to include such a requirement on those entities. Other draft NERC standards include requirements to implement CAPs, and similar language could be adopted for TPL-008. For example, requirement R9 of the PRC-028 draft requires a generator or transmission owner to “develop, maintain, and implement a Corrective Action Plan to provide the required capability,”{C}[9] and requirement R6 of the PRC-030 draft requires “Each applicable Generator Owner shall, for each of its CAPs developed pursuant to Requirement R5:

6.1. Implement the CAP;

6.2. Update the CAP if actions or timetables change; and

6.3. Notify each applicable Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.”[10]{C}

Implementation plan

The draft Implementation Plan proposes that requirements R7-R11, which require the Extreme Temperature Assessment and any resulting Corrective Action Plan, do not take effect until more than 6 years after the Standard is approved by FERC. This unnecessary delay is contrary to FERC’s directive in Order 896 and the urgent importance of planning for extreme heat and cold events.

NERC’s 2023 State of Reliability Overview concluded that “extreme weather events continue to pose the greatest risk to reliability due to the increase in frequency, footprint, duration, and severity.” FERC Order 896 was also clear that the increasing frequency and magnitude of extreme weather events “have created an urgency to address the negative impact of extreme weather on the reliability of the Bulk-Power System” (at paragraphs 21-22). Waiting until after 2030 to address the largest threat to grid reliability does not make sense. Such a delay is also unnecessary, as entities responsible for TPL-008 already conduct nearly all of the elements of TPL-008 today to comply with TPL-001. TPL-008 effectively requires running similar analyses as TPL-001, but for extreme heat and cold scenarios. As a result, it should be straightforward for responsible entities to modify their existing planning practices to incorporate the two additional scenarios.

This unnecessary delay is also at odds with FERC’s directive in Order 896. At paragraph 188, FERC directed “NERC to propose an implementation timeline for the new or modified Reliability Standard, with implementation beginning no later than 12 months after the effective date of a Commission order approving the proposed Reliability Standard.” Under the draft Implementation Plan, the only requirement of TPL-008 that comes close to falling within the 12-month timeline FERC directed is compliance with R1, which begins “the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority’s order approving the standard.”

More importantly, R1 only requires that “Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall determine and identify each entity’s individual and joint responsibilities for performing the studies needed to complete the Extreme Temperature Assessment,” and as such is a minor procedural step towards implementing the actual Extreme Temperature Assessment and any resulting Corrective Action Plan in R7-R11. As noted above, those meaningful requirements do not begin until more than 6 years after the standard is approved by FERC. To comply with FERC’s directive, the drafting team should require compliance with R7-R11 to begin within 12 months of FERC approval of the standard, and the interim steps in R2-R6 should also be moved up from the Implementation Plan’s proposed deadline of 36 months after the effective date of the standard.

{C}[1]{C} NERC, *Consideration of FERC Order 896 Directives* (March 2024), https://www.nerc.com/pa/Stand/Project202307ModtoTPL00151TransSystPlanPerfReqExWe/2023-07_Consideration%20of%20FERC%20Order%20896%20Directives%20Final_032024.pdf, at 5

{C}[2]{C} *See, e.g.*, FERC and NERC*, Winter Storm Elliott Report: Inquiry into Bulk-Power System Operations During December 2022* (October 2023), https://www.ferc.gov/media/winter-storm-elliott-report-inquiry-bulk-power-system-operations-during-december-2022, at 17; FERC and NERC, *The February 2021 Cold Weather Outages in Texas and the South Central United States* (November 2021), https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and, at 16; FERC and NERC, *2019 FERC and NERC Staff Report: The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018* (July 2019), https://www.ferc.gov/legal/staff-reports/2019/07-18-19-ferc-nerc-report.pdf; PJM, *Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events* (May 2014), https://www.pjm.com/~/media/library/reports-notices/weather-related/20140509-analysis-of-operational-events-and-market-impacts-during-the-jan-2014-cold-weather-events.ashx.

{C}[3]{C} For example, see the analysis of GADS data provided in S. Murphy et al., *Resource adequacy risks to the bulk power system in North America* (February 2018), https://www.sciencedirect.com/science/article/pii/S0306261917318202, with Supplementary Material including outage data available at https://ars.els-cdn.com/content/image/1-s2.0-S0306261917318202-mmc1.zip

{C}[4]{C} https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-4.pdf

{C}[5]{C} *See, e.g.*, FERC and NERC, *Winter Storm Elliott Report: Inquiry into Bulk-Power System Operations During December 2022* (October 2023), https://www.ferc.gov/media/winter-storm-elliott-report-inquiry-bulk-power-system-operations-during-december-2022, at 17; FERC and NERC, *The February 2021 Cold Weather Outages in Texas and the South Central United States* (November 2021), https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and, at 16; FERC and NERC, *2019 FERC and NERC Staff Report: The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018* (July 2019), https://www.ferc.gov/legal/staff-reports/2019/07-18-19-ferc-nerc-report.pdf; PJM, *Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events* (May 2014), https://www.pjm.com/~/media/library/reports-notices/weather-related/20140509-analysis-of-operational-events-and-market-impacts-during-the-jan-2014-cold-weather-events.ashx.

{C}[6]{C} https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf

{C}[7]{C} https://www.nrel.gov/docs/fy22osti/78394.pdf

{C}[8]{C} https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-5.pdf, at 21

{C}[9]{C} https://www.nerc.com/pa/Stand/Project202104ModificationstoPRC0022DL/2021-04_AB_PRC-028-1_Clean_03182024.pdf

{C}[10]{C} https://www.nerc.com/pa/Stand/Project202302PerformanceofIBRsDL/2023-02%20PRC-030-1_032524.pdf

Likes 0	
Dislikes 0	

Response

Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC) Project 2023-07 TPL-008-1 Draft #2

Answer	
Document Name	2023-07_Unofficial_Comment_Form_Draft 2_SRC_08-22-24_final.docx

Comment

DRAFT ERO Enterprise Process for TPL-008-1 Benchmark Weather Event Development and Maintenance

The process document says," Refer to the NERC **Glossary of Terms** for the below capitalized terms used in this process." While NERC may have defined these terms, the following terms are ***not*** currently in the NERC Glossary of Terms.

• Affected Regional Entity (ARE)

• Compliance Enforcement Authority (CEA)

• Coordinated Oversight

• Extreme Temperature Assessment (ETA)

• Lead Regional Entity (LRE)

• Multi-Region Registered Entity (MRRE)

Relevance to Canada

The SRC requests that Canadian provinces be considered within the ERO benchmark library.

Need for regional application of benchmark events for PCs covering large areas

SRC requests clarification regarding the following. Is an entity required to use the same benchmark event across its entire footprint or can an entity use different events for different areas of its footprint? For example, if an SRC member selects a benchmark event that has high impacts concentrated in its Southern Region for its first iteration, could the next 5-year iteration use a benchmark event that has high impacts concentrated in that member's Central Region?

Resource uncertainty in the Planning Horizon may lead to unsolvable study cases.

Depending on how far into the future these Extreme Temperature Assessments are performed, there may be great uncertainty as to the resources available. Many states have firm policies driving unit deactivations, but replacement resource location and size may be unknown. This may lead to future cases being un-solvable without large reactive or replacement power assumptions. Furthermore, the farther out in the future an extreme case is studied, the greater the corresponding uncertainties in resource availability due to extreme weather conditions become; study requirements on this topic are only now being considered under the Project 2024-02 Energy Assurance Planning Horizon SAR.

Likes 0	
Dislikes 0	

Response

Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle

Answer	
Document Name	

Comment

A benchmark library maintained by the ERO is a welcome reference for transmission entities, however, local climate and geographic-specific extreme weather conditions should be made at Planning Coordinator and Transmission Planner level.

Extreme Heat/Cold conditions are already sensitivity scenarios to the normal long-term planning scenarios. Adding sensitivity cases on top of these "sensitivity scenarios" is redundant and unnecessarily burdensome to transmission entities.

Likes 0	
Dislikes 0	

Response

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2

Answer	
Document Name	

Comment	
ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
Answer	
Document Name	TPL-008-1 Process Flow.pdf
Comment	
PJM supports the IRC SRC comments and adds a process flow (attached) to assist in document organization and structure that are very important to ease of use and clarity. PJM wants to thank NERC and the Project Team for all their hard work and consideration of the IRC SRC and PJM submitted comments.	
Likes 0	
Dislikes 0	
Response	
John Brewer - National Energy Technology Laboratory - 9 - NA - Not Applicable	
Answer	
Document Name	
Comment	
A more inclusive process for review and approval of benchmark temperature events should be developed. Currently, only events submitted by an entity will go through the more inclusive review process by review panel.	
Likes 0	
Dislikes 0	
Response	

Comments submitted by Long Island Power Authority

Submitter’s Name	
Answer	Y/N
Document Name	(if an attachment is provided by submitter)
Comment	
Submitter’s comments	
Likes 0	# of other submitters who agree with these comments
Dislikes 0	# of other submitters who disagree with these comments
Response	
(Drafting team’s response to submitter’s comments)	
Submitter’s Name	
Answer	Y/N
Document Name	(if an attachment to comments is provided by submitter)
Comment	
Submitter’s comments	
Likes 0	# of other submitters who agree with these comments
Dislikes 0	# of other submitters who disagree with these comments
Response	
(Drafting team’s response to submitter’s comments)	
Submitter’s Name (group info also provided)	
Answer	Y/N
Document Name	(if an attachment to comments is provided by submitter)
Comment	
Submitter’s comments	
Likes 0	# of other submitters who agree with these comments
Dislikes 0	# of other submitters who disagree with these comments
Response	

(Drafting team's response to submitter's comments)

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Summary Response to TPL-008-1 Draft 2 Comments Received

NERC Project 2023-07 Transmission Planning Performance Requirements for Extreme Weather | October 2024

Comments Received Summary

There were 74 sets of responses, including comments from approximately 191 different people from approximately 118 companies representing 10 of the Industry Segments. A summary of comments submitted can be reviewed on the project page.

If you have an interest in joining the distribution list for this project, please reach out to Senior Standards Developer, Jordan Mallory.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact Manager of Standards Jamie Calderon (via email) or at (404) 960-0568.

Consideration of Comments

The NERC Project 2023-07 thanks all of industry for your time and comments. The drafting team (DT) feels that many great points have been provided for the DT to consider during the drafting phase of this project. High level themes received from industry are located below (bolded is the high-level theme followed by the DT's response).

Benchmark Events

Many commenters expressed concern that they cannot fully approve the Extreme Temperature Assessment definition and TPL-008-1 Standard without having benchmark events information. In addition, some entities expressed concern about having to agree to a requirement that has yet to be fully developed. Based on the technical rationale, there is an expectation that the ERO will determine suitability and make available benchmark events representative of future information. Once the initial library of events has been developed, entities would be in a better position to consider support for this requirement.

Drafting team response:

NERC is still committed to providing additional information regarding the criteria used in the development of this initial population of the benchmark event library, the process for maintaining the library, the process for entity submitted benchmark events and the criteria for which they will be evaluated for approval, as well as the future state envisioned for ongoing curation of the library with industry involvement and climate data subject matter experts.

To best assist the team when voting "No," please provide comments specific to the Standard and requirements that is within scope for the team to address. As NERC is directed by FERC to create the benchmark event library, it is unclear what further improvements can be made to the TPL-008-1 Standard by the DT.

Definitions

A commenter recommended that the DT should consider making the definition of Extreme Temperature Assessment align better with the definition of Planning Assessment.

Drafting team response:

The DT originally had the proposed Extreme Temperature Assessment definition aligned with the definition of Planning Assessment. However, to align with the intent of TPL-008-1, the DT included language to specifically focus on extreme heat and extreme cold temperature events. In addition, the DT also removed Corrective Action Plans (CAPs) from the definition because not all CAPs are required for considered Contingencies. Specifically, CAPs are only required when the analysis of a benchmark planning case indicates the responsible entity's portion of the Bulk Electric System is unable to meet performance requirements for TPL-008-1 Table 1 P0 or P1 Contingencies, while possible actions are required in the benchmark planning cases for Table 1 P7 Contingencies and in the sensitivity cases for Table 1 P0, P1, and P7 Contingencies. Therefore, the definition of Planning Assessment in the NERC Glossary of Terms goes beyond the intent of what is required in TPL-008-1 for Corrective Action Plans.

Requirement R1

Maintaining Models

A commenter recommends that the DT add the term "maintaining models" to the wording for R1 as that is an important joint responsibility for the Planning Coordinator (PC) and Transmission Planner (TP) to do in support of the assessment. The modifications in Draft 2 do not address this concern.

Drafting team response:

Requirement R1 is focused on identifying the zone in which the Planning Coordinator belongs and the individual and joint responsibilities between the Planning Coordinator and its Transmission Planner(s) for completing the Extreme Temperature Assessment. The completion of the Extreme Temperature Assessment includes developing models, having criteria, selecting Contingencies for evaluation, completing steady state and transient stability analyses, developing CAPs in the benchmark planning cases for Table 1 P0 and P1 Contingencies, and documenting possible actions in the benchmark planning cases for Table 1 P7 Contingencies and in the sensitivity cases for Table 1 P0, P1, and P7 Contingencies. Therefore, the DT did not feel it was necessary to explicitly identify a list of what needs to be discussed and agreed upon by the Planning Coordinators and Transmission Planners in Requirement R1, as it is identified throughout the TPL-008-1 Standard.

Planning Coordinator or Transmission Planner

A commenter recommends that the DT choose either the PC or TP to be responsible for Requirement R1. By allowing the responsible party to be either the TP or PC, the two parties may not agree on all terms or there may result in a reliability gap. Please provide clarification on which responsibilities will belong to the Planning Coordinator and Transmission Planner.

Drafting team response:
In accordance with Requirement R1, each Planning Coordinator and its Transmission Planner(s) within the PC's footprint must coordinate each entity's individual and joint responsibilities when completing the Extreme Temperature Assessment. The purpose of this requirement is to have the PC and its TP(s) identify their individual and joint responsibilities for the following activities: developing models, having criteria, selecting Contingencies for evaluation, completing steady state and transient stability analyses, developing CAPs in the benchmark planning cases for Table 1 P0 and P1 Contingencies, documenting possible actions in the benchmark planning cases for Table 1 P7 Contingencies and in the sensitivity cases for Table 1 P0, P1, and P7 Contingencies, and providing study results to any functional entity who has a reliability related need. Based on outreach, the DT did not find it appropriate to be overly prescriptive, given regional differences. Therefore, leaving it up to the PC and its TP(s) is appropriate and acceptable by the majority of industry. In general, the Planning Coordinator will lead in its coordination with its Transmission Planner(s) to develop each entity's individual and joint responsibilities for completing Extreme Temperature Assessment.

Category P0

A couple of commenters asked if the use of "category P0" to describe normal system condition in R1 appropriate, given that it includes both benchmark and extreme events, which are not typically considered normal operating conditions.

Drafting team response:
Yes, the use of "Category P0" in the TPL-008-1 Standard specifically refers to benchmark planning cases that are developed from benchmark events. The developed benchmark planning cases establish Category P0 as the normal System condition in TPL-008-1 Table 1 before further Contingencies are applied as part of the assessment.

Requirement R2

Many commenters continued to express concern with the lack of knowing what the benchmark events are, and what data entities will have to work from when selecting benchmark events.

Regional Entities to Complete Assessments

Some commenters stated that Regional Entities should be the entity to develop the benchmark events.

Drafting team response:
Benchmark events are developed based on historical events, which focus on events that may cover a larger area than the Regional Entity oversees. The ERO Enterprise, as an entirety, has the bigger picture and is the appropriate entity to develop benchmark events that could result in reliability issues affecting multiple regions.

Planning Coordinator Maintain Benchmark Events

Some commenters expressed that the Planning Coordinator should be able to develop benchmark events that do not exist within the ERO Benchmark Event library and that entities should be able to maintain the benchmark event data.

Drafting team response:
FERC Order 896 recognizes that historical events may span across regions and therefore, the ERO is in the best position to develop benchmark events. However, based on recent conversations, the DT has updated the TPL-008-1 Standard to allow Planning Coordinators, in coordination with other Planning Coordinators, to develop benchmark events should the events provided by the ERO not be adequate for Planning Coordinators to consider. In addition, Requirement R2 has been updated to reflect what is being provided by the ERO, which addresses the subparts and what would be required from entities should they choose to develop their own benchmark events in coordination with other PCs. The important note here is that one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event is selected and studied among the PCs within the zone identified in Attachment 1 of the TPL-008-1 Standard.

Requirement for NERC to Coordinate with PCs

Some commenters expressed that a requirement should be added to the TPL-008-1 standard requiring NERC to coordinate with Planning Coordinators when developing benchmark events.

Drafting team response:
A NERC Process[1] has been developed and posted to the NERC Project 2023-07 page laying out the process for the 5-year iteration of benchmark events being developed during the second 38-day comment and ballot period. Per the process, the ERO will engage with industry subject matter experts during year one of developing the next round of benchmark events.

Develop an Attachment 1 Like TPL-007

Some commenters expressed that Attachment 1 in TPL-008-1 should reflect TPL-007.

Drafting team response:
TPL-008-1 is different compared to TPL-007. Industry must take into account the FERC directives assigned to this project. FERC states in FERC Order 896 P58 to “[d]irect NERC to develop benchmark events for extreme heat and cold weather events through the Reliability Standards development process. We agree with Indicated Trade Associations that the development of adequate benchmark events is critical and should be committed to the subject matter experts on the DT. We also agree with Entergy that NERC will be able to tailor benchmark events to capture regional differences and the different risks that each region faces during extreme heat and cold weather events. While Regional Entities and reliability coordinators are encouraged to participate in the NERC Reliability Standards development process to develop the benchmark events, we disagree with AEP and other commenters who recommend that entities other than NERC take the lead in the development of benchmark events.” An update made to the TPL-008-1 Standard shows a map of the zones in which PCs are located and has been added as Attachment 1. A

[1] Link to NERC Process document: [NERC Standards Development Process Document]

process regarding the development and update of benchmark events has been drafted and posted to the NERC Project 2023-07 project page.

Coordination through MMWG and ERAG

Some commenters believe it is not appropriate to assign the Electric Reliability Organization (ERO) responsibility within the standard requirement that directly impacts the compliance to the standard requirement. There is a compliance risk to the directly assigned entity if the ERO fails to uphold its responsibility to maintain the database. We suggest coordinating this the way MMWG is coordinated through ERAG in the Eastern Interconnection.

Drafting team response:

A process has been developed for entities to follow regarding the development of the benchmark events over the 5-year iterations. In year one, the ERO will engage with industry subject matter experts to develop the next round of benchmark events and so forth. This will allow groups such as the MMWG or ERAG to provide comments. In addition, the TPL-008-1 Standard has been updated to allow each PC in coordination with other PCs to develop their own benchmark event should the events provided by the ERO not be adequate for Planning Coordinators to consider.

Benchmark Event Framework

Some commenters expressed that the ERO was directed to set a framework with this Reliability Standard that included specific bounds by which the industry could conduct their extreme weather assessments. Yet, TPL-008-1 still does not contain any specific boundary limits that could guide responsible entities in their Extreme Weather Assessments or otherwise limit what might be contained or added to the Extreme Weather Event Library, now or in the future. For these reasons we ask that the DT set clear bounds that guide these Extreme Weather Assessments and set boundaries for any future changes to the Extreme Weather Event Library.

Drafting team response:

A process has been developed to provide entities with the iterative process on how benchmark events will be updated every five years. The process is a separate document from the TPL-008-1 Standard as some of the specifics are not appropriate nor requirements of the TPL-008-1 Standard. For PCs who wish to work with other PCs to develop their own benchmark events should follow the additional requirement language added to Requirement R2. This provides the boundaries entities must follow should the events provided by the ERO not be adequate for Planning Coordinators to consider.

Requirement R3/R4

Benchmark Event Framework

Some commenters requested the DT to clarify “other designated entities.”

Drafting team response:

The DT removed “other designated entities” from the TPL-008-1 Standard.

Number of Studies Required

Some commenters expressed concern regarding the number of studies which must be performed, particularly when a Planning Coordinator (PC) selects a benchmark temperature event that is different from that of its adjacent PC(s). In that situation, each benchmark temperature event may necessitate a significant coordination effort. It was recommended that a governing body identify the scenarios. Extreme temperature events will typically extend beyond the footprint of a single Planning Coordinator. To avoid putting the PCs in a position where they are required to agree on a scenario, a year and the sensitivity to be studied, NERC or other (e.g. ERAG) should identify the extreme heat and extreme cold temperature events to be studied. This is necessary for consistent modeling results across adjacent planning entities. Also, as a benchmark temperature event may extend across several planning areas, the governing body must take this into consideration when determining which extreme heat and extreme cold temperature events are to be studied so that no planning entity is assigned more than one of each.

Drafting team response:

The DT updated the TPL-008-1 Standard to identify that one common extreme heat and one common extreme cold benchmark planning case must be developed, as well as at least one common extreme heat and one common extreme cold sensitivity case. This does not preclude entities from developing more cases, but requires a minimum of one each. Per the FERC Order 896, it is important that entities are studying common historical events in preparation for future events. The ERO will provide entities with one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event for PCs to study within their zones. In addition, the TPL-008-1 Standard has been updated to allow PCs to coordinate with other PCs to develop their own benchmark event should the events provided by the ERO not be adequate for Planning Coordinators to consider.

Extreme Weather is a Sensitivity

Some commenters expressed that Extreme Temperature Events are already a “sensitivity” to normal long-term planning cases and are built with Gen/Load/Transfer based on the extreme weather conditions of an entity’s territory. Additionally, mandatory “sensitivity cases” seem redundant in nature. In addition, another commenter asked if sensitivity cases could be baked in with the benchmark temperature event.

Drafting team response:

TPL-008-1 is different than TPL-001-5.1. The TPL-008-1 Standard focuses on extreme heat and extreme cold temperature events. Entities are to select an extreme heat and cold benchmark event, develop planning cases, and then develop sensitivity cases from that, which may indicate a different approach on how to handle certain scenarios.

Additionally, FERC Order 896 P124 states that “we adopt the NOPR proposal and direct NERC to require the use of sensitivity cases to demonstrate the impact of changes to the assumptions used in the benchmark planning case. Sensitivity analyses help a transmission planner to determine if the results of the base case are sensitive to changes in the inputs. The use of sensitivity analyses is particularly necessary when studying extreme heat and cold events because some of the assumptions made when developing a base case may change if temperatures change – for example, during extreme cold events, load may increase as temperatures decrease, while a decrease in temperature may result in a decrease in generation. We agree with AEP, and we direct NERC to define during the Reliability Standard development process a baseline set of sensitivities for the new or modified Reliability Standard. While we do not require the inclusion of any specific sensitivity in this final rule, NERC should consider including conditions that vary with temperature such as load, generation, and system transfers." P126 continues to explain that "[w]e disagree with NYISO and LCRA that extreme heat and cold weather impacts are already studied as sensitivities under Reliability Standard TPL-001-5.1. Although TPL-001-5.1 mandates sensitivity analysis by varying one or more conditions specified in the standard such as load, generation, and transfers, this analysis alone cannot capture the complexities of extreme heat and cold weather conditions. Sensitivity analyses consider the impact on a base case of the variability of discrete variables. Extreme heat and cold weather impacts, on the other hand, may include numerous concurrent outages and derates which cannot be studied as part of a single-variable sensitivity analysis."

TPL-008-1 Cases Used for TPL-001-5.1

One commenter asked whether language can be added to ensure that entities can take credit for studies that are run as part of the Sensitivity analysis, rather than running those studies again as part of the assessment to be conducted under TPL-001. For example, the Extreme Temperature Assessment could take the place of the sensitivity analysis required within the TPL-001 assessment for both the steady state and stability analyses. Moreover, if the Extreme Temperature Assessment is essentially a type of sensitivity analysis already, the commenter advised removing R4.2 because this would create a sensitivity case based on a sensitivity case.

Drafting team response:

A Planning Assessment must be completed annually in accordance with TPL-001-5.1, while an Extreme Temperature Assessment must be completed at least once every five calendar years in accordance with the TPL-008-1 Standard. Time will be required to coordinate and develop the common cases and therefore, may not meet what is required in TPL-001. TPL-008-1 does not speak to TPL-001; however, both standards have different expectations. The DT does not encourage this, but if an entity decided to go this route, it would be up to that entity to explain and demonstrate compliance with the TPL-008-1 Standard.

Concurrent/Correlated Outage Language

Some commenters expressed that in Order 896 paragraph 88, FERC directs "NERC to require under the new or revised Reliability Standard the study of concurrent/correlated generator and transmission outages due to extreme heat and cold events in benchmark events," explaining in paragraph 89 that "it is necessary that responsible entities evaluate the risk of correlated or concurrent outages and derates of all types of generation resources and transmission facilities as a result of extreme heat and cold events." Commenters suggested modifying "Benchmark planning cases that include seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers" to include "concurrent/correlated generator and transmission outages."

Drafting team response:

Concurrent/correlated outages are addressed through the standard. The DT did not use language verbatim, but the standard is laid out on adjustment of temperature data that is provided by the event selection. Aligning with the directives set forth in FERC Order 896, which emphasizes the importance of incorporating derated generation, transmission capacity, and the availability of generation and transmission in the development of benchmark planning cases, it becomes imperative for responsible entities to consider potential concurrent or correlated generation and transmission outages and/or derates within relevant benchmark planning cases. This ensures that the benchmark planning case accurately reflects System conditions under extreme temperatures, with generation and transmission derates and/or outages already factored.

MOD-032 Data

Some commenters asked if the DT feels it would be necessary to add any additional data to the table in MOD-032 to complete this work. In addition, some sought clarification on how MOD-032 will allow for the collection of additional information related to extreme heat and cold events.

Drafting team response:

MOD-032 ensures an adequate means of data collection for transmission planning and requires applicable registered entities to provide steady-state, dynamic, and short circuit modeling data to their Transmission Planner(s) and Planning Coordinator(s). As outlined in R1 and Attachment 1 of MOD-032, MOD-032 allows various data collection such as in-service status and capability associated with demand, generation, and transmission associated with various case types, scenarios, system operating states, or conditions for the long-term planning horizon. MOD-032 also requires applicable registered entities to provide "other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes" for each of the three types of data required. Because the DT determined the responsible entities that will be developing benchmark planning cases are limited to Planning Coordinators and Transmission Planners, they will be able to request and receive needed data pursuant to MOD-032. Thus, the DT believes that there is no need to update MOD-032 because it allows Planning Coordinators and Transmission Planners to request any specific data needed for developing benchmark planning cases and sensitivity cases required in R4 of TPL-008-1.

"Supplemented by other sources" Clarity

Some commenters requested the DT clarify what is meant by "supplemented by other sources" with the TPL-008-1 Standard.

Drafting team response:

Requirement R4 requires the responsible entity to use data consistent with Reliability Standard MOD-032, supplemented by other sources as needed, for developing benchmark planning cases that represent System conditions based on selected benchmark temperature events. This aligns with directives in FERC Order 896, paragraph 30, emphasizing the requirement of developing both benchmark planning cases and sensitivity study cases. Requirement R4 is consistent with Reliability Standard TPL-001-5.1 in cross-referencing Reliability Standard MOD-032, which establishes consistent modeling data requirements and reporting procedures for the development of planning horizon cases necessary to support analysis of the reliability of the interconnected System. It is also consistent with Reliability Standard TPL-001-5.1 in acknowledging that data from other sources may be required to supplement the data collected through Reliability Standard MOD-032 procedures.

Requirement R5

Use of "System Voltage Limits"

Some comments suggested using the recently adopted NERC Glossary term "System Voltage Limits."

Drafting team response:

The DT determined "System Voltage Limits" focuses on operations and planning information and differs from what is used in the standard. The DT concluded to maintain the proposed language consistent with Reliability Standard TPL-001-5.1.

Violation Risk Factor

The risk factor should be Medium to match TPL 001-5.1. Concern that level of coordination needed to affect the standard will be significant, particularly for "smaller" entities.

Drafting team response:

The DT updated the violation risk factor in Requirement R5 to align with TPL-001-5.1 medium.

Criteria

A commenter mentioned that R5 has criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and applicable Facility Ratings, and asked whether entities will also have to have (and document) applicable thermal criteria for completing the Extreme Temperature Assessment (e.g., allowing for the possible use of STE facility ratings post-contingency).

Drafting team response:

Requirement 5 is drafted to provide flexibility for entities to include thermal criteria depending on the level of risk an entity is willing to take on. This requirement does not mandate which ratings are applicable and leaves that determination up to the entity.

Jurisdiction

A commenter mentioned that in certain jurisdictions, extreme temperature ratings have been established, but that is not necessarily the case in all jurisdictions. Will facility owners be required to establish extreme cold or warm temperature ratings for this standard?

Drafting team response:

Requirement 5 does not require entities to establish extreme temperature ratings, it only requires entities to identify criteria for whichever ratings are applicable.

Requirement R6
Violation Risk Factor

The risk factor should be Medium to match TPL 001-5.1. Concern that level of coordination needed to affect the standard will be significant, particularly for “smaller” entities.

Drafting team response:

The DT determined that based on the planning for events such as instability, uncontrolled separation, or Cascading events would consist of a high VRF and therefore, kept the VRF as a high.

Updated Wording

Requirement 6 needs better wording to indicate instability, uncontrolled separation and cascading must all be monitored for. The “or” makes it seem optional.

Drafting team response:

The DT mirrored language from FERC Order 896 and determined that “or” is appropriate. It is up to the entity to use one, two or all, regarding instability, uncontrolled separation, or Cascading when completing this requirement.

Planning Events or Contingencies

Many commenters questioned if planning events or contingencies was the correct phrasing throughout TPL-008-1 and requested the DT be consistent throughout the standard when using this phrase/term.

Drafting team response:

The DT determined that Contingencies was the correct phrase as it is Contingencies entities will be completing when addressing TPL-008-1.

Requirement R7
Planning Events or Contingencies

One commenter recommends modifying Table 1 to only include P0 and P1 events in accordance with the FERC Order 896 Paragraph 113 Commission Determination that “NERC may determine whether contingencies P1 through P7 should also apply to the new or modified Reliability Standard, or whether a new set of contingencies should be developed.” Paragraph 113 of the Commission Determination does not require the inclusion of events other than P0. ISO-NE believes P0 and P1 events are acceptable for this Standard, however, P2, P4, and P7 events are not.

Drafting team response:

The DT removed everything but P0, P1, and P7. The DT finds it important that multiple Contingencies be included; therefore, entities must develop Corrective Action Plans in the benchmark planning cases for Table 1 P0 and P1 Contingencies, and document possible actions in the benchmark planning cases for Table 1 P7 Contingencies and in the sensitivity cases for Table 1 P0, P1, and P7 Contingencies.

Violation Risk Factor

The risk factor should be Medium to match TPL 001-5.1. Concern that level of coordination needed to affect the standard will be significant, particularly for “smaller” entities.

Drafting team response:

The DT updated the violation risk factor in Requirement R7 to align with TPL-001-5.1 medium.

Requirement R8

Performance of Steady State and/or Stability Analysis

The standard does not clearly and specifically state whether steady-state and/or stability analysis is to be performed for the identified events as TPL-001 does, for instance. The DT should consider modifying R7 to allow the responsible entity to develop a methodology or rationale in the performance of a benchmark event to appropriately assess it for that entity’s planning area, otherwise, additional clarity in the analysis expectations is needed. Different weather events would require a different consideration of applicable contingencies and analysis approaches.

Drafting team response:

Requirement 4 has been updated to state one common extreme heat and one common extreme cold. In addition, R8 has been updated to clarify that steady state and transient stability analyses are to be performed.

Transient Confusion

Adding “transient” to qualify stability may result in more confusion in interpretation between planning entities, auditors, and the referenced ERO. There is a requirement to document stability criteria so this should be clear based on that documentation. Adding “transient” therefore is more detrimental than helpful to this standard.

Drafting team response:

Transient is an understood term among industry; therefore, the DT does not feel it will cause confusion.

Additional Sensitivity Cases

Additional sensitivity studies required in R8.2 would add a significant administrative burden without more clarification to how it benefits the long-term planning horizon.

Drafting team response:

Table 1 has been updated to require P0, P1, and P7 Contingencies. R4 has also been updated to clarify that it is one common extreme heat and one common extreme cold benchmark planning case, as well as at least one common extreme heat and one common extreme cold sensitivity case. In addition, this is a directive from the FERC Order 896 P124 which states “we adopt the NOPR proposal and direct NERC to require the use of sensitivity cases to demonstrate the impact of changes to the assumptions used in the benchmark planning case. Sensitivity analyses help a transmission planner to determine if the results of the base case are sensitive to changes in the inputs. The use of sensitivity analyses is particularly necessary when studying extreme heat and cold events because some of the assumptions made when developing a base case may change if temperatures change – for example, during extreme cold events, load may increase as temperatures decrease, while a decrease in temperature may result in a decrease in generation. We agree with AEP, and we direct NERC to define during the Reliability Standard development process a baseline set of sensitivities for the new or modified Reliability Standard. While we do not require the inclusion of any specific sensitivity in this final rule, NERC should consider including conditions that vary with temperature such as load, generation, and system transfers."

Requirement R9

Regulatory Burden

Many commenters raised concerns about the requirement to submit CAPs to regulatory authorities, suggesting it could delay approval, lacks justification, need clearer definitions, and should be limited or removed.

Drafting team response

The DT reviewed the comments and determined that the requirement is necessary to address the directives of Order 896, specifically the directives mentioned in the paragraphs 152 (i.e., "we direct NERC to develop certain processes to facilitate interaction and coordination with applicable regulatory authorities or governing bodies responsible for retail electric service as appropriate in implementing a corrective action plan") and 165 (i.e., "we direct NERC to require in the new or modified Reliability Standard that responsible entities share their corrective action plans with, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues").

Clarity on Sensitivity Analysis

Various commenters questioned the necessity of a Corrective Action Plan for issues identified in sensitivity analysis, seeking clarity on how sensitivity analysis is handled.

Drafting team response

The DT updated Requirement R9 to clarify that Corrective Action Plans are not required specifically for addressing performance requirements related to sensitivity cases. The responsible entity must develop Corrective Action Plan(s) when the analysis of a benchmark planning case indicates its portion of the Bulk Electric System is unable to meet performance requirements for Table 1 P0 or P1 Contingencies.

Facility Overload Concern

Requirement 9 and Table 1 requires the development of Corrective Action Plans for P1 events where applicable facility ratings are exceeded and steady state voltages are not within limits. This requirement goes beyond the directives in FERC Order 896. The FERC Order is concerned with cascading, instability, and uncontrolled islanding but not with facility overloads.

Drafting team response

Thermal violations are a contributing factor in Cascading events and the DT did not go beyond the intent of FERC Order 896. According to Footnote 2 from FERC Order 896: The FPA defines "Reliable Operation" as "operating the elements of the Bulk-Power System within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements." 16 U.S.C. 824o(a)(4).

CAP Request

A commenter requested the DT to 'make their CAP available' in R9.1 to 'make available on request.'

Drafting team response

FERC Order 896 P153 states: "We adopt our rationale set forth in the NOPR and conclude that the directive to require the development of corrective action plans is needed for Reliable Operation of the Bulk-Power System. Under the currently effective Reliability Standard TPL-001-5.1, planning coordinators and transmission planners are required to evaluate possible actions to reduce the likelihood or mitigate the consequences of extreme weather events, but are not obligated to develop corrective action plans, even if such events are found to cause cascading outages. Experience over the past decade has demonstrated that the potential severity of extreme heat and cold weather events exacerbates the likelihood to cause system instability, uncontrolled separation, or cascading failures as a result of a sudden disturbance or unanticipated failure of system elements. Thus, we conclude that entities should proactively address known system vulnerabilities by developing corrective action plans that include mitigation for specified instances where performance requirements for extreme heat and cold events are not met." Therefore, it is the responsibility of the PC or TP developing the CAPs to provide this information to the respective governing bodies and solicit feedback per the FERC Order.

CAP Process

There are already existing processes for interactions with applicable regulatory authorities and governing bodies regarding CAP for many other issues and items. Extreme weather CAPs are not exceptions and do not need a new way to solicit feedback. R9.1 should be removed because it also creates a compliance requirement without any benefit to reliability and would be confusing.

In addition, a commenter requested 9.1 subpart be removed because it creates a compliance requirement without any incremental benefit to reliability and further conflicts with existing planning requirements and processes.

Drafting team response

An entity may use what is already in place to be compliant with this requirement. This requirement is addressing the FERC Order 896 directive in P152 that states "we direct NERC to develop certain processes to facilitate interaction and coordination with applicable regulatory authorities or governing bodies responsible for retail electric service as appropriate in implementing a corrective action plan." Lastly, the

TPL-008-1 Standard is aligning with what the FERC Order 896 directs. The DT did its best to algin with TPL-001 while meeting the FERC Order 896 directives.

Include Threshold

One commenter believes the requirement for the notification to an applicable regulatory entity should also include a threshold. As written, an entity would need to make a notification if a proposal tripped 0.1 MW of non-consequential load. Recommend the DT add a threshold in a similar way as is included in TPL-001 Attachment 1.

Drafting team response

The DT does not feel that a threshold is needed in the TPL-008-1 Standard. An entity only has report obligations if it is a part of a CAP. Depending on the mechanism used, you may not be required to report smaller amounts of load.

Jurisdiction

One commenter expressed that the "applicable regulatory authorities... electric service" needs better clarification and questioned what this looks like for Jurisdictional vs non-Jurisdictional. The commenter asked the DT to provide better guidance and examples, and highly recommended using operation procedures instead of CAPs since operation procedures have more flexibility to respond to a system's needs and adapt proactively.

Drafting team response

Per FERC Order 896 P165, building generation and transmission is outside the jurisdiction and left up to the states. FERC Order 896 provides some examples of various activities that would be appropriate in P155: "As noted by commenters, the NOPR provided examples of various activities that may be appropriate under a corrective action plan, some of which may require state or local authorizations (e.g., generation or transmission development). Other examples mentioned in the NOPR include "implementing new energy efficiency programs to decrease load, . . . transmission switching, or adjusting transmission and generation maintenance outages based on longer-lead forecasts," none of which involve the construction of generation or transmission capacity. In addition, responsible entities have the option to use controlled load shed as a mitigation measure. In sum, while responsible entities would have the obligation to develop and implement a corrective action plan, the Commission is not directing any specific result or content of the corrective action plan. In such circumstances, the Commission's directive does not exceed the jurisdictional limits set forth in section 215(i) of the FPA0." Also, "applicable regulatory authorities or governing bodies responsible for retail electric service issues" is in TPL-001; therefore, the same entities may be used. Finally, this language was added based on FERC Order 896 P165: "We direct NERC to require in the new or modified Reliability Standard that responsible entities share their corrective action plans with, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues. We agree with commenters that relevant state entities should have the opportunity to provide input during the development of corrective action plans. Just as this final rule seeks to ensure Reliable Operation of the Bulk-Power System during extreme heat and cold weather events, regulatory authorities and governing bodies responsible for retail electric service are taking actions to ensure reliability for local stakeholders. As such, we believe that requiring responsible entities to seek input from applicable regulatory authorities or governing bodies responsible for retail electric service issues when developing corrective action plans could help ensure that shared opportunities to increase system reliability are not missed. Further, as NESCOE points out, such consultation may allow these entities to better understand “the cost implications of various approaches” and, therefore, provide “better insight into the considerations and tradeoffs inherent in the options available.”

Requirement R10

Remove R10

Some commenters feel that R10 requires a significant amount of work without providing additional system reliability and suggested that this requirement be removed.

Drafting team response

The DT removed everything but P0, P1, and P7 Contingencies. The DT finds it important that multiple Contingencies be included; therefore, entities must develop Corrective Action Plans in the benchmark planning cases for Table 1 P0 and P1 Contingencies, and document possible actions in the benchmark planning cases for Table 1 P7 Contingencies and in the sensitivity cases for Table 1 P0, P1, and P7 Contingencies. In addition, an Extreme Temperature Assessment must be completed once every five calendar years.

Reasons for Requiring Possible Actions and Restrictions in Creating CAPs

Certain commenters questioned why possible actions are required for P2, P4, P5, and P7 contingencies, while others disagreed due to limitations in creating CAPs for these contingencies.

Drafting team response

The DT reviewed the comments and affirmed that the Technical Rationale for R10 adequately clarified the necessity for possible actions. Additionally, it is important to note that the TPL-008-1 Standard sets a baseline to fulfill the directives from Order 896 and does not prohibit responsible entities from exceeding these requirements.

Clarity and Communication on Possible Actions

A commenter questioned what actions the responsible entity intends to take based on the identified "possible actions." There is uncertainty about how these actions will be executed. In addition, the commenter suggested that these possible actions should be communicated to the operators so they can prepare necessary plans and processes accordingly.

Drafting team response

The DT acknowledges the commenter's concerns regarding implementing possible actions and their communication to operators. The DT asserts that Requirement 11 outlines the expected actions, mandating responsible entities to share Extreme Temperature Assessment results with any functional entities that has a reliability-related need to enhance readiness for extreme temperature events.

Exclusion of P2, P4, P5, and P7 Contingencies

Some commenters proposed removing P5, citing that extreme weather conditions affect outdoor EHV elements but do not impact protective relaying. Additionally, other comments suggested excluding P2, P4, P5, and P7 events from TPL-008-1.

Drafting team response

The DT reviewed the comments and updated Requirement 10 and Table 1 to remove the P5 Contingency from the TPL-008-1 Standard. The rationale for this decision is detailed in the Technical Rationale of R10.

TPs Ability to Create CAPs

A commenter disagrees with R10 because the requirement does not give TPs the ability to create CAPs for the listed contingencies.

Drafting team response

Requirement 10 does not preclude Transmission Planners from developing CAPs; however, possible actions would be required should a Transmission Planner determine that a CAP is not required.

Requirement R11

Timeline for Distributing Assessment Results

Some comments questioned if the 60 calendar days was appropriate.

Drafting team response:

The DT determined to keep the requirement unchanged as this strikes a good balance between allowing enough time for the responsibility entity to distribute the results and the functional entity requesting the information to receive them.

Distribution of Assessment Results

Some comments questioned if the distribution of the Extreme Temperature Assessment results should be limited to selecting registered entities.

Drafting team response:

The DT determined to keep the requirement unchanged as it meets the following FERC directive in FERC Order 896, Paragraph 72: “Further, responsible entities must share the study results with affected transmission operators, transmission owners, generator owners, and other functional entities with a reliability need for the studies.” Therefore, the responsible entity must share with any functional entity that has a reliability related need and submits a written request for the information. Additionally, this is consistent with other approved NERC Reliability Standards (e.g., TPL-001-5.1 and TPL-007-4).

Table 1

Based on the removal of all except P0, P1, and P7 Contingencies, the table has been condensed and cleaned up. Some comments received may no longer be applicable based on the updated Table 1. Please see the updates in the TPL-008-1 Draft 3.

Stability Performance

A commenter asked the DT how to determine stability performance requirements for P0 events. Currently, Table 1 says that the system shall remain stable, and that instability, uncontrolled separation and cascading shall not occur, but the commenters asked how those would occur for a P0 event.

Drafting team response:

Instability can occur during P0 conditions due to various factors like oscillations, renewable generation behavior, and excessive power transfers. For example, poorly damped oscillations between generators in different areas can grow and destabilize the system if not properly controlled. High levels of wind, solar, or energy storage may also cause instability if these resources don't adequately support grid stability. Additionally, excessive power transfers on key transmission lines can lead to voltage instability and potential voltage collapse.

Implementation Plan

Benchmark Events

Some entities requested a date be established as to when the ERO will have the benchmark event library published.

Drafting team response:

An ERO Benchmark Event Process document has been published with the TPL-008-1 Draft 2 posting. The ERO benchmark event library will be published and up and running by December 2024. This library will contain events for the first 5-year iteration of TPL-008-1. Additional time is essentially provided to entities as the benchmark events will be published and TPL-008-1 will be pending approval from the respective applicable governmental authorities. In addition, example benchmark event examples have been provided in a separate document for entities to see what they will be working with to meet the TPL-008-1 Standard. Please reference the process document for additional details on how the ERO plans to address preparing for the next 5-year iteration of benchmark events.

Requirement R1

Many entities disagreed with making Requirement R1 effective on the effective date of TPL-008-1 because this requirement includes the development of processes that currently do not exist.

Drafting team response:

Per FERC Order 896, Paragraph 7, *"we direct NERC to ensure that the proposed new or modified Reliability Standard becomes mandatory and enforceable beginning no later than 12 months from the effective date of Commission approval of the new or modified Reliability Standard."* To meet this FERC directive, Requirement R1 is the most reasonable requirement to meet the 12-month implementation directive. 12 months from the approval date of TPL-008-1 is adequate time to identify individual and joint responsibilities for completing the Extreme Temperature Assessment. Requirement R3 is when the process should be developed and implemented, which per the TPL-008-1 Implementation Plan has 36-months. In addition, there is nothing precluding entities from starting discussions with other PCs and TPs once the petition has been submitted for approval with the respective governmental authorities.

Requirement R9

Some entities expressed concern that if R9 is intended to include the construction of capital projects, there should be additional time allowed for construction of those projects after the completion of the first Extreme Temperature Assessment study.

Drafting team response:

The drafting team did not change the implementation plan; however, Requirement R9.3 was added to permit the use of Non-Consequential Load Loss as an interim solution, which normally is not permitted in Table 1, in situations that are beyond the control of the Planning Coordinator or Transmission Planner that prevent the implementation of a Corrective Action Plan in the required timeframe. The use of Non-Consequential Load Loss as an interim solution in this situation is permitted, provided that each responsible entity documents the situation causing the problem, alternatives evaluated, and takes actions to resolve the situation. Additionally, Requirement R9.4 was added to permit having revisions to the CAP in subsequent Extreme Temperature Assessments, provided that the planned BES continues to meet the performance requirements of Table 1.

Implementation Plan Diagram

One commenter pointed out that the diagram does not line up with the Implementation Plan Language and requested the DT update it accordingly.

Drafting team response:

The DT updated the timeframes within the Implementation Plan to line up with the intent of timing.

Technical Rationale

Please see the updated Technical Rationale document, which is located on the 2023-07 project page.

Reminder
Standards Announcement
Project 2023-07 Transmission Planning Performance Requirements for Extreme Weather

Additional Ballots and Non-binding Poll Open through August 22, 2024

Now Available

Additional ballots for draft two of **TPL-008-1 – Transmission System Planning Performance Requirements for Extreme Temperature Events** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels are open through **8 p.m. Eastern, Thursday, August 22, 2024**.

The standard drafting team's considerations of the responses received from the last comment period are reflected in this draft of the standard.

Reminder Regarding Corporate RBB Memberships

Under the NERC Rules of Procedure, each entity and its affiliates is collectively permitted one voting membership per Registered Ballot Body Segment. Each entity that undergoes a change in corporate structure (such as a merger or acquisition) that results in the entity or affiliated entities having more than the one permitted representative in a particular Segment must withdraw the duplicate membership(s) prior to joining new ballot pools or voting on anything as part of an existing ballot pool. Contact ballotadmin@nerc.net to assist with the removal of any duplicate registrations.

Balloting

Members of the ballot pools associated with this project can log in and submit their votes by accessing the Standards Balloting and Commenting System (SBS) here.

Note: Votes cast in previous ballots, will not carry over to additional ballots. It is the responsibility of the registered voter in the ballot pools to place votes again. To ensure a quorum is reached, if you do not want to vote affirmative or negative, cast an abstention.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*

- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will review all responses received during the comment period and determine the next steps of the project.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Jordan Mallory (via email) or at 404-479-7358. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2023-07 Transmission Planning Performance Requirements for Extreme Weather observer list” in the Description Box.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2023-07 Transmission Planning Performance Requirements for Extreme Weather

Formal Comment Period Open through August 22, 2024

Now Available

A 38-day formal comment period for draft two of **TPL-008-1 – Transmission System Planning Performance Requirements for Extreme Temperature Events** is open through **8 p.m. Eastern, Thursday, August 22, 2024**.

The standard drafting team's considerations of the responses received from the previous comment period are reflected in this draft of the standard.

Reminder Regarding Corporate RBB Memberships
Under the NERC Rules of Procedure, each entity and its affiliates is collectively permitted one voting membership per Registered Ballot Body Segment. Each entity that undergoes a change in corporate structure (such as a merger or acquisition) that results in the entity or affiliated entities having more than the one permitted representative in a particular Segment must withdraw the duplicate membership(s) prior to joining new ballot pools or voting on anything as part of an existing ballot pool. Contact ballotadmin@nerc.net to assist with the removal of any duplicate registrations.

Commenting
Use the Standards Balloting and Commenting System (SBS) to submit comments. An unofficial Word version of the comment form is posted on the project page.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps
Additional ballots for the standard and implementation plan, as well as a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **August 13-22, 2024**.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Jordan Mallory (via email) or at 404-479-7358. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2023-07 Transmission Planning Performance Requirements for Extreme Weather observer list” in the Description Box.

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NERC Balloting Tool (/) Dashboard (/) Users Ballots Comment Forms

Login (/Users/Login) / Register (/Users/Register)

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/338)
Ballot Name: 2023-07 Transmission Planning Performance Requirements for Extreme Weather TPL-008-1 AB 2 ST
Voting Start Date: 8/13/2024 12:01:00 AM
Voting End Date: 8/22/2024 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 276
Total Ballot Pool: 314
Quorum: 87.9
Quorum Established Date: 8/22/2024 3:45:36 PM
Weighted Segment Value: 18.17

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	89	1	10	0.139	62	0.861	0	10	7
Segment: 2	8	0.7	0	0	7	0.7	0	1	0
Segment: 3	68	1	8	0.145	47	0.855	1	5	7
Segment: 4	18	1	2	0.154	11	0.846	0	2	3
Segment: 5	76	1	8	0.163	41	0.837	0	10	17
Segment: 6	47	1	9	0.243	28	0.757	0	6	4
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	1	0	0	0	0	0	0	1	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	7	0.6	3	0.3	3	0.3	0	1	0
Totals:	314	6.3	40	1.145	199	5.155	1	36	38

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Negative	Comments Submitted
1	Ameren - Ameren Services	Tamara Evey		Negative	Third-Party Comments
1	American Transmission Company, LLC	Amy Wilke		Negative	Comments Submitted
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Negative	Third-Party Comments
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Negative	Comments Submitted
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		None	N/A
1	Black Hills Corporation	Micah Runner		Abstain	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Negative	Third-Party Comments
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Third-Party Comments
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	Third-Party Comments
1	Colorado Springs Utilities	Corey Walker		Negative	Third-Party Comments
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Third-Party Comments
1	Dominion - Dominion Virginia Power	Steven Belle		Negative	Comments Submitted
1	Duke Energy	Katherine Street	Ellese Murphy	Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Robert Blackney		Negative	Comments Submitted
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Eversource Energy	Joshua London		Affirmative	N/A
1	Exelon	Daniel Gacek		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Negative	Comments Submitted
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
1	Great River Energy	Gordon Pietsch		None	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Lidija Efremova	Negative	Comments Submitted
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Negative	Comments Submitted
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
1	JEA	Joseph McClung		Negative	Third-Party Comments
1	KAMO Electric Cooperative	Micah Breedlove		Negative	Third-Party Comments
1	Lakeland Electric	Larry Watt		Negative	Third-Party Comments
1	Lincoln Electric System	Josh Johnson		None	N/A
1	Long Island Power Authority	Isidoro Behar		Negative	Comments Submitted
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Matt Lewis		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	LS Power Transmission, LLC	Jennifer Richardson		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Negative	Third-Party Comments
1	Manitoba Hydro	Nazra Gladu		Negative	Comments Submitted
1	MEAG Power	David Weekley	Rebika Yitna	Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Nikki Carson-Marquis	Negative	Third-Party Comments
1	Muscatine Power and Water	Andrew Kurriger		Negative	Third-Party Comments
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Third-Party Comments
1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	NB Power Corporation	Jeffrey Streifling		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
1	New York Power Authority	Daniel Valle		Negative	Comments Submitted
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Negative	Comments Submitted
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Negative	Third-Party Comments
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Negative	Comments Submitted
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Negative	Comments Submitted
1	Platte River Power Authority	Marissa Archie		Negative	Third-Party Comments
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
1	Portland General Electric Co.	Brooke Jockin		None	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	Third-Party Comments
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Negative	Third-Party Comments
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Negative	Comments Submitted
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Negative	Comments Submitted
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Abstain	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	Comments Submitted
1	Salt River Project	Laura Somak	Israel Perez	Negative	Comments Submitted
1	Santee Cooper	Chris Wagner		Negative	Comments Submitted
1	SaskPower	Wayne Guttormson		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Negative	Comments Submitted
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Negative	Third-Party Comments
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Donna Wood		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Negative	Comments Submitted
1	VELCO -Vermont Electric Power Company, Inc.	Randall Buswell		Abstain	N/A
1	Western Area Power Administration	Ben Hammer		Affirmative	N/A
1	Xcel Energy, Inc.	Eric Barry		Negative	Third-Party Comments
2	California ISO	Darcy O'Connell		Abstain	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
2	Independent Electricity System Operator	Helen Lainis		Negative	Comments Submitted
2	ISO New England, Inc.	John Pearson	Keith Jonassen	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	Midcontinent ISO, Inc.	Bobbi Welch		Negative	Comments Submitted
2	New York Independent System Operator	Gregory Campoli		Negative	Third-Party Comments
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Negative	Third-Party Comments
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips	Shannon Mickens	Negative	Comments Submitted
3	AEP	Leshel Hutchings		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr	Danielle Moskop	Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Third-Party Comments
3	Austin Energy	Lovita Griffin		None	N/A
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Third-Party Comments
3	Black Hills Corporation	Josh Combs	Carly Miller	Abstain	N/A
3	Bonneville Power Administration	Ron Sporseen		None	N/A
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Negative	Third-Party Comments
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Third-Party Comments
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Negative	Comments Submitted
3	Colorado Springs Utilities	Hillary Dobson		Negative	Third-Party Comments
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Victoria Crider		Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Abstain	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Hayden Maples	Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		Negative	Third-Party Comments
3	Great River Energy	Michael Brytowski		Negative	Third-Party Comments
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
3	JEA	Marilyn Williams		None	N/A
3	Lakeland Electric	Steven Marshall		Negative	Third-Party Comments
3	Lincoln Electric System	Sam Christensen		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Los Angeles Department of Water and Power	Fausto Serratos		Abstain	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Negative	Third-Party Comments
3	Manitoba Hydro	Mike Smith		Negative	Comments Submitted
3	MEAG Power	Roger Brand	Rebika Yitna	Negative	Comments Submitted
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	Third-Party Comments
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
3	New York Power Authority	Richard Machado		Negative	Comments Submitted
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney		None	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Negative	Third-Party Comments
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
3	Omaha Public Power District	David Heins		Negative	Third-Party Comments
3	OTP - Otter Tail Power Company	Wendi Olson		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Negative	Comments Submitted
3	Platte River Power Authority	Richard Kiess		Negative	Third-Party Comments
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted
3	Portland General Electric Co.	Mayra Franco		Negative	Third-Party Comments
3	PPL - Louisville Gas and Electric Co.	James Frank		Negative	Comments Submitted
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Negative	Third-Party Comments
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Negative	Comments Submitted
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Negative	Comments Submitted
3	Salt River Project	Mathew Weber	Israel Perez	Negative	Comments Submitted
3	Santee Cooper	Vicky Budreau		Negative	Comments Submitted
3	Seminole Electric Cooperative, Inc.	Usama Tahir		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Negative	Third-Party Comments
3	Snohomish County PUD No. 1	Holly Chaney		Negative	Third-Party Comments
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Negative	No Comment Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Negative	Third-Party Comments
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
3	Tri-State G and T Association, Inc.	Ryan Walter		Negative	Comments Submitted
3	Xcel Energy, Inc.	Nicholas Friebel		Negative	Third-Party Comments
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Third-Party Comments
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		None	N/A
4	Austin Energy	Tony Hua		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Third-Party Comments
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		Negative	Third-Party Comments
4	CMS Energy - Consumers Energy Company	Aric Root		Negative	Comments Submitted
4	DTE Energy	Patricia Ireland		Abstain	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
4	Georgia System Operations Corporation	Katrina Lyons		Negative	Third-Party Comments
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Third-Party Comments
4	Northern California Power Agency	Marty Hostler		None	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Negative	Comments Submitted
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Comments Submitted
4	Seminole Electric Cooperative, Inc.	Ken Habgood		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Negative	Third-Party Comments
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
4	Western Power Pool	Kevin Conway		Negative	Comments Submitted
5	AEP	Thomas Foltz		Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		None	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Third-Party Comments
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Negative	Third-Party Comments
5	Austin Energy	Michael Dillard		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		None	N/A
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		None	N/A
5	Black Hills Corporation	Sheila Suurmeier		Abstain	N/A
5	Bonneville Power Administration	Juergen Bermejo		None	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Negative	Third-Party Comments
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Negative	Comments Submitted
5	Colorado Springs Utilities	Jeffrey Icke		Negative	Third-Party Comments
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
5	Constellation	Alison MacKellar		Abstain	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Third-Party Comments
5	Dominion - Dominion Resources, Inc.	Barbara Marion		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Abstain	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Negative	Comments Submitted
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A
5	Great River Energy	Jacalynn Bentz		None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Abstain	N/A
5	Grid Strategies LLC	Michael Goggin		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Hydro-Quebec (HQ)	Junji Yamaguchi		Negative	Comments Submitted
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	Invenergy LLC	Rhonda Jones		None	N/A
5	JEA	John Babik		Negative	Third-Party Comments
5	Lincoln Electric System	Brittany Millard		None	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Negative	Comments Submitted
5	LS Power Development, LLC	C. A. Campbell		Abstain	N/A
5	Manitoba Hydro	Kristy-Lee Young	Helen Zhao	Negative	Comments Submitted
5	Muscatine Power and Water	Chance Back		Negative	Third-Party Comments
5	National Grid USA	Robin Berry		None	N/A
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		Negative	Comments Submitted
5	Nebraska Public Power District	Ronald Bender		Negative	Third-Party Comments
5	New York Power Authority	Zahid Qayyum		Negative	Comments Submitted
5	NextEra Energy	Richard Vendetti		Negative	Comments Submitted
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Third-Party Comments
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Oglethorpe Power Corporation	Donna Johnson		Negative	Third-Party Comments
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Third-Party Comments
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
5	Orlando Utilities Commission	Dania Colon		None	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		None	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Negative	Comments Submitted
5	Pattern Operators LP	George E Brown		Negative	Third-Party Comments
5	Platte River Power Authority	Jon Osell		Negative	Third-Party Comments
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	PSEG Nuclear LLC	Tim Kucey		None	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Negative	Comments Submitted
5	Public Utility District No. 2 of Grant County, Washington	Nikkee Hebdon		None	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	Comments Submitted
5	Salt River Project	Thomas Johnson	Israel Perez	Negative	Comments Submitted
5	Santee Cooper	Carey Salisbury		Negative	Comments Submitted
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Comments Submitted
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Abstain	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Negative	Third-Party Comments
5	Talen Generation, LLC	Donald Lock		Negative	Comments Submitted
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		None	N/A
5	Tennessee Valley Authority	Darren Boehm		Negative	Comments Submitted
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Negative	Comments Submitted
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Negative	Third-Party Comments
6	AEP	Mathew Miller		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Third-Party Comments
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Third-Party Comments
6	Austin Energy	Imane Mrini		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A
6	Black Hills Corporation	Rachel Schuldt		Abstain	N/A
6	Bonneville Power Administration	Tanner Brier		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Cleco Corporation	Robert Hirchak		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
6	Constellation	Kimberly Turco		Abstain	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Stephanie Kenny		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted
6	Great River Energy	Brian Meloy		Negative	Third-Party Comments
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Negative	Third-Party Comments
6	Lincoln Electric System	Eric Ruskamp		None	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Manitoba Hydro	Brandin Stoesz		Negative	Comments Submitted
6	Muscatine Power and Water	Nicholas Burns		Negative	Third-Party Comments
6	New York Power Authority	Shelly Dineen		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Third-Party Comments
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments
6	Platte River Power Authority	Sabrina Martz		Negative	Third-Party Comments
6	Portland General Electric Co.	Stefanie Burke		Negative	Third-Party Comments
6	Powerex Corporation	Raj Hundal		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Comments Submitted
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		None	N/A
6	Public Utility District No. 1 of Chelan County	Robert Witham		Negative	Comments Submitted
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	Comments Submitted
6	Salt River Project	Timothy Singh	Israel Perez	Negative	Comments Submitted
6	Santee Cooper	Marty Watson		Negative	Comments Submitted
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Negative	Comments Submitted
6	Snohomish County PUD No. 1	John Liang		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
6	Southern Indiana Gas and Electric Co.	Kati Barr		Abstain	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Negative	Third-Party Comments
6	Western Area Power Administration	Jennifer Neville		Affirmative	N/A
6	Xcel Energy, Inc.	Steve Szablya		Negative	Third-Party Comments
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		Negative	Third-Party Comments
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Tyler Schwendiman	Greg Sorenson	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Negative	Comments Submitted

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Showing 1 to 314 of 314 entries

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/338)
Ballot Name: 2023-07 Transmission Planning Performance Requirements for Extreme Weather Implementation Plan AB 2 OT
Voting Start Date: 8/13/2024 12:01:00 AM
Voting End Date: 8/22/2024 8:00:00 PM
Ballot Type: OT
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 275
Total Ballot Pool: 314
Quorum: 87.58
Quorum Established Date: 8/22/2024 3:48:39 PM
Weighted Segment Value: 31.97

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	89	1	18	0.247	55	0.753	0	9	7
Segment: 2	8	0.5	1	0.1	4	0.4	0	2	1
Segment: 3	68	1	15	0.263	42	0.737	0	5	6
Segment: 4	18	1	3	0.231	10	0.769	0	2	3
Segment: 5	76	1	16	0.327	33	0.673	0	9	18
Segment: 6	47	1	13	0.351	24	0.649	0	6	4
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	1	0	0	0	0	0	0	1	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	7	0.5	4	0.4	1	0.1	0	2	0
Totals:	314	6	70	1.918	169	4.082	0	36	39

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Negative	Comments Submitted
1	Ameren - Ameren Services	Tamara Evey		Negative	Third-Party Comments
1	American Transmission Company, LLC	Amy Wilke		Negative	Comments Submitted
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Negative	Third-Party Comments
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Negative	Comments Submitted
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		None	N/A
1	Black Hills Corporation	Micah Runner		Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Negative	Third-Party Comments
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Third-Party Comments
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	Third-Party Comments
1	Colorado Springs Utilities	Corey Walker		Negative	Third-Party Comments
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Third-Party Comments
1	Dominion - Dominion Virginia Power	Steven Belle		Negative	Comments Submitted
1	Duke Energy	Katherine Street	Ellese Murphy	Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Robert Blackney		Negative	Comments Submitted
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Eversource Energy	Joshua London		Affirmative	N/A
1	Exelon	Daniel Gacek		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Negative	Comments Submitted
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Lidija Efremova	Affirmative	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Negative	Comments Submitted
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
1	JEA	Joseph McClung		Negative	Third-Party Comments
1	KAMO Electric Cooperative	Micah Breedlove		Negative	Third-Party Comments
1	Lakeland Electric	Larry Watt		Negative	Third-Party Comments
1	Lincoln Electric System	Josh Johnson		None	N/A
1	Long Island Power Authority	Isidoro Behar		Negative	Comments Submitted
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Matt Lewis		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	LS Power Transmission, LLC	Jennifer Richardson		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Negative	Third-Party Comments
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
1	MEAG Power	David Weekley	Rebika Yitna	Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Nikki Carson-Marquis	Negative	Third-Party Comments
1	Muscatine Power and Water	Andrew Kurriger		Negative	Third-Party Comments
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Third-Party Comments
1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	NB Power Corporation	Jeffrey Streifling		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
1	New York Power Authority	Daniel Valle		Negative	Comments Submitted
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Negative	Comments Submitted
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Negative	Third-Party Comments
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Negative	Comments Submitted
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Negative	Comments Submitted
1	Platte River Power Authority	Marissa Archie		Negative	Third-Party Comments
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
1	Portland General Electric Co.	Brooke Jockin		None	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	Comments Submitted
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Negative	Third-Party Comments
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Negative	Comments Submitted
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Abstain	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	Comments Submitted
1	Salt River Project	Laura Somak	Israel Perez	Negative	Comments Submitted
1	Santee Cooper	Chris Wagner		Negative	Comments Submitted
1	SaskPower	Wayne Guttormson		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Negative	Comments Submitted
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Negative	Third-Party Comments
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Negative	Comments Submitted
1	VELCO -Vermont Electric Power Company, Inc.	Randall Buswell		Abstain	N/A
1	Western Area Power Administration	Ben Hammer		Affirmative	N/A
1	Xcel Energy, Inc.	Eric Barry		Negative	Third-Party Comments
2	California ISO	Darcy O'Connell		Abstain	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A
2	Independent Electricity System Operator	Helen Lainis		Abstain	N/A
2	ISO New England, Inc.	John Pearson	Keith Jonassen	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	Midcontinent ISO, Inc.	Bobbi Welch		Negative	Comments Submitted
2	New York Independent System Operator	Gregory Campoli		Negative	Third-Party Comments
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	None	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips	Shannon Mickens	Negative	Comments Submitted
3	AEP	Leshel Hutchings		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr	Danielle Moskop	Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Third-Party Comments
3	Austin Energy	Lovita Griffin		None	N/A
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Third-Party Comments
3	Black Hills Corporation	Josh Combs	Carly Miller	Affirmative	N/A
3	Bonneville Power Administration	Ron Sporseen		None	N/A
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Negative	Third-Party Comments
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Third-Party Comments
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Negative	Third-Party Comments
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Victoria Crider		Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Abstain	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Hayden Maples	Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		Negative	Third-Party Comments
3	Great River Energy	Michael Brytowski		Negative	Third-Party Comments
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
3	JEA	Marilyn Williams		None	N/A
3	Lakeland Electric	Steven Marshall		Negative	Third-Party Comments
3	Lincoln Electric System	Sam Christensen		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Los Angeles Department of Water and Power	Fausto Serratos		Abstain	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Negative	Third-Party Comments
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
3	MEAG Power	Roger Brand	Rebika Yitna	Negative	Comments Submitted
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	Third-Party Comments
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
3	New York Power Authority	Richard Machado		Negative	Comments Submitted
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney		None	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Negative	Third-Party Comments
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
3	Omaha Public Power District	David Heins		Negative	Third-Party Comments
3	OTP - Otter Tail Power Company	Wendi Olson		None	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Platte River Power Authority	Richard Kiess		Negative	Third-Party Comments
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted
3	Portland General Electric Co.	Mayra Franco		Negative	Third-Party Comments
3	PPL - Louisville Gas and Electric Co.	James Frank		Negative	Comments Submitted
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Negative	Third-Party Comments
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Negative	Comments Submitted
3	Salt River Project	Mathew Weber	Israel Perez	Negative	Comments Submitted
3	Santee Cooper	Vicky Budreau		Negative	Comments Submitted
3	Seminole Electric Cooperative, Inc.	Usama Tahir		Negative	Comments Submitted
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Negative	Third-Party Comments
3	Snohomish County PUD No. 1	Holly Chaney		Negative	Third-Party Comments
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Abstain	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Negative	Third-Party Comments
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Third-Party Comments
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		None	N/A
4	Austin Energy	Tony Hua		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Third-Party Comments
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		Negative	Third-Party Comments
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
4	DTE Energy	Patricia Ireland		Abstain	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
4	Georgia System Operations Corporation	Katrina Lyons		Negative	Third-Party Comments
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Third-Party Comments
4	Northern California Power Agency	Marty Hostler		None	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Negative	Comments Submitted
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Seminole Electric Cooperative, Inc.	Ken Habgood		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Negative	Third-Party Comments
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
4	Western Power Pool	Kevin Conway		Negative	Comments Submitted
5	AEP	Thomas Foltz		Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		None	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Third-Party Comments
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Negative	Third-Party Comments
5	Austin Energy	Michael Dillard		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		None	N/A
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		None	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
5	Bonneville Power Administration	Juergen Bermejo		None	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Negative	Third-Party Comments
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Negative	Third-Party Comments
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
5	Constellation	Alison MacKellar		Abstain	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Third-Party Comments
5	Dominion - Dominion Resources, Inc.	Barbara Marion		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Abstain	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Negative	Comments Submitted
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A
5	Great River Energy	Jacalynn Bentz		None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Abstain	N/A
5	Grid Strategies LLC	Michael Goggin		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Hydro-Quebec (HQ)	Junji Yamaguchi		Negative	Comments Submitted
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	Invenergy LLC	Rhonda Jones		None	N/A
5	JEA	John Babik		Negative	Third-Party Comments
5	Lincoln Electric System	Brittany Millard		None	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Negative	Comments Submitted
5	LS Power Development, LLC	C. A. Campbell		Abstain	N/A
5	Manitoba Hydro	Kristy-Lee Young	Helen Zhao	Affirmative	N/A
5	Muscatine Power and Water	Chance Back		Negative	Third-Party Comments
5	National Grid USA	Robin Berry		None	N/A
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		Negative	Comments Submitted
5	Nebraska Public Power District	Ronald Bender		Negative	Third-Party Comments
5	New York Power Authority	Zahid Qayyum		Negative	Comments Submitted
5	NextEra Energy	Richard Vendetti		Negative	Comments Submitted
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Third-Party Comments
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Oglethorpe Power Corporation	Donna Johnson		Negative	Third-Party Comments
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Third-Party Comments
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
5	Orlando Utilities Commission	Dania Colon		None	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		None	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Negative	Comments Submitted
5	Pattern Operators LP	George E Brown		Negative	Third-Party Comments
5	Platte River Power Authority	Jon Osell		Negative	Third-Party Comments
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	PSEG Nuclear LLC	Tim Kucey		None	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Negative	Comments Submitted
5	Public Utility District No. 2 of Grant County, Washington	Nikkee Hebdon		None	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	Comments Submitted
5	Salt River Project	Thomas Johnson	Israel Perez	Negative	Comments Submitted
5	Santee Cooper	Carey Salisbury		Negative	Comments Submitted
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Abstain	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Negative	Third-Party Comments
5	Talen Generation, LLC	Donald Lock		None	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		None	N/A
5	Tennessee Valley Authority	Darren Boehm		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Negative	Third-Party Comments
6	AEP	Mathew Miller		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Third-Party Comments
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Third-Party Comments
6	Austin Energy	Imane Mrini		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A
6	Black Hills Corporation	Rachel Schuldt		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Cleco Corporation	Robert Hirchak		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
6	Constellation	Kimberly Turco		Abstain	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Stephanie Kenny		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted
6	Great River Energy	Brian Meloy		Negative	Third-Party Comments
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Negative	Third-Party Comments
6	Lincoln Electric System	Eric Ruskamp		None	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Manitoba Hydro	Brandin Stoesz		Affirmative	N/A
6	Muscatine Power and Water	Nicholas Burns		Negative	Third-Party Comments
6	New York Power Authority	Shelly Dineen		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Third-Party Comments
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments
6	Platte River Power Authority	Sabrina Martz		Negative	Third-Party Comments
6	Portland General Electric Co.	Stefanie Burke		Abstain	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Comments Submitted
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		None	N/A
6	Public Utility District No. 1 of Chelan County	Robert Witham		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	Comments Submitted
6	Salt River Project	Timothy Singh	Israel Perez	Negative	Comments Submitted
6	Santee Cooper	Marty Watson		Negative	Comments Submitted
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Negative	Comments Submitted
6	Snohomish County PUD No. 1	John Liang		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Abstain	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Negative	Third-Party Comments
6	Western Area Power Administration	Jennifer Neville		Affirmative	N/A
6	Xcel Energy, Inc.	Steve Szablya		Negative	Third-Party Comments
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Tyler Schwendiman	Greg Sorenson	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A

Showing 1 to 314 of 314 entries

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BALLOT RESULTS

Ballot Name: 2023-07 Transmission Planning Performance Requirements for Extreme Weather TPL-008-1 | Non-binding Poll AB 2 NB
Voting Start Date: 8/13/2024 12:01:00 AM
Voting End Date: 8/22/2024 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 258
Total Ballot Pool: 297
Quorum: 86.87
Quorum Established Date: 8/22/2024 3:49:21 PM
Weighted Segment Value: 20.71

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	86	1	11	0.183	49	0.817	18	8
Segment: 2	7	0.4	0	0	4	0.4	3	0
Segment: 3	63	1	8	0.178	37	0.822	10	7
Segment: 4	18	1	2	0.154	11	0.846	2	3
Segment: 5	72	1	8	0.195	33	0.805	14	17
Segment: 6	44	1	9	0.29	22	0.71	9	4
Segment: 7	0	0	0	0	0	0	0	0
Segment: 8	1	0	0	0	0	0	1	0
Segment: 9	0	0	0	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 10	6	0.4	3	0.3	1	0.1	2	0
Totals:	297	5.8	41	1.3	157	4.5	59	39

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Negative	Comments Submitted
1	Ameren - Ameren Services	Tamara Evey		Abstain	N/A
1	American Transmission Company, LLC	Amy Wilke		Negative	Comments Submitted
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Negative	Comments Submitted
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Negative	Comments Submitted
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		None	N/A
1	Black Hills Corporation	Micah Runner		Abstain	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Negative	Comments Submitted
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Comments Submitted
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	Comments Submitted
1	Colorado Springs Utilities	Corey Walker		Negative	Comments Submitted
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Steven Belle		Negative	Comments Submitted
1	Duke Energy	Katherine Street	Ellese Murphy	Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Robert Blackney		Negative	Comments Submitted
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Negative	Comments Submitted
1	Eversource Energy	Joshua London		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Exelon	Daniel Gacek		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Negative	Comments Submitted
1	Glencoe Light and Power Commission	Terry Volkmann		Abstain	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Lidija Efremova	Negative	Comments Submitted
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Negative	Comments Submitted
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
1	JEA	Joseph McClung		Negative	Comments Submitted
1	KAMO Electric Cooperative	Micah Breedlove		Negative	Comments Submitted
1	Lakeland Electric	Larry Watt		Negative	Comments Submitted
1	Lincoln Electric System	Josh Johnson		None	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Matt Lewis		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	LS Power Transmission, LLC	Jennifer Richardson		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Negative	Comments Submitted
1	MEAG Power	David Weekley	Rebika Yitna	Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Nikki Carson-Marquis	Negative	Comments Submitted
1	Muscatine Power and Water	Andrew Kurriger		Negative	Comments Submitted
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Comments Submitted
1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	NB Power Corporation	Jeffrey Streifling		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Daniel Valle		Negative	Comments Submitted
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Negative	Comments Submitted
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	Omaha Public Power District	Doug Peterchuck		Negative	Comments Submitted
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Negative	Comments Submitted
1	Platte River Power Authority	Marissa Archie		Negative	Comments Submitted
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
1	Portland General Electric Co.	Brooke Jockin		None	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		None	N/A
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Abstain	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Negative	Comments Submitted
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Negative	Comments Submitted
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Abstain	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	Comments Submitted
1	Salt River Project	Laura Somak	Israel Perez	Negative	Comments Submitted
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Negative	Comments Submitted
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Negative	Comments Submitted
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Abstain	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Negative	Comments Submitted
1	VELCO -Vermont Electric Power Company, Inc.	Randall Buswell		Abstain	N/A
1	Western Area Power Administration	Ben Hammer		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
2	Independent Electricity System Operator	Helen Lainis		Abstain	N/A
2	ISO New England, Inc.	John Pearson	Keith Jonassen	Negative	Comments Submitted
2	Midcontinent ISO, Inc.	Bobbi Welch		Negative	Comments Submitted
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips	Shannon Mickens	Negative	Comments Submitted
3	AEP	Leshel Hutchings		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr	Danielle Moskop	Abstain	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
3	Austin Energy	Lovita Griffin		None	N/A
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs	Carly Miller	Abstain	N/A
3	Bonneville Power Administration	Ron Sporseen		None	N/A
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Comments Submitted
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Negative	Comments Submitted
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Negative	Comments Submitted
3	Colorado Springs Utilities	Hillary Dobson		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Victoria Crider		Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Abstain	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Hayden Maples	Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Great River Energy	Michael Brytowski		Negative	Comments Submitted
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
3	JEA	Marilyn Williams		None	N/A
3	Lakeland Electric	Steven Marshall		Negative	Comments Submitted
3	Lincoln Electric System	Sam Christensen		None	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Negative	Comments Submitted
3	MEAG Power	Roger Brand	Rebika Yitna	Negative	Comments Submitted
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Muscatine Power and Water	Seth Shoemaker		Negative	Comments Submitted
3	National Grid USA	Brian Shanahan		Negative	No Comment Submitted
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	Richard Machado		Negative	Comments Submitted
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney		None	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
3	Omaha Public Power District	David Heins		Negative	Comments Submitted
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Negative	Comments Submitted
3	Platte River Power Authority	Richard Kiess		Negative	Comments Submitted
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted
3	Portland General Electric Co.	Mayra Franco		Negative	Comments Submitted
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Negative	Comments Submitted
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Negative	Comments Submitted
3	Salt River Project	Mathew Weber	Israel Perez	Negative	Comments Submitted
3	Santee Cooper	Vicky Budreau		Abstain	N/A
3	Seminole Electric Cooperative, Inc.	Usama Tahir		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Negative	Comments Submitted
3	Snohomish County PUD No. 1	Holly Chaney		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Abstain	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Comments Submitted
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		None	N/A
4	Austin Energy	Tony Hua		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		Negative	Comments Submitted
4	CMS Energy - Consumers Energy Company	Aric Root		Negative	Comments Submitted
4	DTE Energy	Patricia Ireland		Abstain	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
4	Georgia System Operations Corporation	Katrina Lyons		Negative	Comments Submitted
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Comments Submitted
4	Northern California Power Agency	Marty Hostler		None	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Negative	Comments Submitted
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Comments Submitted
4	Seminole Electric Cooperative, Inc.	Ken Habgood		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Negative	Comments Submitted
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
4	Western Power Pool	Kevin Conway		Negative	Comments Submitted
5	AEP	Thomas Foltz		Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		None	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Associated Electric Cooperative, Inc.	Chuck Booth		Negative	Comments Submitted
5	Austin Energy	Michael Dillard		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		None	N/A
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		None	N/A
5	Black Hills Corporation	Sheila Suurmeier		Abstain	N/A
5	Bonneville Power Administration	Juergen Bermejo		None	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Negative	Comments Submitted
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Negative	Comments Submitted
5	Colorado Springs Utilities	Jeffrey Icke		Negative	Comments Submitted
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
5	Constellation	Alison MacKellar		Abstain	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Barbara Marion		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Negative	Comments Submitted
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Abstain	N/A
5	Grid Strategies LLC	Michael Goggin		Negative	Comments Submitted
5	Hydro-Quebec (HQ)	Junji Yamaguchi		Negative	Comments Submitted
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	JEA	John Babik		Negative	Comments Submitted
5	Lincoln Electric System	Brittany Millard		None	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Negative	Comments Submitted
5	LS Power Development, LLC	C. A. Campbell		Abstain	N/A
5	Muscatine Power and Water	Chance Back		Negative	Comments Submitted
5	National Grid USA	Robin Berry		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		Negative	Comments Submitted
5	Nebraska Public Power District	Ronald Bender		Abstain	N/A
5	New York Power Authority	Zahid Qayyum		Negative	Comments Submitted
5	NextEra Energy	Richard Vendetti		Negative	Comments Submitted
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Comments Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		None	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Negative	Comments Submitted
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Comments Submitted
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
5	Orlando Utilities Commission	Dania Colon		None	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		None	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Negative	Comments Submitted
5	Pattern Operators LP	George E Brown		Negative	Comments Submitted
5	Platte River Power Authority	Jon Osell		Negative	Comments Submitted
5	Portland General Electric Co.	Ryan Olson		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	PSEG Nuclear LLC	Tim Kucey		None	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Negative	Comments Submitted
5	Public Utility District No. 2 of Grant County, Washington	Nikkee Hebdon		None	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	Comments Submitted
5	Salt River Project	Thomas Johnson	Israel Perez	Negative	Comments Submitted
5	Santee Cooper	Carey Salisbury		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Negative	Comments Submitted
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Comments Submitted
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Abstain	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Negative	Comments Submitted
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		None	N/A
5	Tennessee Valley Authority	Darren Boehm		None	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Negative	Comments Submitted
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Abstain	N/A
6	AEP	Mathew Miller		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Comments Submitted
6	Austin Energy	Imane Mrini		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A
6	Black Hills Corporation	Rachel Schuldt		Abstain	N/A
6	Bonneville Power Administration	Tanner Brier		Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
6	Constellation	Kimberly Turco		Abstain	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Stephanie Kenny		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted
6	Great River Energy	Brian Meloy		Negative	Comments Submitted
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Negative	Comments Submitted
6	Lincoln Electric System	Eric Ruskamp		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Muscatine Power and Water	Nicholas Burns		Negative	Comments Submitted
6	New York Power Authority	Shelly Dineen		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Comments Submitted
6	Omaha Public Power District	Shonda McCain		Negative	Comments Submitted
6	Platte River Power Authority	Sabrina Martz		Negative	Comments Submitted
6	Portland General Electric Co.	Stefanie Burke		Abstain	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		None	N/A
6	Public Utility District No. 1 of Chelan County	Robert Witham		Negative	Comments Submitted
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	Comments Submitted
6	Salt River Project	Timothy Singh	Israel Perez	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Santee Cooper	Marty Watson		Abstain	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Negative	Comments Submitted
6	Snohomish County PUD No. 1	John Liang		Negative	Comments Submitted
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
6	Southern Indiana Gas and Electric Co.	Kati Barr		Abstain	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Negative	Comments Submitted
6	Western Area Power Administration	Jennifer Neville		Affirmative	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Tyler Schwendiman	Greg Sorenson	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Negative	Comments Submitted

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Showing 1 to 297 of 297 entries

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the third draft of the proposed standard posted for a 15-day formal comment period with additional ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	July 19, 2023
SAR posted for comment	August 8–September 27, 2023
45-day formal comment period with initial ballot	March 20–May 3, 2024
38-day formal comment period with additional ballot	July 16–August 22, 2024

Anticipated Actions	Date
15-day formal comment period with additional ballot	October 7–21, 2024
15-day formal comment period with additional ballot	November 7–21, 2024
5-day final ballot	December 2–6, 2024
Board adoption	December 11, 2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

Extreme Temperature Assessment – Documented evaluation of future Bulk Electric System performance for extreme heat and extreme cold benchmark temperature events.

A. Introduction

1. **Title:** Transmission System Planning Performance Requirements for Extreme Temperature Events

2. **Number:** TPL-008-1

3. **Purpose:** Establish Transmission system planning performance requirements to develop a Bulk Power System (BPS) that will operate reliably during extreme heat and extreme cold temperature events.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Transmission Planner

   4.1.2. Planning Coordinator

5. **Effective Date:** See Implementation Plan for Project 2023-07.

B. Requirements and Measures

R1. Each Planning Coordinator shall identify, in conjunction with its Transmission Planner(s), each entity's individual and joint responsibilities for completing the Extreme Temperature Assessment, which shall include each of the responsibilities described in Requirements R2 through R11. Each responsible entity shall complete its responsibilities such that the Extreme Temperature Assessment is completed at least once every five calendar years. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M1. Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall provide documentation of each entity's individual and joint responsibilities, such as meeting minutes, agreements, copies of procedures or protocols, in effect between entities or between departments of a vertically integrated system, or email correspondence that identifies an agreement has been reached on individual and joint responsibilities for completing the Extreme Temperature Assessment and that these responsibilities were completed such that the Extreme Temperature Assessment was completed once every five calendar years.

R2. Each Planning Coordinator shall identify the zone(s) to which the Planning Coordinator belongs to under Attachment 1, and shall coordinate with all Planning Coordinators within each of its identified zone(s), to select one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event for each of its identified zone(s) when completing the Extreme Temperature Assessment.[1] Selected benchmark temperature events shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. Consider no less than a 40-year period of temperature data ending no more than five years prior to the time the benchmark temperature events are selected; and

2.2. Represent one of the 20 most extreme temperature conditions based on the three-day rolling average of daily maximum (heat) or daily minimum (cold) temperature across the zone.

M2. Each Planning Coordinator shall have evidence in either electronic or hard copy format that it identified the zone(s) to which it belongs to, under Attachment 1, and coordinated with all other Planning Coordinators within each of its identified zone(s) to select one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event meeting the criteria of Requirement R2 for each of their identified zone(s) when completing the Extreme Temperature Assessment.

[1] The Electric Reliability Organization (ERO) will maintain a library of benchmark temperature events that meet the criteria of Requirement R2.

R3. Each Planning Coordinator shall coordinate with all Planning Coordinators within each of its zone(s) identified in Requirement R2, to implement a process for developing benchmark planning cases for the Extreme Temperature Assessment that represent the benchmark temperature events selected in Requirement R2 and sensitivity cases to demonstrate the impact of changes to the basic assumptions used in the benchmark planning cases. This process shall include the following: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Selection of System models within the Long-Term Transmission Planning Horizon to form the basis for the benchmark planning cases.

3.2. Forecasted seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers within the zone.

3.3. Assumed seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers in areas outside the zone, as needed.

3.4. Identification of changes to at least one of the following conditions for sensitivity cases: generation, real and reactive forecasted Load, or transfers.

M3. Each Planning Coordinator shall have dated evidence that it implemented a process for coordinating the development of benchmark planning cases and sensitivity cases for the Extreme Temperature Assessment as specified in Requirement R3.

R4. Each responsible entity, as identified in Requirement R1, shall use the coordination process developed in Requirement R3 and data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, to develop the following and establish category P0 as the normal System condition in Table 1: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

4.1. One common extreme heat and one common extreme cold benchmark planning case.

4.2. One common extreme heat and one common extreme cold sensitivity case.

M4. Each responsible entity, as identified in Requirement R1, shall have dated evidence in either electronic or hard copy format that it developed benchmark planning cases and sensitivity cases in accordance with Requirement R4.

R5. Each responsible entity, as identified in Requirement R1, shall have criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations for completing the Extreme Temperature Assessment. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M5. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of the documentation, specifying the criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations for completing the Extreme Temperature Assessment.

R6. Each responsible entity, as identified in Requirement R1, shall define and document the criteria or methodology to be used in the Extreme Temperature Assessment to identify instability, uncontrolled separation, or Cascading within an Interconnection. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M6. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of documentation, specifying the criteria or methodology to be used in the Extreme Temperature Assessment to identify instability, uncontrolled separation, or Cascading within an Interconnection in accordance with Requirement R6.

R7. Each responsible entity, as identified in Requirement R1, shall identify the Contingencies for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System. The rationale for those Contingencies selected for evaluation shall be available as supporting information. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M7. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of documentation, of the Contingencies for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System along with supporting rationale.

R8. Each responsible entity, as identified in Requirement R1, shall complete steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, and shall document the assumptions and results. Steady state and transient stability analyses shall be performed for the following: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

8.1. Benchmark planning cases developed in accordance with Requirement R4 Part 4.1.

8.2. Sensitivity cases developed in accordance with Requirement R4 Part 4.2.

M8. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of documentation, of the assumptions and results of the steady state and transient stability analyses completed in the Extreme Temperature Assessment.

R9. Each responsible entity, as identified in Requirement R1, shall develop a Corrective Action Plan(s) when the analysis of a benchmark planning case, in accordance with Requirement R8 Part 8.1, indicates its portion of the Bulk Electric System is unable to meet performance requirements for category P0 or P1 in Table 1. For each Corrective Action Plan, the responsible entity shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

9.1. Make its Corrective Action Plan available to, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.

9.2. Document alternative(s) considered, and notify the applicable regulatory authorities or governing bodies responsible for retail electric service issues when Non-Consequential Load Loss is utilized as an element of a Corrective Action Plan for a Table 1 P1 Contingency.

9.3. Be permitted to utilize Non-Consequential Load Loss as an interim solution, which normally is not permitted in Table 1, in situations that are beyond the control of the Planning Coordinator or Transmission Planner that prevent the implementation of a Corrective Action Plan in the required timeframe, provided that the responsible entity documents the situation causing the problem, alternatives evaluated, and takes actions to resolve the situation.

9.4. Be allowed to have revisions to the Corrective Action Plan in subsequent Extreme Temperature Assessments, provided that the planned Bulk Electric System shall continue to meet the performance requirements of Table 1.

M9. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of documentation, of each Corrective Action Plan developed in accordance with Requirement R9, including dated documentation of correspondence with applicable regulatory authorities or governing bodies responsible for retail electric service issues and any revision history, when the analysis of a benchmark planning case indicates its portion of the Bulk Electric System is unable to meet performance requirements for category P0 or P1 in Table 1.

R10. Each responsible entity, as identified in Requirement R1, shall evaluate and document possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) if analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection, for the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

10.1. Table 1 P7 Contingencies in benchmark planning cases analyzed in accordance with Requirement R8 Part 8.1.

10.2. Categories P0, P1, and P7 in Table 1 in sensitivity cases analyzed in accordance with Requirement R8 Part 8.2.

M10. Each responsible entity, as identified in Requirement R1, shall provide dated evidence such as electronic or hard copies of documentation that it evaluated and documented possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts when the analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection for Table 1 P7 Contingencies in benchmark planning cases or categories P0, P1, or P7 in Table 1 in sensitivity cases.

R11. Each responsible entity, as identified in Requirement R1, shall provide its Extreme Temperature Assessment results within 60 calendar days of a request to any functional entity that has a reliability related need and submits a written request for the information. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M11. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient, or a demonstration of a public posting, that it provided its Extreme Temperature Assessment to any functional entity who has a reliability need within 60 calendar days of a written request.

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. **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.

   - Each responsible entity shall retain evidence of compliance with each requirement in this standard for five calendar years or one complete Extreme Temperature Assessment cycle, whichever is longer.

   1.3. **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.

Table 1 – Steady State & Stability Performance Events
Steady State & Stability: a. Instability, uncontrolled separation, or Cascading within an Interconnection, defined in accordance with Requirement R6, shall not occur. b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0. c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event. d. Simulate Normal Clearing unless otherwise specified. e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings. **Steady State Only:** f. Applicable Facility Ratings shall not be exceeded. g. System steady state voltages and post-Contingency voltage deviations shall meet the criteria identified in Requirement R5.

<table>
<tr><th colspan="8">Table 1 – Steady State & Stability Performance Events</th></tr>
<tr><th rowspan="2">Category</th><th rowspan="2">Initial Condition</th><th rowspan="2">Event[1]</th><th rowspan="2">Fault Type[2]</th><th rowspan="2">Contingency BES Level</th><th rowspan="2">Interruption of Firm Transmission Service Allowed</th><th colspan="2">Non-Consequential Load Loss Allowed</th></tr>
<tr><th>Benchmark Planning Cases</th><th>Sensitivity Cases</th></tr>
<tr><td>P0
No Contingency</td><td>Normal System</td><td>None</td><td>N/A</td><td>≥ 200 kV</td><td>Yes</td><td>No[6]</td><td>Yes</td></tr>
<tr><td rowspan="2">P1
Single Contingency</td><td rowspan="2">Normal System</td><td>Loss of one of the following:
1. Generator
2. Transmission Circuit
3. Transformer[3]
4. Shunt Device[4]</td><td>3Ø</td><td rowspan="2">≥ 200 kV</td><td rowspan="2">Yes</td><td rowspan="2">Yes[6]</td><td rowspan="2">Yes</td></tr>
<tr><td>5. Single Pole of a DC line</td><td>SLG</td></tr>
<tr><td>P7
Multiple Contingency
(Common Structure)</td><td>Normal System</td><td>The loss of:
1. Any two adjacent (vertically or horizontally) circuits on common structure[5]
2. Loss of a bipolar DC line</td><td>SLG</td><td>≥ 200 kV</td><td>Yes</td><td>Yes</td><td>Yes</td></tr>
</table>

Table 1 – Steady State & Stability Performance Events
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the BES level of the event. For P7 events, the BES level of the event is the highest System voltage level of the element(s) removed for the analyzed event.   2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.   3. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.   4. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.   5. Excludes circuits that share a common structure for 1 mile or less.   6. Benchmark planning cases require the development of a Corrective Action Plan when the responsible entity's portion of the BES is unable to meet the performance requirements for categories P0 or P1. Additionally, in benchmark planning cases, Non-Consequential Load Loss is not permitted for category P0 and requires notification of applicable regulatory authorities or governing bodies responsible for retail electric service issues when utilized as an element of a Corrective Action Plan for P1 Contingencies. See Requirement R9 for the relevant requirements.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed less than or equal to six months late.	The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed more than six months but less than or equal to 12 months late.	The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed more than 12 months but less than or equal to 18 months late.	The Planning Coordinator, in conjunction with its Transmission Planner(s), failed to identify individual and joint responsibilities for completing the Extreme Temperature Assessment. OR The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed more than 18 months late.
R2.	N/A	N/A	The Planning Coordinator coordinated with all Planning Coordinators within each identified zone to select one common extreme heat and one common extreme cold benchmark temperature event for completing the Extreme Temperature Assessment, but one of the selected events	The Planning Coordinator coordinated with all Planning Coordinators within each identified zone to select one common extreme heat and one common extreme cold benchmark temperature event for completing the Extreme Temperature Assessment, but both of the selected events

			failed to meet all the criteria of Requirement R2.	failed to meet all of the criteria of Requirement R2. OR The Planning Coordinator failed to coordinate with all Planning Coordinators within each identified zone to select one common extreme heat and one common extreme cold benchmark temperature event for completing the Extreme Temperature Assessment.
R3.	N/A	N/A	N/A	The Planning Coordinator did not coordinate with all Planning Coordinators within each of its identified zone(s) to implement a process for developing benchmark planning cases. OR The Planning Coordinator coordinated with all Planning Coordinators within each of its identified zone(s) to implement a process for developing benchmark planning cases, but the process did not include all of the required elements.

R4.	N/A	N/A	N/A	The responsible entity, as identified in Requirement R1, did not use the coordination process to develop benchmark planning cases or sensitivity cases. OR The responsible entity, as identified in Requirement R1, used the coordination process to develop benchmark planning cases and sensitivity cases, but did not use data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, for one or more of the required cases. OR The responsible entity, as identified in Requirement R1, used the coordination process and data consistent with that provided in accordance with the MOD-032 standard, supplemented as needed, but failed to develop one or more of the required planning or sensitivity cases.

R5.	N/A	N/A	N/A	The responsible entity, as identified in Requirement R1, did not have criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations for completing the Extreme Temperature Assessment.
R6.	N/A	N/A	N/A	The responsible entity, as identified in Requirement R1, failed to define or document the criteria or methodology to be used in the Extreme Temperature Assessment to identify instability, uncontrolled separation, or Cascading within an Interconnection.
R7.	N/A	N/A	The responsible entity, as identified in Requirement R1, identified Contingencies for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System, but did not include the rationale for those Contingencies selected for evaluation as supporting information.	The responsible entity, as identified in Requirement R1, did not identify Contingencies for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System.

R8.	The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to document the assumptions for one or more sensitivity cases in accordance with Requirement R8.	The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to document the assumptions for one or more benchmark planning cases in accordance with Requirement R8.	The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to evaluate and document results for one or more of the sensitivity cases in accordance with Requirement R8.	The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to evaluate and document results for one or more of the benchmark planning cases in accordance with Requirement R8. OR The responsible entity, as identified in Requirement R1, failed to complete steady state or transient stability analyses and document results in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, in accordance with Requirement R8.
R9.	N/A	N/A	The responsible entity, as identified in Requirement R1, developed a Corrective Action Plan in accordance with Requirement R9, but failed to make its Corrective Action Plan available to, or solicit	The responsible entity, as identified in Requirement R1, failed to develop a Corrective Action Plan when the benchmark planning case study results indicate the System is unable to meet

			feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.	performance requirements for the Table 1 P0 or P1 Contingencies. OR The responsible entity, as identified in Requirement R1, developed a Corrective Action Plan, but it was missing one or more of the elements of Requirement R9 Part 9.2-9.4 (as applicable).
R10.	N/A	N/A	The responsible entity, as identified in Requirement R1, evaluated and documented possible actions to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection where required under Requirement R10 Part 10.1, but failed to evaluate and document possible actions where required under Requirement R10 Part 10.2.	The responsible entity, as identified in Requirement R1, evaluated and documented possible actions to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection where required under Requirement R10 Part 10.2, but failed to evaluate and document possible actions where required under Requirement R10 Part 10.1. OR The responsible entity, as identified in Requirement R1, failed to evaluate and

				document possible actions to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection where required under Requirement R10 Parts 10.1 and 10.2.
R11.	The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 60 days but less than or equal to 80 days following the request.	The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 80 days but less than or equal to 100 days following the request.	The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 100 days but less than or equal to 120 days following the request.	The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 120 days following the request. OR The responsible entity, as identified in Requirement R1, did not provide its Extreme Temperature Assessment results to functional entities having a reliability related need who submitted a written request for the information.

D. Regional Variances

None.

E. Associated Documents

- Implementation Plan for Project 2023-07
- Technical Rationale Document
- Consideration of Issues and Directives for FERC Order 896.

Version History

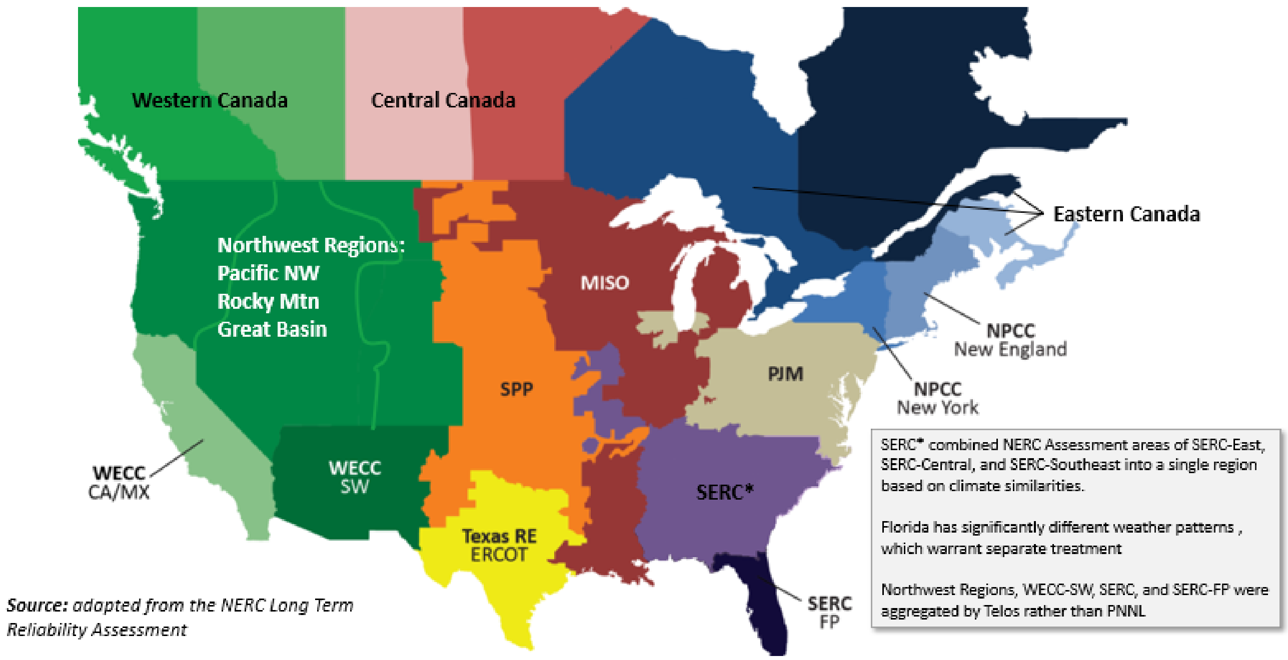
Version	Date	Action	Change Tracking
1	TBD	Addressing FERC Order 896	New Standard

Attachment 1: Extreme Temperature Assessment Zones

The table below lists the zones to be used in the Extreme Temperature Assessment and identifies the Planning Coordinators that belong to each zone. In accordance with Requirement R2, each Planning Coordinator is required to identify the zone(s) to which it belongs.

Zone	Planning Coordinators
Eastern Interconnection	
MISO	MISO
SPP	SPP
PJM	PJM
NPCC (New England)	Planning Coordinators in NPCC that primarily serve the six New England States
NPCC (New York)	Planning Coordinators in NPCC that primarily serve New York
SERC	Planning Coordinators in SERC excluding those that primarily serve Florida and those in MISO, SPP, or PJM
SERC (Florida)	Planning Coordinators in SERC that primarily serve Florida
Central Canada	Planning Coordinators that primarily serve Saskatchewan and/or Manitoba region of MRO
Eastern Canada	Planning Coordinators in NPCC that primarily serve Ontario, New Brunswick, and Nova Scotia
Western Interconnection	
WECC Southwest	Planning Coordinators in the Southwest region of WECC, including El Paso in West Texas
Pacific Northwest	Planning Coordinators in the Pacific Northwest region of WECC
Great Basin	Planning Coordinators in the Great Basin region of WECC
Rocky Mountain	Planning Coordinators in the Rocky Mountain region of WECC
California/Mexico	Planning Coordinators in the California/Mexico region of WECC
Western Canada	Planning Coordinators that primarily serve British Columbia and/or Alberta region of WECC
ERCOT Interconnection	
ERCOT	Areas in Texas subject to ERCOTs jurisdiction.
Quebec Interconnection	
Quebec	Planning Coordinators that primarily serve Quebec in the NPCC Region.

The map below depicts an approximation of the zones to be used in the Extreme Temperature Assessment and is provided as a visual aid; to the extent that there is a conflict between the map and the table, the table controls. This map is not to be used for compliance purposes.



Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the third draft of the proposed standard posted for a 15-day formal comment period with additional ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	July 19, 2023
SAR posted for comment	August 8–September 27, 2023
45-day formal comment period with initial ballot	March 20–May 3, 2024
38-day formal comment period with additional ballot	July 16–August 22, 2024

Anticipated Actions	Date
15-day formal comment period with additional ballot	October 7–21, 2024
15-day formal comment period with additional ballot	November 7–21, 2024
5-day final ballot	December 2–6, 2024
Board adoption	December 11, 2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

Extreme Temperature Assessment – Documented evaluation of future Bulk Electric System performance for extreme heat and extreme cold benchmark temperature ~~benchmark~~ events.

A. Introduction

1. **Title:** Transmission System Planning Performance Requirements for Extreme Temperature Events
2. **Number:** TPL-008-1
3. **Purpose:** Establish Transmission system planning performance requirements to develop a Bulk Power System (BPS) that will operate reliably during extreme heat and extreme cold temperature events.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Transmission Planner
     - **4.1.2.** Planning Coordinator
5. **Effective Date:** See Implementation Plan for Project 2023-07.

B. Requirements and Measures

R1. Each Planning Coordinator shall identify, in conjunction with its Transmission Planner(s),~~ shall identify~~ each entity's individual and joint responsibilities for completing the Extreme Temperature Assessment~~.~~, which shall include each of the responsibilities described in Requirements R2 through R11. Each responsible entity shall complete its responsibilities such that the Extreme Temperature Assessment is completed at least once every five calendar years. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M1. Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall provide documentation of each entity's individual and joint responsibilities, such as meeting minutes, agreements, copies of procedures or protocols, in effect between entities or between departments of a vertically integrated system, or email correspondence that identifies an agreement has been reached on individual and joint responsibilities for completing the Extreme Temperature Assessment and that these responsibilities were completed such that the Extreme Temperature Assessment was completed once every five calendar years.

R2. ~~Each responsible entity, as~~ Each Planning Coordinator shall identify the zone(s) to which the Planning Coordinator belongs to under Attachment 1, and shall coordinate with all Planning Coordinators within each of its identified ~~in Requirement R1, shall~~zone(s), to select ~~at least~~ one common extreme heat benchmark temperature event and ~~at least~~ one common extreme cold benchmark temperature event~~, from the benchmark library, approved and maintained by the Electric Reliability Organization (ERO),~~ for each of its identified zone(s) when completing the Extreme Temperature Assessment.[1] Selected benchmark temperature events shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. Consider no less than a 40-year period of temperature data ending no more than five years prior to the time the benchmark temperature events are selected; and

2.2. Represent one of the 20 most extreme temperature conditions based on the three-day rolling average of daily maximum (heat) or daily minimum (cold) temperature across the zone.

M2. Each ~~responsible entity, as identified in Requirement R1,~~Planning Coordinator shall have evidence in either electronic or hard copy format ~~of selecting at least one extreme heat benchmark event and at least~~that it identified the zone(s) to which it belongs to, under Attachment 1, and coordinated with all other Planning Coordinators within each of its identified zone(s) to select one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event

[1] The Electric Reliability Organization (ERO) will maintain a library of benchmark temperature events that meet the criteria of Requirement R2.

~~for~~meeting the criteria of Requirement R2 for each of their identified zone(s) when completing the Extreme Temperature Assessment.

R3. Each Planning Coordinator shall ~~develop and~~coordinate with all Planning Coordinators within each of its zone(s) identified in Requirement R2, to implement a process for ~~coordinating the development of~~ developing benchmark planning cases~~, using~~ for the ~~selected~~ Extreme Temperature Assessment that represent the benchmark temperature events ~~identified~~selected in Requirement R2~~, Planning Coordinator(s), Transmission Planner(s), and other designated study entities, within an.~~ and sensitivity cases to demonstrate the impact of changes to the basic assumptions used in the benchmark planning cases. This process shall include the following: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Selection of System models within the Long-Term Transmission Planning Horizon to form the basis for the benchmark planning cases.

3.2. Forecasted seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers ~~to represent the selected benchmark temperature events.~~ ~~*[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*~~ *within the zone.*

3.3. Assumed seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers in areas outside the zone, as needed.

3.4. Identification of changes to at least one of the following conditions for sensitivity cases: generation, real and reactive forecasted Load, or transfers.

M3. Each Planning Coordinator shall have dated evidence that it ~~developed and~~ implemented a process for coordinating the development of benchmark planning cases and sensitivity cases for the Extreme Temperature Assessment as specified in Requirement R3~~that includes seasonal and temperature dependent adjustment for Load, generation, Transmission, and transfers to represent the selected benchmark temperature events~~.

~~**R3.**~~**R4.** Each responsible entity, as identified in Requirement R1, shall use the coordination process developed in ~~accordance with~~ Requirement R3 and data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, to develop ~~and maintain~~ the following and establish category P0 as the normal System condition in Table 1: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

~~**3.1.** Benchmark planning cases that include seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers to represent the System conditions of the selected benchmark temperature events as identified in Requirement R2 for one of the years in the Long-Term Transmission Planning Horizon. The rationale for the year selected for evaluation shall be available as~~

~~supporting information. This establishes Category P0 as the normal System condition in Table 1.~~

~~**3.2.** Sensitivity cases to demonstrate the impact of changes to the basic assumptions used in the benchmark planning cases. To accomplish this, the sensitivity cases shall have changes to at least one of the following conditions:~~

- ~~Generation;~~
- ~~Real and reactive forecasted Load; or~~
- ~~Transfers.~~

4.1. One common extreme heat and one common extreme cold benchmark planning case.

4.2. One common extreme heat and one common extreme cold sensitivity case.

M4. Each responsible entity, as identified in Requirement R1, shall have dated evidence in either electronic or hard copy format that it developed ~~and maintained~~ benchmark planning cases and sensitivity cases ~~for completing the Extreme Temperature Assessment~~in accordance with Requirement R4.

~~R4.~~R5. Each responsible entity, as identified in Requirement R1, shall have criteria for acceptable System steady state voltage limits~~,~~ and post-Contingency voltage deviations~~, and applicable Facility Ratings~~ for completing the Extreme Temperature Assessment. *[Violation Risk Factor: ~~High~~Medium] [Time Horizon: Long-term Planning]*

M5. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of the documentation, specifying the criteria for acceptable System steady state voltage limits~~,~~ and post-Contingency voltage deviations~~, and applicable Facility Ratings~~ for completing the Extreme Temperature Assessment.

~~R5.~~R6. Each responsible entity, as identified in Requirement R1, shall define and document the criteria or methodology to be used in the Extreme Temperature Assessment~~ analysis~~ to identify instability, uncontrolled separation, or Cascading within an Interconnection. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M6. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard ~~copy~~copies of documentation~~ of~~, specifying the criteria or methodology ~~used~~to be used in the Extreme Temperature Assessment to identify instability, uncontrolled separation, or Cascading within an Interconnection~~.~~ in accordance with Requirement R6.

R7. Each responsible entity, as identified in Requirement R1, shall identify the ~~planning events~~Contingencies for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System. The rationale for those Contingencies selected for evaluation shall be available as supporting information. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

~~R6.~~ Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of documentation, of the Contingencies for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System~~. The rationale for those Contingencies selected for evaluation shall be available as supporting information.~~ ~~*[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*~~

M7. ~~Each responsible entity, as identified in Requirement R1, shall provide dated evidence such as electronic or hard copy documentation of the planning events for each event category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System~~ along with supporting rationale.

~~R7.~~R8. Each responsible entity, as identified in Requirement R1, shall complete steady state and transient stability analyses in ~~its~~the Extreme Temperature Assessment ~~at least once every five calendar years~~ using the Contingencies identified in Requirement R7, and shall document the assumptions and results ~~of the steady~~. Steady state and transient stability analyses~~. The Extreme Temperature Assessment~~ shall ~~include~~be performed for the following: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

~~7.1.~~8.1. ~~Analysis of the benchmark~~Benchmark planning cases developed in accordance with Requirement R4 Part 4.1.

~~7.2.~~8.2. ~~Analysis of the sensitivity~~Sensitivity cases developed in accordance with Requirement R4 Part 4.~~.~~2.

M8. Each responsible entity, as identified in Requirement R1, shall provide dated evidence ~~that it completed the~~ , such as electronic or hard copies of documentation, of the assumptions and results of the steady state and transient stability analyses completed in ~~its~~the Extreme Temperature Assessment~~, such as electronic or hard copies of the analyses, meeting all the requirements in Requirement R8~~.

~~R8.~~R9. Each responsible entity, as identified in Requirement R1, shall develop a Corrective Action Plan(s) ~~(CAPs)~~ when the ~~assessment~~analysis of a benchmark planning case, in accordance with Requirement R8 Part 8.1, indicates its portion of the Bulk Electric System is unable to meet performance requirements for ~~Table 1~~category P0 or P1 ~~Contingencies.~~in Table 1. For each Corrective Action Plan, the responsible entity shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

~~8.1.~~9.1. Make ~~their CAP~~its Corrective Action Plan available to, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.

~~8.2.~~9.2. Document ~~the~~ alternative(s) considered, and notify the applicable regulatory authorities or governing bodies responsible for retail electric service issues when Non-Consequential Load Loss is utilized as an element of a ~~CAP~~Corrective Action Plan for ~~the~~a Table 1 P1 Contingency.

~~8.3.~~**9.3.** Be permitted to utilize Non-Consequential Load Loss as an interim solution, which normally is not permitted in Table 1, in situations that are beyond the control of the Planning Coordinator or Transmission Planner that prevent the implementation of a Corrective Action Plan in the required timeframe~~. The use of Non-Consequential Load Loss as an interim solution in this situation is permitted, provided that each~~, provided that the responsible entity documents the situation causing the problem, alternatives evaluated, and takes actions to resolve the situation.

~~8.4.~~**9.4.** Be allowed to have revisions to the ~~CAP~~Corrective Action Plan in subsequent Extreme Temperature Assessments, provided that the planned ~~BES~~Bulk Electric System shall continue to meet the performance requirements of Table 1.

M9. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard ~~copy~~copies of documentation, of each ~~CAP~~Corrective Action Plan developed ~~for its Extreme Temperature Assessment~~in accordance with Requirement R9, including dated documentation of correspondence with applicable regulatory authorities or governing bodies responsible for retail electric service issues and any revision history, when the ~~assessment~~analysis of ~~the~~a benchmark planning ~~cases indicate~~case indicates its portion of the ~~BES~~Bulk Electric System is unable to meet performance requirements for ~~Table 1~~category P0 or P1 ~~Contingencies in accordance with Requirement R9.~~in Table 1.

~~R9.~~**R10.** Each responsible entity, as identified in Requirement R1, shall evaluate and document possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) if analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection, for the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

~~**9.1.** Benchmark planning cases where possible actions are designed to mitigate the consequences and adverse impacts when the study results indicate the System could result in instability, uncontrolled separation, or Cascading for the Table 1 P2, P4, and P7 Contingencies.~~

~~**9.2.** Sensitivity cases where possible actions are designed to mitigate failures to meet the performance requirements in Table 1 for category P0, P1, P2, P4, and P7 Contingencies.~~

10.1. Table 1 P7 Contingencies in benchmark planning cases analyzed in accordance with Requirement R8 Part 8.1.

10.2. Categories P0, P1, and P7 in Table 1 in sensitivity cases analyzed in accordance with Requirement R8 Part 8.2.

M10. Each responsible entity, as identified in Requirement R1, shall provide dated evidence such as electronic or hard ~~copy~~copies of documentation that it evaluated and documented possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts when the ~~benchmark planning case study results indicate the System~~analyses conclude there could ~~result in~~be instability, uncontrolled separation, or Cascading within an Interconnection for ~~the~~ Table 1 ~~P2, P4, and~~ P7 Contingencies in benchmark planning cases or categories P0, P1, or P7 in Table 1 in sensitivity cases.

~~R10.~~R11. Each responsible entity, as identified in Requirement R1, shall provide its Extreme Temperature Assessment results within 60 calendar days of a request to any functional entity that has a reliability related need and submits a written request for the information. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M11. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient~~;~~, or a demonstration of a public posting, that it provided its Extreme Temperature Assessment to any functional entity who has a reliability need within 60 calendar days of a written request.

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. 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.

- Each responsible entity shall retain evidence of compliance with each requirement in this standard for five calendar years or one complete Extreme Temperature Assessment cycle, whichever is longer.

1.3. 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.

Table 1 ~~1: Contingencies Category~~ ~~See Footnote 2 for BES Level~~ – Steady State & Stability Performance Events			
~~Category~~		~~Event~~	~~Fault type~~
~~P0~~ ~~No Contingency~~	~~Normal System~~	~~None~~	~~N/A~~
~~P1~~ ~~Single Contingency~~	~~Normal System~~	~~Loss of one of the following:~~ ~~1. Generator~~ ~~2. Transmission Circuit~~ ~~3. Transformer~~ ~~4. Shunt Device[3]~~	~~3Ø~~
		~~5. Single Pole of a DC line~~	~~SLG~~
~~P2~~ ~~Single Contingency~~	~~Normal System~~	~~1. Opening of a line section w/o a Fault [4]~~	~~N/A~~
		~~2. Bus Section Fault~~	~~SLG~~
		~~3. Internal Breaker Fault[5] (non-Bus-tie Breaker)~~	~~SLG~~
		~~4. Internal Breaker Fault (Bus-tie Breaker)[5]~~	~~SLG~~

Steady State & Stability:

a. Instability, uncontrolled separation, or Cascading within an Interconnection, defined in accordance with Requirement R6, shall not occur.

b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings. **Steady State Only:** Applicable Facility Ratings shall not be exceeded.~~Loss of multiple Elements caused by a stuck breaker[6](non-Bus-tie Breaker) attempting to clear a Fault on one of the following:~~ f. ~~1.~~ System steady state voltages and post-Contingency voltage deviations shall meet the criteria identified in Requirement R5.~~Generator~~ ~~2. Transmission Circuit~~ ~~1. Transformer~~ ~~2. Shunt Device[3]~~ ~~5. Bus Section~~ ~~a.~~g. ~~Loss of multiple Elements caused by a stuck breaker[6] (Bus-tie Breaker) attempting to clear a Fault on the associated bus~~			
~~**P7**~~ ~~Multiple Contingency~~ ~~*(Common Structure)*~~		~~The loss of:~~ ~~1. Any two adjacent (vertically or horizontally) circuits on common structure~~ ~~2. Loss of a bipolar DC line~~	~~SLG~~

Table 1~~.2:~~ – Steady State & Stability Performance ~~Requirements~~Events					
	~~P0~~	~~P1~~	~~P2~~	~~P4~~	~~P7~~
~~Steady State Performance Requirements~~	• ~~Applicable Facility Ratings shall not be exceeded.~~ • ~~System steady state voltages shall be within acceptable limits as defined in Requirement R5.~~	• ~~Applicable Facility ratings shall not be exceeded.~~ • ~~System steady state voltages shall be within acceptable limits as defined in Requirement R5.~~	~~Instability, uncontrolled separation, or Cascading, as defined in Requirement R6, shall not occur.~~		
~~Stability Performance Requirements~~	~~The System shall remain stable. Instability, uncontrolled separation, or Cascading, as defined in Requirement R6, shall not occur.~~	~~Instability, uncontrolled separation, or Cascading, as defined in Requirement R6, shall not occur.~~	~~Instability, uncontrolled separation, or Cascading, as defined in Requirement R6, shall not occur.~~		
~~Requirements for Benchmark Planning Case Assessment Results~~					
~~Corrective Action Plan Required~~	~~Yes (See Requirement R9)~~	~~Yes (See Requirement R9)~~	~~No (See Requirement R10)~~		
~~Non-Consequential Load Loss Allowed~~	~~No (See Requirement R9)~~	~~Yes (See Requirement R9)~~	~~Yes~~		

Table 1~~.2:~~ – Steady State & Stability Performance ~~Requirements~~Events							
Category	Initial Condition	Event[1]	Fault Type[2]	Contingency BES Level	Interruption of Firm Transmission Service Allowed	~~Yes~~Non-Consequential Load Loss Allowed	
						Benchmark Planning Cases	~~Requirements for~~ Sensitivity ~~Case Assessment Results~~Cases
P0 No ~~(See Requirement R10)~~Contingency	Normal System~~No (See Requirement R10)~~	None~~No (See Requirement R10)~~	N/A	≥ 200 kV	Yes	No[6]	Yes
P1 Single Contingency	Normal System	~~Non-Consequential Load~~ Loss of one of the following: 1. Generator 2. Transmission Circuit 3. ~~Allowed~~ Transformer[3] ~~3.~~4. Shunt Device[4]	~~Yes~~ 3Ø	≥ 200 kV	Yes	Yes[6]	Yes
		5. Single Pole of a DC line	SLG				
P7 Multiple Contingency	Normal System	The loss of: 1. Any two adjacent (vertically or	SLG	≥ 200 kV	Yes	Yes	Yes

Table 1~~.2:~~ – Steady State & Stability Performance ~~Requirements~~Events							
(Common Structure)		horizontally) circuits on common structure[5] ~~1.~~2. Loss of a bipolar DC line~~Interruption of Firm Transmission Service Allowed~~					

Table 1~~.3~~ – Steady State & Stability Performance ~~Footnotes~~Events
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the BES level of the event. For P7 events, the BES level of the event is the highest System voltage level of the element(s) removed for the analyzed event. ~~1.~~2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria. ~~1. Facility voltage level of Contingency is applicable to:~~ ~~a. BES level 200 kV and above (referenced Contingency voltage)~~ ~~b. For P7 events include Contingencies that have at least one 200kV voltage and above Facilities on common structure that has more than one mile in length.~~ ~~2.~~3. For non-generator step up transformer outage events, the reference voltage, as used in footnote ~~2a~~1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers. ~~3.~~4. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground. ~~2. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.~~ ~~3. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.~~ 5. ~~A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.~~Excludes circuits that share a common structure for 1 mile or less. ~~4.~~6. Benchmark planning cases require the development of a Corrective Action Plan when the responsible entity's portion of the BES is unable to meet the performance requirements for categories P0 or P1. Additionally, in benchmark planning cases, Non-Consequential Load Loss is not permitted for category P0 and requires notification of applicable regulatory authorities or governing bodies responsible for retail electric service issues when utilized as an element of a Corrective Action Plan for P1 Contingencies. See Requirement R9 for the relevant requirements.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	~~N/A~~The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed less than or equal to six months late.	~~N/A~~The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed more than six months but less than or equal to 12 months late.	~~N/A~~The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed more than 12 months but less than or equal to 18 months late.	The Planning Coordinator, in conjunction with its Transmission Planner(s), failed to ~~determine and~~ identify individual and joint responsibilities for completing the Extreme Temperature Assessment. OR The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed more than 18 months late.
R2.	N/A	N/A	The ~~responsible entity did not~~Planning Coordinator coordinated with all Planning Coordinators within each identified zone to select ~~at least~~ one common extreme heat ~~benchmark event or~~and one common extreme cold benchmark temperature event ~~from the ERO approved benchmark library~~ for	The ~~responsible entity did not~~Planning Coordinator coordinated with all Planning Coordinators within each identified zone to select ~~an~~one common extreme heat ~~benchmark event and~~and one common extreme cold benchmark temperature event for completing the Extreme Temperature Assessment, but

			~~performing~~completing the Extreme Temperature Assessment, but one of the selected events failed to meet all the criteria of Requirement R2.	both of the selected events failed to meet all of the criteria of Requirement R2. OR The Planning Coordinator failed to coordinate with all Planning Coordinators within each identified zone to select one common extreme heat and one common extreme cold benchmark temperature event ~~from the ERO approved benchmark library~~ for ~~performing~~completing the Extreme Temperature Assessment.
R3.	N/A	N/A	N/A	The Planning Coordinator did not ~~develop or~~ coordinate with all Planning Coordinators within each of its identified zone(s) to implement a process for ~~coordinating the development of~~ developing benchmark planning cases ~~among impacted adjacent Planning Coordinator(s), Transmission Planner(s), and other designated study entities, within the same Interconnection~~.

				OR The Planning Coordinator ~~developed and implemented~~coordinated with all Planning Coordinators within each of its identified zone(s) to implement a process for ~~coordinating the development of~~ developing benchmark planning cases ~~among impacted adjacent Planning Coordinator(s), Transmission Planner(s), and other designated study entities within the same Interconnection~~, but ~~this~~the process did not ~~modify the benchmark planning cases to~~ include ~~seasonal and temperature dependent adjustments load, generation, Transmission, and transfers.~~ all of the required elements.
R4.	N/A	N/A	N/A	The responsible entity ~~did not~~, as identified in Requirement R1, did not use the coordination process to develop ~~or maintain~~ benchmark planning cases or sensitivity cases ~~for performing the Extreme Temperature Assessment.~~.

				OR The responsible entity ~~developed and maintained~~, as identified in Requirement R1, used the coordination process to develop benchmark planning cases ~~or~~and sensitivity cases ~~for performing the Extreme Temperature Assessment~~, but did not use data consistent with that provided in accordance with the MOD-032 standard~~.~~, supplemented by other sources as needed, for one or more of the required cases. OR The responsible entity, as identified in Requirement R1, used the coordination process and data consistent with that provided in accordance with the MOD-032 standard, supplemented as needed, but failed to develop one or more of the required planning or sensitivity cases.
R5.	N/A	N/A	N/A	The responsible entity, as ~~determined~~identified in Requirement R1, did not have criteria for acceptable System

				steady state voltage limits~~,~~ and post-Contingency voltage deviations~~, and applicable Facility Ratings~~ for ~~performing~~completing the Extreme Temperature Assessment.
R6.	N/A	N/A	N/A	The responsible entity, as identified in Requirement R1, failed to define ~~and~~or document~~,~~ the criteria or methodology to be used in the ~~analysis~~Extreme Temperature Assessment to identify ~~System~~ instability, uncontrolled separation, or Cascading within an Interconnection.
R7.	N/A	N/A	The responsible entity, as ~~determined~~identified in Requirement R1, identified Contingencies for ~~performing Extreme Temperature Assessment for~~ each ~~of the planning events~~category in Table 1 that are expected to produce more severe System impacts ~~within~~on its ~~planning area~~portion of the Bulk Electric System, but did not include the rationale for those Contingencies selected for	The responsible entity, as ~~determined~~identified in Requirement R1, did not identify Contingencies for ~~performing Extreme Temperature Assessment for~~ each ~~of the planning events~~category in Table 1 that are expected to produce more severe System impacts ~~within~~on its ~~planning area~~portion of the Bulk Electric System.

			evaluation as supporting ~~documentation~~information.	
R8.	The responsible entity, as ~~determined~~identified in Requirement R1, completed ~~an~~steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but ~~it was performed less than~~failed to document the assumptions for one or ~~equal to six months late.~~ more sensitivity cases in accordance with Requirement R8.	The responsible entity, as ~~determined~~identified in Requirement R1, completed ~~an~~steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but ~~it was performed~~ failed to document the assumptions for one or more ~~than six months but less than or equal to 12 months late.~~ benchmark planning cases in accordance with Requirement R8.	The responsible entity, as ~~determined~~identified in Requirement R1, completed ~~an~~steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but ~~it was performed~~ failed to evaluate and document results for one or more ~~than 12 months but less than or equal to 18 months late.~~of the sensitivity cases in accordance with Requirement R8.	The responsible entity, as ~~determined~~identified in Requirement R1, ~~performed an~~ completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but ~~it was more than 18 months late.~~ failed to evaluate and document results for one or more of the benchmark planning cases in accordance with Requirement R8. OR The responsible entity, as ~~determined~~identified in Requirement R1, ~~did not perform an~~failed to complete steady state or transient stability analyses and document results in the Extreme Temperature Assessment~~.~~ ~~OR~~ ~~The responsible entity, as determined~~ using the Contingencies identified in Requirement ~~R1, performed~~

				~~an Extreme Temperature Assessment, but it was missing one or more of the required elements~~R7, in accordance with Requirement R8.
R9.	N/A	N/A	The responsible entity, as ~~determined~~identified in Requirement R1, developed a Corrective Action Plan ~~meeting each of the elements in~~in accordance with Requirement R9, but failed to make ~~their~~its Corrective Action Plan available to, or solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.	The responsible entity, as ~~determined~~identified in Requirement R1, failed to develop a Corrective Action Plan ~~meeting each of the elements of Requirement R9~~ when the benchmark planning case study results indicate the System is unable to meet performance requirements for the Table 1 P0 or P1 Contingencies. OR The responsible entity, as identified in Requirement R1, developed a Corrective Action Plan, but it was missing one or more of the elements of Requirement R9 Part 9.2-9.4 (as applicable).
R10.	N/A	N/A	~~N/A~~The responsible entity, as identified in Requirement R1, evaluated and documented possible actions to reduce the likelihood or mitigate the	~~Each~~The responsible entity, as ~~determined~~identified in Requirement R1, ~~failed to evaluate~~evaluated and ~~document~~documented

			consequences and adverse impacts of the event(s) when analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection where required under Requirement R10 Part 10.1, but failed to evaluate and document possible actions where required under Requirement R10 Part 10.2.	possible actions~~,~~ to reduce the likelihood or mitigate the consequences~~,~~ and adverse impacts of the event(s) when ~~the benchmark planning case study results indicate the System~~analyses conclude there could ~~result in~~be instability, uncontrolled separation, or Cascading ~~for~~within an Interconnection where required under Requirement R10 Part 10.2, but failed to evaluate and document possible actions where required under Requirement R10 Part 10.1. OR The responsible entity, as identified in Requirement R1, failed to evaluate and document possible actions to reduce the ~~Table 1 P2, P4, and P7 Contingencies~~likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection where required under

				Requirement R10 Parts 10.1 and 10.2.
R11.	The responsible entity, as ~~determined~~identified in Requirement R1, ~~distributed~~provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 60 days but less than or equal to 80 days following the request.	The responsible entity, as ~~determined~~identified in Requirement R1, ~~distributed~~provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 80 days but less than or equal to 100 days following the request.	The responsible entity, as ~~determined~~identified in Requirement R1, ~~distributed~~provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 100 days but less than or equal to 120 days following the request.	The responsible entity, as ~~determined~~identified in Requirement R1, ~~distributed~~provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 120 days following the request. OR The responsible entity, as ~~determined~~identified in Requirement R1, did not ~~distribute~~provide its Extreme Temperature Assessment results to functional entities having a reliability related need who ~~requested~~submitted a written request for the information~~ in writing~~.

D. Regional Variances

None.

E. Associated Documents

- Implementation Plan for Project 2023-07
- Technical Rationale Document
- Consideration of Issues and Directives for FERC Order 896.

Version History

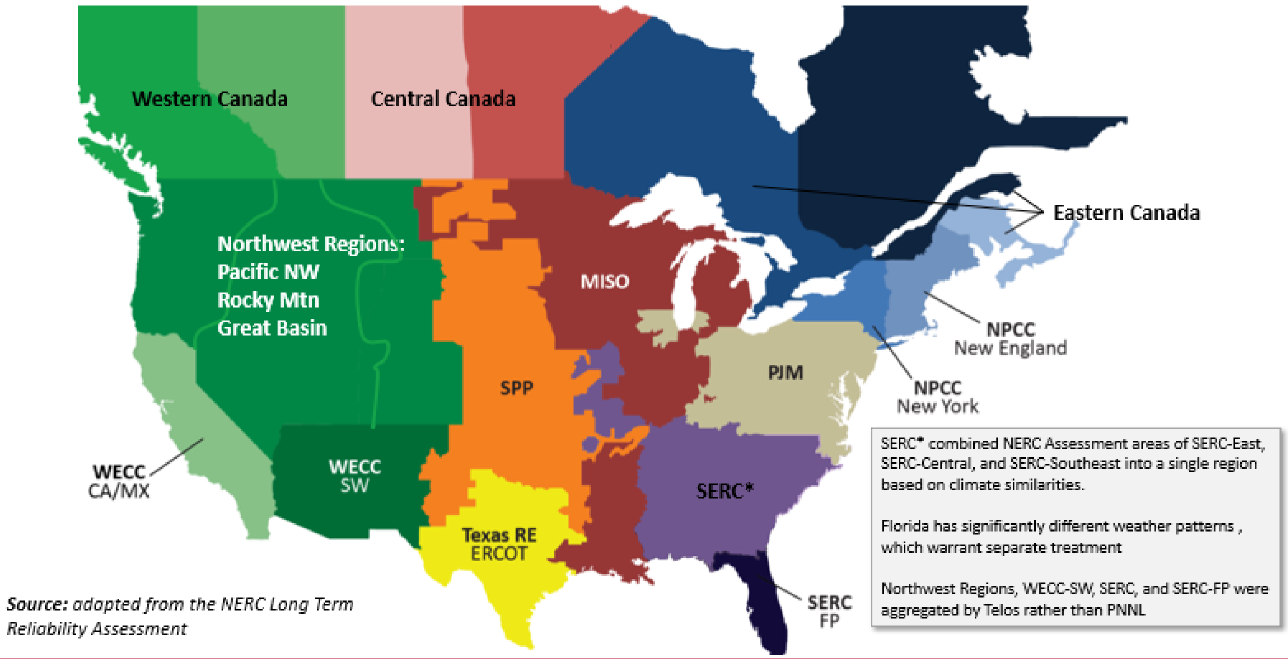
Version	Date	Action	Change Tracking
1	TBD	Addressing FERC Order 896	New Standard

Attachment 1: Extreme Temperature Assessment Zones

The table below lists the zones to be used in the Extreme Temperature Assessment and identifies the Planning Coordinators that belong to each zone. In accordance with Requirement R2, each Planning Coordinator is required to identify the zone(s) to which it belongs.

Zone	Planning Coordinators
Eastern Interconnection	
MISO	MISO
SPP	SPP
PJM	PJM
NPCC (New England)	Planning Coordinators in NPCC that primarily serve the six New England States
NPCC (New York)	Planning Coordinators in NPCC that primarily serve New York
SERC	Planning Coordinators in SERC excluding those that primarily serve Florida and those in MISO, SPP, or PJM
SERC (Florida)	Planning Coordinators in SERC that primarily serve Florida
Central Canada	Planning Coordinators that primarily serve Saskatchewan and/or Manitoba region of MRO
Eastern Canada	Planning Coordinators in NPCC that primarily serve Ontario, New Brunswick, and Nova Scotia
Western Interconnection	
WECC Southwest	Planning Coordinators in the Southwest region of WECC, including El Paso in West Texas
Pacific Northwest	Planning Coordinators in the Pacific Northwest region of WECC
Great Basin	Planning Coordinators in the Great Basin region of WECC
Rocky Mountain	Planning Coordinators in the Rocky Mountain region of WECC
California/Mexico	Planning Coordinators in the California/Mexico region of WECC
Western Canada	Planning Coordinators that primarily serve British Columbia and/or Alberta region of WECC
ERCOT Interconnection	
ERCOT	Areas in Texas subject to ERCOTs jurisdiction.
Quebec Interconnection	
Quebec	Planning Coordinators that primarily serve Quebec in the NPCC Region.

The map below depicts an approximation of the zones to be used in the Extreme Temperature Assessment and is provided as a visual aid; to the extent that there is a conflict between the map and the table, the table controls. This map is not to be used for compliance purposes.



Implementation Plan

Project 2023-07 Transmission System Planning Performance Requirements for Extreme Weather
Reliability Standard TPL-008-1

Applicable Standard

- TPL-008-1 – Transmission System Planning Performance Requirements for Extreme Temperature Events

Requested Retirement

- Not applicable

Prerequisite Standard

- Not applicable

Applicable Entities

- Planning Coordinators
- Transmission Planners

New Term in the NERC Glossary of Terms

This section includes all newly defined, revised, or retired terms used or eliminated in the NERC Reliability Standard. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

- **Extreme Temperature Assessment** – Documented evaluation of future Bulk Electric System performance for extreme heat and extreme cold benchmark temperature events.

Background

On June 15, 2023, the U.S. Federal Energy Regulatory Commission ("FERC") issued Order No. 896, a final rule directing NERC to develop a new or modified Reliability Standard to address the lack of a long-term planning requirement(s) for extreme heat and cold weather events.[1] Specifically, FERC directed NERC to develop modifications to Reliability Standard TPL-001-5.1 or develop a new Reliability Standard that requires the following: (1) development of benchmark planning cases based on major prior extreme heat and cold weather events and/or meteorological projections; (2) planning for extreme heat and cold weather

[1] *Transmission System Planning Requirements for Extreme* Weather, Order No. 896, 183 FERC ¶ 61,191 (2023).

events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios including the expected resource mix's availability during extreme heat and cold weather conditions, and including the wide-area impacts of extreme heat and cold weather; and (3) development of Corrective Action Plans that mitigate any instances where performance requirements for extreme heat and cold weather events are not met. FERC further directed NERC to ensure that the proposed new or modified Reliability Standard becomes mandatory and enforceable beginning no later than 12 months from the effective date of FERC approval.

General Considerations

Proposed Reliability Standard TPL-008-1 would require the performance of an Extreme Temperature Assessment at least once every five calendar years (Requirement R1). This implementation plan provides a staggered approach for the performance of the first Extreme Temperature Assessment, with phased-in compliance dates beginning 12 months from the effective date of regulatory approval consistent with Order No. 896. For subsequent Extreme Temperature Assessments, entities may establish timeframes appropriate to their facts and circumstances for carrying out their responsibilities under the standard, provided that the Extreme Temperature Assessment is completed no later than five calendar years following the previous Extreme Temperature Assessment.

Effective Date

The effective date for the proposed Reliability Standard is provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of the proposed Reliability Standard (e.g., an entire Requirement or a portion thereof), the additional time for compliance with that section is specified below. These phased-in compliance dates represent the dates that entities must begin to comply with that particular section of the Reliability Standard, even where the Reliability Standard goes into effect at an earlier date.

TPL-008-1 and Definition

Where approval by an applicable governmental authority is required, the standard and definition of Extreme Temperature Assessment shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard and definition of Extreme Temperature Assessment is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Phased-In Compliance Dates

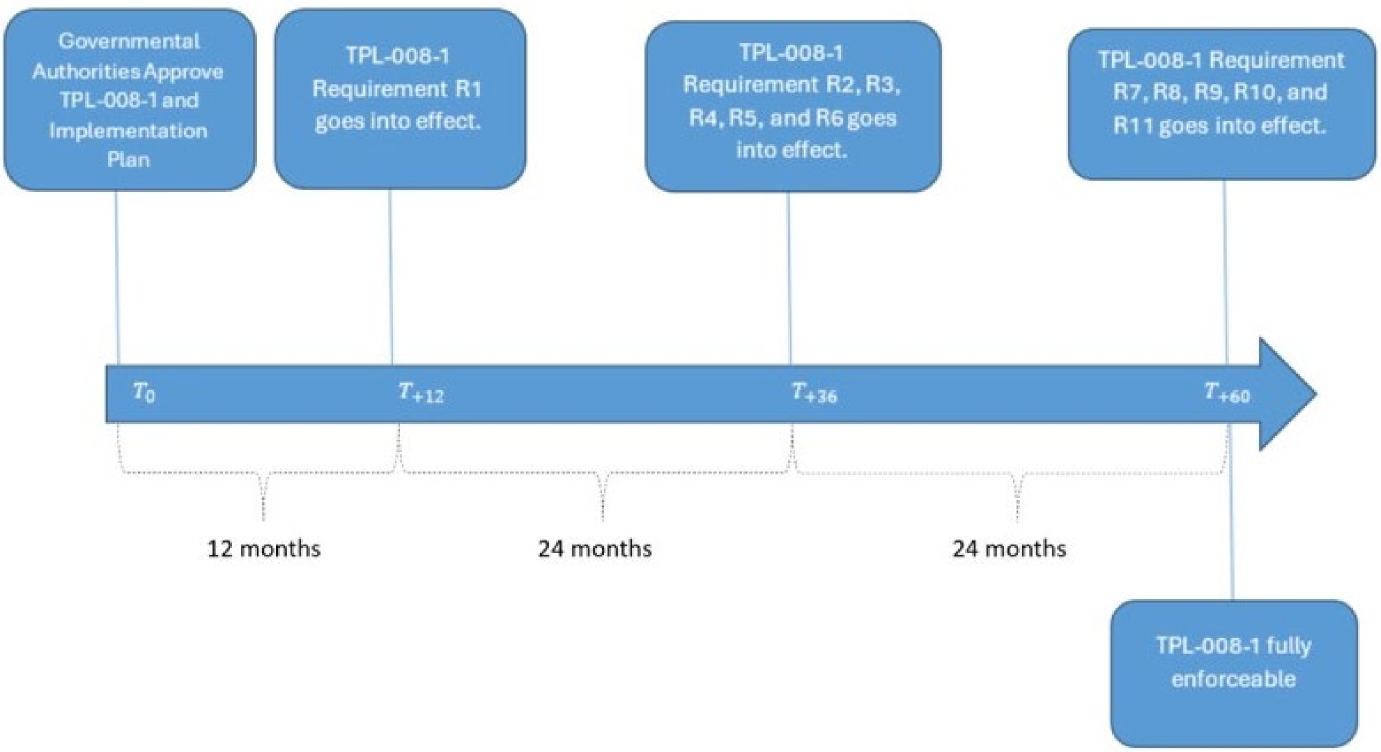
Compliance Date for TPL-008-1 Requirement R1

Entities shall be required to comply with Requirement R1, pertaining to the identification of individual and joint responsibilities for completing the Extreme Temperature Assessment, upon the effective date of Reliability Standard TPL-008-1.

Compliance Date for TPL-008-1 Requirements R2, R3, R4, R5, R6
Entities shall not be required to comply with Requirements R2, R3, R4, R5, and R6 until twenty-four (24) months after the effective date of Reliability Standard TPL-008-1.

Compliance Date for TPL-008-1 Requirements R7, R8, R9, R10, R11
Entities shall not be required to comply with Requirements R7, R8, R9, R10, R11 until forty-eight (48) months after the effective date of Reliability Standard TPL-008-1.

Figure 1: Implementation Plan, Demonstrating Effective Date and Phased-in Compliance Dates from Regulatory Approval



Initial Performance of Periodic Requirements

Entities shall complete the Extreme Temperature Assessment no later than forty-eight (48) months after the effective date of Reliability Standard TPL-008-1. Subsequent Extreme Temperature Assessments shall be completed by no later than five calendar years following the completion of the previous Extreme Temperature Assessment.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Technical Rationale and Justification for TPL-008-1

Project 2023-07 Transmission Planning Performance Requirements for Extreme Weather

October 2024

RELIABILITY | RESILIENCE | SECURITY

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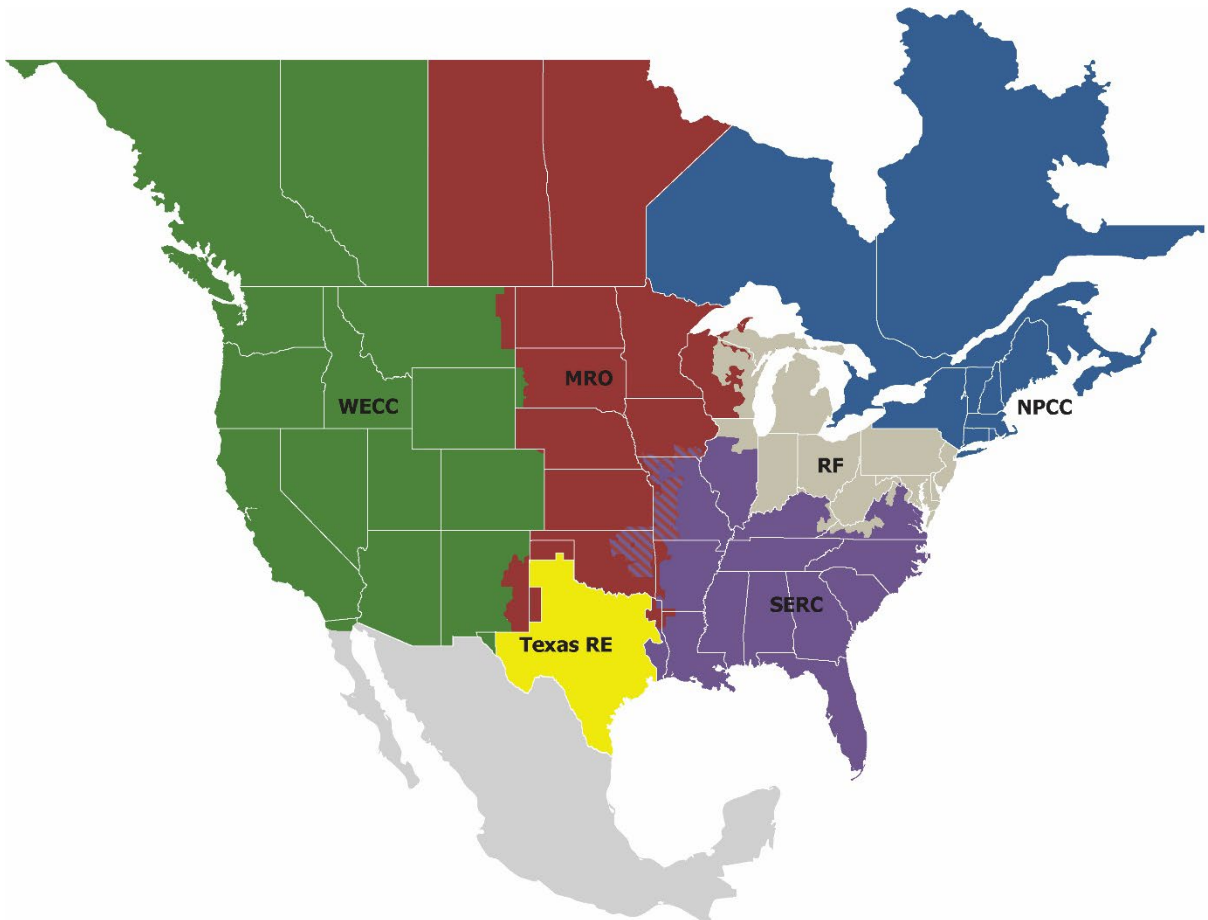
Preface

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

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

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



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

Introduction

This document explains the technical rationale and justification for the proposed Reliability Standard TPL-008-1. It provides stakeholders and the ERO Enterprise with an understanding of the technology and technical requirements in the Reliability Standard. This Technical Rationale and Justification for TPL-008-1 is not a Reliability Standard and should not be considered mandatory and enforceable.

Background

On June 15, 2023, FERC issued FERC Order No. 896 that acknowledges the "challenges associated with planning for extreme heat and cold weather events, particularly those that occur during periods when the Bulk-Power System must meet unexpectedly high demand. Extreme heat and cold weather events have occurred with greater frequency in recent years and are projected to occur with even greater frequency in the future. These events have shown that load shed during extreme temperatures result in unacceptable risk to life and have extreme economic impact. As such, the impact of concurrent failures of Bulk-Power System generation and transmission equipment and the potential for cascading outages that may be caused by extreme heat and cold weather events should be studied and corrective actions should be identified and implemented."[1]

Therefore, the Commission directed in FERC Order No. 896 to develop a new or modified Reliability Standard to address a lack of long-term planning requirement(s) for extreme heat and cold weather events. Specifically, FERC directed NERC to develop modifications to Reliability Standard TPL-001-5.1 or a new Reliability Standard, to require the following: (1) development of benchmark planning cases based on major prior extreme heat and cold weather events and/or meteorological projections; (2) planning for extreme heat and cold weather events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios including the expected resource mix's availability during extreme heat and cold weather conditions, and including the wide-area impacts of extreme heat and cold weather; and (3) development of corrective action plans that mitigate any instances where performance requirements for extreme heat and cold weather events are not met.

[1] N. Am. Elec. Reliability Corp., 183 FERC ¶ 61,191 (2023) (FERC Order), Final Rule. eLibrary | File List (ferc.gov)

Defined Terms

The Standard Drafting Team (SDT) defined one term to be added to the NERC Glossary of Terms to make the requirements easier to read and understand.

Extreme Temperature Assessment
Documented evaluation of future Bulk Electric System performance for extreme heat and extreme cold benchmark temperature events.

The definition of Extreme Temperature Assessment was developed by the SDT to limit wordiness throughout the requirements.

TPL-008-1 Standard

The FERC Order No. 896 directed NERC to submit a new Reliability Standard or modifications to Reliability Standard TPL-001-5.1 to address the concerns pertaining to transmission system planning for extreme heat and cold weather events that impact the Reliable Operation of the Bulk-Power System.

The SDT determined that a new Reliability Standard was the cleanest way to address FERC's directives versus modifying Reliability Standard TPL-001-5.1. While the TPL-008-1 standard uses similar requirements, this allows industry to have one standard that focuses on extreme heat and extreme cold benchmark temperature events.

The purpose of TPL-008-1 is to "Establish Transmission system planning performance requirements to develop a Bulk Power System (BPS) that will operate reliably during extreme heat and extreme cold temperature events." The directives in FERC Order No. 896 pertain to the reliable operation of the BPS, and the requirements of TPL-008-1 support that by ensuring Planning Coordinators and Transmission Planners are planning their portions of the Bulk Electric System to meet performance requirements in extreme heat and extreme cold benchmark temperature events.

Requirement R1

Requirement R1 requires each Planning Coordinator (PC) and the Transmission Planner(s) (TP) within the PC's footprint to identify each entity's individual and joint responsibilities when completing the Extreme Temperature Assessment at least once every five calendar years. The purpose of this requirement is to have the PC and its TP(s) identify their individual and joint responsibilities for the following activities:

- Identifying the PC's zone(s) and coordinating with all PCs in each of its identified zone(s) to select one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event (Requirement R2),
- Implementing a process for developing benchmark planning cases and sensitivity cases (Requirement R3),
- Developing benchmark planning cases and sensitivity cases (Requirement R4),
- Having acceptable criteria (Requirements R5 and R6),
- Identifying Contingencies for evaluation (Requirement R7),
- Performing steady state and transient stability analyses (Requirement R8),
- Developing Corrective Action Plans when required (Requirement R9),
- Evaluating and documenting possible actions for performance deficiencies that do not require Corrective Action Plans (Requirement R10), and
- Providing study results to any functional entity that has a reliability related need (Requirement R11).

The responsibilities described in Requirements R2 and R3 are explicitly assigned to the PC. The responsibilities described in Requirements R4 through R11 may be completed by either the PC or one or more of its TPs. Requirement R1 requires that an agreement is reached on the individual and joint responsibilities for completing the Extreme Temperature Assessment between the PC and its TPs.

Requirement R2

Requirement R2 requires each Planning Coordinator (PC) to identify the zone(s) it will participate in for the components of the Extreme Temperature Assessment that require coordination. PCs in the same zone are required to coordinate to:

- Select one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event (Requirement R2), and
- Implement a process for developing benchmarking planning cases and sensitivity cases (Requirement R3).

FERC Order No. 896 directed NERC to require that transmission planning studies under the new or revised Reliability Standard consider the wide-area impacts of extreme heat and cold weather. NERC already defines "Wide Area" as "The entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits." Reliability Coordinator Areas can be geographically very large – for example the Reliability Coordinator West (RCW) region extends from the Pacific Northwest to the southern borders of California and Arizona. Thus, defining coordination requirements based on these boundaries may not accurately capture weather events and system impacts at a sufficiently granular level. In addition, it is recognized that electrical boundaries such as those defining the Eastern/Western/ERCOT interconnections limit the potential for events in one area to affect reliability in another.

Considering the above, the SDT identified the zones depicted in Attachment 1 as reasonable boundaries that balance the need for studies to cover large regions with similar weather patterns with the need for a manageable level of coordination. An earlier proposal to limit coordination to only adjacent PCs was not adequate for meeting FERC's directives. While the zones depicted in Attachment 1 will require some PCs to coordinate with many other PCs, the industry has demonstrated, through various working groups and organizations, that it is capable of cooperating to build models that represent large areas.

Requirement R2 describes the need to select extreme benchmark temperature events necessary for the creation of benchmark planning cases. Specifically, extreme hot and cold temperatures experienced during benchmark events are assumed to be outside the ranges used as the basis of planning cases studied under Reliability Standard TPL-001-5.1. Since temperature levels and associated weather conditions affect load levels, generation performance, and transfer levels, the selection of benchmark events is critical to ensuring the Extreme Temperature Assessment appropriately evaluates probable System conditions.

Since any region can experience temperatures that are higher or lower than normal, PCs within the same zone must coordinate to select one common temperature event that includes hotter temperature assumptions and one common temperature event that includes colder temperature assumptions. While it is understood that, for example, one region may typically experience hotter summers and milder winters than another region, both a hotter than average summer and a colder than average winter could result in reliability concerns. Therefore, the requirement is for one common case specific to extreme heat and one common case specific to extreme cold conditions to be studied for the Extreme Temperature Assessment. By selecting the same, common events, PCs ensure that extreme temperatures are studied over the entire zone. The evaluation of a common event taking place over a wide area is foundational to FERC Order No. 896. Furthermore, selecting the same, common events reasonably limits coordination requirements. PCs are required to participate in the selection of events for their zone(s), but have no responsibilities for the selection of events in other zones.

The SDT determined that the extreme heat and extreme cold temperatures selected must have a verified statistical basis based on weather data from credible sources. The SDT has identified several key features that are used to determine when a temperature event will constitute a valid extreme benchmark temperature event for the purposes of completing the Extreme Temperature Assessment. Specifically, extreme benchmark temperature events must:

- Consider no less than 40 years of temperature data,
- Utilize data ending no more than 5 years prior to the time benchmark temperature events are selected, and
- Represent one of the worst 20 extreme temperature conditions within the zone.

Temperature events are ranked by computing the 3-day rolling average of daily maximum temperatures (for extreme heat) or daily minimum temperatures (for extreme cold). The ERO will maintain a library of benchmark events to provide responsible entities access to vetted benchmark temperature events that meet the criteria of Requirement R2. While selection of events from the ERO's provided library assures entities they are selecting valid events, Requirement R2 does not preclude entities from collecting temperature data and identifying benchmark temperature events through their own process. Entities that elect to develop their own benchmark temperature events are responsible for ensuring the input temperature data and selected benchmark temperature events meet the criteria of Requirement R2. Additionally, because Requirement R2 requires PCs within a zone to coordinate in the selection of the benchmark temperature events, the process used to identify these events must be agreeable to those PCs.

The requirement to consider no less than 40 years of temperature data was established based on the observation that many of the worst events identified in various regions of North America occurred in the 1980s and 1990s. For example, preliminary data indicated that the five worst extreme cold temperature events in the PJM region over the last 43 years occurred between 1983 and 1994. Similar results were seen in other regions for both extreme heat and extreme cold temperature events. Thus, the SDT determined that a minimum of 40 years of temperature data should be used to ensure more extreme events weren't excluded by using a shorter duration of temperature data.

Requirement R3

Requirement R3 aligns with directives in FERC Order No. 896, emphasizing the importance of coordinating the development of benchmark planning cases and sensitivity cases amongst PCs within a zone, where the scope of extreme temperature event studies will likely cover large geographical areas exceeding smaller individual planning areas. The SDT considered comments from the industry expressing concerns regarding the necessity to coordinate among all impacted PCs in developing benchmark planning cases and sensitivity cases for various extreme benchmark temperature events. Recognizing that coordination among all impacted PCs may not be necessary to ensure reliability within an individual planning area, the SDT drafted Requirement R3 to require each PC to coordinate with all PCs within a zone to implement a process for the development of benchmark planning cases and sensitivity cases. The SDT believes this change balances the need to ensure the planning cases capture impacts to/from entities affected by the same benchmark temperature event, while recognizing that reliability will be less impacted by system changes far removed from the zone.

PCs within a zone must coordinate to implement a process that results in the development of benchmark planning cases that represent the benchmark temperature events selected in accordance with Requirement R2, and sensitivity cases that demonstrate the impact of changes to the basic assumptions used in the benchmark planning cases. This process requires several components, outlined in the sub-requirements of Requirement R3.

First, Requirement R3 Part 3.1 requires PCs within a zone to identify System models form the basis for developing the benchmark planning cases. These models must represent one of the years in the Long-Term Transmission Planning Horizon. PCs will also need to ensure models include stability modeling data to provide for the performance of stability analysis later in the process. It is reasonable anticipated that PCs will likely utilize a summer peak model as the starting point for the extreme heat benchmark temperature event and a winter peak model as the starting point for the extreme cold benchmark temperature event.

Secondly, Requirement R3 Part 3.2 requires that PCs within a zone provide forecasted data for their area within the zone that represents the benchmark temperature events selected in accordance with Requirement R2. Each PC must provide data for their area within the zone that represents seasonal and temperature adjustments for Load, generation, Transmission, and transfers. The provided data should be used to update the starting point models to reflect the selected benchmark temperature events.

Thirdly, Requirement R3 Part 3.3 allows PCs to agree on assumptions for seasonal and temperature adjustments for Load, generation, Transmission, and transfers in areas *outside* of the zone. As a sub-requirement of Requirement R3, these assumptions must be coordinated among PCs in the zone, as needed. As an example, PCs within the zone may identify the need for imported power during a benchmark event. The PCs may evaluate historical import availability and assume an import from an area outside of the zone is reasonable and should be modeled.

Finally, Requirement R3 Part 3.4 requires PCs to coordinate and identify changes to generation, real and reactive forecasted Load, or transfers that should be reflected in sensitivity cases. Sensitivity cases are intended to demonstrate the impact of changes to the basic assumptions used in the benchmark planning cases, and Requirement R3 Part 3.4 ensures PCs are cooperating to identify changes that sufficiently alter the assumptions reflected in the benchmark planning cases. For example, PCs that identified an import external source to the zone for a benchmark planning case may elect to alter the source of that import in the sensitivity case.

Requirement R4

The SDT drafted Requirement R4 to require the responsible entity to use data consistent with Reliability Standard MOD-032, supplemented by other sources as needed, for developing benchmark planning cases that represent System conditions based on selected benchmark temperature events. This aligns with directives in FERC Order No. 896, paragraph 30, emphasizing the requirement of developing both benchmark planning cases and sensitivity study cases. Requirement R4 is consistent with Reliability Standard TPL-001-5.1 in cross-referencing Reliability Standard MOD-032, which establishes consistent modeling data requirements and reporting procedures for the development of planning horizon cases necessary to support analysis of the reliability of the interconnected System. It is also consistent with Reliability Standard TPL-001-5.1 in acknowledging that data from other sources may be required to supplement the data collected through Reliability Standard MOD-032 procedures.

Requirement R4 requires entities to use the coordination process developed in accordance with Requirement R3 to develop the following four cases:

- One common extreme heat benchmark planning case (Requirement R4 Part 4.1),
- One common extreme cold benchmark planning case (Requirement R4 Part 4.1),
- One common extreme heat sensitivity case (Requirement R4 Part 4.2), and
- One common extreme cold sensitivity case (Requirement R4 Part 4.2).

At the completion of the case development process implemented in accordance with Requirement R3, and executed in Requirement R4, responsible entities will have the four cases listed above. This establishes category P0 as the normal System condition in Table 1 for each case. Requirement R3 does not preclude PCs from implementing a process that develops cases for multiple benchmark temperature events or additional sensitivity cases. Moreover, entities may elect to develop additional cases for their internal use.

As per FERC Order No. 896, paragraph 94, it is clarified that resource adequacy benchmarks are not within the scope of TPL-008-1. The intent of the standard is to evaluate benchmark events where sufficient generation is available to supply load. However, under an extreme heat or extreme cold temperature condition, there may be instances where the benchmark planning cases and/or sensitivity cases may not have sufficient available generation to supply the load. In these scenarios, it may be acceptable for the responsible entity to revise the model to reduce the forecasted Load, or include forecasted generation, to achieve a solution for the benchmark planning cases and/or sensitivity cases and evaluate future Bulk Electric System performance for extreme temperature events. Each responsible entity, as identified in Requirement R1, shall have dated evidence in either electronic or hard copy format that it developed benchmark planning cases and sensitivity cases in accordance with Requirement R4.

Requirement R5

Requirement R5 was drafted to require each responsible entity to set the criteria needed for limits that will be used to evaluate System steady state voltage and post-Contingency voltage deviations for completing the Extreme Temperature Assessment. The establishment of these criteria allows auditors to compare the results of the Extreme Temperature Assessment with the established criteria.

Requirement R6

Requirement R6 was drafted to require the responsible entity to define and document the criteria or methodology used in evaluating the Extreme Temperature Assessment analysis to identify instability, uncontrolled separation, or Cascading within an Interconnection. Adequate and thorough criteria should be built into the Extreme Temperature Assessment to help identify instability, uncontrolled separation, and Cascading conditions. The establishment of these criteria allows auditors to compare the results of the Extreme Temperature Assessment with the established criteria.

Requirement R7

This requirement addresses directives in FERC Order No. 896 to define a set of Contingencies that responsible entities will be required to consider when conducting wide-area studies of extreme heat and cold weather events. FERC's preference to rely on established Contingency definitions, "[w]e believe that it is necessary to establish a set of common contingencies for all responsible entities to analyze. Required contingencies, such as those listed in Table 1 of Reliability Standard TPL-001-5.1 (i.e., category P1 through P7), establish common planning events that set the starting point for transmission system planning assessments," was also considered by the SDT. It is necessary to establish a set of common Contingencies for all responsible entities to analyze. Requiring the study of predefined Contingencies, such as those listed in Table 1, will ensure a level of uniformity across planning regions, considering that extreme heat and cold weather events often exceed the geographic boundaries of most existing planning footprints. Defining the Contingencies in Table 1 consistently with Table 1 of Reliability Standard TPL-001-5.1 meets FERC's preference for commonality.

If feasible, all Contingencies listed in Table 1 should be considered for evaluation by the responsible entity; however, the language affords flexibility in identifying the most appropriate Contingencies. As such, the responsible entity should implement a method and establish sufficient supporting rationale to ensure Contingencies within each category of Table 1 that are expected to produce more severe System impacts within its planning area are adequately identified. It is noted that since the benchmark planning cases are developed from the extreme temperature benchmark events, they already represent extreme System conditions and thus not all Contingencies from Reliability Standard TPL-001-5.1 Table 1 are included in the TPL-008-1 Table 1 for assessment. The Events included in TPL-008-1 Table 1 represent the more likely Contingencies to occur.

The SDT included categories P0, P1, and P7 in Table 1 of TPL-008-1. The SDT finds it reasonable to exclude P2, P3, P4, P5 and P6 Contingencies from the Extreme Temperature Assessment. Studying categories P0, P1 and P7 is the minimum requirement of TPL-008-1. The standard does not preclude entities from studying additional Contingencies if desired. The following discusses the rationale for excluding P2 through P6 Contingencies for TPL-008-1:

1. Excluding P2 and P4 Contingencies:

   After consideration of comments received from the industry, the SDT removed P2 and P4 Contingencies due to lower probability of occurrence than P1 and P7 Contingencies. The standard establishes minimum requirement for Contingencies with higher probability of occurrence. To the extent that the responsible entity determines the need for studying beyond the minimum requirements, the standard does not preclude the entity from doing so.

2. Excluding P3 and P6 Contingencies:

   Part of the decision stems from the complexity of P3 and P6 Contingencies, which involve multiple element outages triggered by multiple Contingencies, with System adjustments allowed between them. Consequently, the occurrence likelihood of P3 and P6 Contingencies could be even lower compared to P1 and P7 Contingencies. Moreover, aligning with the directives set forth in FERC Order 896, which emphasizes the importance of incorporating derated generation, transmission capacity, and the availability of generation and transmission in the development of benchmark planning cases, it becomes imperative for responsible entities to consider potential concurrent or correlated generation and transmission outages and/or derates within relevant benchmark planning cases. This ensures that the benchmark planning case accurately reflects System conditions under extreme temperatures, with generation and transmission derates and/or outages already factored. Therefore, the SDT believes excluding P3 and P6 is justified, as generation and transmission derates and/or outages are already accounted for within the benchmark planning cases.

3. Excluding P5 Contingencies:

   After consideration of comments were received, the SDT removed P5 Contingency (Delayed Fault Clearing due to failure of non-redundant component of a Protection System). This is because while some categories of Contingencies may be assessed in a straightforward approach, category P5 Contingency events often require a significant level of engineering analysis (including protection and/or control analysis). These analyses are sensitive to the System topology and expected dispatch. As the planning benchmark cases are developed for TPL-008-1 that represent System conditions that are different than the typical summer or winter peak conditions, the development of category P5 Contingency events is expected to be a significant burden. Since these events only require evaluations of possible mitigations (and not Corrective Action Plans), violations resulting from these events are unlikely to result in significant transmission System investment. Furthermore, any violations resulting from category P5 events may be mitigated by eliminating and addressing the single point of failure included in the event definition. Thus, the evaluation of possible actions is unlikely to result in further insight beyond the general reliability improvements associated with eliminating single points of failure.

The SDT discussed and decided to keep the P7 Contingency category because common structure Contingencies are often evaluated after categories P0 and P1 as the most common minimum level of transmission reliability assessment. These events have a high likelihood of occurrence due to the following reasons:

- Historical events that include simultaneous forced outage due to tripping of the double-circuit power lines due to electrical storms events;
- Environment-caused factors include pollution buildup such as dust that could cause faulted condition that trips both transmission lines on a common tower;
- Avian-caused outages that impact both transmission lines on a common tower;
- Smoke from nearby wildfires can cause simultaneous tripping of both circuits on a common tower;
- Nearby wildfires can impact System Operation as System Operators proactively de-energize both lines on a common tower to avoid further impact to the transmission grid in the event of a simultaneous tripping of both lines that may be carrying high power transfer between areas;
- Weather-related causes such as lightning, flooding, wind, icing can cause tripping of both transmission lines on a common tower;
- Natural disaster such as winter storm can cause transmission tower to collapse, taking out both lines strung on the same tower;
- Other incidents such as vehicle accident, aircraft accident, vandalism, animal contact can adversely impact both transmission lines on the common tower.
- Loss of two circuits running in parallel simultaneously is likely to have a greater system impact versus loss of two unrelated or geographically separated circuits. Therefore, there is greater potential for reliability concerns, especially during heavy transfers that are likely during periods of extreme weather, due to loss of a both circuits of a double-circuit line.
- Due to the reasons above, Contingencies that involve double-line circuits on a common tower are mostly included in the critical multiple Contingency list in System Operations reliability assessment.

Some, but not all, items to consider when developing the rationale for selecting Contingencies are:

- Past studies,
- Subject matter expert knowledge of the responsible entity’s System (to be supplemented with data or analysis), and
- Historical data from past operating events.

Requirement R8

Requirement R8 was drafted to provide clarity on the following:

1. What planning study cases are required?

   The Requirement R8 includes the following number of assessments to complete the Extreme Temperature Assessment and address FERC Order No. 896 directives per paragraph 111 that "direct NERC to require in the proposed new or modified Reliability Standard that responsible entities perform both steady state and transient stability (dynamic) analyses in the extreme heat and cold weather planning studies". In addition, Requirement R8 also addresses FERC Order No. 896 directives per paragraph 124 that "require the use of sensitivity cases to demonstrate the impact of changes to the assumptions used in the benchmark planning case". Requirement R8 also addresses FERC Order No. 896 directives per paragraph 124 that sensitivity cases "should consider including conditions that vary with temperature such as load, generation, and system transfers." Since the benchmark planning case(s) already include System conditions under extreme heat or extreme cold events, the sensitivity analysis is to include changes to at least one of the following conditions: generation, real and reactive forecasted Load, or transfers. Since the minimum requirement includes changes to one of these conditions, the PCs and the TPs can include further sensitivity assessments to change more conditions if they choose to do so.

   The following provides the number of assessments required for the benchmark planning and sensitivity cases to complete the Extreme Temperature Assessment.

Type of Extreme Temperature Assessment	Extreme Cold Temperature Event	Extreme Heat Temperature Event	Total
Benchmark Planning Case Analysis	One extreme cold benchmark planning case assessment	One extreme heat benchmark planning case assessment	Two benchmark planning case assessments
Sensitivity Case Analysis	One sensitivity case with changes to at least one of the following conditions: generation, real and reactive forecasted Load, or transfers	One sensitivity case with changes to at least one of the following conditions: generation, real and reactive forecasted Load, or transfers	Two sensitivity case assessments
Total			A total of four assessments to complete the Extreme Temperature Assessment

2. What are the types of analyses required?

   There are two types of analyses required: steady-state and transient stability. Each type of analysis must be completed for each of the four cases described in the table above. This requirement is to satisfy FERC Order No. 896 directive paragraph 111.

Requirement R9

FERC Order No. 896 identifies a deficiency in the existing Reliability Standard TPL-001-5.1 where “planning coordinators and transmission planners are required to evaluate possible actions to reduce the likelihood or mitigate the consequences of extreme temperature events but are not obligated to develop corrective action plans” (¶139).

Given potential severe consequences of extreme cold and extreme heat events, FERC Order No. 896 raises the bar and “directs NERC to require in the new or modified Reliability Standard the development of extreme weather corrective action plans for specified instances when performance standards are not met” (¶152).

Due to higher likelihood of categories P0 and P1, these categories are held to a higher performance requirement in benchmark planning cases. Corrective Action Plans are required to address performance deficiencies for categories P0 and P1 in benchmark planning cases analyzed in the Extreme Temperature Assessment.

Furthermore, having a Corrective Action Plan requirement for categories P0 and P1 in benchmark planning cases ensures resilience during future extreme cold and extreme heat temperature events, when the transmission System is required to be P1 Contingency-secure (for steady-state and transient stability).

Given that a category P0 represents a continuous System condition without any system disturbances, the SDT determined that load shedding should not be considered as a Corrective Action Plan. However, the SDT has determined that load curtailment may be considered for a P1 Contingency as a Corrective Action Plan where load shed is allowed to prevent system-wide failures and ensuring the continued operation of essential services under a critical P1 Contingency in the extreme heat and cold temperature events. The SDT also emphasizes that alternative solutions, other than firm load curtailment, are evaluated in higher priorities. Non-Consequential Load Loss is permitted as an interim solution in situations that are beyond the control of the Planning Coordinator or Transmission Planner that prevent the implementation of a Corrective Action Plan in the required timeframe; however, the responsible entity must document the situation causing the problem, alternatives evaluated, and take actions to resolve the situation. Future revisions to the Corrective Action Plan are allowed, provided that the planned Bulk Electric System continues to meet the performance requirements of Table 1.

FERC Order No. 896 also directs NERC “to develop certain processes to facilitate interaction and coordination with applicable regulatory authorities or governing bodies responsible for retail electric service as appropriate in implementing a corrective action plan” (¶152). In the event that Non-Consequential Load Loss is included in the Corrective Action Plan for a P1 Contingency, the responsible entity shall document alternative(s) considered, make the Corrective Action Plan available to, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.

Requirement R10

The requirement for responsible entities to evaluate and document possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts when the study results in the benchmark planning cases analyses conclude there could be instability, uncontrolled separation, or Cascading for P7 Contingencies is in response to directives outlined in FERC Order No. 896.

P7 Contingencies involve multiple element outages resulting from a single event, making them relatively less likely to occur, compared to categories P0 and P1, but potentially causing more severe system impacts. Considering both the likelihood of these Contingencies, and the fact that the Extreme Temperature Assessment already addresses low-probability System conditions, the SDT determined that Corrective Action Plans should not be required for P7 Contingencies. However, due to the potential severity resulting from single-Contingency multiple element outages, the SDT believes it is appropriate for responsible entities to at least evaluate and document possible mitigation actions to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses conclude there could be instability, uncontrolled separation, or Cascading. The biggest benefit from the evaluation and documentation of the possible mitigating actions is it allows a responsible entity to see where major reliability concerns exist that may need to be addressed; and, if a sufficiently large number of reliability concerns are identified, it may encourage transmission upgrade mitigation option(s) to be considered and implemented without it being strictly called for in the standard. Not requiring Corrective Action Plans for these Contingencies, but requiring the evaluation, is a compromise from having Corrective Action Plans for all studied Contingencies.

Furthermore, FERC Order No. 896 requires "the use of sensitivity cases to demonstrate the impact of changes to the assumptions used in the benchmark planning case" (¶124). FERC Order No. 896 also states: "NERC should determine whether corrective action plans should be required for single or multiple sensitivity cases, and whether corrective action plans should be developed if a contingency event that is not already included in benchmark planning case would result in cascading outages, uncontrolled separation, or instability" (¶158). The SDT acknowledges that sensitivity analysis is an important component of a robust transmission planning study. A requirement to develop and implement Corrective Action Plans for sensitivity cases may incentivize responsible entities to select fewer or less severe sensitivities. An incentive to select fewer sensitivities is undesirable because sensitivity study results are used to identify constraints and initiate deeper analysis into the variables that impact those constraints. The study results of sensitivity cases are also important to inform the development of Corrective Action Plans in the benchmark planning cases. Therefore, the SDT determined the responsible entity must evaluate and document possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses of sensitivity cases conclude there could be instability, uncontrolled separation, or Cascading for categories P0, P1, and P7. Finally, TPL-008-1 does not preclude the responsible entity from developing Corrective Action Plans for sensitivity cases beyond what is required in the standard.

Requirement R11

The requirement for responsible entities to share Extreme Temperature Assessment results aligns with directives in FERC Order No. 896, emphasizing coordination and sharing of study findings. It ensures collaboration among stakeholders and timely dissemination of critical information to entities with reliability-related needs. This fosters a collective understanding of reliability concerns identified in wide-area studies, thereby enhancing overall grid reliability.

Unofficial Comment Form

Project 2023-07 Transmission Planning Performance Requirements for Extreme Weather

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on draft three of **TPL-008-1 – Transmission System Planning Performance Requirements for Extreme Temperature Events** by **8 p.m. Eastern, October 21, 2024.**

Additional information is available on the project page. If you have questions, contact Senior Standards Developer, Jordan Mallory (via email), or at 470-479-7538.

Background Information

On June 15, 2023, FERC issued FERC Order No. 896 that acknowledges the "challenges associated with planning for extreme heat and cold weather events, particularly those that occur during periods when the Bulk-Power System must meet unexpectedly high demand. Extreme heat and cold weather events have occurred with greater frequency in recent years, and are projected to occur with even greater frequency in the future. These events have shown that load shed during extreme temperature result in unacceptable risk to life and have extreme economic impact. As such, the impact of concurrent failures of Bulk-Power System generation and transmission equipment and the potential for cascading outages that may be caused by extreme heat and cold weather events should be studied and corrective actions should be identified and implemented."[1]

Therefore, the Commission directed, in FERC Order No. 896, to develop a new or modified Reliability Standard to address a lack of long-term planning requirement(s) for extreme heat and cold weather events. Specifically, FERC directed NERC to develop modifications to Reliability Standard TPL-001-5.1 or a new Reliability Standard, to require the following: (1) development of benchmark planning cases based on major prior extreme heat and cold weather events and/or meteorological projections; (2) planning for extreme heat and cold weather events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios including the expected resource mix's availability during extreme heat and cold weather conditions, and including the wide-area impacts of extreme heat and cold weather; and (3) development of corrective action plans that mitigate any instances where performance requirements for extreme heat and cold weather events are not met.

[1] N. Am. Elec. Reliability Corp., 183 FERC ¶ 61,191 (2023) (FERC Order), Final Rule. eLibrary | File List (ferc.gov)

Questions

1. Requirement R1 requires Planning Coordinators (PCs) to identify their zone in the map included in Attachment 1. Do you agree with the zones identified on this map? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

☐ Yes
☐ No

Comments:

2. The Drafting Team (DT) updated Requirement R2 based on comments received. Do you agree with the updated proposed TPL-008-1 Reliability Standard Requirement? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

☐ Yes
☐ No

Comments:

3. The DT updated Requirements R3 – R4 based on comments received. Do you agree with the updated proposed TPL-008-1 Reliability Standard Requirements? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

☐ Yes
☐ No

Comments:

4. The DT updated Requirements R7 – R8 based on comments received. Do you agree with the updated proposed TPL-008-1 Reliability Standard Requirements? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

☐ Yes
☐ No

Comments:

5. The DT updated Requirements R9 – R11 based on comments received. Do you agree with the updated proposed TPL-008-1 Reliability Standard Requirements? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

☐ Yes
☐ No

Comments:

6. The DT believes proposed modifications in TPL-008-1 provide entities with flexibility to meet the reliability objectives in a cost-effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost-effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

☐ Yes
☐ No

Comments:

7. Provide any additional comments for the drafting team to consider, including the provided technical rationale document, if desired.

Comments:

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Justifications

Project 2023-07 Transmission System Planning Performance Requirements for Extreme Weather

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Project 2023-07 Transmission System Planning Performance Requirements for Extreme Weather. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for TPL-008-1, Requirement R1	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to the fact that the Planning Coordinators, in conjunction with its Transmission Planner(s) will determine joint responsibilities for requirements throughout TPL-008-1.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed less than or equal to six months late.	The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed more than six months but less than or equal to 12 months late.	The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed more than 12 months but less than or equal to 18 months late.	The Planning Coordinator, in conjunction with its Transmission Planner(s), failed to identify individual and joint responsibilities for completing the Extreme Temperature Assessment. OR The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed more than 18 months late.

VSL Justifications for TPL-008-1, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL has been assigned as a binary due to the Planning Coordinator and Transmission Planner to determine who completes the responsibilities throughout TPL-008-1. The responsibilities documentation will either be developed or not.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R2	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of high is appropriate due to the fact that selecting a benchmark event to perform an extreme temperature assessment can affect the grid based on planning analysis for future events.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Planning Coordinator coordinated with all Planning Coordinators within each identified zone to select one common extreme heat and one common extreme cold benchmark temperature event for completing the Extreme Temperature Assessment, but one of the selected events failed to meet all the criteria of Requirement R2.	The Planning Coordinator coordinated with all Planning Coordinators within each identified zone to select one common extreme heat and one common extreme cold benchmark temperature event for completing the Extreme Temperature Assessment, but both of the selected events failed to meet all of the criteria of Requirement R2. OR The Planning Coordinator failed to coordinate with all Planning Coordinators within each identified zone to select to select one common extreme heat and one common extreme cold benchmark temperature event for completing the Extreme Temperature Assessment.

VSL Justifications for TPL-008-1, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	This VSL has been assigned as a binary due to the benchmark event needing to be selected for benchmark planning cases to be completed. You either select a benchmark event or not.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R3	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of medium is appropriate due to the fact that it is important to develop and maintain System models within an entity's planning area for performing Extreme Temperature Assessments. Connecting to MOD-032 to provide important data needed to assist entities with System models is also important for accurate information to be used.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Planning Coordinator did not coordinate with all Planning Coordinators within each of its identified zone(s) to implement a process for developing benchmark planning cases. OR The Planning Coordinator coordinated with all Planning Coordinators within each of its identified zone(s) to implement a process for developing benchmark planning cases, but the process did not include all of the required elements.

VSL Justifications for TPL-008-1, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL has been assigned as a binary due to the responsible entity either develops and maintains the System models within its planning area or it does not develop and maintain the System models within its planning area.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R4	
Proposed VRF	**High**
NERC VRF Discussion	The VRF of High is appropriate because it could directly affect the electrical state or capability of the BPS if coordination is not completed for benchmark planning cases and sensitivity cases for the Extreme Temperature Assessment results.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity, as identified in Requirement R1, did not use the coordination process to develop benchmark planning cases or sensitivity cases. OR The responsible entity, as identified in Requirement R1, used the coordination process to develop benchmark planning cases and sensitivity cases, but did not use data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, for one or more of the required cases. OR The responsible entity, as identified in Requirement R1, used the coordination process and data consistent with that provided in accordance with the MOD-032 standard, supplemented as needed, but failed to develop one or more of the required planning or sensitivity cases.

VSL Justifications for TPL-008-1, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL has been assigned as a binary due to the Planning Coordinator to develop and implement a process for coordinating the development of benchmark planning cases. The benchmark planning cases will either be developed and implemented or not.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R5	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of medium is appropriate due to the importance of having criteria for acceptable System steady state voltage limits of post-Contingency voltage deviations for performing Extreme Temperature Assessments.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity, as identified in Requirement R1, did not have criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations for completing the Extreme Temperature Assessment.

VSL Justifications for TPL-008-1, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL has been assigned as a binary due to the responsible entity either having acceptable criteria for System steady state voltage limits and post-contingency voltage deviations or not.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R6	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate due to the importance of defining and documenting the criteria or methodology for System instability, uncontrolled separation, or Cascading.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity, as identified in Requirement R1, failed to define or document the criteria or methodology to be used in the Extreme Temperature Assessment to identify instability, uncontrolled separation, or Cascading within an Interconnection.

VSL Justifications for TPL-008-1, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R7	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of medium is appropriate for this requirement. Identifying Contingencies for performing Extreme Temperature Assessments for each of the event categories in Table 1 can indirectly impact the BES.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The responsible entity, as identified in Requirement R1, identified Contingencies for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System, but did not include the rationale for those Contingencies selected for evaluation as supporting information.	The responsible entity, as identified in Requirement R1, did not identify Contingencies for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System.

VSL Justifications for TPL-008-1, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R8	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate due to the importance of performing an Extreme Temperature Assessment every 5 years.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to document the assumptions for one or more sensitivity cases in accordance with Requirement R8.	The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to document the assumptions for one or more benchmark planning cases in accordance with Requirement R8.	The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to evaluate and document results for one or more of the sensitivity cases in accordance with Requirement R8.	The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to evaluate and document results for one or more of the benchmark planning cases in accordance with Requirement R8. OR The responsible entity, as identified in Requirement R1, failed to complete steady state or transient stability analyses and document results in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, in accordance with Requirement R8.

VSL Justifications for TPL-008-1, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R9	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate for this requirement. Developing a Corrective Action Plan is important to the BES as it assists entities when Systems are unable to meet performance requirements.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R9			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The responsible entity, as identified in Requirement R1, developed a Corrective Action Plan in accordance with Requirement R9, but failed to make its Corrective Action Plan available to, or solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.	The responsible entity, as identified in Requirement R1, failed to develop a Corrective Action Plan when the benchmark planning case study results indicate the System is unable to meet performance requirements for the Table 1 P0 or P1 Contingencies. OR The responsible entity, as identified in Requirement R1, developed a Corrective Action Plan, but it was missing one or more of the elements of Requirement R9 Part 9.2-9.4 (as applicable).

VSL Justifications for TPL-008-1, Requirement R9	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL has been assigned as a binary due to the responsible entity either having acceptable criteria for System steady state voltage limits and post-contingency voltage deviations or not.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R10	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of lower has been assigned to Requirement R10. Documenting possible actions to reduce the likelihood or mitigate the consequences and adverse impacts are administrative in nature.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R10			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The responsible entity, as identified in Requirement R1, evaluated and documented possible actions to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection where required under Requirement R10 Part 10.1, but failed to evaluate and document possible actions where required under Requirement R10 Part 10.2.	The responsible entity, as identified in Requirement R1, evaluated and documented possible actions to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection where required under Requirement R10 Part 10.2, but failed to evaluate and document possible actions where required under Requirement R10 Part 10.1. OR The responsible entity, as identified in Requirement R1, failed to evaluate and document possible actions to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection where required under Requirement R10 Parts 10.1 and 10.2.

VSL Justifications for TPL-008-1, Requirement R10	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL has been assigned as a binary due to the fact that the responsible entity will have evaluated and documented possible actions to mitigate adverse impacts.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R11	
Proposed VRF	**Medium**
NERC VRF Discussion	The VRF of Medium is appropriate because it could directly affect the electrical state or capability of the BES if entities are not aware of the results from its Extreme Temperature Assessment results.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R11			
Lower	**Moderate**	**High**	**Severe**
The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 60 days but less than or equal to 80 days following the request.	The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 80 days but less than or equal to 100 days following the request.	The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 100 days but less than or equal to 120 days following the request.	The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 120 days following the request. OR The responsible entity, as identified in Requirement R1, did not provide its Extreme Temperature Assessment results to functional entities having a reliability related need who submitted a written request for the information.

VSL Justifications for TPL-008-1, Requirement R11	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of FERC Order 896 Directives

Project 2023-07 Transmission System Planning Performance Requirements for Extreme Weather
October 2024

On June 15, 2023, FERC issued a Final Rule, Order No. 896, directing NERC to develop a new or modified Reliability Standard to address a lack of a long-term planning requirement(s) for extreme heat and cold weather events. Specifically, FERC directed NERC to develop modifications to Reliability Standard TPL-001-5.1 or to develop a new Reliability Standard to require the following: (1) development of benchmark planning cases based on major prior extreme heat and cold weather events and/or meteorological projections; (2) planning for extreme heat and cold weather events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios including the expected resource mix's availability during extreme heat and cold weather conditions, and including the wide-area impacts of extreme heat and cold weather; and (3) development of corrective action plans that mitigate any instances where performance requirements for extreme heat and cold weather events are not met. FERC directed NERC to submit a new or revised standard within 18 months, or by December 2024. The below provides the directives from FERC Order 896 along with the drafting team's consideration of the directives.

FERC Order 896 Directives	
Directive Language	**Consideration of Directives**
P35. "[W]e direct NERC to: (1) develop extreme heat and cold weather benchmark events, and (2) require the development of benchmark planning cases based on identified benchmark events." **P36**: "…As recommended by commenters, NERC should consider the examples of approaches for defining benchmark events identified in the NOPR (e.g., the use of projected frequency or probability distribution). NERC may also consider other approaches that achieve the objectives outlined in this final rule."	The ERO has worked with respective subject matter experts, including climate experts, the six regions, etc., to explore extreme heat and extreme cold benchmark temperature events. NERC, in consultation with climate data subject matter expert consultants on the benchmark events, utilized publicly available modeled data to address the requirements of TPL-008-1 that define extreme heat and extreme cold benchmark temperature events. Specifically, based on the available data, the drafting team determined that extreme benchmark temperature events must: 1) consider no less than forty years of historical temperature data, 2) include recent temperature

FERC Order 896 Directives	
Directive Language	**Consideration of Directives**
	data due to ongoing climate changes, and 3) represent one of the twenty worst extreme temperature conditions over the forty year period, based on a 3-day rolling average of daily maximum (heat) or minimum (cold) temperatures. The ERO will maintain a library of benchmark temperature events that meet these requirements. Responsible entities will be able to review and select benchmark temperature events from this library to assist with the development of benchmark planning cases. However, responsible entities may also identify benchmark temperature events via their own processes, provided that the event meets the criteria of Requirement R2 and is agreed upon by all PCs within the zone. Should the extreme heat and cold weather benchmark events provided not suffice for the entities zone, the Planning Coordinator (PC) in coordination with all PCs within its zone, may develop a common extreme heat and extreme cold weather benchmark event to use for the TPL-008-1 Standard. The drafting team developed requirements within TPL-008-1 to require PCs within zones to select one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event (Requirement R2). After selecting its benchmark events, the responsible entity is required to implement a process for coordinating the development of benchmark planning cases and sensitivity cases among the responsible entities (Requirement R3) and to develop benchmark planning cases and sensitivity cases (Requirement R4).

FERC Order 896 Directives	
Directive Language	**Consideration of Directives**
P37. "Because the impact of most extreme heat and cold events spans beyond the footprints of individual planning entities, it is important that all responsible entities likely to be impacted by the same extreme weather events use consistent benchmark events. Doing so is important to ensuring that neighboring planning regions are assuming similar weather conditions and are able to coordinate their assumptions accordingly. As a result, defining the benchmark event in a manner that provides responsible entities significant discretion to determine the applicable meteorological conditions would not meet the objectives of this final rule."	NERC, in consultation with climate data subject matter expert consultants on benchmark events, developed subregions or "zones" of North America that are likely to experience similar weather conditions. These zones also consider practical concerns with coordination such as the boundaries of Interconnections and Balancing Authority Areas. The drafting team developed Requirement R2 such that PCs within the same zone are required to select one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event. This process balances the opportunity to provide input with the need for common events to be modeled over wide areas.
P38. "[I]n developing extreme heat and cold benchmark events, NERC shall ensure that benchmark events reflect regional differences in climate and weather patterns."	NERC, in consultation with climate data subject matter expert consultants on benchmark events, has utilized publicly available modeled data in the last forty-three years (1980-2022), as well as more than eighty years of projected hourly meteorology data from PNNL to ensure regional differences in climate and weather patterns are reflected in the zones depicted in Attachment 1 of TPL-008-1. A Map has been added to the TPL-008-1 Standard showing the zones split throughout the US and Canada. These are to be considered wide area, and regional differences went into consideration when developing the data based on extreme historical events over the past 40 years.
P39. "We also direct NERC to include in the Reliability Standard the framework and criteria that responsible entities shall use to develop from the relevant benchmark event planning cases to represent potential weather-related contingencies (e.g., concurrent/correlated generation and transmission outages, derates) and expected future conditions of the system such as changes in load, transfers, and generation resource mix, and impacts on generators sensitive to extreme heat or cold, due to the weather conditions indicated in the benchmark events. Developing such a	The directive is addressed in Requirements R3 and R4 of the proposed TPL-008-1 standard. Requirement R3 obligates the PC to implement a process to coordinate the development of the benchmark planning cases and sensitivity cases. This process shall include: 1) the selection of System models within the Long-Term Transmission Planning Horizon to serve as a starting point for the benchmark planning cases, 2) forecasted seasonal and temperature

FERC Order 896 Directives	
Directive Language	**Consideration of Directives**
framework would provide a common design basis for responsible entities to follow when creating benchmark planning cases. This would not only help establish a clear set of expectations for responsible entities to follow when developing benchmark planning events, but also facilitate auditing and enforcement of the Standard.”	dependent adjustments for Load, generation, Transmission, and transfers within the zone to represent the selected benchmark temperature events, 3) assumed seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers outside of the zone as needed, and 4) the identification of changes to at least one of generation, real and reactive forecasted load, or transfers to serve as a sensitivity case. Requirement R4 obligates the responsible entity to develop benchmark planning cases and sensitivity cases for performing the Extreme Temperature Assessment which reflects System conditions from the selected benchmark events. Requirement R4 also references the NERC MOD-032 Reliability Standard that provides PCs and Transmission Planners a mechanism for obtaining the data needed to develop the benchmark planning cases.
P40. “We also direct NERC to ensure the reliability standard contains appropriate mechanisms for ensuring the benchmark event reflects up-to-date meteorological data.”	Requirement R2 Part 2.1 requires that the temperature data collected to identify benchmark temperature events includes 40 years of data “ending no more than 5 years prior to the time the benchmark temperature events are selected”. This requirement ensures that the window of time considered for benchmark temperature events reflects up-to-date data. The up-to five-year gap was included due to potential lags in data sources.
P50. “[W]e…direct NERC to require that transmission planning studies under the new or revised Reliability Standard consider the wide-area impacts of extreme heat and cold weather. We direct NERC to clearly describe the process that an entity must use to define the wide-area boundaries. While commenters provide various views in favor of both a geographical approach and electrical approach to defining wide-area boundaries, we do not adopt any one approach in this final rule…NERC should consider the comments in this proceeding when developing a new or modified reliability standard that considers the broad area impacts of extreme heat and cold weather.”	To understand the complexities of defining wide-area boundaries, the drafting team reviewed the extreme weather events mentioned within FERC Order No. 896, as well as the comments received during the FERC Order proceeding. In addition, NERC consulted with climate data subject matter experts who evaluated publicly available modeled data in the last forty-three years (1980-2022) and more than eighty years of projected hourly meteorology data from PNNL. The drafting team struck a balance between a geographical approach and an electrical approach by dividing North America into zones that are likely to experience similar weather conditions but also consider practical

FERC Order 896 Directives	
Directive Language	**Consideration of Directives**
	concerns with coordination such as the boundaries of Interconnections and Balancing Authority Areas. These zones are depicted in Attachment 1 of TPL-008-1, and PCs will be required to coordinate with all PCs in the zone(s) they belong to.
P58. “[W]e…direct NERC to develop benchmark events for extreme heat and cold weather events through the Reliability Standards development process. We agree … that the development of adequate benchmark events is critical and should be committed to the subject matter experts on the standards drafting team. ”	The drafting team considered various approaches to developing benchmark temperature events. With assistance from NERC’s subject matter expert consultants, the drafting team identified the key components of temperature events that are necessary for the event to constitute an adequate benchmark temperature event. These components were included in Requirement R2. Specifically, based on the available data, the drafting team determined that extreme benchmark temperature events must: 1) consider no less than forty years of historical temperature data, 2) include recent temperature data due to ongoing climate changes, and 3) represent one of the twenty worst extreme temperature conditions over the forty year period based on a 3-day rolling average of daily maximum (heat) or minimum (cold) temperatures. The ERO will maintain a library of benchmark temperature events that meet these requirements. Responsible entities will be able to review and select benchmark temperature events from this library to assist with the development of benchmark planning cases. However, responsible entities may also identify benchmark temperature events via their own processes provided that the event meets the criteria of Requirement R2 and is agreed upon by all PCs within the zone. In addition to describing the minimum requirements of a benchmark temperature event, Requirement R2 obligates PCs within the same zone to coordinate in selecting one common extreme heat benchmark temperature event and one common extreme cold benchmark

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	temperature event for completing the Extreme Temperature Assessment. This coordination is required to ensure the benchmark temperature event is reflected over a wide-area.
P60. “[W]e…direct NERC to designate the type(s) of entities responsible for developing benchmark planning cases and conducting wide-area studies under the new or modified Reliability Standard…benchmark planning cases should be developed by registered entities such as large planning coordinators, or groups of planning coordinators, with the capability of planning on a regional scope.” **P61**: “We believe the designated responsible entities should have certain characteristics, including having a wide-area view of the Bulk-Power System and the ability to conduct long-term planning studies across a wide geographic area. The responsible entities should also have the planning tools, expertise, processes, and procedures to develop benchmark planning cases and analyze extreme weather events in the long-term planning horizon.” **P62**: “To comply with this directive, NERC may designate the tasks of developing benchmark planning cases and conducting wide-area studies to an existing functional entity or a group of functional entities (e.g., a group of planning coordinators). NERC may also establish a new functional entity registration to undertake these tasks. In the petition accompanying the proposed Reliability Standard NERC should explain how the applicable registered entity or entities meet the objectives outlined above.”	The drafting team discussed that the Transmission Planner (TP) and/or Planning Coordinator (PC) would be the responsible entities to address TPL-008-1 Requirements. Requirement R1 obligates both the TP and PC to identify their individual and joint responsibilities. Requirement R3 obligates each PC to implement a process for coordinating the development of benchmark planning cases and sensitivity cases, using the selected benchmark temperature events identified in Requirement R2. This process must be implemented in coordination with all PCs within the same zone. Requirement R4 obligates each responsible entity, as identified in Requirement R1, to use the coordination process developed in accordance with Requirement R3 and data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, to develop benchmark planning cases and sensitivity cases. The identification of joint and individual responsibilities in Requirement R1 provides a measure of flexibility for PCs and TPs to agree on a distribution of responsibilities. Thus, while PCs are responsible for implementing the case development process in Requirement R3, TPs may be responsible for providing data and completing the case development according to that process. The development of benchmark planning cases and sensitivity cases will require cooperation amongst many PCs and TPs. By requiring participation from all entities within a zone, TPL-008-1 ensures that the group of functional entities have a sufficient wide-area view of the Bulk Power

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	System and the planning tools, expertise, processes and procedures necessary for developing benchmark planning cases and sensitivity cases.
P72. "[W]e direct NERC to require functional entities to share with the entities responsible for developing benchmark planning cases and conducting wide-area studies the system information necessary to develop benchmark planning cases and conduct wide-area studies. Further, responsible entities must share the study results with affected transmission operators, transmission owners, generator owners, and other functional entities with a reliability need for the studies."	The directive is addressed in proposed TPL-008-1 in Requirements R3, R4 and R11. Requirement R3 obligates each PC to implement a process for coordinating the development of benchmark planning cases, using the selected benchmark temperature events identified in Requirement R2, among all Planning Coordinators within a zone. Requirement R4 obligates each responsible entity, as identified in Requirement R1, to use the coordination process implemented in accordance with Requirement R3 and data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, to develop benchmark planning cases and sensitivity cases. Requirement R11 obligates each responsible entity, as identified in Requirement R1, to provide its Extreme Temperature Assessment results within 60 calendar days of a request to any functional entity that has a reliability related need and submits a written request for the information.
P73. "Because in this final rule we direct NERC to determine the responsible entities that will be developing benchmark planning cases and conducting wide-area studies, it is possible that the selected responsible entities under the new or modified Reliability Standard will not be able to request and receive needed data pursuant to MOD-032-1, absent modification to that Standard."	The drafting team discussed and determined that data needed to address the Extreme Temperature Assessment would still be appropriate to receive through MOD-032. MOD-032 ensures an adequate means of data collection for transmission planning and requires applicable registered entities to provide steady-state, dynamic, and short circuit modeling data to their Transmission Planner(s) and Planning Coordinator(s). As outlined in Requirement R1 and Attachment 1 of MOD-032, MOD-032 allows various data collection such as in-service status and capability associated with demand, generation, and transmission associated with various case types, scenarios, system operating states, or conditions for the long-term planning horizon. MOD-032 also requires applicable registered entities to

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	provide "other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes" for each of the three types of data required. Because the drafting team determined the responsible entities that will be developing benchmark planning cases are limited to Planning Coordinators and Transmission Planners, they will be able to request and receive needed data pursuant to MOD-032. Thus, the drafting team believes that there is no need to update MOD-032.
P76: "[W]e…direct NERC to address the requirement for wide-area coordination through the standards development process, giving due consideration to relevant factors identified by commenters in this proceeding."	The drafting team reviewed all the extreme weather events mentioned within the FERC Order 896. For this project, the drafting team focused the scope of Requirement R3 to require each PC to implement a process for coordinating the development of benchmark planning cases and sensitivity cases, using the selected benchmark temperature events identified in Requirement R2, among all PCs within a zone.
P77. "[W]e direct NERC to require in the new or modified Reliability Standard that responsible entities share the results of their wide-area studies with other registered entities such as transmission operators, transmission owners, and generator owners that have a reliability related need for the studies."	This directive is addressed in proposed TPL-008-1 Requirement R11. Requirement R11 obligates each responsible entity to provide the wide-area study results within 60 calendar days of a request to any functional entity that has a reliability related need and has submitted a written request for the information.
P88. "[W]e direct NERC to require under the new or revised Reliability Standard the study of concurrent/correlated generator and transmission outages due to extreme heat and cold events in benchmark events as described in more detail below." **P92.** "These contingencies (i.e., correlated/concurrent, temperature sensitive outages, and derates) shall be identified based on similar contingencies that occurred in recent extreme weather events or expected to occur in future forecasted events."	This directive is addressed in proposed TPL-008-1 through Requirements R3 and R4. Per Requirement R3 Part 3.2, the benchmark planning case development process must include forecasted seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers within the zone. Per Requirement R4, the data necessary to build the benchmark planning cases must be provided via MOD-032, supplemented by other sources as needed. Any concurrent/correlated generator and transmission outages due to extreme heat and cold events in benchmark temperature events should be reflected in the model data and thus represented in the initial conditions of the benchmark planning cases.
P111. "[W]e direct NERC to require in the proposed new or modified Reliability Standard that responsible entities perform both steady state and	This directive is addressed in proposed TPL-008-1 through Requirement R8 and Table 1.

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transient stability (dynamic) analyses in the extreme heat and cold weather planning studies. In a steady state analysis, the system components are modeled as either in-service or out-of-service and the result is a single point-in-time snapshot of the system in a state of operating equilibrium. A transient stability (dynamic) analysis examines the system from the start to the end of a disturbance to determine if the system regains a state of operating equilibrium. Performing both analyses ensures that the system has been thoroughly assessed for instability, uncontrolled separation, and cascading failures in both the steady state and the transient stability realms." (internal citations omitted).	Requirement R8 requires the responsible entity to complete both steady state and transient stability analyses and document the assumptions and results. Table 1 obligates each responsible entity to perform both steady state and transient stability analyses and compare the study results against steady state and stability performance requirements.
P112. "[W]e direct NERC to define a set of contingencies that responsible entities will be required to consider when conducting wide-area studies of extreme heat and cold weather events under the new or modified Reliability Standard. We believe that it is necessary to establish a set of common contingencies for all responsible entities to analyze. Required contingencies, such as those listed in Table 1 of Reliability Standard TPL-001-5.1 (i.e., category P1 through P7), establish common planning events that set the starting point for transmission system planning assessments. Requiring the study of predefined contingencies will ensure a level of uniformity across planning regions—a feature that will be necessary in the new or revised Reliability Standard considering that extreme heat and cold weather events often exceed the geographic boundaries of most existing planning footprints." **P113:** "[T]he contingencies required in the new or revised Reliability Standards should reflect the complexities of transmission system planning studies for extreme heat and cold weather events."	This directive is addressed in proposed TPL-008-1 through Requirement R7 and Table 1. Requirement R7 requires the responsible entity to identify Contingencies for completing the Extreme Temperature Assessment. The rationale, for those Contingencies selected for evaluation, shall be available as supporting information. The Contingencies for each category in Table 1 of TPL-008-1 correspond to the well-established Contingencies defined in Reliability Standard TPL-001-5.1. Utilizing these well-established Contingencies will ensure a level of uniformity across planning regions.
P116. "[W]e direct NERC to require in the new or modified Reliability Standard that responsible entities model demand load response in their extreme weather event planning area. As indicated by several commenters, because demand load response is generally a mitigating	TPL-008-1 Requirement R4 meets this directive by requiring each responsible entity to develop benchmark planning cases using data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed.

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action that involves reducing distribution load during periods of stress to stabilize the Bulk-Power System, its effect during an extreme weather event should be modeled." **P 117:** "[I]n addressing this directive, we expect NERC to determine whether responsible entities will need to take additional steps to ensure that the impacts of demand load response are accurately modeled in extreme weather studies, such as by analyzing demand load response as a sensitivity, as is currently the case under Reliability Standard TPL-001-5.1."	Specifically, Attachment 1 of MOD-032 requires information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes.
P124. "[W]e direct NERC to require the use of sensitivity cases to demonstrate the impact of changes to the assumptions used in the benchmark planning case. Sensitivity analyses help a transmission planner to determine if the results of the base case are sensitive to changes in the inputs. The use of sensitivity analyses is particularly necessary when studying extreme heat and cold events because some of the assumptions made when developing a base case may change if temperatures change – for example, during extreme cold events, load may increase as temperatures decrease, while a decrease in temperature may result in a decrease in generation. We… direct NERC to define during the Reliability Standard development process a baseline set of sensitivities for the new or modified Reliability Standard. While we do not require the inclusion of any specific sensitivity in this final rule, NERC should consider including conditions that vary with temperature such as load, generation, and system transfers." **P125**. "We do not agree ... that responsible entities alone should determine the sensitivity cases that must be considered in the responsible entity's study. … We…believe that responsible entities should be free to study additional sensitivities relevant to their planning areas…cooperation will be necessary between responsible entities conducting extreme heat and extreme cold weather studies and other registered entities within their	This directive is addressed in proposed TPL-008-1 in Requirement R3, which requires all PCs within the same zone to coordinate to implement a process for developing benchmark planning cases and sensitivity cases. Sensitivity cases are used to demonstrate the impact of changes to the basic assumptions used in the benchmark planning cases. Per Requirement R3 Part 3.4, PCs must include provisions in the case development process to identify changes to generation, real and reactive forecasted Load, and/or transfers to develop sensitivity cases. The identification of changes for sensitivity cases within the coordinated process of Requirement R3 addresses the directive that precludes responsible entities from determining sensitivities alone. However, nothing prevents responsible entities from conducting additional sensitivity studies they find relevant to their planning areas.

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extreme weather study footprints to ensure the selection of appropriate sensitivities."	
P134. "[W]e directs NERC to require in the new or modified Reliability Standard the use of planning methods that ensure adequate consideration of the broad characteristics of extreme heat and cold weather conditions. We further direct NERC to determine during the standard development process whether probabilistic elements can be incorporated into the new or modified Reliability Standard and implemented presently by responsible entities. If NERC identifies probabilistic elements which responsible entities can feasibly implement and that would improve upon existing planning practices, we expect the inclusion of those methods in the proposed Reliability Standard." **P138.** "[W]e direct NERC to identify during the standard development process any probabilistic planning methods that would improve upon existing planning practices, but that NERC deems infeasible to include in the proposed Reliability Standard at this time. If any such methods are identified, NERC shall describe in its petition for approval of the proposed Reliability Standard the barriers preventing the implementation of those probabilistic elements. We intend to use this information to determine whether and what next steps may be warranted to facilitate the use of probabilistic methods in transmission system planning practices."	The drafting team discussed probabilistic elements and determined while probabilistic analysis would be a good step forward, it would be better suited for the future as the methodology, process, and tools mature. Probabilistic assessment of generation and transmission facilities for the benchmark planning cases was discussed during the process of drafting the TPL-008-1 standard. However, based on the actual extreme heat and extreme cold events that have occurred, outages for generation and transmission facilities were unique for each of these events. Thus, it was challenging to draw correlation for the outages that occurred for different extreme heat and cold events for different regions and different timeframes. In addition, the data, available from these events, was limited to perform an adequate probabilistic assessment. Due to these reasons, the drafting team has decided not to pursue any probabilistic assessment for the current TPL-008-1 standard. This, however, does not preclude future development of probabilistic assessment when having additional data, as well as mature methodology, process and tools that can provide meaningful probabilistic assessment for generation and transmission outages under extreme temperature conditions.
P152. "[W]e direct NERC to require in the new or modified Reliability Standard the development of extreme weather corrective action plans for specified instances when performance standards are not met. In addition, as explained below, we direct NERC to develop certain processes to facilitate interaction and coordination with applicable regulatory authorities or governing bodies responsible for retail electric service as appropriate in implementing a corrective action plan."	The directive is addressed in the proposed TPL-008-1 Requirement R9. When the benchmark planning case study results indicate the System is unable to meet performance requirements for P0 and P1 Contingencies, Corrective Action Plans (CAPs) must be developed. Additionally, in accordance with Requirement R9 Part 9.1, responsible entities shall make their CAP available to, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.

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P155: "[T]he Commission is not directing any specific result or content of the corrective action plan."	
P157. "[W]e direct NERC to require in the new or modified Reliability Standard the development of corrective action plans that include mitigation for specified instances where performance requirements for extreme heat and cold events are not met—i.e., when certain studies conducted under the Standard show that an extreme heat or cold event would result in cascading outages, uncontrolled separation, or instability." **P158**: "[W]e give NERC in this final rule the flexibility to specify the circumstances that require the development of a corrective action plan."	The directive is addressed in the proposed TPL-008-1 Requirement R9. When the benchmark planning case study results indicate the system is unable to meet performance requirements for P0 and P1 Contingencies, Corrective Action Plans must be developed.
P165. "[w]e direct NERC to require in the new or modified Reliability Standard that responsible entities share their corrective action plans with, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues."	The directive is addressed in the proposed TPL-008-1 Requirement R9. Requirement R9.1 requires the responsible entities to make their CAP available and solicit feedback from applicable regulatory authorities or governing bodies responsible for retail electric service issues.
P167. "Further, because an important goal of transmission planning is to avoid load shed, any responsible entity that includes non-consequential load loss in its corrective action plan should also identify and share with applicable regulatory authorities or governing bodies responsible for retail electric service alternative corrective actions that would, if approved and implemented, avoid the use of load shedding."	This directive is addressed in proposed TPL-008-1 Requirement R9. As stipulated in Requirement R9 Part 9.2, when Non-Consequential Load Loss is utilized as an element of a CAP for a Table 1 P1 Contingency, the responsible entity must document the alternative(s) considered, and notify the applicable regulatory authorities or governing bodies responsible for retail electric service issues.
P188. "[W]e direct NERC to submit a new or modified Reliability Standard within 18 months of the date of publication of this final rule in the Federal Register. Further, we direct NERC to propose an implementation timeline for the new or modified Reliability Standard, with implementation beginning no later than 12 months after the effective date of a Commission order approving the proposed Reliability Standard."	The directive is addressed with the publication of TPL-008-1 and will be filed with the regulatory government no later than December 23, 2024, within 18 months of the date Order No. 896 was published in the *Federal Register*. The implementation plan addresses Requirement R1 becoming effective 12 months from the effective date of the Commission order approving the

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	TPL-008-1. In addition, phased-in approaches have been provided for other Requirements needing additional time. See the TPL-008-1 Implementation Plan.
P193. "[W]e direct NERC to establish an implementation timeline for the proposed Reliability Standard. In complying with this directive, NERC will have discretion to develop a phased-in implementation timeline for the different requirements of the proposed Reliability Standard (i.e., developing benchmark cases, conducting studies, developing corrective action plans). However, this phased-in implementation must begin within 12 months of the effective date of a Commission order approving the proposed Reliability Standard and must include a clear deadline for implementation of all requirements."	The implementation plan addresses Requirement R1 becoming effective 12 months from the effective date of the Commission order approving the TPL-008-1. In addition, phased-in approaches have been provided for other Requirements needing additional time. See the TPL-008-1 Implementation Plan.

DRAFT ERO Enterprise Process for TPL-008-1 Benchmark Weather Event Development and Maintenance

Standards Development and Engineering Process Document
October 2024

Background

This Electric Reliability Organization (ERO) Enterprise Process for TPL-008-1[1] Benchmark Weather Event Development and Maintenance addresses how ERO Enterprise staff will develop and maintain a library of benchmark weather events (herein as the Weather Event Library) to be used by Planning Coordinators and Transmission Planners for TPL-008-1 studies. Per Requirement R3 of TPL-008-1 and consistent with directives outlined in FERC Order No. 896[2], Planning Coordinators and Transmission Planners will have benchmark temperature events available via the Weather Event Library to select from when developing their benchmark planning cases.

Purpose

The purpose of this process document is to formalize a repeatable approach to develop and maintain the Weather Event Library. While both the TPL-008-1 study requirements and this process are in the initial stages of development, it is essential that industry is informed of this process and how it will be designed and implemented following the completion of NERC Project 2023-07. This process document outlines an initial set of process objectives and approach but is not considered to be complete at this time. This document will be revised as needed throughout the development of NERC Project 2023-07.

Document Maintenance

NERC will maintain this document to assure it is consistent with acceptable practices and publicly available. This document will be reviewed as it is implemented. Updates will be made by NERC Standards Development and Engineering, as needed, to reflect lessons learned as the process matures. Any substantive changes to this process, supplemental/attached criteria, or other guidance to be used by NERC in developing additional benchmark events, archiving/removing benchmark events, or other modifications to the Weather Event Library, will be reviewed in consultation with NERC Legal, NERC Compliance Assurance, Zoneal Entity staff, and FERC. Approved substantive revisions to this document will be detailed in the Appendix, broadly communicated to industry, and included as part of informational filings to FERC.

[1] *Link pending final approval of TPL-008-1*
[2] FERC Docket No. RM22-10-000; Order No. 896; https://www.ferc.gov/media/e-1-rm22-10-000; June 15, 2023

Definitions

Refer to the NERC Glossary of Terms[3] for the below capitalized terms used in this process.

- Affected Zoneal Entity (ARE)
- Compliance Enforcement Authority (CEA)
- Coordinated Oversight
- Extreme Temperature Assessment (ETA)
- Lead Zoneal Entity (LRE)
- Multi-Zone Registered Entity (MRRE)

Process Overview

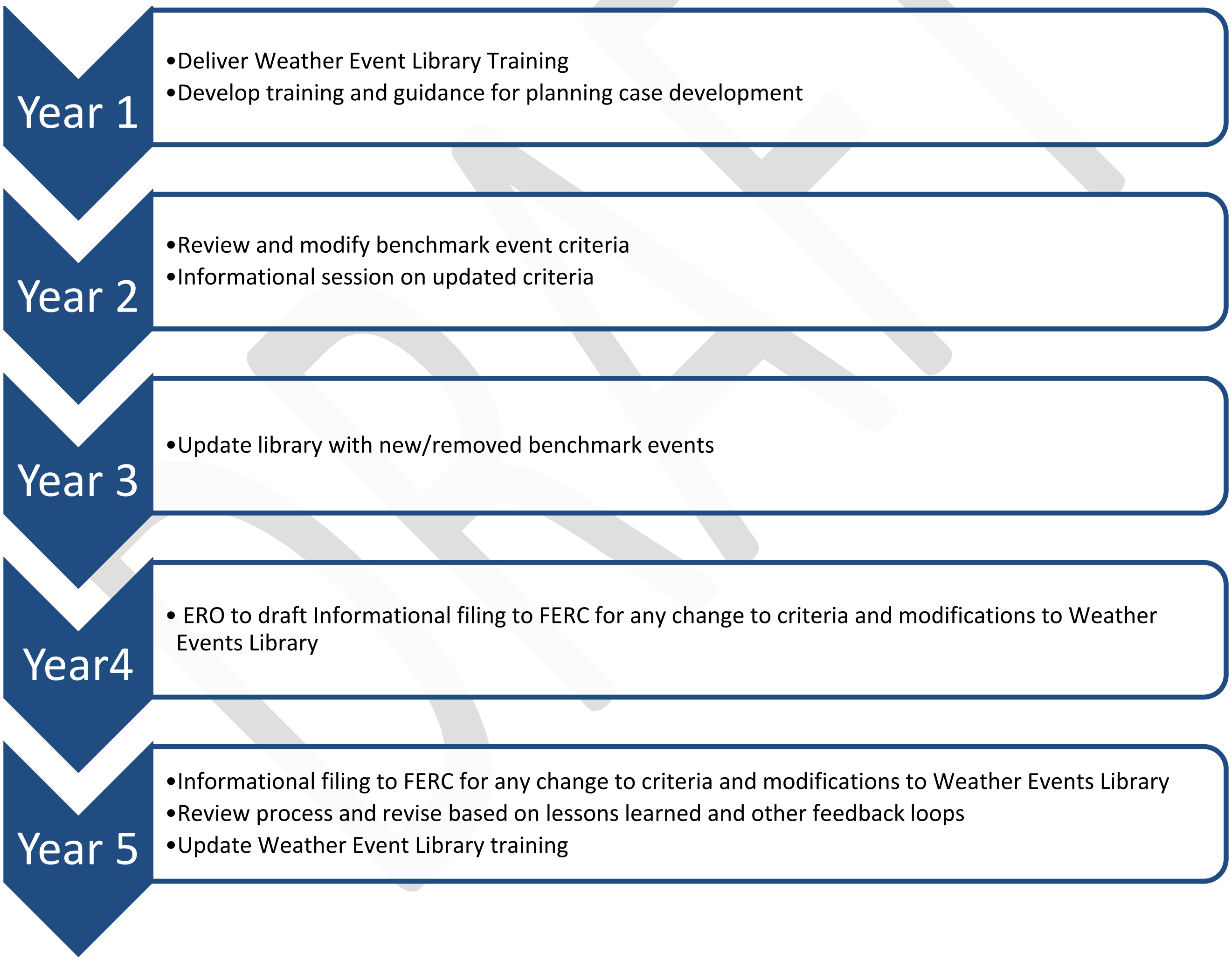
The following is a five-year iterative process coinciding with Planning Coordinator and Transmission Planner implementation of TPL-008-1. As TPL-008-1 and associated benchmark event(s) will be submitted to FERC in December 2024, the first iteration of this process will cover five years (2025—2029).

- December 2024
    - Weather Event Library developed and ready to go live for industry.
    - Benchmark Events, for the first five-years required per the TPL-008-1 Reliability Standard, completed and uploaded to the Weather Event Library.
- Year One (2025):
    - ERO to provide Weather Event Library training.
    - ERO to engage with industry subject matter experts (SMEs), Planning Coordinators, research labs, and trade organizations, and NERC technical committees on additional and updated criteria for developing benchmark events.
- Year Two (2026):
    - ERO to initiate review of benchmark event criteria, identify any changes needed, and incorporate feedback from year one.
    - ERO to deliver a webinar on updated criteria for developing benchmark events.
- Year Three (2027):
    - ERO to develop new benchmark events[4] based on updated criteria in year two.
    - ERO to update the Weather Event Library with updated benchmark events.
- Year Four (2028):
    - ERO to draft informational filing with FERC.

[3] NERC Glossary of Terms: Glossary_of_Terms.pdf (nerc.com)
[4] Note: This is for the second iteration of benchmark events being developed.

    - ERO will engage with industry subject matter experts (SMEs), Planning Coordinators, research labs, and trade organizations, and NERC technical committees on additional information needed.

- Year Five (2029):
    - ERO to File informational filing with FERC.
    - ERO to conduct review of this process and make necessary revisions based on lessons-learned and feedback (e.g., CMEP feedback loops, FERC, SMEs)
    - ERO to provide training on benchmark event process and changes to the Weather Event Library.



Criteria in Attachment B

Scoping

While the development of the extreme weather event library was intended to be comprehensive, it was not exhaustive. Instead, this initial assessment is a part of a multi-year effort by NERC and industry to develop a robust, North American weather dataset and detailed process for extreme weather events. In the interim, this library of extreme heat and cold events has notable considerations:

- Only extreme heat and cold temperature events were evaluated. The analysis did not assess other weather events such as hydrologic droughts, wind and solar droughts, wildfires, hurricanes, or other extreme weather events that could jeopardize grid reliability.
- Only historical meteorological data was considered. The analysis did not incorporate climate projections or future weather patterns.
- The analysis identified extreme events over a 43-year historical record and did not give higher priority to recent events
- The study is limited in identifying extreme events, not validating or explaining meteorological drivers of that event
- The analysis relied on historical reanalysis and *modeled* weather data rather than historical observed data for the United States (A smaller observed dataset was used for Canada).

Data Sources

A Pacific Northwest National Laboratory (PNNL) weather dataset[5] used in this study consists of 43 years (1980-2022) of historical hourly meteorology and roughly 80 years (2020-2099) of projected hourly meteorology. Hourly observations were dynamically downscaled from historical reanalysis of ERA5 data into higher temporal and spatial resolutions using the Weather Research and Forecasting Model (WRF). The model resolution consisted of 12km^2 areas that were spatially-averaged by county and then population-weighted to 54 Balancing Authorities (BAs) in the conterminous United States. The variables included in the final BA weather data are listed in Table 1. While additional parameters like humidity, solar irradiance, and wind speed are available in the dataset, the identification of extreme weather events in this study was solely determined by the temperature value.

Table 1: Weather Variables in PNNL Dataset

Variable	Name	Description	Units
Time	Time_UTC	Hour in Coordinated Universal Time	-
Temperature	T2	2-m temperature	K
Specific Humidity	Q2	2-m water vapor mixing ratio	kg kg^{-1}
Shortwave Radiation	SWDOWN	Downwelling shortwave radiative flux at the surface	W m^{-2}
Longwave Radiation	GLW	Downwelling longwave radiative flux at the surface	W m^{-2}
Wind Speed	WSPD	10-m wind speed (derived from U10 and V10)	m s^{-1}

[5] Burleyson, C., Thurber, T., & Vernon, C. (2023). Projections of Hourly Meteorology by Balancing Authority Based on the IM3/HyperFACETS Thermodynamic Global Warming (TGW) Simulations (v1.0.0) [Data set]. MSD-LIVE Data Repository. https://doi.org/10.57931/1960530

The PNNL dataset and contributing model were chosen for this study due to the consistency, breadth and granularity of the weather data. The availability of weather data at the BA-level coincides with topology standards in power-system coordination in North America. Temperature observation methods can differ zoneally, so a standardized weather model, such as one in the PNNL dataset, offers unparallelled data consistency across large geographical areas.

Topology

The zone topology is a function of balancing authority jurisdiction and general knowledge of zoneal weather patterns. The goal of the topology was to split the North American System into several distinct zones that have similar electric power system properties (i.e. balancing authority and interconnections) and similar weather or climatological patterns. Balancing authorities with large areas of jurisdiction, exclusively ISOs and RTOs, are assigned their own weather zone. In geographical areas comprised of multiple balancing authorities, generalized weather zones are created to best represent zoneal weather patterns.

Table 2: Balancing Authority to Weather Zone Mappings

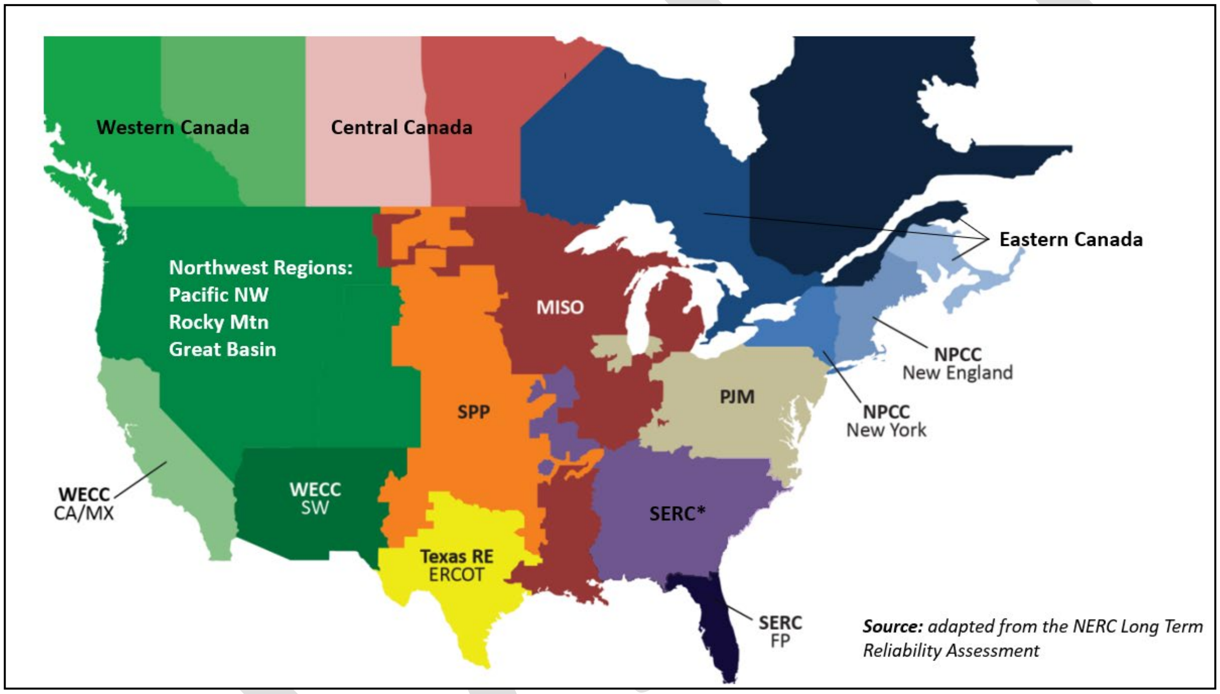
Zone	Balancing Authorities
Midwest	MISO
New England	ISONE
Central US	SPP
Texas	ERCOT
New York	NYISO
Central Atlantic	PJM
California	5 balancing authorities
Pacific Northwest	10 balancing authorities
Rocky Mountain	3 balancing authorities
Great Basin	4 balancing authorities
Southwest	6 balancing authorities
Southeast	7 balancing authorities
Florida	9 balancing authorities

In addition to the 13 weather zones representing the United States, three weather zones were developed to represent Eastern, Central, and Western Canada. The PNNL weather dataset does not contain data for Canada, so this study compiled observed weather data from weather stations in the lower Canadian Provinces. The sixteen weather zones best represent the area of study and complement the granularity of available data. A graphical representation of the final weather zones is shown in Figure 1.

Table 3: Canadian Weather Stations to Weather Zone Mappings

Weather Zones	Province	Weather Stations
Eastern Canada	Ontario	1 weather station
	Quebec	3 weather stations
	New Brunswick	1 weather station
	Nova Scotia	1 weather station
Central Canada	Saskatchewan	2 weather stations
	Manitoba	1 weather station
Western Canada	British Columbia	2 weather stations
	Alberta	2 weather stations

Figure 1: North American Weather Zones for Extreme Weather Events



Event Selection Process
Extreme weather events are defined in this study as extremely hot or cold multi-day events spanning across multiple weather zones. The process to select these extreme events used temperature as the sole defining variable, with emphasis placed on date ranges where multiple weather zones were experiencing historically hot or cold temperatures.

Aggregating balancing authority data to geographical weather zones
Following the topology detailed above, the hourly temperature observations from either the PNNL weather dataset or Canadian weather stations are assigned to weather zones. For each balancing area in the United States, the PNNL data is aggregated from a county-level basis up to the balancing authority based on the

population in each county. The balancing authority temperature aggregation was therefore provided in the PNNL dataset.

Additional aggregations were required to develop an average minimum, average, and maximum temperature for zones with multiple balancing authorities in the Northwest, Southwest, and Southeast. In these weather zones, the hourly temperature of each balancing authority was weighted by the 2022 peak load value reported in the EIA Form-861 database. For the Canadian zones, weather station temperature observations were assigned to the nearest population center and weighted by 2021 Census population.

Calculating Three-Day Rolling Average Min/Max Temperatures

Rather than isolating single hours of extreme weather, the rolling 3-day average of minimum and maximum daily temperatures are chosen to represent prolonged periods of extreme weather. The three-day averaging period is centered on every day in the data set (January 1, 1980, to December 31, 2022) and identifies the average minimum and maximum temperature from the day before, day of, and day after. The output of this process develops a dataset of multi-day minimum and maximum temperatures to filter out individual days of extreme heat or cold under the assumption that the power system is more challenged by sustained periods of extreme heat or cold due to cumulative effects on increasing demand and generator outages.

Selecting and Ranking Extreme Weather Events by Severity

Once 3-day average temperatures were calculated for every day, the forty coldest minimum values and forty warmest maximum values were isolated and ranked for each zone, with rank 1 illustrating the most extreme event. To avoid overlap of events within the same period, any ranked weather events within one week of another would be removed in favor of the most extreme event. For example, if a zone's seventh- and tenth-most extreme event occur within a 7-day period, only the day with the seventh-most extreme event would remain in the event database. As a result, some zones may have a discontinuous ranked list given the removal of "duplicate" events.

A similar one-week overlap method was developed to group contemporaneous extreme weather events amongst weather zones. First, all event dates were expanded to have a one-week "overlap period" centered on each date. Then, beginning with the earliest event date, all events that share at least one day of their overlap periods with the selected event date's overlap period will be grouped together. The final event date range will take the earliest and latest dates of all grouped event overlap periods.

The design of the distinct event date ranges encourages multiple weather zones to share extreme weather events over the course of a one- to two-week event period. To graphically represent the shared extreme events, all event ranges are listed with the affected zones' ranks in west-to-east order. A final shortlist of extreme weather events was developed across all zones. This list included the top one and two most extreme events, done separately for heat and cold periods. Any event that included at least three zones experience a top five event simultaneous was also included. For example, if PJM, NYISO, and ISONE all experienced a top five extreme event, but it was not a top one or two event for any zone in isolation, the event was included in the final shortlist.

Results
The result tables show the filtered list of event date ranges with the event ranks for each affected zone; a lower rank represents a more extreme event and is shaded darker.

Cold Events
The cold events shown in Table 4 demonstrate more concentrated events among nearby zones, with the most extreme temperature event occurring December 20th to December 29th, 1983. The event uniquely spanned across the conterminous United States and yielded top ten coldest 3-day average minimum temperatures in 10 different weather zones.

Under these results, the following cold events are recommended for the NERC library:

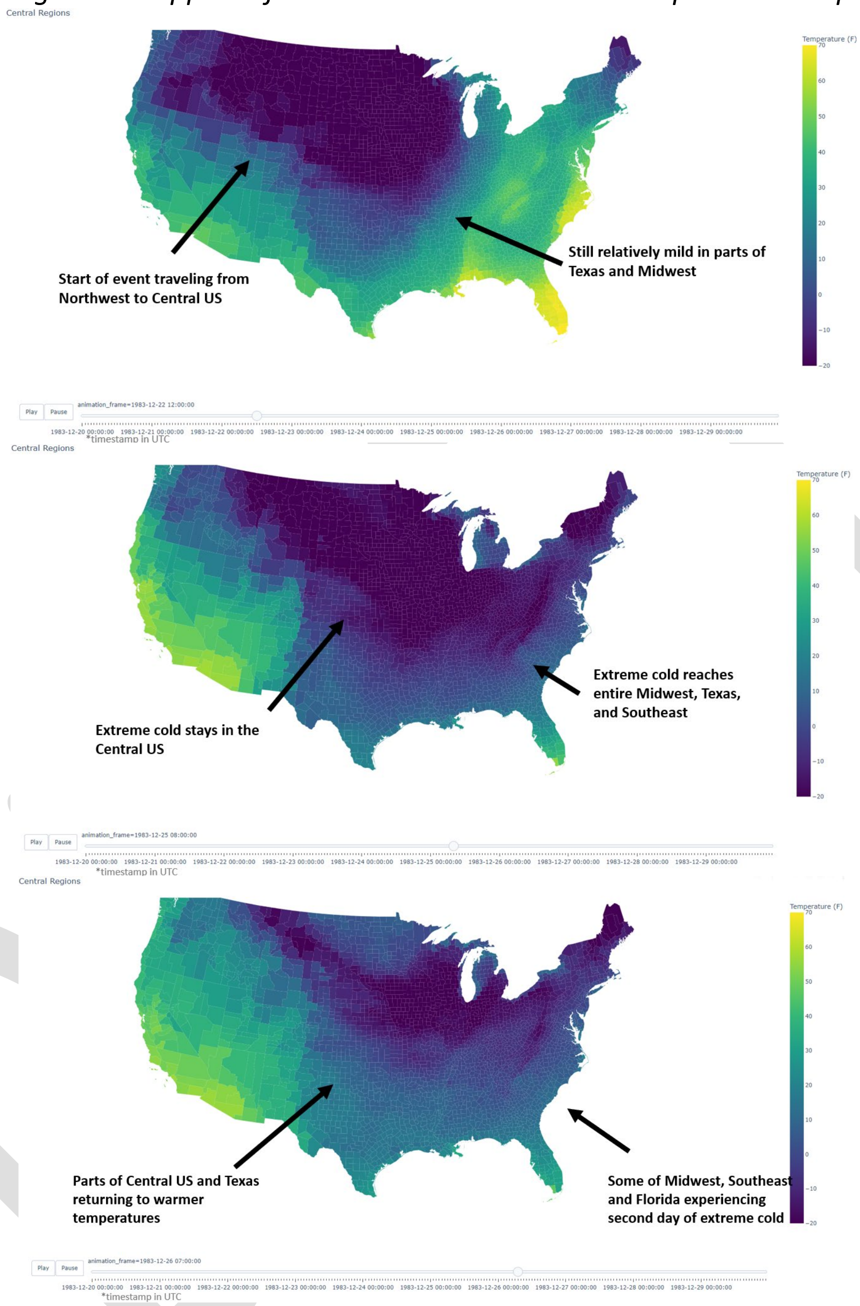
- 12/17/1990 – 1/2/1991 for the Western U.S. and Canada
  - 12/21 for Pacific NW
  - 12/22 for Rocky Mountain, Great Basin, California
  - 12/23 for Southwest
  - 12/29 for Western Canada
- 12/19/1989 – 12/27/1989 for Central and Southeast U.S. and Canada
  - 12/23 for Central Canada
  - 12/24 for Central US
  - 12/25 for Texas, Midwest, Southeast
  - 12/26 for Florida
- 1/13/1994 – 1/29/1994 for the Northeast U.S. and Canada
  - 1/16 for New England, Eastern Canada
  - 1/20 for Central Atlantic, New York

Table 4: Shortlist of Cold Events

Start Date	End Date	Western Canada	Pacific NW	Rocky Mountain	Great Basin	California	Southwest	Texas	Central Canada	Central US	Midwest	Southeast	Florida	Central Atlantic	New York	New England	Eastern Canada
1/1/1981	1/7/1981														10	1	1
1/9/1981	1/16/1981											12	4	10	2	12	11
1/15/1982	1/21/1982													9	7	6	2
12/20/1983	12/29/1983	9	3	4				3	6	2	4	2	3	3			
1/16/1984	1/24/1984			7						13	3	15		2	3		16
1/17/1985	1/25/1985							11		10	10	1	1	4			
1/29/1985	2/7/1985		15	2	3	12	6	9		7	9						
1/29/1989	2/9/1989	1	2	3	2	2			16	12							
12/19/1989	12/27/1989							1		1	5	3	2	5			15
12/17/1990	1/2/1991	8	1	1	1	1	1			16							
1/13/1994	1/29/1994										2	7		1	1	3	4
1/28/1996	2/8/1996	15	10	9				5	1	3	1	5		7	18		
1/23/1997	1/29/1997	2							7								
1/11/2004	1/18/2004														9	2	6
1/30/2011	2/12/2011			5			2	4		11	13						
1/10/2013	1/17/2013				4	5	3										
2/10/2021	2/19/2021			12				2	2	4	15						

It is important to note that these weather events do not affect all zones simultaneously, but instead move across the continent in predictable patterns. This has important implications for power system operations and reliability as load and generator availability may be affected in different zones in different times. An example of this is from the 1983 event shown geographically in Figure 2. In this example, the worst case does not occur at the same time in each zone and ideally multiple time periods should be assessed by the planning coordinators.

Figure 2: Snippets of Animated Weather Event Temperature Map



Heat Events

The heat events shown in Table 5 are more numerous and disparate from one another. In other words, while extreme cold events tend to affect large geographies simultaneously, heat events can be more localized. The unconcentrated nature of heat events makes selecting the most extreme event more ambiguous.

Under these results, the following heat events are recommended for the NERC library:

- 7/13/2006 – 7/26/2006 for the Western U.S. and Canada
  - 7/16 for Rocky Mountain, Great Basin
  - 7/22 for Western Canada, Pacific NW
  - 7/23 for California, Southwest
- 6/21/2012 – 7/9/2012 for Central and Southeast U.S. and Canada
  - 6/26 for Texas
  - 6/28 for Central Canada, Central US
  - 6/30 for Southeast, Florida
  - 7/5 for Midwest
- 7/16/2021 – 7/25/2021 for the Northeast U.S. and Canada
  - 7/21 for Central Atlantic, Eastern Canada
  - 7/22 for New York, New England

Table 5: Shortlist of Heat Events

Start Date	End Date	Western Canada	Pacific NW	Rocky Mountain	Great Basin	California	Southwest	Texas	Central Canada	Central US	Midwest	Southeast	Florida	Central Atlantic	New York	New England	Eastern Canada
6/24/1980	7/2/1980						13	2									
8/23/1984	8/29/1984								2								
7/3/1988	7/11/1988										13			13			1
8/11/1988	8/19/1988										1			4	7	17	
6/23/1990	6/29/1990						2										
7/16/1991	7/24/1991													16	9	1	8
7/25/1995	7/31/1995			10			1	10									
6/15/1998	6/21/1998												1				
6/28/1998	7/4/1998												2				
7/9/1998	7/22/1998			2	3			14									
7/2/1999	7/8/1999													2	1	6	
9/1/2000	9/7/2000							1									
8/5/2001	8/11/2001													8	3	5	2
6/23/2002	7/6/2002	4		7										18	13	2	3
7/8/2002	7/16/2002	5			1												
7/8/2005	7/26/2005			1	8		8			13							16
7/13/2006	7/26/2006	2	6	5		3				3	9						
8/13/2007	8/19/2007											2					
7/16/2011	7/25/2011									9	14			6	2	3	4
7/30/2011	8/6/2011							5		2		4					
6/21/2012	7/9/2012			3				9		5	2	1		1			
7/29/2012	8/5/2012									1	8						
8/6/2018	8/14/2018	3	18						1								
9/3/2020	9/9/2020					1											
6/25/2021	7/2/2021	1	1												16	21	
7/8/2021	7/14/2021				2												
8/10/2021	8/18/2021	8	2						5								

Recommendations

The results of this study should inform planning coordinators of potential dates of when to study power system conditions under extreme weather scenarios. While the final selection of event date ranges aligns with historical records of extreme weather, a few recommendations and considerations should be made before proceeding with this study's results.

- Planning coordinators should assess the entire list of distinct events shown and determine which events were the most extreme for their jurisdiction along with neighboring areas
- Modelled temperature data provides widespread consistency of weather data across many years and many zones. Observed temperature data can recognizably vary from modelled values due to the variety of observation methods at individual weather stations. The temperatures derived from the PNNL dataset for the extreme weather event selection can be provided, but actual temperature values used in planning scenarios may need to be derived from observed weather records for local consistency.

- While temperature is a strong indicator of extreme weather events, it is not the only indicator available in historical weather data sets. The inclusion of other weather variables such as humidity and wind speed could further quantify the severity of extreme weather events.
- Care should be taken when developing wind, solar, and generator outage assumptions in the planning cases, using meteorological information to dispatch.
- Exceptions need to be accounted for – including HVDC and switchable units.

Attachment B: Criteria used to develop the benchmark events

Criteria

Criteria for benchmark events to be drafted.

TPL-008-1 ERO Enterprise Benchmark Weather Event Development and Maintenance Process Document Version History			
Version	**Date**	**Owner**	**Change tracking**
1	TBD	Standards Staff	Initial Version

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

TPL-008-1 Benchmark Temperature Events

November 2024

The below provides extreme heat and extreme cold benchmark temperature event data per the zones identified in Attachment 1 of the TPL-008-1 Standard. Should entities not agree with the data provided below, you are welcome to coordinate with all Planning Coordinators within your zone to developing one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event per Requirement R2.

Benchmark Events			
Zone	**Daily Data**	**Top 40 Hottest/Coldest 3-Day Average**	**Hourly Data Selected Events**
Eastern Interconnection			
Canada Central	Daily	Top 40	*N/A*
Florida	Daily	Top 40	Hourly
ISO-NE	Daily	Top 40	Hourly
Maritimes	Daily	Top 40	*N/A*
MISO North	Daily	Top 40	Hourly
MISO South	Daily	Top 40	Hourly
NYISO	Daily	Top 40	Hourly
Ontario	Daily	Top 40	*N/A*
PJM	Daily	Top 40	Hourly
SERC	Daily	Top 40	Hourly
SPP North	Daily	Top 40	Hourly
SPP South	Daily	Top 40	Hourly
Western Interconnection			
California/Mexico	Daily	Top 40	Hourly
Great Basin	Daily	Top 40	Hourly
Rocky Mtn	Daily	Top 40	Hourly
Pacific NW	Daily	Top 40	Hourly

WECC Southwest	Daily	Top 40	Hourly
Canada West	Daily	Top 40	*N/A*
ERCOT Interconnection			
ERCOT	Daily	Top 40	Hourly
Quebec Interconnection			
Quebec	Daily	Top 40	*N/A*

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Standards Announcement

Project 2023-07 Transmission Planning Performance Requirements for Extreme Weather

Formal Comment Period Open through October 21, 2024

Now Available

A 15-day formal comment period for draft three of **TPL-008-1 – Transmission System Planning Performance Requirements for Extreme Temperature Events** is open through **8 p.m. Eastern, Monday, October 21, 2024**.

The Standards Committee approved waivers to the Standards Process Manual at their December 2023 meeting. These waivers were sought by NERC Standards for reduced formal comment and ballot periods to assist the drafting teams in expediting the standards development process due to firm timeline expectations set by FERC Order 896.

The standard drafting team's considerations of the responses received from the previous comment period are reflected in this draft of the standard.

Reminder Regarding Corporate RBB Memberships
Under the NERC Rules of Procedure, each entity and its affiliates is collectively permitted one voting membership per Registered Ballot Body Segment. Each entity that undergoes a change in corporate structure (such as a merger or acquisition) that results in the entity or affiliated entities having more than the one permitted representative in a particular Segment must withdraw the duplicate membership(s) prior to joining new ballot pools or voting on anything as part of an existing ballot pool. Contact ballotadmin@nerc.net to assist with the removal of any duplicate registrations.

Commenting
Use the Standards Balloting and Commenting System (SBS) to submit comments. An unofficial Word version of the comment form is posted on the project page.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

Additional ballots for the standard and implementation plan, as well as a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **October 11-21, 2024**.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Jordan Mallory (via email) or at 404-479-7358. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2023-07 Transmission Planning Performance Requirements for Extreme Weather observer list” in the Description Box.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comment Report

Project Name:	2023-07 Transmission Planning Performance Requirements for Extreme Weather | Draft 3
Comment Period Start Date:	10/7/2024
Comment Period End Date:	10/21/2024
Associated Ballots:	2023-07 Transmission Planning Performance Requirements for Extreme Weather Implementation Plan AB 3 OT 2023-07 Transmission Planning Performance Requirements for Extreme Weather TPL-008-1 AB 3 ST

There were 66 sets of responses, including comments from approximately 156 different people from approximately 101 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Requirement R1 requires Planning Coordinators (PCs) to identify their zone in the map included in Attachment 1. Do you agree with the zones identified on this map? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

2. The Drafting Team (DT) updated Requirement R2 based on comments received. Do you agree with the updated proposed TPL-008-1 Reliability Standard Requirement? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

3. The DT updated Requirements R3 – R4 based on comments received. Do you agree with the updated proposed TPL-008-1 Reliability Standard Requirements? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

4. The DT updated Requirements R7 – R8 based on comments received. Do you agree with the updated proposed TPL-008-1 Reliability Standard Requirements? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

5. The DT updated Requirements R9 – R11 based on comments received. Do you agree with the updated proposed TPL-008-1 Reliability Standard Requirements? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

6. The DT believes proposed modifications in TPL-008-1 provide entities with flexibility to meet the reliability objectives in a cost-effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost-effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

7. Provide any additional comments for the drafting team to consider, including the provided technical rationale document, if desired.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
MRO	Anna Martinson	1,2,3,4,5,6	MRO	MRO Group	Shonda McCain	Omaha Public Power District (OPPD)	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jamison Cawley	Nebraska Public Power District	1,3,5	MRO
					Jay Sethi	Manitoba Hydro (MH)	1,3,5,6	MRO
					Husam Al-Hadidi	Manitoba Hydro (System Preformance)	1,3,5,6	MRO
					Kimberly Bentley	Western Area Power Adminstration	1,6	MRO
					Jaimin Patal	Saskatchewan Power Coporation (SPC)	1	MRO
					George Brown	Pattern Operators LP	5	MRO
					Larry Heckert	Alliant Energy (ALTE)	4	MRO
					Terry Harbour	MidAmerican Energy Company (MEC)	1,3	MRO
					Dane Rogers	Oklahoma Gas and Electric (OG&E)	1,3,5,6	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Ayotte	ITC Holdings	1	MRO
					Andrew Coffelt	Board of Public Utilities-Kansas (BPU)	1,3,5,6	MRO
					Peter Brown	Invenergy	5,6	MRO

					Angela Wheat	Southwestern Power Administration	1	MRO
					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Joshua Phillips	Southwest Power Pool	2	MRO
					Patrick Tuttle	Oklahoma Municipal Power Authority	4,5	MRO
Midcontinent ISO, Inc.	Bobbi Welch	2	MRO,RF,SERC	ISO/RTO Council Standards Review Committee (SRC) Project 2023-07 TPL-008-1 Draft #3	Helen Lainis	IESO	2	NPCC
					Keith Jonassen	ISO-NE	2	NPCC
					Bobbi Welch	MISO	2	RF
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Charles Yeung	SPP	2	MRO
					Elizabeth Davis	PJM	2	RF
Jennie Wike	Jennie Wike		WECC	Tacoma Power	Jennie Wike	Tacoma Public Utilities	1,3,4,5,6	WECC
					John Merrell	Tacoma Public Utilities (Tacoma, WA)	1	WECC
					John Nierenberg	Tacoma Public Utilities (Tacoma, WA)	3	WECC
					Hien Ho	Tacoma Public Utilities (Tacoma, WA)	4	WECC
					Terry Gifford	Tacoma Public Utilities (Tacoma, WA)	6	WECC
					Ozan Ferrin	Tacoma Public Utilities (Tacoma, WA)	5	WECC
Eversource Energy	Joshua London	1		Eversource	Joshua London	Eversource Energy	1	NPCC
					Vicki O'Leary	Eversource Energy	3	NPCC
Public Utility District No. 1	Joyce Gundry	3		CHPD	Rebecca Zahler	Public Utility District No. 1	5	WECC

of Chelan County						of Chelan County		
					Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC
					Diane Landry	Public Utility District No. 1 of Chelan County	1	WECC
					Tamarra Hardie	Public Utility District No. 1 of Chelan County	6	WECC
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	RF
National Grid USA	Michael Jones	1		National Grid	Michael Jones	National Grid USA	1	NPCC
					Brian Shanahan	National Grid USA	3	NPCC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC

Randy Buswell	Vermont Electric Power Company	1	NPCC
James Grant	NYISO	2	NPCC
Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
David Burke	Orange and Rockland	3	NPCC
Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
Salvatore Spagnolo	New York Power Authority	1	NPCC
Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
David Kwan	Ontario Power Generation	4	NPCC
Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
Sean Cavote	PSEG	4	NPCC
Jason Chandler	Con Edison	5	NPCC
Tracy MacNicoll	Utility Services	5	NPCC
Shivaz Chopra	New York Power Authority	6	NPCC
Vijay Puran	New York State Department of Public Service	6	NPCC
David Kiguel	Independent	7	NPCC
Joel Charlebois	AESI	7	NPCC
Joshua London	Eversource Energy	1	NPCC
Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC

					Joel Charlebois	AESI	7	NPCC
					John Hastings	National Grid	1	NPCC
					Erin Wilson	NB Power	1	NPCC
					James Grant	NYISO	2	NPCC
					Michael Couchesne	ISO-NE	2	NPCC
					Kurtis Chong	IESO	2	NPCC
					Michele Pagano	Con Edison	4	NPCC
					Bendong Sun	Bruce Power	4	NPCC
					Carvers Powers	Utility Services	5	NPCC
					Wes Yeomans	NYSRC	7	NPCC
					Chantal Mazza	Hydro Quebec	1	NPCC
					Nicolas Turcotte	Hydro Quebec	2	NPCC
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Victoria Crider	Dominion Energy	3	NA - Not Applicable
					Sean Bodkin	Dominion Energy	6	NA - Not Applicable
					Steven Belle	Dominion Energy	1	NA - Not Applicable
					Barbara Marion	Dominion Energy	5	NA - Not Applicable
Shannon Mickens	Shannon Mickens		MRO,SPP RE,WECC	SPP RTO	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Mia Wilson	Southwest Power Pool Inc.	2	MRO
					Eddie Watson	Southwest Power Pool Inc.	2	MRO
					Erin Cullum	Southwest Power Pool Inc.	2	MRO
					Jonathan Hayes	Southwest Power Pool Inc.	2	MRO
					Jeff McDiarmid	Southwest Power Pool Inc.	2	MRO

					Scott Jordan	Southwest Power Pool Inc	2	MRO
					Mason Favazza	Southwest Power Pool Inc	2	MRO
					Sherri Maxey	Southwest Power Pool Inc.	2	MRO
					Josh Phillips	Southwest Power Pool Inc.	2	MRO
Western Electricity Coordinating Council	Steven Rueckert	10		WECC	Steve Rueckert	WECC	10	WECC
					Curtis Crews	WECC	10	WECC

1. Requirement R1 requires Planning Coordinators (PCs) to identify their zone in the map included in Attachment 1. Do you agree with the zones identified on this map? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Devin Shines – LG&E/KU	
Answer	Yes
Document Name	
Comment	
LG&E/KU agrees with the modifications to R1 that clarify the responsibilities to be identified between the PC and TP, and that require the Extreme Temperature Assessment (ETA) to be completed once every five years. Identification of zones is required in Requirement R2 rather than R1. LG&E/KU agrees with the content of Attachment 1 and the identification of zones according to the table (not map). LG&E/KU notes that the question in this comment form was not updated to reflect changes made to the standard just before the comment period (namely, zones being identified in Requirement R2 and the table of Attachment 1 controlling rather than the table).	
Likes 0	
Dislikes 0	
Response	

Michele Tondalo - United Illuminating Co. - 1	
Answer	No
Document Name	
Comment	
Comparing the table and map is confusing. There are 20 regions shown in the map and 17 in the table; it is not clear why there is a discrepancy. In addition, the map shows the Quebec colored region as part of Eastern Canada which is different than the table, which separates Quebec and Ontario.	
Likes 0	
Dislikes 0	
Response	

Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	

Many of the zones are very big, often including a large north-to-south range, such that a single heat or cold benchmark event cannot adequately cover all locations within a zone. Consider MISO in particular – can a single criterion suffice for Minnesota and Louisiana?

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	

Comment
FirstEnergy supports EEI's response, which state: In general, EEI member companies see some value in retaining the maps included in the TPL-008-1, however, we remain concerned that the temperature regions as proposed in those maps (and elsewhere) are in a number of cases far too large to provide meaningful analysis (e.g., MISO and SPP in particular). Additionally, EEI does not agree that maintaining disconnected parts of SERC and PJM into the broader SERC and PJM temperature zones makes any sense. For this reason, we do not support the temperature zones as currently proposed and ask that they be modified. To address our concerns, we suggest at a minimum that 1) SPP and MISO both be split into a north and south region, and 2) the disconnected portions of SERC and PJM be included into zones that more closely align with their temperature regions.

Likes 0	
Dislikes 0	

Response

Mark Flanary - Midwest Reliability Organization - 10	
Answer	No
Document Name	

Comment
The Requirement R1 language doesn't refer to zones. Please see our comments below to question 2.

Likes 0	
Dislikes 0	

Response

Helen Lainis - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	

The IESO does not support nor agree with the zone mapping for Ontario. The zone developed for Eastern Canada includes the balancing authority jurisdictions for Ontario, Nova Scotia and New Brunswick. Ontario does not have similar weather and climatological patterns to Nova Scotia and New Brunswick. Aggregating these 3 balancing authorities to the same geographical weather zone is not supported by the actual extreme events experienced by each jurisdiction. In fact, Ontario is more likely to share similar weather and climatological patterns with US neighboring balancing authorities NYISO and ISONE than it does with Nova Scotia and New Brunswick.

We strongly suggest that the Province of Ontario be assigned its own weather zone. In addition, at least 2 more weather stations would need to be sampled, similar to what is done for Quebec (refer to table in ERO Benchmark Process). It is not clear which weather station is being currently used for Ontario, but assuming it is from southwestern Ontario (Pearson), weather data from northern (Thunder Bay) and eastern Ontario (Ottawa) would be required for a more accurate representation of Ontario weather patterns.

Likes 1	Ontario Power Generation Inc., 5, Chitescu Constantin
Dislikes 0	
Response	

Erin Wilson - NB Power Corporation - New Brunswick Power Transmission Corporation - 5	
Answer	No
Document Name	
Comment	

The zones shown in Attachment 1 lumps Ontario with the Maritimes (New Brunswick, Nova Scotia, and parts of Northern Maine); however, practical experience has shown that there is no reliability benefit to coordinating the extreme weather planning assessments for two reasons:

- Experience has shown that Ontario and the Maritimes are sufficiently distant from each other as to experience extreme temperature conditions at different times. An extreme temperature event in Ontario would not occur at the same time as an extreme temperature event in the Maritimes.
- The balancing areas of Ontario and the Maritimes are not adjacent and the capacity of the transmission system to transfer power between Ontario and the Maritimes is small enough that the power transfered between Ontario and the Maritimes would most likely be negligible during an extreme temperature event.

For the NPCC region, it would make the most sense to divide the weather zones for extreme weather planning assessments along the boundaries of the existing Reliability Coordinator areas, resulting in five different weather zones:

- ISO New York

- ISO New England
- Ontario
- Quebec
- The Maritimes, including New Brunswick, Nova Scotia, and Northern Maine

In addition to the foregoing, New Brunswick Power would like to support the comments of Helen Lainis, Independent Electricity System Operator.

Note that these comments actually apply to R2, which is the requirements for PCs to identify their zone on the map in Attachment 1 -- R1 is actually unrelated to the above question.

Likes 0	
Dislikes 0	

Response

Jeffrey Streifling - NB Power Corporation - 1	
Answer	No
Document Name	

Comment

The zones shown in Attachment 1 lumps Ontario with the Maritimes (New Brunswick, Nova Scotia, and parts of Northern Maine); however, practical experience has shown that there is no reliability benefit to coordinating the extreme weather planning assessments for two reasons:

- Experience has shown that Ontario and the Maritimes are sufficiently distant from each other as to experience extreme temperature conditions at different times. An extreme temperature event in Ontario would not occur at the same time as an extreme temperature event in the Maritimes.
- The balancing areas of Ontario and the Maritimes are not adjacent and the capacity of the transmission system to transfer power between Ontario and the Maritimes is small enough that the power transfered between Ontario and the Maritimes would most likely be negligible during an extreme temperature event.

For the NPCC region, it would make the most sense to divide the weather zones for extreme weather planning assessments along the boundaries of the existing Reliability Coordinator areas, resulting in five different weather zones:

- ISO New York
- ISO New England
- Ontario
- Quebec
- The Maritimes, including New Brunswick, Nova Scotia, and Northern Maine

In addition to the foregoing, New Brunswick Power would like to support the comments of Helen Lainis, Independent Electricity System Operator.

Note that these comments actually apply to R2, which is the requirements for PCs to identify their zone on the map in Attachment 1 -- R1 is actually unrelated to the above question.

Likes 0	
Dislikes 0	

Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Dominion Energy supports EEI comments	
Likes 0	
Dislikes 0	
Response	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) on question 1	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon does not agree with the zones identified on the map in Attachment 1. We suggest the map should better align to the various temperature gradients a zone may experience. The map that has been proposed seems to prioritize PC and TP boundaries over identifying the geographic regions extreme temperature events have occurred in. Additionally, Exelon supports the comments submitted by the EEI.	
Likes 0	

Dislikes 0	

Response

Casey Perry - PNM Resources - 1,3 - WECC,Texas RE

Answer	No
Document Name	

Comment

PNM Resources (PNMR) is concerned with picking weather data that is comparable between New Mexico and Arizona. We believe differences in weather patterns would impact New Mexico study if building that study to Arizona's summer temperatures.

Likes 0	
Dislikes 0	

Response

Sharon Darwin - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

Southern Company supports EEI's comments.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment

In general, EEI member companies see some value in retaining the maps included in the TPL-008-1, however, we remain concerned that the temperature regions as proposed in those maps (and elsewhere) are in a number of cases far too large to provide meaningful analysis (e.g., MISO and SPP in particular). Additionally, EEI does not agree that maintaining disconnected parts of SERC and PJM into the broader SERC and PJM temperature zones makes any sense. For this reason, we do not support the temperature zones as currently proposed and ask that they be modified. To address our concerns, we suggest at a minimum that 1) SPP and MISO both be split into a north and south region, and 2) the disconnected portions of SERC and PJM be included into zones that more closely align with their temperature regions.

EEI is also concerned that benchmark temperature events reside outside of this Reliability Standard placing unnecessary compliance risks for companies. To address this concern, we ask that the benchmark temperature event be included into TPL-008-1 as an attachment.

Likes 0	
Dislikes 0	

Response

Michael Brytowski - Great River Energy - 3

Answer	No
Document Name	

Comment

The MISO zone should be divided into 2 zones – MISO North and MISO south.

The weather differences between Northern Minnesota and Southern Louisiana are too extreme to conduct a meaningful assessment.

The winter temperatures in the MISO benchmark event data are just an average January for Minnesota and those winter temperatures will not be experienced in Louisiana. Similarly, the SPP zone should be spilt north and south as well.

Likes 1	Scott Brame, N/A, Brame Scott
Dislikes 0	

Response

Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza

Answer	No
Document Name	

Comment

We support Independent Electricity System Operator's and NB Power Corporation comments.

Furthermore, Attachment 1 – Extreme Temperature Assessment Zones in accordance with Requirement R2: We agree with Québec being its own Interconnection in the map and in the table, however Québec is the only area that has its own zone in the table which does not correspond to a Weather Zone identified in the Benchmark Process. Similarly, it is not in the list of benchmark temperature event data on the project page under "Benchmark Event Data". For example, ERCOT is identified as its own Interconnection and has its own list of benchmark temperature events. Another example is Florida in the SERC region warrants a separate treatment and has its own benchmark temperature event data.

Lastly, the Quebec zone does not appear in the TPL-008 Attachment 1 map, while it is in the table just above. We suggest adding the label "Québec" or "Quebec Interconnection" in white font in the dark blue space represented by the province of Quebec and changing the color of the province of Québec to better reflect that it is its own interconnection.

Likes 0	

Dislikes 0	
Response	
Joseph Knight - Joseph Knight On Behalf of: Jacalynn Bentz, Great River Energy, 3, 1, 5, 6; - Joseph Knight	
Answer	No
Document Name	
Comment	

The MISO zone should be divided into 2 zones – MISO North and MISO south.

The weather differences between Northern Minnesota and Southern Louisiana are too extreme to conduct a meaningful assessment.

The winter temperatures in the MISO benchmark event data are just an average January for Minnesota and those winter temperatures will not be experienced in Louisiana. Similarly, the SPP zone should be spilt north and south as well.

Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	
Comment	

AZPS supports the following comments that were submitted by EEI on behalf of its members:

In general, EEI member companies see some value in retaining the maps included in the TPL-008-1, however, we remain concerned that the temperature regions as proposed in those maps (and elsewhere) are in a number of cases far too large to provide meaningful analysis (e.g., MISO and SPP in particular). Additionally, EEI does not agree that maintaining disconnected parts of SERC and PJM into the broader SERC and PJM temperature zones makes any sense. For this reason, we do not support the temperature zones as currently proposed and ask that they be modified. To address our concerns, we suggest at a minimum that 1) SPP and MISO both be split into a north and south region, and 2) the disconnected portions of SERC and PJM be included into zones that more closely align with their temperature regions.

EEI is also concerned that benchmark temperature events reside outside of this Reliability Standard placing unnecessary compliance risks for companies. To address this concern, we ask that the benchmark temperature event be included into TPL-008-1 as an attachment.

Likes 0	
Dislikes 0	
Response	

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC (CEHE) supports EEI's partial response to question 1, in regard to benchmark temperature events residing outside the Reliability Standard placing unnecessary compliance risks for companies. CEHE requests that the benchmark temperature events be included into TPL-008-1 as an attachment.	
Likes 0	
Dislikes 0	
Response	

Kinte Whitehead - Exelon - 3	
Answer	No
Document Name	
Comment	
Exelon does not agree with the zones identified on the map in Attachment 1. We suggest the map should better align to the various temperature gradients a zone may experience. The map that has been proposed seems to prioritize PC and TP boundaries over identifying the geographic regions extreme temperature events have occurred in. Additionally, Exelon supports the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	No
Document Name	
Comment	
Comparing the table and map is confusing. There are 20 regions shown in the map and 17 in the table; it is not clear why there is a discrepancy. In addition, the map shows the Quebec colored region as part of Eastern Canada which is different than the table, which separates Quebec and Ontario.	
Likes 0	
Dislikes 0	

Response	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
OPG supports NPCC Regional Standards Committee's comments.	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	No
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	

Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	No
Document Name	
Comment	
R2 (not R1) requires PC to identify their zone in the map included in attachment1. The MISO and SPP zones are spread across multiple temperature regions. This would make it difficult for MISO and SPP to choose a single extreme temperature event that would provide meaningful assessment results across their respective zones. The MISO and SPP zones should be split into MISO North, MISO South, SPP North, and SPP South. Also, the disjointed sections of SERC Central are in a different temperature region that others included in the SERC zone. The disjointed section s of SERC Central should be included in the appropriate MISO or SPP zone that aligns with their temperature region.	
Likes 0	
Dislikes 0	
Response	
Wayne Guttormson - SaskPower - 1	
Answer	No
Document Name	
Comment	
Zones are nominally adequate, except Eastern Canada which needs to be split into Ontario and the Maritimes. Support SPP's comment - "if the goal is for the PCs to study a 1 in 40-year event for temperature that each PC perform a study for their footprint and share results to the adjacent PCs, similar to the way existing NERC standards are coordinated."	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
ITC sees some value in retaining the maps included in the TPL-008-1, however, we remain very concerned that the temperature regions as proposed in the map (and elsewhere) are in a number of cases far too large to provide meaningful analysis (e.g., MISO and SPP in particular). Additionally, the benchmark temperature events identified for both MISO and SPP do not represent what would be considered extreme temperature events due to their	

large geographically diverse regions. To address our concerns, we suggest at a minimum that SPP and MISO both be split into a north and south region.

ITC is also concerned that benchmark temperature events reside outside of this Reliability Standard placing unnecessary compliance risks for companies. To address this concern, we ask that the benchmark temperature event be included into TPL-008-1 as an attachment.

Likes 0	
Dislikes 0	

Response

Michele Shafer - New York State Electric & Gas (NYSEG) - 6

Answer	No
Document Name	

Comment

Comparing the table and map is confusing. There are 20 regions shown in the map and 17 in the table; it is not clear why there is a discrepancy. In addition, the map shows the Quebec colored region as part of Eastern Canada which is different than the table, which separates Quebec and Ontario.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO

Answer	No
Document Name	

Comment

SPP does not have any issues with the eastern interconnect portion of the Table and Map. However, SPP does have concerns with the western portion of the Table and Map. The Table and Map seem to group together PCs in a way that could create issues when trying to identify which PCs belong to those zones. There is currently no requirement to post publicly which zone a PC is within, therefore knowing which PC belongs to each zone is not possible.

Consideration is also needed for when a PC footprint changes in the future for this standard since the Table and Map represent current boundaries. If these boundaries change in the future this would require either more coordination or a change to the standard to allow for the boundary to change. A change to the standard would be overly administratively burdensome for such a future change.

There is also a reference in the requirement to Attachment 1 which refers to the Table, however the Map creates confusion when applying the Table due to the use of color code in the east and the lack of color coding in the west for the northwest region. There seems to be a lack of PC boundaries in the western footprint denoted in the Map. SPP would offer that if the Map is needed for Table 1 then the PC boundaries in the west should be identified and color coded appropriately.

Additionally, the technical rationale states the zones have been determined by the Reliability Coordinator (RC) area. SPP believes that breaking the zone by RC footprint is not accurate and should be divided by the PC footprint especially considering that the standard only applies to the PC. PC and RC footprints can be drastically different across the grid.

SPP would like to offer a secondary suggestion that if the goal is for the PCs to study a 1 in 40-year event for temperature that each PC perform a study for their footprint and share results to the adjacent PCs, similar to the way existing NERC standards are coordinated. For instance, there are other standards that utilize language for the applicable entity to study its PC footprint and coordinate with 1st tier entities. SPP believes that language similar to this can accomplish the intended goal without creating a burden if the boundaries change in the Map.

Likes 0	
Dislikes 0	

Response

Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - ReliabilityFirst - 10 - RF

Answer	No
Document Name	

Comment

When considering this requirement with the others for PC's that cover large diverse areas like SPP or MISO, the single temperature consideration for extreme hot or extreme cold does not seem to make sense. For instance, for MISO to use one extreme cold temperature for Texas and for northern Minnesota when they should consider very different extreme temperatures, an extreme cold temperature of 0 in Texas is normal cold for Minnesota. Opposite is true for extreme hot temperatures. PC's should have the ability to select different extreme temperatures within their zone, as worded it does not appear they have that option. This will work if latitude is considered and PC's can use different extreme temperatures within their zone

Likes 0	
Dislikes 0	

Response

Robert Blackney - Edison International - Southern California Edison Company - 1

Answer	No
Document Name	

Comment

See comments submitted by Edison Electric Institute.

Likes 0	
Dislikes 0	

Response

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
It is not Requirement R1, which requires PCs to identify their zones. Requirement R2 requires PCs to identify their zones and coordinate with other PCs in that zone. Manitoba Hydro has no issues with the identification of the Central Canada zone in Attachment 1.	
Likes 0	
Dislikes 0	
Response	

Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
SNPD has identified a potential typo in Question 1. Requirement R1 does not stipulate that PCs must identify their zone on the map included in Attachment 1. However, Requirement R2 clearly requires PCs to identify their zone on this map, and SNPD concurs with this requirement.	
Likes 0	
Dislikes 0	
Response	

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Although this appears to be an R2.	
Likes 0	
Dislikes 0	
Response	

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	

Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
We assume this is in reference to Requirement R2.	
Likes 0	
Dislikes 0	
Response	
Robert Jones - Seattle City Light - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Assuming this is referencing R2, not R1: The Zones are appropriate, assuming that the sub-zones in the "Northwest Regions" are treated as separate zones.	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC) Project 2023-07 TPL-008-1 Draft #3	
Answer	Yes
Document Name	

Comment	
The response to Question 1 is on behalf of MISO since (as the submitter of joint SRC comments) is otherwise unable to submit a Comment Form of its own.	
Likes 0	
Dislikes 0	
Response	

Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle

Answer	Yes
Document Name	
Comment	
PGAE agrees with the zoning, however, overlapping of zones within neighboring entities should be allowed to meet the requirements of extreme weather conditions. Although we agree that the focus of the study is within the boundary, PCs should have the flexibility to consider maybe a little bit past the confines of identified zone as identified in Attachment 1.	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF

Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ben Hammer - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Srikanth Chennupati - Entergy - 1,3,5,7 - SERC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gary Trezza - Long Island Power Authority - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Broc Bruton - Broc Bruton On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Broc Bruton	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE notes that it is Requirement R2, not Requirement R1 that requires to the PC to identify the zones.

In the Attachment 1 Table, Texas RE recommends revising the Planning Coordinators description to Areas in Texas that are part of the ERCOT Interconnection. This removes the word jurisdiction, since ERCOT does not have jurisdiction over NERC Reliability Standards.

In Requirement R1, Texas RE recommends the following revision for clarity:

R1. Each Planning Coordinator shall identify, in conjunction with its Transmission Planner(s), **shall identify and document** each entity's individual and joint responsibilities for completing the Extreme Temperature Assessment, which shall include each of the responsibilities described in Requirements R2 through R11. Each responsible entity shall complete its responsibilities such that the Extreme Temperature Assessment is completed at least once every five calendar years.

This clarifies that each Planning Coordinator and Transmission Planner(s) shall document the individual and joint responsibilities for completing the Extreme Temperature Assessment for clarity and to show proof of obligations as the responsible personnel may change from time to time. M1 details that the Planning Coordinator, in conjunction with its Transmission Planner(s), shall provide documentation of each entity's individual and joint responsibilities. However, need for documentation is not included in the Requirement.

Likes 0	
Dislikes 0	

Response

2. The Drafting Team (DT) updated Requirement R2 based on comments received. Do you agree with the updated proposed TPL-008-1 Reliability Standard Requirement? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Devin Shines – LG&E/KU	
Answer	Yes
Document Name	
Comment	
LG&E/KU appreciates the effort of the DT to create a process for identifying extreme benchmark temperature events that balances the need for transparency, practicality, and effectiveness. The process described in Requirement R2 provides entities with sufficient clarity on what constitutes an extreme benchmark temperature event, while also affording entities flexibility in how and which events are selected. LG&E/KU would request the DT consider whether Requirement R2 and its VSLs could be modified to address the situation where one (or more) Planning Coordinators in a zone does not coordinate. As-is, the Requirement R2 language could be understood as all other PCs in that zone also being out of compliance.	
Likes 0	
Dislikes 0	
Response	

Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle

Answer	No
Document Name	
Comment	
The role of ERO seems to be reduced to footnote 1, the DT further needs to clarify what "maintain" means in this context. PGAE would like to better understand the benefits of using benchmark libraries over local extreme weather conditions. We would like to see the periodicity of this maintain obligation for the ERO. If the DT could expand on the footnote 1 to provide clarification of ERO maintaining the library and how often ERO would be updating the library of benchmark temperature events.	
Likes 0	
Dislikes 0	
Response	

Michael Goggin - Grid Strategies LLC - 5

Answer	No
Document Name	
Comment	

the new requirement proposed in R2 2.1 in the updated draft that the event selected represent "one of the 20 most extreme temperature conditions" may result in entities selecting events that are not representative of the most severe generation shortfalls they are likely to experience. First, entities should be required to select from a smaller number of most severe events, like the three most severe events. Second, the ranking of events should not be based on most extreme temperature, but rather most severe generation shortage, accounting for both higher demand and higher generator outage rates during the event. This will accurately reflect that temperature alone does not determine the severity of an event, as wind speed, insolation, and other factors affect how extreme cold and heat affect both generator outages and the need for building heating or cooling.

Likes 0	
Dislikes 0	
Response	

Carver Powers - Utility Services, Inc. - 4

Answer	No
Document Name	
Comment	

USV has concerns about the proposed language in R2, Part 2.1. 40 years of temperature data is an immense amount of data. The data collected 40 years ago compared to today's temperatures may not be accurate and could construed the data from the last 20-25 years. We believe that there have been enough recent extreme weather events in the last 25 years to accurately consider extreme heat and extreme cold benchmark temperatures. We recommend that the drafting team consider utilizing a timeline closer to 20 years and not 40 years.

Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO

Answer	No
Document Name	
Comment	

The Table and Map seem to group together PCs in a way that could create issues when trying to identify which PCs belong to those zones. There is currently no requirement to post which zone the PC is in, therefore knowing which PC belongs to each zone is not possible, specifically for the western portion of the Table and Map.

Likes 0	

Dislikes 0	

Response

Michele Shafer - New York State Electric & Gas (NYSEG) - 6

Answer	No
Document Name	

Comment

The intent of the standard is to perform an extreme temperature assessment, but R2 allows for selection from the “20 most extreme” events from a period of 40 years. This could result in an entity being able to select an event that is relatively mild but still maintain compliance. This could be mitigated by narrowing the number of extreme events to select from down to a lower number, for example 10.

Likes 0	
Dislikes 0	

Response

Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford

Answer	No
Document Name	

Comment

See comments for question1. Additionally, the SDT should consider an official library or other repository from which the common extreme heat benchmark temperature event and common extreme cold benchmark temperature event is chosen. This library should either be included as an attachment to this standard, or the official location and maintenance should be documented within this standard.

If no official library is document, this could lead to ambiguities and inconsistencies in performing the assessment and in auditing this requirement.

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	No
Document Name	

Comment

OPG supports NPCC Regional Standards Committee’s comments.

Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	No
Document Name	
Comment	
The intent of the standard is to perform an extreme temperature assessment, but R2 allows for selection from the “20 most extreme” events from a period of 40 years. This could result in an entity being able to select an event that is relatively mild but still maintain compliance. This could be mitigated by narrowing the number of extreme events to select from down to a lower number, for example 10.	
Likes 0	
Dislikes 0	
Response	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
In the current zone designations, there are some zones where temperature differences would be significant due to their very large north/south geographical spans. A concern arises whether the chosen extreme temperature event case is applicable to the overall zone in these cases. It might not be representative of certain parts of the zone. Each Planning Coordinator, in conjunction with its Transmission Planner(s) shall select which extreme heat and extreme cold weather events to develop benchmark extreme temperature events applicable to their region.	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC) Project 2023-07 TPL-008-1 Draft #3	
Answer	No
Document Name	
Comment	

The **ISO/RTO Council (IRC) Standards Review Committee (SRC)**[1] supports the intent of Requirement R2, i.e., to provide Planning Coordinators (PCs) with the option of selecting a benchmark temperature event from the ERO library or the ability to develop one or more benchmark temperature events on their own. If the PC(s) select an event from either the ERO library, the ERO is responsible for providing data in support of Parts 2.1 and 2.2. Alternatively, if the PC(s) elects to develop a benchmark temperature event, the PC(s) is responsible for providing data in support of Parts 2.1 and 2.2. Therefore, the SRC proposes the following modification to clarify the intent of Requirement R2:

R2. Each Planning Coordinator shall identify the zone(s) to which the Planning Coordinator belongs to under Attachment 1, and shall coordinate with all Planning Coordinators within each of its identified zone(s), to select one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event ***from either the benchmark library developed, approved and maintained by the Electric Reliability Organization (ERO) or elect to develop one or both common benchmark temperature event(s)*** for each of its identified zone(s) when completing the Extreme Temperature Assessment.1 ***Each*** benchmark temperature event shall: [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

The SRC recommends that Part 2.2 be revised as follows to clarify the link between Part 2.2 and Part 2.1: "Represent one of the 20 most extreme temperature conditions **within the period identified in Part 2.1** based on the three-day rolling average…"

The SRC recommends that footnote 1 be revised to clarify that the ERO library may not contain all valid benchmark temperature events as Planning Coordinators are free to develop their own benchmark temperature events: "The Electric Reliability Organization (ERO) will maintain a library of the benchmark temperature events developed by the ERO that meet the criteria of Requirement R2, inclusive of Parts 2.1 and 2.2."

The SRC also requests that the drafting team clarify how the event temperature information (available on NERC's website) is intended to be used, and more specifically, whether it is to be applied across the entire zone.

[1] For purposes of these comments, the IRC SRC includes the following entities: IESO, ISO-NE, MISO, NYISO (except for a portion of our response to question 3 as noted in our response to question 3), PJM and SPP.

Likes 0	
Dislikes 0	

Response

Joseph Knight - Joseph Knight On Behalf of: Jacalynn Bentz, Great River Energy, 3, 1, 5, 6; - Joseph Knight

Answer	No
Document Name	

Comment

Requirement R2 and R3 following R1 creates confusion when reading the responsibilities of requirements 4-11. Consider reordering – R2, R3 then R1. Coordinating Zones, develop benchmark planning then conducting the assessments. The Transmission Planner (TP) is not referenced in R2 or R3.

R2 currently – Coordinating Zones

Each Planning Coordinator shall identify the zone(s) to which the Planning Coordinator belongs to under Attachment 1, and shall coordinate with all Planning Coordinators within each of its identified zone(s), to select one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event for each of its identified zone(s) when completing the Extreme Temperature Assessment.

R3 currently – a process for developing benchmark planning

Each Planning Coordinator shall coordinate with all Planning Coordinators within each of its zone(s) identified in Requirement R2, to implement a process for developing benchmark planning cases for the Extreme Temperature Assessment that represent the benchmark temperature events selected in Requirement R2 and sensitivity cases to demonstrate the impact of changes to the basic assumptions used in the benchmark planning cases.

R1 currently – The assessments

Each Planning Coordinator shall identify, in conjunction with its Transmission Planner(s), each entity's individual and joint responsibilities for completing the Extreme Temperature Assessment, which shall include each of the responsibilities described in Requirements R2 through R11. Each responsible entity shall complete its responsibilities such that the Extreme Temperature Assessment is completed at least once every five calendar years.

Likes 0	
Dislikes 0	

Response

Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop

Answer	No
Document Name	

Comment

Ameren believes the language in sections 2.1 and 2.2 are too prescriptive. We believe the Planning Coordinator should work with stakeholders to determine the data set that will be used to derive extreme heat and cold weather temperatures. Does the planning coordinator have the ability to carve the zones?

Likes 0	
Dislikes 0	

Response

Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza

Answer	No
Document Name	

Comment

We support Independent Electricity System Operator’s and NB Power Corporation comments.

Furthermore, our understanding of the Benchmark Process is that the Weather Zones were used to develop the lists (library) of Benchmark Events, and therefore each Weather Zone has its library. Our interpretation of the current document would be that Québec shares the same library "Eastern Canada" as our Canadian neighbors, without however having to choose the same events every 5 years because we are alone in our ETA Zone as per the table in Attachment 1.

Likes 0	
Dislikes 0	

Response

Michael Brytowski - Great River Energy - 3

Answer	No
Document Name	

Comment

Requirement R2 and R3 following R1 creates confusion when reading the responsibilities of requirements 4-11. Consider reordering – R2, R3 then R1. Coordinating Zones, develop benchmark planning then conducting the assessments. The Transmission Planner (TP) is not referenced in R2 or R3.

R2 currently – Coordinating Zones

Each Planning Coordinator shall identify the zone(s) to which the Planning Coordinator belongs to under Attachment 1, and shall coordinate with all Planning Coordinators within each of its identified zone(s), to select one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event for each of its identified zone(s) when completing the Extreme Temperature Assessment.

R3 currently – a process for developing benchmark planning

Each Planning Coordinator shall coordinate with all Planning Coordinators within each of its zone(s) identified in Requirement R2, to implement a process for developing benchmark planning cases for the Extreme Temperature Assessment that represent the benchmark temperature events selected in Requirement R2 and sensitivity cases to demonstrate the impact of changes to the basic assumptions used in the benchmark planning cases.

R1 currently – The assessments

Each Planning Coordinator shall identify, in conjunction with its Transmission Planner(s), each entity’s individual and joint responsibilities for completing the Extreme Temperature Assessment, which shall include each of the responsibilities described in Requirements R2 through R11. Each responsible entity shall complete its responsibilities such that the Extreme Temperature Assessment is completed at least once every five calendar years.

Likes 1	Scott Brame, N/A, Brame Scott
Dislikes 0	

Response

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	
Tacoma Power is concerned that there may be circumstances where not all Planning Coordinators in a zone will agree to one common cold and heat event. Instead of using "all Planning Coordinators" in the R2 Requirement language, Tacoma Power recommends using "majority of Planning Coordinators", as shown in the mark-up below. Tacoma Power also recommends the following changes to the R2 language. This change makes it clear that there's two distinct steps to this Requirement: 1) identifying the zone(s) and then 2) selecting two common events for all PCs in that zone. "Each Planning Coordinator shall identify the zone(s) to which the Planning Coordinator belongs to under Attachment 1. **The majority of Planning Coordinators within each of its identified zone(s) shall select** one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event for each of its identified zone(s) when completing the Extreme Temperature Assessment."	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Dominion Energy supports EEI comments	
Likes 0	
Dislikes 0	
Response	
Jeffrey Streifling - NB Power Corporation - 1	
Answer	No
Document Name	
Comment	
Please see comments for Question 1.	

Likes 0	
Dislikes 0	
Response	
Erin Wilson - NB Power Corporation - New Brunswick Power Transmission Corporation - 5	
Answer	No
Document Name	
Comment	
Please see comments for Question 1	
Likes 0	
Dislikes 0	
Response	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	No
Document Name	
Comment	
In the current zone designations, there are some zones where temperature differences would be significant due to their very large north/south geographical spans. A concern arises whether the chosen extreme temperature event case is applicable to the overall zone in these cases. It might not be representative of certain parts of the zone.	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	

It is inadequate for TPL-008 and for all NERC cold weather-related standards to select. just one cold weather benchmark, based exclusively on temperature. Several scenarios must be studied, covering the vulnerabilities of the various generation plant types – extreme cold plus high wind for conventional facilities, ice storms and wind droughts for wind turbines, nighttime and snow coverage for solar farms.

The best benchmarks are “perfect storm” combination events. What made Winter Storm Uri so destructive, for example, was that it began with an ice storm that took-out the wind fleet of northern Texas, followed by a deep freeze with high winds that tripped many conventional plants, then a wind drought that prevented the now-deiced wind turbines from helping.

The lookback period should be 50 years, to coincide with the 50-year periodicity data published by ASHRAE. NERC should in general make more use of ASHRAE data, to avoid making entities develop databases that are already available as a look-up.

Likes 0	
Dislikes 0	

Response

Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD

Answer	No
Document Name	

Comment

The Attachment 1 graphic would greatly benefit from including state boundaries, as well as mentioning the NERC benchmark library. Additionally, clarification added that entities may select events that meet these criteria, either from the library or as identified by the group of Coordinators. Please emphasize this flexibility of choice - it is likely to be lost in time.

NERC's consultant uses BA load weighting (based on notes and conversations provided in the 9/10 TPL-008 presentation). As a result, this weighting practice does not appear to directly meet this proposed R2.2 language regarding the most extreme events for a region. The temperature may not actually be representative of “across the zone” because of this weighting. Of reliability considerations, load is certainly part of the need, but potential impacts to generation and the connecting transmission, which may be in other regions, are also important pieces to the delivery of resource to load. Removal or modification of this R2 ‘most extreme’ language is recommended; or exempting the NERC library from needing to follow these criteria. Alternately, the SDT may modify to allow weighting to be used in method.

Because the NERC Extreme Weather Event library is only updated every 3 years in the current plan, it is possible that an event in the library would contain events that would not meet these R2 criteria for event “freshness”. The SDT may wish to consider modifying the language regarding time, or an additional clause, to permit events currently in the NERC Extreme Weather Event library to not be subject to the selection criteria currently in R2, or that entities may use the other criteria to evaluate and select other events.

Likes 0	
Dislikes 0	

Response

Michele Tondalo - United Illuminating Co. - 1

Answer	No

Document Name	
Comment	

The intent of the standard is to perform an extreme temperature assessment, but R2 allows for selection from the “20 most extreme” events from a period of 40 years. This could result in an entity being able to select an event that is relatively mild but still maintain compliance. This could be mitigated by narrowing the number of extreme events to select from down to a lower number, for example 10.

Likes 0	
Dislikes 0	
Response	

Robert Blackney - Edison International - Southern California Edison Company - 1

Answer	Yes
Document Name	
Comment	

See comments submitted by Edison Electric Institute.

Likes 0	
Dislikes 0	
Response	

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2

Answer	Yes
Document Name	
Comment	

ERCOT agrees with the updates to Requirement R2, and proposes the following clarifications based on ERCOT’s understanding of the intent and function of Requirement R2.

- To better reflect the role that the Planning Coordinator’s selection plays in Parts 2.1 and 2.2, ERCOT recommends that the last sentence of the first paragraph of Requirement R2 be revised to read “The Planning Coordinator’s selection of benchmark temperature events shall:”

- ERCOT recommends that Part 2.2 be revised as follows to clarify the link between Part 2.2 and Part 2.1: “Represent one of the 20 most extreme temperature conditions **within the period identified in Part 2.1** based on the three-day rolling average…”

- ERCOT recommends that footnote 1 either be removed or revised as follows to clarify that the ERO library might not contain all valid benchmark temperature events, as Planning Coordinators are free to select benchmark temperature events that meet the criteria of Requirement R2 even if those events are not in the ERO library: “The Electric Reliability Organization (ERO) will maintain a library of **some, but not necessarily all, of the** benchmark temperature events that meet the criteria of Requirement R2.”

Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
ITC supports the proposed changes made to Requirement R2.	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
WECC voted Affirmative for TPL-008 due to the timelines imposed on NERC by FERC. However, WECC still has some comments for the DT to consider. WECC is concerned that the proposed language for R2 may be unclear. WECC understands that the intent of R2 is to allow PCs the option of selecting a benchmark temperature event f rom the ERO library OR the ability to develop one or more benchmark temperature events based on their own experiences. If a PC selects an event fromt he ERO library, the EOR would be responsible for providing supporting data. However, if the PC elects	

to develop a benchmark temmperature event, the PC would be responsible for providing supproing data. If our understanding is corret, WECC suggests the following modifications for clarity in R2:

Each Planning Coordinator shall identify the zone(s) to which the Planning Coordinator belongs to under Attachment 1, and shall coordinate with all Planning Coordinators within each of its identified zone(s), to select one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event **from the benchmark library approved and maintained by the Electric Reliability Organization (ERO) or elect to develop one or both common benchmark temperature event(s)** for each of its identified zone(s) when completing the Extreme Temperature Assessment.1 Selected Each benchmark temperature events shall: [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

Additionally, it is WECC's understanding that a Minimum of one of each type of benchmark temperature event is required to be seleted. As written, the requirement seems to indicate that only one may be seleted. It a minimum of one of each type is necessary, WECC suggests that the words "at least" be added back to the requirement. If accepted this would need to be reflected in the Measure and VSLs as well.

Likes 0	
Dislikes 0	
Response	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon agrees with the updated proposed TPL-008 Reliability Standard Requirement R2.	
Likes 0	
Dislikes 0	
Response	

Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the proposed changes made to Requirement R2.	
Likes 0	
Dislikes 0	
Response	

Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
PNMR supports R2.	
Likes 0	
Dislikes 0	
Response	

Daniel Gacek - Exelon - 1	
Answer	Yes

Document Name	
Comment	
Exelon agrees with the updated proposed TPL-008 Reliability Standard Requirement R2.	
Likes 0	
Dislikes 0	
Response	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	Yes
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 2	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	

Comment	
SNPD supports the zones outlined in the map provided in Attachment 1. However, the graphic would be significantly improved by incorporating state boundaries and referencing the NERC benchmark library.	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Manitoba Hydro supports the intent of R2, where PC identifies common extreme heat and extreme cold weather events applicable to its zone. However, Manitoba Hydro recommends that PCs be given the option to select such events from the ERO-maintained benchmark event list or use their own experience to develop benchmark extreme temperature events applicable to their region.	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	Yes
Document Name	
Comment	
The MRO NSRF supports the intent of Requirement R2; however, believes the proposed language as currently written is unclear. Our understanding is the intent of R2 is to provide Planning Coordinators (PCs) with the option of selecting a benchmark temperature event from the ERO library or the ability to develop one or both benchmark temperature events on their own. If the PC(s) select an event from the ERO library, the ERO is responsible for providing data in support of Parts 2.1 and 2.2. Alternatively, if the PC(s) elects to develop a benchmark temperature event, the PC(s) is responsible for providing data in support of Parts 2.1 and 2.2. Therefore, the MRO NSRF proposes the following modification to clarify the intent of Requirement R2: R2. Each Planning Coordinator shall identify the zone(s) to which the Planning Coordinator belongs to under Attachment 1, and shall coordinate with all Planning Coordinators within each of its identified zone(s), to select one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event **from the benchmark library approved and maintained by the Electric Reliability Organization (ERO) or elect to develop one or both common benchmark temperature event(s)** for each of its identified zone(s) when completing the Extreme Temperature Assessment. **Each** benchmark temperature events shall: [Violation Risk Factor: High] [Time Horizon: Long-term Planning]	

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	Yes
Document Name	

Comment

FirstEnergy has no comments toward R2.

Likes 0	
Dislikes 0	

Response

Ben Hammer - Western Area Power Administration - 1

Answer	Yes
Document Name	

Comment

The proposed R2 language as currently written is unclear. Our understanding is the intent of R2 is to provide Planning Coordinators (PCs) with the option of selecting a benchmark temperature event from the ERO library or the ability to develop one or both benchmark temperature events on their own. If the PC(s) select an event from the ERO library, the ERO is responsible for providing data in support of Parts 2.1 and 2.2. Alternatively, if the PC(s) elects to develop a benchmark temperature event, the PC(s) is responsible for providing data in support of Parts 2.1 and 2.2. Therefore, we proposes the following modification to clarify the intent of Requirement R2:

R2. Each Planning Coordinator shall identify the zone(s) to which the Planning Coordinator belongs to under Attachment 1, and shall coordinate with all Planning Coordinators within each of its identified zone(s), to select one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event from the benchmark library approved and maintained by the Electric Reliability Organization (ERO) or elect to develop one or both common benchmark temperature event(s) for each of its identified zone(s) when completing the Extreme Temperature Assessment. Each benchmark temperature event shall: [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	Yes

Document Name	
Comment	
AEP agrees with the changes made to R2, but requests that content be added to make it clear that usage of the ERO-maintained library of benchmark temperature events is optional.	
Likes 0	
Dislikes 0	
Response	
Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - ReliabilityFirst - 10 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Broc Bruton - Broc Bruton On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Broc Bruton	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sharon Darwin - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gary Trezza - Long Island Power Authority - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Helen Lainis - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Srikanth Chennupati - Entergy - 1,3,5,7 - SERC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Jones - Seattle City Light - 1,3,4,5,6	
Answer	
Document Name	
Comment	
We agree with the plan, although there should be some method to help ensure coordination on scenario selection and case data submittal among all PCs in a zone. How will disagreements among PC's be resolved? Voting? Regions can probably resolve this on their own most of the time, but there may be disputes that need to be resolved somehow.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE noticed the Technical Rationale states that “Requirement R2 does not preclude entities from collecting collect temperature data and identifying benchmark temperature events through their own processes”. Texas RE recommends Footnote 1 acknowledge this and recommends the following revision (in bold):	

"The Electric Reliability Organization (ERO) will maintain a library of benchmark temperature events that meet the criteria of Requirement R2. **Planning Coordinator(s) may identify their own benchmark temperature events provided the selected benchmark meet R2 criteria and the Planning Coordinator provides evidence of technical justification**."

Since the periodicity of extreme heat and cold events are increasing in the recent years and the trend may continue to show strongest increase in extremes. The selected benchmark temperature event shall include all the extreme events closest to the benchmark selection process. Consider changing the requirement in 2.1 to include 'temperature data ending no more than two years prior to the time the benchmark temperature events are selected". Texas RE recommends the following revision (in bold):

2.1. Consider no less than a 40-year period of temperature data ending no more than **two** years prior to the time the benchmark temperature events are selected; and

Likes 0	
Dislikes 0	

Response

3. The DT updated Requirements R3 – R4 based on comments received. Do you agree with the updated proposed TPL-008-1 Reliability Standard Requirements? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Devin Shines – LG&E/KU	
Answer	Yes
Document Name	
Comment	
LG&E/KU agrees with the modifications in Requirements R3 and R4. These changes adequately balance the need for transparency, practicality, and effectiveness. LG&E/KU would request the DT consider whether Requirement R3 and its VSLs could be modified to address the situation where one (or more) Planning Coordinators in a zone does not coordinate. As-is, the Requirement R3 language could be understood as all other PCs in that zone also being out of compliance.	
Likes 0	
Dislikes 0	
Response	

Ben Hammer - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
Requirement R3: The prior draft of TPL-008 contained language in R3 that required "Planning Coordinator(s), Transmission Planner(s), and other designated study entities" to collectively implement the requirement. We request language along these lines be reinstated such that all parties that play a role in implementing the process for developing benchmark planning cases must comply. Our suggested language modification below: **R3.** Each Planning Coordinator shall coordinate with all Planning Coordinators and each responsible entity (identified in Requirement R1) within each of its zone(s) identified in Requirement R2, to implement a process for developing benchmark planning cases… Note: If adopted, the Technical Rationale for R3 will also need to be updated to reflect this change.	
Likes 0	
Dislikes 0	
Response	

Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD

Answer	No
Document Name	
Comment	

In FERC Order 896, paragraph 39, there is a Commission Determination as follows:

"*We also direct NERC to include in the Reliability Standard the framework and criteria that responsible entities shall use to develop from the relevant benchmark event planning cases to represent potential weather-related contingencies (e.g., concurrent/correlated generation and transmission outages, derates) and expected future conditions of the system such as changes in load, transfers, and generation resource mix, and impacts on generators sensitive to extreme heat or cold, due to the weather conditions indicated in the benchmark events. Developing such a framework would provide a common design basis for responsible entities to follow when creating benchmark planning cases. This would not only help establish a clear set of expectations for responsible entities to follow when developing benchmark planning events, but also facilitate auditing and enforcement of the Standard*."

In review of Order 896, we find the term "contingencies" is used two different ways. Paragraph 39 describes things that are in the base or N-0 state – for example, a cold weather event occurs, and certain wind generators can no longer operate – this as a base contingency. Similarly, in paragraph 88, there is an additional Commission Determination as follows, in further support of these baseline "contingency" outages:

"*Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to require under the new or revised Reliability Standard the study of concurrent/correlated generator and transmission outages due to extreme heat and cold events in benchmark events as described in more detail below*."

Then later, in Paragraph 92 (still under the Commission Determination), FERC further clarifies:

"*Regarding the comments of NYISO and EPRI on the difference between extreme events and contingencies covered under Reliability Standard TPL-001-5.1, we clarify that all contingencies included in benchmark planning cases under the new or modified Reliability Standard will represent initial conditions for extreme weather event planning and analysis. These contingencies (i.e., correlated/concurrent, temperature sensitive outages, and derates) shall be identified based on similar contingencies that occurred in recent extreme weather events or expected to occur in future forecasted events*."

From these, it is clear that Order 896 is expecting "contingencies" of weather-based equipment outages to be part of the base or N-0 system state. The more traditional "contingencies" are then addressed on top of this condition, as presented in Order 896, Section G, starting at Paragraph 95.

The specific request from this comment is for the SDT to clarify how it expects such base "contingencies" to be included in the model. There does not appear to be language currently in the standard in support of this, and it is clear from Order 896 that it is expected both the base model outage "contingencies" and then subsequent contingency events to test system performance.

Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	

Once again, focusing exclusively on dry bulb temperature is inadequate for TPL-008 and for all NERC winter weather-related standards. Ref. R3.2 for example, there are no simple and reliable, “[dry bulb] temperature dependent adjustments for Load.” A wind chill basis is needed. Mistakenly assuming that load tracks the DBT is why some ISOs severely under-predicted the peak load for Winter Storm Elliott, which was only moderately cold but had extremely strong winds.	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	
Requirement R3: The prior draft of TPL-008 contained language in R3 that required “Planning Coordinator(s), Transmission Planner(s), and other designated study entities” to collectively implement the requirement. The MRO NSRF requests language along these lines be reinstated such that all parties that play a role in implementing the process for developing benchmark planning cases must comply. Our suggested language modification below: R3. Each Planning Coordinator shall coordinate with all Planning Coordinators **and each responsible entity (identified in Requirement R1)** within each of its zone(s) identified in Requirement R2, to implement a process for developing benchmark planning cases… Note: If adopted, the Technical Rationale for R3 will also need to be updated to reflect this change.	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Dominion Energy supports EEI comments	
Likes 0	

Dislikes 0	

Response

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power

Answer	No
Document Name	

Comment

Tacoma Power is concerned that there may be circumstances where not all Planning Coordinators in a zone will agree to one common cold and heat event. Instead of using “all Planning Coordinators” in the R3 Requirement language, Tacoma Power recommends using “majority of Planning Coordinators”, as shown in the mark-up below.

“Each Planning Coordinator shall coordinate with **the majority of the** Planning Coordinators within each of its zone(s) identified in Requirement R2, to implement a process for developing benchmark planning cases for the Extreme Temperature Assessment that represent the benchmark temperature events selected in Requirement R2 and sensitivity cases to demonstrate the impact of changes to the basic assumptions used in the benchmark planning cases.”

Likes 0	
Dislikes 0	

Response

Joshua London - Eversource Energy - 1, Group Name Eversource

Answer	No
Document Name	

Comment

Eversource recommends reinserting from Draft 2 the Transmission Planner as part of the coordination in R3:

Each Planning Coordinator shall coordinate with all Planning Coordinators **and Transmission Planners** within each of its zone(s)…

Likes 0	
Dislikes 0	

Response

Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop

Answer	No

Document Name	
Comment	
Ameren would like more clarification around R3 sections 3.2 and 3.3. Will MOD-032 be revised to include extreme temperature data?	
Likes 0	
Dislikes 0	
Response	
Joseph Knight - Joseph Knight On Behalf of: Jacalynn Bentz, Great River Energy, 3, 1, 5, 6; - Joseph Knight	
Answer	No
Document Name	
Comment	
GRE supports the comments of the NSRF and GRE has additional comments	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC) Project 2023-07 TPL-008-1 Draft #3	
Answer	No
Document Name	
Comment	

Requirement R3: The prior draft of TPL-008 contained language in R3 that required "Planning Coordinator(s), Transmission Planner(s), and other designated study entities" to collectively implement the requirement. The SRC requests language along these lines be reinstated such that all parties that play a role in implementing the process for developing benchmark planning cases must comply. Our suggested language modification below:

R3. Each Planning Coordinator shall coordinate with all Planning Coordinators ***and each responsible entity (identified in Requirement R1)*** within each of its zone(s) identified in Requirement R2, to implement a process for developing benchmark planning cases…

Note: If adopted, the Technical Rationale for R3 will also need to be updated to reflect this change.

In addition, the SRC[1] is concerned that Requirement R3 unnecessarily and inadvertently limits the ability of entities to properly develop their benchmark planning cases. Specifically, the SRC is concerned that R3 could be understood to mean that entities are limited to making the adjustments specifically described in R3 and are prevented from making adjustments necessary to update the planning cases to reflect the expected future state of the system or to ensure that the generation necessary to serve load is available so that the case can solve. As the drafting team recognizes in the Technical Rationale, adjusting the case to ensure that it contains enough generation to serve the modeled load is essential to ensure that the standard does not stray into the realm of resource adequacy issues and fully complies with paragraph 94 of FERC Order No. 896, which states that resource adequacy is not in scope for this project.

To address this, the SRC recommends that the drafting team renumber the current Part 3.4 to Part 3.5 and add a new Part 3.4 that reads as follows:

"3.4. Adjustments to the total modeled generation or Load in each case as necessary to allow the total modeled generation to serve the total modeled System Load."

The SRC also recommends that Requirement R4 be revised as needed to align with any revisions made to Requirement R3.

Requirement R4: FERC Order 896 paragraph 154 is clear that FERC does not intend to order the construction of new transmission facilities through this standard. However, due to the inherently extreme nature of these contingency scenarios, Corrective Action Plans will likely have to include facility upgrades that would not have been needed under current system design criteria under TPL-001-5.1. Since TPL-001-5.1 studies are conducted annually, and ISO/RTOs have processes outside NERC standards to identify transmission expansion projects that may be identified before the next 5-year TPL-008 study period, we recommend TPL-008 be revised to allow the CAPs to be updated as determined by the PC, thereby accommodating regional planning solutions to mitigate deficiencies identified under TPL-008 without having to wait 5 years for the next TPL-008 study cycle or conduct a completely new series of TPL-008 studies to update the CAP.

Requirement R3.4: We recommend the SDT consider updating R3.4 or the Technical Rationale to include broader system conditions for sensitivity studies, as the conditions for the sensitivity cases seem to be focused on steady state analysis when there could be other assumptions to consider that affect system dynamic performance, for example, dynamic load models, DER dynamics, etc.

[1] NYISO abstains from this comment and the associated proposed revision to Part 3.4.

Likes 0	
Dislikes 0	

Response

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	

Comment

CenterPoint Energy Houston Electric, LLC (CEHE) does not agree sensitivity case requirements are needed as these place an unnecessary burden on Entities with little reliability benefit. CEHE recommends the removal of Requirement R4.2 in order to agree with Requirements R3 and R4 as written. FERC Order 896 is expecting "contingencies" of weather-based equipment outages to be part of the base or N-0 system state. The more traditional "contingencies" are then addressed on top of this condition, as presented in Order 896, Section G, starting at Paragraph 95. CEHE recommends for the SDT to clarify how it expects such base "contingencies" to be included in the model. There does not appear to be language currently in the standard in support of this, and it is clear from Order 896 that it is expected both the base model outage "contingencies" and then subsequent contingency events test system performance.

Likes 0	
Dislikes 0	

Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	No
Document Name	
Comment	
See comment to question 2, If "at least" one of each type of benchmark temperature event is required, Parts 4.1 and 4.2 would need to be modified to reflect this.	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	No
Document Name	
Comment	
There are no issues with R3. The SDT should consider removing R4.2, since the assessment already covers multiple extreme weather scenarios. There is questionable reliability benefit in running additional sensitivities that do not rise to the level of requiring (or eliminating) corrective actions.	
Likes 0	
Dislikes 0	
Response	
Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - ReliabilityFirst - 10 - RF	
Answer	No
Document Name	
Comment	
10 year cases may not be the most appropriate for identification of binding improvements as estimates of generation additions and retirements and load additions are still developing. Five year cases should provide sufficient detail to identify needed reliability improvements while still allowing time for construction.	
Likes 0	

Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	

ERCOT is concerned that Requirement R3 unnecessarily and inadvertently limits the ability of entities to properly develop their benchmark planning cases. Specifically, ERCOT is concerned that R3 could be understood to mean that entities are limited to making the adjustments specifically described in R3 and are prevented from making adjustments necessary to ensure that the generation necessary to serve load is available so that the case can solve. As the drafting team recognizes in the Technical Rationale, adjusting the case to ensure that it contains enough generation to serve the modeled load is essential to ensure that the standard does not stray into the realm of resource adequacy issues and fully complies with paragraph 94 of FERC Order No. 896, which states that resource adequacy is not in scope for this project.

To address this, ERCOT recommends that the drafting team revise Part 3.2 by replacing the period at the end of Part 3.2 with the following: ", provided that the responsible entity may adjust the total modeled generation or Load in each case as necessary to allow the total modeled generation to serve the total modeled System Load."

ERCOT also recommends that Requirement R4 be revised as needed to align with any revisions made to Requirement R3.

Likes 0	
Dislikes 0	
Response	
Michael Goggin - Grid Strategies LLC - 5	
Answer	No
Document Name	
Comment	

First, to comply with FERC Order 896, the standard should specify that benchmark events and Extreme Temperature Assessments will account for concurrent/correlated outages of generators during extreme heat and cold events. In Order 896 paragraph 88, FERC directs "NERC to require under the new or revised Reliability Standard the study of concurrent/correlated generator and transmission outages due to extreme heat and cold events in benchmark events," explaining in paragraph 89 that "it is necessary that responsible entities evaluate the risk of correlated or concurrent outages and derates of all types of generation resources and transmission facilities as a result of extreme heat and cold events."

The draft of TPL-008 R3 appears to put the burden on responsible entities and not NERC for accounting for correlated outages in making "seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers" and conducting sensitivity analyses.

Having responsible entities and not NERC conduct this adjustment increases the risk that different regions will use inconsistent methods for doing so, and at worst responsible entities that want to avoid addressing reliability concerns through a Corrective Action Plan will use unrealistically low assumptions for the rate of correlated generator outages or other input assumptions like load and transfers. This assumption can have such a large impact on results it cannot be left to responsible entities, and should be made by NERC. The drafting team's Technical Rationale used similar logic in deciding that NERC (the Electric Reliability Organization or ERO) should assemble the benchmark planning cases: "to ensure consistency across regions, it is necessary for the ERO to have the responsibility for determining the suitability of benchmark events to represent probable future conditions."

Given the significant variation in the rates at which different fuel types experience correlated outages,[1] and rapid changes in the generation mix that may cause the future power system to have greater or lesser exposure to correlated outage risk, it is particularly important for the benchmark events and Extreme Temperature Assessments to account for the concurrent/correlated outage risk of each fuel type in the future generation mix. In recent cold snap events, gas generator outages due to equipment failures and fuel supply interruptions have accounted for the majority of outages. NERC GADS data can be used to assess the rate of correlated outages and derates of generators by fuel type.{C}[2]

Second, the benchmark cases and Extreme Temperature Assessments should account for changes to generation, demand, and transmission resulting from climate change, electrification of heating, and other factors that are affecting the risk posed by extreme heat and cold. Accounting for how climate change is increasing the frequency and magnitude of extreme heat and cold events is consistent with FERC's Order 896 directive in paragraph 40: "We also direct NERC to ensure the reliability standard contains appropriate mechanisms for ensuring the benchmark event reflects up-to-date meteorological data. The increasing intensity, frequency, and unpredictability of extreme weather conditions requires that key aspects of the benchmark events be reviewed, and if necessary, updated periodically to ensure the corresponding benchmark planning cases reflect updated meteorological data." Electrification of heating is also increasing the sensitivity of electricity demand to extreme cold conditions, which should be accounted for in the benchmark cases and Extreme Temperature Assessments.

Third, due to the impact of climate change, electrification, and rapid changes in the generation mix, requirement R1 should require responsible entities to complete an Extreme Temperature Assessment more frequently than at least once every five calendar years. As noted above, FERC Order 896 specifies that the meteorology underlying benchmark cases should be updated at least every five years, but the generation mix and other grid conditions can change more rapidly than that. TPL-001 requirement R2 requires Planning Assessments to be conducted annually, and a similar annual requirement for Extreme Temperature Assessments is appropriate given that extreme heat and cold events are the largest threat to electric reliability.

{C}[1]{C} *See, e.g.*, FERC and NERC*, Winter Storm Elliott Report: Inquiry into Bulk-Power System Operations During December 2022* (October 2023), https://www.ferc.gov/media/winter-storm-elliott-report-inquiry-bulk-power-system-operations-during-december-2022, at 17; FERC and NERC, *The February 2021 Cold Weather Outages in Texas and the South Central United States* (November 2021), https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and, at 16; FERC and NERC, *2019 FERC and NERC Staff Report: The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018* (July 2019), https://www.ferc.gov/legal/staff-reports/2019/07-18-19-ferc-nerc-report.pdf; PJM, *Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events* (May 2014), https://www.pjm.com/~/media/library/reports-notices/weather-related/20140509-analysis-of-operational-events-and-market-impacts-during-the-jan-2014-cold-weather-events.ashx.

{C}[2]{C} For example, see the analysis of GADS data provided in S. Murphy et al., *Resource adequacy risks to the bulk power system in North America* (February 2018), https://www.sciencedirect.com/science/article/pii/S0306261917318202, with Supplementary Material including outage data available at https://ars.els-cdn.com/content/image/1-s2.0-S0306261917318202-mmc1.zip

Likes 0	
Dislikes 0	

Response

Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle

Answer	No
Document Name	

Comment

In R4, Extreme Temperature Events is already a “sensitivity” to the normal long-term planning cases. The cases will be built with Gen/Load/Transmission/Transfer based on the extreme weather conditions. The need for sensitivity cases on top of “sensitivity cases” is not very convincing.

Furthermore, the DT should explain if the sensitivity would be the same factor that one would modify or if you could change the sensitivity factor that you modify. For example, let's say we have decided to adjust loads so that they're higher in the extreme heat sensitivity, but we wanted to pick transfer levels with extreme cold. In R3.4 it is not specified if a different adjustment factor can be used for each one of the extreme cold/extreme heat sensitivity cases or there is flexibility.

We request DT to add clarity to prevent misinterpretation, or for an auditor to step in and assign a restriction that's not there. We would prefer to see R3.4 modified to say a different sensitivity, a different change can be made to the two different temperature cases or something that specifies you don't have to use the same one.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	Yes
Document Name	

Comment

R3 and R4 appear duplicative in that they both involve the formation of study cases. R3 states “Implement a process for developing benchmark planning cases” while R4 states “Use the coordination process… to develop the following… planning benchmark cases.”

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	Yes
Document Name	

Comment

FirstEnergy has no comments toward these requirement drafts.

Likes 0	
Dislikes 0	

Response

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO

Answer	Yes
Document Name	

Comment

To improve the clarity of R3.4, it is recommended to consider updating R3.4, as shown below:

3.4. Identification of changes to at least one of the following conditions for sensitivity cases:

· Generation additions, retirements. (it is not clear what is expected by just listing generation)

· Real and reactive forecasted Load.

· Expected transfers.

· Expected in service dates of new or modified Transmission Facilities. (a new addition that Manitoba Hydro recommends to be included in the sensitivity list)

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	Yes
Document Name	

Comment

None.

Likes 0	
Dislikes 0	

Response

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples

Answer	Yes
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 3	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon agrees with the updated proposed TPL-008 Reliability Standard Requirements R3 and R4.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
PNMR supports R3 and R4.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	

Comment	
EEI supports the proposed changes made to Requirements R3 and R4.	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon agrees with the updated proposed TPL-008 Reliability Standard Requirements R3 and R4.	
Likes 0	
Dislikes 0	
Response	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	

See EEI Comments

Likes 0	
Dislikes 0	

Response

Selene Willis - Edison International - Southern California Edison Company - 5

Answer	Yes
Document Name	

Comment

See EEI Comments

Likes 0	
Dislikes 0	

Response

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	Yes
Document Name	

Comment

ITC supports the proposed changes made to Requirements R3 and R4.

Likes 0	
Dislikes 0	

Response

Carver Powers - Utility Services, Inc. - 4

Answer	Yes
Document Name	

Comment

We understand and approve the proposed language in R3-R4. However, we recommend that the drafting team includes more clarity and benchmarks for the process for sensitivity cases. The technical rationale currently does not include details as to how to develop or implement sensitivity cases.

Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1	
Answer	Yes
Document Name	
Comment	
See comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michele Tondalo - United Illuminating Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Srikanth Chennupati - Entergy - 1,3,5,7 - SERC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Helen Lainis - Independent Electricity System Operator - 2	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Erin Wilson - NB Power Corporation - New Brunswick Power Transmission Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Streifling - NB Power Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gary Trezza - Long Island Power Authority - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Jones - Seattle City Light - 1,3,4,5,6	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sharon Darwin - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Broc Bruton - Broc Bruton On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Broc Bruton	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Michele Shafer - New York State Electric & Gas (NYSEG) - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE recommends defining "the zone" in Requirement Part R3.3. Texas RE recommends the following revision (in bold):	

R3.3. Assumed seasonal and temperature dependent adjustments for Load,

generation, Transmission, and transfers in areas outside the zone **identified in Requirement R2**, as needed.

Texas RE noticed that neither R3 nor R4 mention a requirement to include "concurrent" generator and transmission outages as noted in FERC Order No. 896, which states: "…the impact of concurrent failures of Bulk-Power System generation and transmission equipment and the potential for cascading outages that may be caused by extreme heat and cold weather events should be studied". The Considerations of the Order document says "Per Requirement R4, the data necessary to build the benchmark planning cases must be provided via MOD-032 and supplemented by other sources as needed. Any concurrent/correlated generator and transmission outages due to extreme heat and cold events in benchmark temperature events should be reflected in the model data and thus represented in the initial conditions of the benchmark planning cases."

Based on the current Requirements R3 and R4 language, the cases could be built with high loads and high generation dispatch for the extreme weather without including concurrent outages. Therefore, a requirement in R3 or R4 that specifically says to include "concurrent" generator and transmission outages in the initial conditions of the benchmark planning cases needs to be added in accordance with the FERC Order. Also, the rationale for those concurrent outages selected for the initial conditions shall be available as supporting information. Texas RE noticed that the Technical Rationale does mention concurrent outages and recommends incorporating this language directly into the requirement language itself through the note described below.

Requirement R4.2 also does not specify which system conditions should be varied to create sensitivity cases. Normally sensitivity studies are conducted to identify system deficiencies under stressed system conditions such as generation changes, load variations, delays in implementing system improvements, multiple system elements being unavailable due to extended outages, etc.

Texas RE recommends the following revisions to Requirement R4 and Requirement 4.2 to clarify the language, address concurrent outages, and clarify the requirements for sensitivity cases:

R4. Each responsible entity, as identified in Requirement R1, shall use the coordination process developed in accordance with Requirement R3 and data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, **to develop the following and** establish category P0 as the normal System condition in Table 1 **and develop and maintain the following**:

4.2 One common extreme heat and one common extreme cold sensitivity case **by varying one or more of the system conditions such as forecasted load, generation dispatch, unavailability of multiple system elements (overlapping outages), etc. to stress the system sufficiently to demonstrate measurable changes in system responses**.

Texas RE further recommends adding the following as a note under Requirement 4:

Planning Coordinator shall use coincident peak load for extreme temperature assessments to more appropriately reflect load conditions during system-wide weather conditions. Transmission Planner(s) shall use the forecasted non-coincident peak load for evaluating its respective area assessments.

Likes 0	
Dislikes 0	

Response

4. The DT updated Requirements R7 – R8 based on comments received. Do you agree with the updated proposed TPL-008-1 Reliability Standard Requirements? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Devin Shines – LG&E/KU	
Answer	Yes
Document Name	
Comment	
LG&E/KU agrees with the modifications in Requirements R7 and R8 (as well as those in Requirements R5 and R6 which do not have a dedicated question on this comment form). These modifications improve the clarity of the standard.	
Likes 0	
Dislikes 0	
Response	

Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle

Answer	No
Document Name	
Comment	
Please see PG&E's comments in (Q3) for R4 as R8 is in reference to R4.	
Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO

Answer	No
Document Name	
Comment	
SPP has identified an inconsistency between the proposed requirement language and the technical rationale. The technical rationale denotes the expectation to run at a minimum P0, P1, P7 whereas the language in the requirement states "Contingencies for each category in Table 1 that are	

expected to produce more severe System impacts”. This indicates a compliance obligation to produce a contingency list for the entire table instead of only those in the P0, P1, P7 categories as stated in the technical rationale.	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	No
Document Name	
Comment	
Regarding R8, it is unclear if the responsible entity must identify continencies for each event type shown within each category, or only those event types that are expected to produce more severe System impacts on its portion of the Bulk Electric System	
Likes 0	
Dislikes 0	
Response	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CEHE does not agree with sensitivity cases in Extreme Temperature Assessments for the same reasons as mentioned in Q3. CEHE recommends the removal of 8.2 in order to agree with Requirements R7 and R8.	
Likes 0	
Dislikes 0	
Response	
Joseph Knight - Joseph Knight On Behalf of: Jacalynn Bentz, Great River Energy, 3, 1, 5, 6; - Joseph Knight	
Answer	No
Document Name	
Comment	

GRE supports the comments of the NSRF and GRE has additional comments

Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	
The steady state contingencies do not necessarily apply for transient stability. The transient stability contingencies are a subset of the steady-state contingencies.	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1	
Answer	Yes
Document Name	
Comment	
See comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
ITC is supportive of the proposed changes made to Requirements R7 and R8.	

Likes 0	
Dislikes 0	

Response

Selene Willis - Edison International - Southern California Edison Company - 5

Answer	Yes
Document Name	

Comment

See EEI Comments

Likes 0	
Dislikes 0	

Response

Stephanie Kenny - Edison International - Southern California Edison Company - 6

Answer	Yes
Document Name	

Comment

See EEI Comments

Likes 0	
Dislikes 0	

Response

Kinte Whitehead - Exelon - 3

Answer	Yes
Document Name	

Comment

Exelon agrees with the updated proposed TPL-008 Reliability Standard Requirements R7 and R8.

Likes 0	

Dislikes 0	

Response

Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	

Comment

EEI is supportive of the proposed changes made to Requirements R7 and R8.

Likes 0	
Dislikes 0	

Response

Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	

Comment

PNMR supports R7 and R8.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	

Exelon agrees with the updated proposed TPL-008 Reliability Standard Requirements R7 and R8.

Likes 0	
Dislikes 0	
Response	

Gary Trezza - Long Island Power Authority - 1 - NPCC	
Answer	Yes
Document Name	
Comment	

Requirement # 7 states:

"Each responsible entity, as identified in Requirement R1, shall identify the Contingencies for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System. The rationale for those Contingencies selected for evaluation shall be available as supporting information."

Questions to the SDT for clarification: Is the intent is that the entity **must** identify contingencies for each contingency Event (such as P1.1, P1.2, P7.2 for example) – or must have a rationale why certain events (such as P7.2 for example) are not the more severe? Without clarification, this requirement could be interpreted differently by auditors.

Additionally, we interpret that the BES Contingency voltage level of >= 200 kV is meant to be a filter or screening criteria for identifying events that must be considered and that would have a more severe impact on the BES. We also interpret that as part of the Extreme Temperature Assessment, an entity is responsible for monitoring their entire BES.

Is this interpretation correct? Some elaboration on the 200 kV threshold within the Technical Rationale would be helpful.

Likes 0	
Dislikes 0	
Response	

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	

Comment	
R8: For Table 1 – Steady State & Stability Performance Events, #6, please explain the rationale for stating the requirements for CAP's in Footnote 6 rather than in Requirement 9. R9: Organization of Footnote 6 is confusing because it is written with Requirement-like language that should reside in R9 itself.	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	Yes
Document Name	
Comment	
n/a	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy has no comments toward these requirement drafts.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	

Comment	
Please see AEP’s response to Question #7 which includes references to R8.	
Likes 0	
Dislikes 0	
Response	

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - ReliabilityFirst - 10 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Michele Shafer - New York State Electric & Gas (NYSEG) - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC) Project 2023-07 TPL-008-1 Draft #3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Sharon Darwin - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Jones - Seattle City Light - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Streifling - NB Power Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Erin Wilson - NB Power Corporation - New Brunswick Power Transmission Corporation - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Helen Lainis - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Srikanth Chennupati - Entergy - 1,3,5,7 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michele Tondalo - United Illuminating Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Broc Bruton - Broc Bruton On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Broc Bruton

Answer	
Document Name	

Comment

Abstain

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE is concerned that multiple contingencies may not be used to assess the system in extreme temperature events. In Requirement R7, Table 1 only shows single contingencies and double circuit contingencies for assessing steady state and stability performances. Based on the contingencies listed in Table 1, the reasoning for R7 is not clear. Are the responsible entities expected to select single contingencies and double circuit contingencies and use those contingencies to assess the system? During extreme temperature events, multiple overlapping contingencies generally happens, and they are expected. Registered entities should study the overlapping contingencies to identify system deficiencies and prepare the mitigation plans.

Additionally, the NERC Glossary Definition of Firm Transmission Service states: The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption. Texas RE inquires as to why interruption of Firm Transmission Service is allowed under P0 conditions.

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	
Document Name	
Comment	
Dominion Energy supports EEI comments	
Likes 0	
Dislikes 0	
Response	

5. The DT updated Requirements R9 – R11 based on comments received. Do you agree with the updated proposed TPL-008-1 Reliability Standard Requirements? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Devin Shines – LG&E/KU	
Answer	Yes
Document Name	
Comment	
LG&E/KU agrees with the modifications in Requirements R9, R10, and R11. These modifications improve the clarity of the standard and, in the case of Requirement R10, make a good change to permit possible actions designed to reduce the likelihood of the event to be considered as well.	
Likes 0	
Dislikes 0	
Response	

Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD

Answer	No
Document Name	
Comment	

Many of the CHPD concerns from the previous draft redline still exist in this redline version. CHPD believes the updates made to R9 were very good, with a couple concerns remaining. The first concern is to the statement 'make its Corrective Action Plan available to' in R9.1. CHPD suggests this be changed to 'make its Corrective Action Plan available on request', to align with a similar request-based mechanism under R11. We've found the general "make available" is murky language for compliance.

The second concern is the expectation in 9.1 and 9.2 for soliciting feedback and notifications to "regulatory authorities or governing bodies responsible for retail electric service issues". The intent here is not clear. Could the SDT provide some examples of what is intended here, both for Jurisdictional and non-Jurisdictional entities? Our entity is a Public Utility District – who does the SDT envision we would provide this notification to – our publicly elected commissioners?

It is noted that the R9 Measures now appear to include the solicitation and notification as part of the measures for compliance with R9 which is an improvement from the previous draft version.

Lastly, in Order 896, FERC's Commission determination in paragraph 157 reads:

"*As stated above, we adopt and modify the NOPR proposal and direct NERC to require in the new or modified Reliability Standard the development of corrective action plans that include mitigation for specified instances where performance requirements for extreme heat and cold events are not met—i.e., when certain studies conducted under the Standard show that an extreme heat or cold event would result in cascading outages, uncontrolled separation, or instability.*"

FERC's directive is when the outcome of studies would result in cascading outages, uncontrolled separation, or instability, a corrective action plan is required. However, in TPL-008, the SDT has gone further. The current state of draft TPL-001-8 R9 states:

"*Each responsible entity, as identified in Requirement R1, shall develop a Corrective Action Plan(s) when the analysis of a benchmark planning case, in accordance with Requirement R8 Part 8.1, indicates its portion of the Bulk Electric System is unable to meet performance requirements for category P0 or P1 in Table 1. For each Corrective Action Plan, the responsible entity shall*:"

The difference here is Order 896 is only requiring corrective action plans for cascading outages, uncontrolled separation, or instability. the SDT is proposing to require corrective action plans for not meeting performance criteria, which also includes normal voltage limits or normal line ratings, even though these exceedances may not result in cascading outages, uncontrolled separation, or instability. The request is for the SDT to align its R9 language with Order 896 paragraph 157 language. These other limits are needed to assess for cascading outages, uncontrolled separation, or instability, but the requirement to develop a corrective action plan for such exceedances is beyond Order 896's request for this proposed standard.

Likes 0	
Dislikes 0	

Response

Donald Lock - Talen Generation, LLC - 5

Answer	No
Document Name	

Comment

The term, "Non-Consequential Load Loss," is an oxymoron. It is also unrealistic to imagine that load shedding can be limited to a small, tolerable amount. The uncertainties associated with extreme cold weather in particular are so severe that PCs and TPs should be required to serve all load with a sizeable reserve margin.

The expression, "beyond their control," should be replaced with an objective, auditable criterion.

CAPs for winter issues should be required to include early starting of generation units, to help accommodate the additional starting time that may be required during extreme cold weather.

Likes 0	
Dislikes 0	

Response

Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1

Answer	No
Document Name	

Comment

The "applicable regulatory authorities or governing bodies responsible for retail electric service" in R9 needs better clarification - what does this look like for jurisdictional vs non-jurisdictional - is this not applicable to non-jurisdictional? Ask of SDT to provide better guidance & examples.

Requirement R10 should explicitly clarify that a Corrective Action Plan is not required for P7 Contingencies, as stated in the previous draft 2, Table 2.1, page 11.

Likes 0	
Dislikes 0	

Response

Mark Flanary - Midwest Reliability Organization - 10

Answer	No
Document Name	

Comment

In the current draft, it is not clear what the time frame is for providing the CAP or soliciting feedback from the regulatory authorities or governing bodies in R9.1. In addition, there is no time frame when to notify the applicable regulatory authorities or governing bodies in R9.2. R9.4 indicates allowing revision to the Corrective Action Plan but does not clarify when and what triggers the revision.

Likes 0	
Dislikes 0	

Response

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

(R9.1 and R9.2) We recommend that further clarification be given to how “applicable” regulatory authorities or governing bodies are determined. In addition, we believe that soliciting feedback (R9.1) and notification (R9.2) should be replaced with “make available upon request.”

(R10) No issues.

(R11) We recommend that the timeframe be extended to 90 calendar days.

Likes 0	
Dislikes 0	

Response

Gary Trezza - Long Island Power Authority - 1 - NPCC	
Answer	No
Document Name	
Comment	

Requirement #9.3 states:

"Be permitted to utilize Non-Consequential Load Loss as an interim solution, which normally is not permitted in Table 1, in situations that are beyond the control of the Planning Coordinator or Transmission Planner that prevent the implementation of a Corrective Action Plan in the required timeframe, provided that the responsible entity documents the situation causing the problem, alternatives evaluated, and takes actions to resolve the situation."

The Extreme Temperature Assessment would have to be performed at least once every 5 years, assessing one year in the Long Term Planning Horizon.

It is recognized that the details of the extreme heat/cold benchmark temperature events may change over time, and that the underlying assumptions utilized in the Extreme Temperature Assessment for one of the years in the Long Term Planning Horizon may change over time. CAPs identified in one Assessment may not be needed in a future Assessment. It may be difficult to pursue expensive CAPs understanding that assumptions may change.

With this in mind, we find it difficult from a compliance perspective to clearly identify what is meant by "in the required timeframe". This language, while allowing for flexibility, seems very ambiguous. The Technical Rationale does not elaborate on this point.

We recommend that the SDT clarify what is intended by "*in the required timeframe."*

Comment on Requirement #11

Requirement #11 states:

"Each responsible entity, as identified in Requirement R1, shall provide its Extreme Temperature Assessment results within 60 calendar days of a request to any functional entity that has a reliability related need and submits a written request for the information."

This could be interpreted in different ways.

We would recommend the SDT consider modifying the wording (see TPL-001-5.1 Req #8 for reference) and **timeframe** to be more consistent with TPL-001-5.1 Req #, 8 as follows:

"Each responsible entity, as identified in Requirement R1, shall provide its latest completed Extreme Temperature Assessment results within 90 calendar days of a request to any functional entity that has a reliability related need and submits a written request for the information.

Likes 0	
Dislikes 0	
Response	

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	No

Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) on question 5	
Likes 0	
Dislikes 0	
Response	
Sharon Darwin - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Southern Company supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

EEI has no concerns with Requirements R10 and R11, however, we do suggest changes to the subparts of Requirement R9 in order to more clearly define R9.1-R9.3 as being specific to the utilization of 'Non-Consequential Load Loss as an interim solution' and to better align with TPL-001 Attachment 1 III (Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required) with the TPL-008-1 Technical Rationale.

Each responsible entity, as identified in Requirement R1, shall develop a Corrective Action Plan(s) when the analysis of a benchmark planning case, in accordance with Requirement R8 Part 8.1, indicates its portion of the Bulk Electric System is unable to meet performance requirements for category P0 or P1 in Table 1. For each Corrective Action Plan, the responsible entity shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

9.1 {C}Be allowed to have revisions to the Corrective Action Plan in subsequent Extreme Temperature Assessments, provided that the planned Bulk Electric System shall continue to meet the performance requirements of Table 1. (*formally 9.4*)

9.2 Be permitted to utilize Non-Consequential Load Loss as an interim solution, which normally is not permitted in Table 1, in situations that are beyond the control of the Planning Coordinator or Transmission Planner that prevent the implementation of a Corrective Action Plan in the required timeframe, provided that the responsible entity**:** (*formally 9.3*)

9.2.1 **D**ocuments the situation causing the problem, and **make changes to mitigate the identified problem**. (*extracted from 9.3*)

9.2.2 Documents alternative(s) considered and **notifies the** applicable regulatory authorities or governing bodies responsible for retail electric service issues when Non-Consequential Load Loss is utilized as an element of a Corrective Action Plan for a Table 1 P1 Contingency. *(Moved from old 9.2)*

9.2.3 Make its Corrective Action Plan available to, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues. (*formally 9.1*)

Likes 0	
Dislikes 0	

Response

Joseph Knight - Joseph Knight On Behalf of: Jacalynn Bentz, Great River Energy, 3, 1, 5, 6; - Joseph Knight

Answer	No
Document Name	

Comment

GRE supports the comments of the NSRF and GRE has additional comments

Likes 0	
Dislikes 0	

Response

Daniela Atanasovski - APS - Arizona Public Service Co. - 1

Answer	No
Document Name	

Comment

AZPS supports the following comments submitted by EEI on behalf of its members:

EEI has no concerns with Requirements R10 and R11, however, we do suggest changes to the subparts of Requirement R9 in order to more clearly define R9.1-R9.3 as being specific to the utilization of 'Non-Consequential Load Loss as an interim solution' and to better align with TPL-001 Attachment 1 III (Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required) with the TPL-008-1 Technical Rationale.

R9. Each responsible entity, as identified in Requirement R1, shall develop a Corrective Action Plan(s) when the analysis of a benchmark planning case, in accordance with Requirement R8 Part 8.1, indicates its portion of the Bulk Electric System is unable to meet performance requirements for category P0 or P1 in Table 1. For each Corrective Action Plan, the responsible entity shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

9.1 Be allowed to have revisions to the Corrective Action Plan in subsequent Extreme Temperature Assessments, provided that the planned Bulk Electric System shall continue to meet the performance requirements of Table 1. (*formally 9.4*)

9.2 Be permitted to utilize Non-Consequential Load Loss as an interim solution, which normally is not permitted in Table 1, in situations that are beyond the control of the Planning Coordinator or Transmission Planner that prevent the implementation of a Corrective Action Plan in the required timeframe, provided that the responsible entity: (*formally 9.3)*

9.2.1 Documents the situation causing the problem, and makes changes to mitigate the identified problem (*extracted from 9.3)*

9.2.2 Documents alternative(s) considered and notifies the applicable regulatory authorities or governing bodies responsible for retail electric service issues when Non-Consequential Load Loss is utilized as an element of a Corrective Action Plan for a Table 1 P1 Contingency. *(Moved from old 9.2)*

9.2.3 Make its Corrective Action Plan available to, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues. (*formally 9.1*)

Likes 0	
Dislikes 0	

Response

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	

Comment

CEHE believes sensitivity cases are unnecessary and believes Requirement 10.2 should be removed since planning cases are already planned for extreme events. Refer to CEHE's comments in Q3. In the current draft, it is not clear what the timeframe is for providing the CAP in R9.1. In addition, there is no timeframe when to notify the applicable regulatory authorities or governing bodies in R9.2. R9.4 indicates allowing revision to the Corrective Action Plan but does not clarify when and what triggers the revision. R11 - CEHE recommends that the timeframe be extended to at least 90 calendar days.

Likes 0	
Dislikes 0	

Response

Stephanie Kenny - Edison International - Southern California Edison Company - 6

Answer	No
Document Name	

Comment

See EEI Comments

Likes 0	
Dislikes 0	

Response

Broc Bruton - Broc Bruton On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Broc Bruton

Answer	No
Document Name	

Comment

Oncor strongly disagrees with the following statement in R9.1: "Make its Corrective Action Plan available to, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues." We propose that "applicable regulatory authorities or governing bodies" be defined and limited. For example, a TP should only need to provide their PC with CAP information.

In addition, we disagree with the following phrase "and notify the applicable regulatory authorities or governing bodies responsible for retail electric service issues" as it relates to Load Shed. The intended regulatory audience needs to be clearly defined.

Oncor disagrees with R10 as well. The requirement does not give TPs the ability to create CAPs for the listed contingencies.

Likes 0	
Dislikes 0	

Response

Selene Willis - Edison International - Southern California Edison Company - 5

Answer	No
Document Name	

Comment

See EEI Comments

Likes 0	
Dislikes 0	

Response

Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford

Answer	No

Document Name	
Comment	

- The purpose and required response actions related to the sharing of CAPs and solicitation of feedback is not clear.
- Documentation of alternatives is an additional administrative burden and provides little benefit to reliability. It is also unclear if there is some type of expectation these alternatives are reviewed or potentially challenged as invalid.
- The role of the TO and/or GO in implementing or otherwise responding to CAPs that may require additions or modifications to their systems/facilities is not captured in these requirements.
- There appears to be a significant amount of outside review required but no clear actions the responsible entity is required to take, particularly if there is a dispute. What is the purpose of the review and the expected response? This potentially produces an undue burden on the PC/TP and adds subjectivity in requiring a review with no documented guidelines for conducting the review.
- GTC recommends the restructuring of requirement 9 such that documentation of alternatives along with the sharing and soliciting feedback back is only necessary when utilizing Non-Consequential Load Loss as an interim solution.

Likes 0	
Dislikes 0	
Response	

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	No
Document Name	2023-07_Unofficial_Comment_Form_Draft 3_100724 ITC (002).docx
Comment	

See attachment with suggested changes.

Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO

Answer	No
Document Name	
Comment	

SPP has multiple concerns around CAPs. The first concern is that the mechanism to issue a CAP for FERC Order 1000 is typically limited in SPP to the Near-Term Transmission Planning Horizon. Secondly, if other SPP planning assessments evaluate extreme weather, SPP would like to consider those CAPs for revision to the CAPs identified in the 5-year extreme temperature assessment. (potential verbiage could include Corrective Action Plan in subsequent Extreme Temperature Assessments or other planning assessments that evaluate extreme weather conditions). This would also help if other transmission projects came to fruition in between the 5-year assessments that could potentially mitigate the need for the CAP in the extreme weather study.

Likes 0	
Dislikes 0	

Response

Robert Blackney - Edison International - Southern California Edison Company - 1

Answer	No
Document Name	

Comment

See comments submitted by Edison Electric Institute.

Likes 0	
Dislikes 0	

Response

Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle

Answer	No
Document Name	

Comment

Requirements R9 and R10 both regard obligations of the responsible entity based on inability to meet certain performance requirements. These requirements should be combined into a single requirement (with sub-requirements) to make this aspect of the standard clearer to follow. With respect to Requirement R9 Parts 9.1 and 9.2, it is unclear why Part 9.2 is necessary if the entire Corrective Action Plan is required to be made available to applicable regulatory authorities or governing bodies responsible for retail electric service issues under Part 9.1. Perhaps Part 9.2 should instead be a sub requirement under Part 9.1 that specifies certain information that must be included in the distributed Corrective Action Plan under Part 9.1; otherwise, it may be confusing to the responsible entity how to implement Part 9.1 and Part 9.2 as separate items (including interpreting differences in language such as “make available to” and “solicit feedback from” in Part 9.1 and “document” and “notify” in Part 9.2 directed to the same entities).

Likes 0	
Dislikes 0	

Response

Michael Goggin - Grid Strategies LLC - 5

Answer	No
Document Name	

Comment

a. Requirement R9 should be modified to specify that the expected impact of extreme heat and cold should be accounted for when designing and measuring the impact of the solutions proposed in a Corrective Action Plan (CAP). Many potential solutions in a CAP can have greater or lesser impact under extreme heat or cold conditions. For example, a CAP that relies on adding gas generation can be less effective under extreme heat due to output reductions due to ambient temperature derates, and under extreme cold due to correlated gas generator outages. Gas generator outages due to equipment failures and fuel supply interruptions have accounted for the majority of outages during recent cold snap events.{C}[1] As noted above in response to question 4, FERC's directive in paragraph 89 of Order 896 states that "it is necessary that responsible entities evaluate the risk of correlated or concurrent outages and derates of all types of generation resources and transmission facilities as a result of extreme heat and cold events." On the other hand, CAPs that include demand response and energy efficiency programs related to building HVAC systems can offer contributions that are larger than expected during extreme heat or cold because load associated with cooling or heating is higher during such events.

During extreme cold events, expanded transmission ties with neighboring grid operators can also exceed the benefits they offer under normal conditions because transmission line thermal limits are higher during extreme cold and wind chill conditions. Transmission ties also tend to offer large benefits during extreme heat and cold, as severe weather events tend to be at their most extreme in geographically confined areas, ensuring at least some nearby grid operators are not experiencing shortfalls in generation.[2] The benefits of interregional transmission are even greater at higher renewable penetrations.[3] The value of transmission ties during extreme heat and cold events should be accounted for when assessing baseline performance during benchmark events as well as quantifying the value of expanding these ties as part of a CAP.

The higher transfer capacity of advanced conductors under extreme heat and cold conditions should also be accounted for, as carbon and composite core conductors sag roughly half as much as comparable ACSR conductors. Finally, Grid-Enhancing Technologies like dynamic line ratings, topology optimization, and power flow control devices offer significant benefits when the grid may be congested due to extreme temperatures. Dynamic line ratings are particularly valuable for enabling operators to safely use transmission lines' higher thermal limits during extreme cold and wind chill conditions.

Accounting for how a CAP will fare under the extreme heat or cold conditions it is designed to solve is essential for ensuring reliability. Without accounting for the reduced effectiveness of some CAP elements under extreme heat or cold, planners will be blind to potential reliability risks. In other cases, failing to account for the effectiveness of specific CAP measures under extreme heat or cold will result in a suboptimal selection of solutions. Extreme heat and cold must not only be accounted for in identifying reliability risks, but also designing solutions to those risks.

b. The draft of R9 also includes a potential loophole that a responsible entity could use to avoid implementing a CAP that is needed to address reliability concerns.

First, allowing load curtailment for a P1 contingency under TPL-008 is a major departure from the requirements of TPL-001, which do not allow load shedding for a P1 contingency.{C}[4] Allowing responsible entities plans' to include load shed when they experience a single P1 contingency under extreme heat or cold conditions is contrary to FERC's intent in Order 896 that NERC enact a standard that will ensure reliable operations under extreme heat and cold conditions.

More generally, a major concern with the draft standard is that there is no compliance mechanism to ensure CAPs are implemented. If implementing some CAP solutions requires action by an entity other than the transmission planner or planning coordinator responsible entities, the draft standard should be revised to include such a requirement on those entities. Other draft NERC standards include requirements to implement CAPs, and similar language could be adopted for TPL-008. For example, requirement R9 of the PRC-028 draft requires a generator or transmission owner to "develop, maintain, and implement a Corrective Action Plan to provide the required capability,"{C}[5] and requirement R6 of the PRC-030 draft requires "Each applicable Generator Owner shall, for each of its CAPs developed pursuant to Requirement R5:

6.1. Implement the CAP;

6.2. Update the CAP if actions or timetables change; and

6.3. Notify each applicable Reliability Coordinator if CAP actions or timetables change and when the CAP is completed."[6]{C}

{C}[1]{C} *See, e.g.*, FERC and NERC*, Winter Storm Elliott Report: Inquiry into Bulk-Power System Operations During December 2022* (October 2023), https://www.ferc.gov/media/winter-storm-elliott-report-inquiry-bulk-power-system-operations-during-december-2022, at 17; FERC and NERC, *The*

February 2021 Cold Weather Outages in Texas and the South Central United States (November 2021), https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and, at 16; FERC and NERC, *2019 FERC and NERC Staff Report: The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018* (July 2019), https://www.ferc.gov/legal/staff-reports/2019/07-18-19-ferc-nerc-report.pdf; PJM, *Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events* (May 2014), https://www.pjm.com/~/media/library/reports-notices/weather-related/20140509-analysis-of-operational-events-and-market-impacts-during-the-jan-2014-cold-weather-events.ashx.

{C}[2]{C} https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf

{C}[3]{C} https://www.nrel.gov/docs/fy22osti/78394.pdf

{C}[4]{C} https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-5.pdf, at 21

{C}[5]{C} https://www.nerc.com/pa/Stand/Project202104ModificationstoPRC0022DL/2021-04_AB_PRC-028-1_Clean_03182024.pdf

{C}[6]{C} https://www.nerc.com/pa/Stand/Project202302PerformanceofIBRsDL/2023-02%20PRC-030-1_032524.pdf

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	Yes
Document Name	

Comment

FirstEnergy has no comments toward these requirement drafts.

Likes 0	
Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	Yes
Document Name	

Comment

n/a

Likes 0	
Dislikes 0	

Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA supports leaving only P7 contingencies in R10	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon agrees with the updated proposed TPL-008 Reliability Standard Requirements R9, R10, and R11. Exelon would support the clarification suggested by the EEI for R9. .	
Likes 0	
Dislikes 0	
Response	

Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	

Exelon agrees with the updated proposed TPL-008 Reliability Standard Requirements R9, R10, and R11.

Exelon would support the clarification suggested by the EEI for R9.

Likes 0	
Dislikes 0	
Response	

Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	

Based on other projects that include developing and implementing CAPs, USV would feel more confident with the proposed modifications if there were guidelines and more structured timelines set for the CAPs. Perhaps not in the standard itself, but guidance on timelines could be explained in the technical rationale and include timelines for implementing CAPs and when entities can utilize backup action plans such as Non-Consequential Load Loss.

Likes 0	
Dislikes 0	
Response	

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	

ERCOT understands Requirement R9 and Table 1 to allow the use of Non-Consequential Load Loss (NCLL) to address a performance deficiency in a P1 event. ERCOT supports this approach, as the planning cases that TPL-008 addresses are based on extreme grid events that, coupled with a P1 scenario, are unlikely to reflect realistic future system conditions and therefore should not be treated the same way as planning events are treated under TPL-001-5.1. Consistent with this understanding, ERCOT recommends that Part 9.3 be revised as follows to more clearly align with the language in Table 1:

"9.3. Be permitted to utilize Non-Consequential Load Loss as an interim solution, which normally is not permitted ***for P0 events*** in Table 1…"	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michele Tondalo - United Illuminating Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ben Hammer - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Srikanth Chennupati - Entergy - 1,3,5,7 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Helen Lainis - Independent Electricity System Operator - 2	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Erin Wilson - NB Power Corporation - New Brunswick Power Transmission Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Streifling - NB Power Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Robert Jones - Seattle City Light - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC) Project 2023-07 TPL-008-1 Draft #3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Michele Shafer - New York State Electric & Gas (NYSEG) - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - ReliabilityFirst - 10 - RF	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	
Document Name	
Comment	
Dominion Energy supports EEI comments	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	
Document Name	
Comment	
PNMR supports R10 and R11. PNMR supports EEI's proposed changes to R9.1 thru R9.4.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE continues to recommend including a timeframe for which the CAPs need to be developed and submitted for review once the benchmark planning case study results indicate the System is unable to meet performance requirements.

Texas RE likewise continues to have concerns about the submission of CAPs solely to “applicable regulatory authorities…responsible for retail electric service.” As an initial matter, it is unclear how this requirement will work in practice and how the ERO could maintain visibility into the CAP review process. More broadly, since the Reliability Coordinator (RC) is the functional entity responsible for the Reliable Operation of the Bulk Electric System within the NERC jurisdictional model, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations, the CAP should at least be submitted to the RC in addition to applicable regulatory authorities.

Consistent with this approach, Texas RE recommends the following revision:

9.1 Make their CAPs CAP available and solicit feedback from their Reliability Coordinator and applicable regulatory authorities or governing bodies responsible for retail electric service issues within 60 days of developing the CAPs.

Additionally, Texas RE noticed that while Non-Consequential Load Loss is allowed for single and multiple circuit contingencies based on Table 1 performance criteria, the amount of Non-Consequential Load Loss allowed is not specified. This could lead to inconsistent application of load interruptions to maintain system performance.

Likes 0	
Dislikes 0	

Response

Wayne Guttormson - SaskPower - 1

Answer	
Document Name	

Comment

R11 is purely administrative in nature and based on previous NERC/industry efforts to remove administrative details it should be removed. Technical rationale provided for R11 seems lacking as to need and essentially could be used for any standard.

Likes 0	
Dislikes 0	

Response

6. The DT believes proposed modifications in TPL-008-1 provide entities with flexibility to meet the reliability objectives in a cost-effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost-effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

Devin Shines – LG&E/KU	
Answer	Yes
Document Name	
Comment	
The modifications in this draft improve entity flexibility while also providing much needed transparency and alignment with FERC directives. The FERC directives in Order 896 will require a significant (and costly) effort to meet. Recognizing the DT must make a standard to meet these directives, the modifications to TPL-008-1 make it effective while also allowing entities flexibility in meeting the reliability objectives.	
Likes 0	
Dislikes 0	
Response	

Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle

Answer	No
Document Name	
Comment	
Sensitivity to generation, load and transfers are already studied as part of TPL-001-5.1 yearly for near and long-term scenarios (year 10/year 12). The sensitivity additional studies proposed for R8.2 are unlikely to yield any new information and will be duplicative work for Transmission Planners. The Extreme Temperature Assessment is already a very extreme sensitivity study itself that should already capture modified load, generation, transmission, and transfers befitting this analysis per R3, so it is not needed nor appropriate to study sensitivities for sensitivity cases. Further sensitivity cases to adjust such power flow variables would be a nice idea, but it does not appear cost effective to mandate developing and evaluating “sensitivity” cases in addition to the already sensitive nature if the extreme weather assessment. · If sensitivity cases are deemed necessary, it would be more cost-effective to waive the obligation to study and analyze stability for those sensitivities.	
Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO	
Answer	No
Document Name	
Comment	
Being that this is a new assessment, entities will likely have to build additional models, coordinate with appropriate entities, perform the assessment, and train staff, there will likely be a large cost associated with implementation of this standard.	
Likes 0	
Dislikes 0	
Response	

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
ITC believes it is not cost effective to build a sensitivity model and analyze the required events yet not require any Corrective Action Plans.	
Likes 0	
Dislikes 0	
Response	

Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	No
Document Name	
Comment	
The attempt for flexibility is appreciated but this standard still falls short of something that is clear and allows the PC/TP to appropriately plan to meet reliability goals. The inclusion of outside entity reviews of CAPs offers the reviewer flexibility as there are no bounds provided to them. The PC/TP, however is potentially subjected to subjective reviews that have no framework with which the PC/TP can effectively respond.	
Likes 0	
Dislikes 0	
Response	

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CEHE would be interested in more information on any economic analysis that was performed and believes the new Standard imposes a cost and time burden to PCs/TPs without necessarily providing substantial benefits to the reliability of the BPS.	
Likes 0	
Dislikes 0	
Response	

Joseph Knight - Joseph Knight On Behalf of: Jacalynn Bentz, Great River Energy, 3, 1, 5, 6; - Joseph Knight	
Answer	No
Document Name	
Comment	
GRE supports the comments of the NSRF and GRE has additional comments	
Likes 0	
Dislikes 0	
Response	

Jeffrey Streifling - NB Power Corporation - 1	
Answer	No
Document Name	
Comment	
NERC already defines Reliability Coordinator as "The entity that ... has the Wide Area view of the Bulk Electric System...." Rather than asking individual Planning Coordinators and Transmission Planners to coordinated in some ad-hoc, unspecified way, it might be more efficient to assign the responsibility for identifying the weather zones and groups of planning entitites that should coordinate their studies to the Reliability Coordinator, who already has a wide-area vew and is has operational experience with how the power system in their area behaves during temperature extremes.	
Likes 0	
Dislikes 0	
Response	

Erin Wilson - NB Power Corporation - New Brunswick Power Transmission Corporation - 5	
Answer	No
Document Name	
Comment	
NERC already defines Reliability Coordinator as "The entity that ... has the Wide Area view of the Bulk Electric System...." Rather than asking individual Planning Coordinators and Transmission Planners to coordinated in some ad-hoc, unspecified way, it might be more efficient to assign the responsibility for identifying the weather zones and groups of planning entitites that should coordinate their studies to the Reliability Coordinator, who already has a wide-area vew and is has operational experience with how the power system in their area behaves during temperature extremes.	
Likes 0	
Dislikes 0	
Response	

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
At this time, we are unable to fully agree that this standard provides the necessary flexibility to meet the reliability objectives in a cost-effective manner. We would be interested in more information on any economic analysis that was performed.	
Likes 0	
Dislikes 0	
Response	

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
Duke Energy does not provide comments on cost effectiveness of the proposed modifications.	
Likes 0	
Dislikes 0	
Response	

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	
This consumes resources that could be put to better use in the basic TPL analysis.	
Likes 0	
Dislikes 0	
Response	

Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
The reliability objectives are not being met, ref. our comments above.	
Likes 0	
Dislikes 0	
Response	

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	No
Document Name	
Comment	
New Standard requiring extensive coordination with adjacent PCs/TPs within the defined “zones”. New Standards impose a cost and time burden to PCs/TPs without necessarily providing substantial benefits to the reliability of the BPS.	
Likes 0	
Dislikes 0	
Response	

Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes

Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
While the DT is offering flexibility, we request the DT keep this standard from becoming overly prescriptive allowing members to obtain these in a cost effective manner. Until we see the final result from the PC, FirstEnergy cannot fully determine flexibility to meet the reliability objectives in a cost-effective manner.	
Likes 0	
Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
The updates to TPL-008 in the Draft 3 redline provide more flexibility for entities to meet the objectives in the standard than previous draft versions. This is best reflected by the removal of R2 language such that R2 no longer requires entities to select a benchmark event from the benchmark library if the selected event meets the requirements described in R2.2.1 and R2.2.2.	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michele Shafer - New York State Electric & Gas (NYSEG) - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Sharon Darwin - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Jones - Seattle City Light - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gary Trezza - Long Island Power Authority - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Srikanth Chennupati - Entergy - 1,3,5,7 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Michele Tondalo - United Illuminating Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Broc Bruton - Broc Bruton On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Broc Bruton	
Answer	
Document Name	
Comment	
Abstain	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	
Document Name	
Comment	
WECC leaves comments of the cost-effectiveness to those that must compy with the proposed standard.	

Likes 0	
Dislikes 0	

Response

Stephanie Kenny - Edison International - Southern California Edison Company - 6

Answer	
Document Name	

Comment

See EEI Comments

Likes 0	
Dislikes 0	

Response

Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop

Answer	
Document Name	

Comment

Ameren offers no comment on the cost effectiveness of the project.

Likes 0	
Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	
Document Name	

Comment

MRO NSRF has no comment on the cost effectiveness of the draft language at this time.

Likes 0	
Dislikes 0	

Response

7. Provide any additional comments for the drafting team to consider, including the provided technical rationale document, if desired.

Devin Shines – LG&E/KU	
Answer	
Document Name	
Comment	
This comment form did not include a question to provide feedback on the modifications to Table 1, but LG&E/KU supports all modifications.	
Likes 0	
Dislikes 0	
Response	

Barbara Marion – Dominion Energy	
Answer	
Document Name	
Comment	
The issues deal primarily with the referenced methodology for referenced events as well as the arbitrary nature of dividing the country into study regions based on the objectives of the proposed standard.	
Likes 0	
Dislikes 0	
Response	

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	
Document Name	
Comment	
Consumers Energy maintains its stance that the SDT must change “Bulk Power System (BPS)” to “Bulk Electric System (BES)” in section A.3. for consistency with the proposed Extreme Temperature Assessment definition and TPL-001 purpose statement.	

“Contingency BES Level” for a Category P0 event in Table 1 should be changed to “N/A” as there are no contingencies to be applied when the Event is “None”. This would provide consistency with the Fault Type listing for the P0 Category as well.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	
Document Name	

Comment

AEP offers the following additional comments regarding potential overlapping or duplicative obligations.

R1’s “shall complete its responsibilities such that the … assessment is completed…” appears duplicative with R8’s “shall complete steady-state and stability analysis… ”. AEP recommends removing the last sentence from R1 regarding completing the Extreme Temperature Assessment at least once every five calendar years and appending it to R8.

Regarding R5, the TP and PC should already possess steady state voltage criteria to satisfy TPL-001 R5. As a result, AEP recommends removing R5 to avoid compliance risk associated with duplicative obligations. If the drafting team chooses to retain R5, the phrase “shall have criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations” might benefit from something more actionable than “shall have.” AEP recommends the drafting team consider “shall devise” or “shall develop.”

R6’s identification of instability, uncontrolled separation, and cascading per criteria or methodology is already required in TPL-001 R6, which once again appears duplicative and would unnecessarily increase compliance risk. AEP recommends it be removed.

Likes 0	
Dislikes 0	

Response

Robert Follini - Avista - Avista Corporation - 3

Answer	
Document Name	

Comment

This includes all changes and/or clarifications requested by Avista

Likes 0	
Dislikes 0	

Response

Kevin Conway - Western Power Pool - 4	
Answer	
Document Name	
Comment	
We would like to thank the STD for being responsive to the industry concerns and making this proposed standard more flexible for the various entities to conform to.	
Likes 0	
Dislikes 0	
Response	

Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	
Document Name	
Comment	
• The clean-up of Table 1 to better align with TPL-001-5's Table 1 is noted and appreciated. • The VRF for R5 was changed to "Medium" for this draft 3, however the VRF for R6 was not changed to "Medium". It is requested the VRF for R6 be set as "Medium" for consistency with TPL-008 R5.	
Likes 0	
Dislikes 0	
Response	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	
Document Name	
Comment	
MRO NSRF has no additional comments.	
Likes 0	
Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	
Document Name	
Comment	
R6 VRF is 'High', but it should be set as 'Medium' to match TPL-008 R5, R7, and TPL 001-5 R6. Corrective Action Plan requirement column should be added back to Table 1, as stated in the previous draft 2, Table 2.1, page 11.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Michael Jones - National Grid USA - 1, Group Name National Grid	

Answer	
Document Name	

Comment

National Grid supports EEI's comments and in-addition:

1. Please consider adding clarity regarding Stability Only Events, noting that in TPL-001-5.1 - Item j (Stability Only) was not included in Table 1 of TPL-008-1. It is unclear whether the exclusion of Stability Only events was intentional or an unintentional omission. If this was unintentional, we suggest adding the following:

Page 10 (Stability Only Section – NEW):

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Note: *If adding item j above was an unintentional omission, then we further suggest that the following edits are additionally required in Requirement R5. See below:*

Each responsible entity, as identified in Requirement R1, shall have criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations and the transient voltage response for its system for completing the Extreme Temperature Assessment. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

2. Please consider adding a new footnote (Page 12 of Table 1) to better clarify the BES voltage levels for Events and align with Footnote 1 from TPL-001-5.1 (See below)

For P0 and P1 events, the BES level of the event is the lowest System voltage level of the element(s) removed for the analyzed event. For P7 events, the BES level of the event is the highest System voltage level of the element(s) removed for the analyzed event.

Likes 0	
Dislikes 0	

Response

Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

BPA suggests that the Violation Risk Factor for R6 be changed from high to medium to be consistent with R5 as well as TPL-001 R5 and R6.

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	
Document Name	
Comment	
Please see EEI coments	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	
Document Name	
Comment	
The zones identified in draft TPL-008-01, R2 cover large areas with widely varying temperature extremes. Selection of a single temperature event to represent all generators within a zone is not realistic. The draft TPL-008 Tech Rationale acknowledges the limitation of using a single temperature over wide areas. The NERC Standard EOP-12 extreme cold weather drafting teams struggled with the challenge of widely varying temperature conditions across geographical areas and developed the Extreme Cold Weather Temperature (ECWT) as a "good enough" bounding temperature for cold weather preparation planning. These ECWTs have been provided to PCs and TOPs as part of routine data requests from these entities. However, neither the draft TPL-008 Standard or the Tech Rationale appear to include any consideration of the use of ECWT in planning studies, And the terms "extreme cold" and "extreme heat' are not defined in the draft TPL-008 Standard. Suggest the Tech Rationale be revised to include some mention of the generator cold weather planning Standard or the data which the PC / TOP may have requested from generators, as a way to "fine tune" the results of the PC TPL-008 benchmark studies. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	
Document Name	
Comment	

The zones identified in draft TPL-008-01, R2 cover large areas with widely varying temperature extremes. Selection of a single temperature event to represent all generators within a zone is not realistic. The draft TPL-008 Tech Rationale acknowledges the limitation of using a single temperature over wide areas. The NERC Standard EOP-12 extreme cold weather drafting teams struggled with the challenge of widely varying temperature conditions across geographical areas and developed the Extreme Cold Weather Temperature (ECWT) as a "good enough" bounding temperature for cold weather preparation planning. These ECWTs have been provided to PCs and TOPs as part of routine data requests from these entities. However, neither the draft TPL-008 Standard or the Tech Rationale appear to include any consideration of the use of ECWT in planning studies, And the terms "extreme cold" and "extreme heat' are not defined in the draft TPL-008 Standard. Suggest the Tech Rationale be revised to include some mention of the generator cold weather planning Standard or the data which the PC / TOP may have requested from generators, as a way to "fine tune" the results of the PC TPL-008 benchmark studies.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples

Answer	
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) on question 7

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	
Document Name	

Comment

Exelon supports the clarification suggested by the EEI for Table 1.

Likes 0	
Dislikes 0	

Response

Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	
Document Name	
Comment	
PNMR supports EEI's comments related to Table 1 events 1 & 6.	
Likes 0	
Dislikes 0	
Response	

Robert Jones - Seattle City Light - 1,3,4,5,6	
Answer	
Document Name	
Comment	
As stated above, since this standard requires entities come to a consensus on scenarios and and coordination methodology within each zone, there should be some method of deispute resolution to ensure that process can be completed successfully.	
Likes 0	
Dislikes 0	
Response	

Sharon Darwin - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
Southern Company supports the additional comments provided by EEI. Southern greatly appreciates the efforts of the SDT to address and incorporate industry feedback and is very encouraged by the changes made in recent drafts.	
Likes 0	
Dislikes 0	
Response	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	

EEI suggests the following changes to Table 1 – Steady State & Stability Performance Events as follows:

Formatting issue with P7 (Sensitivity Cases): The “Yes” statement is out of alignment with the other cells.

Page 10 (Steady State only Section)

Item h. from TPL-001-5.1 should be added to Table 1 of TPL-008-1 (see below):

h. Planning event P0 is applicable to Steady State only.

EEI asks for clarity regarding Stability Only Events, noting that in TPL-001-5.1 - Item j (Stability Only) was not included in Table 1 of TPL-008-1. It is unclear whether the exclusion of Stability Only events was intentional or an unintentional omission. If this was unintentional, we suggest adding the following:

EEI offers the following edits to Footnote 1 (Page 12), which we believe provides greater clarity to the footnote (proposed changes in boldface below including first sentence removed):

For P1 events, the BES level of the event **is determined by the lowest System voltage level of the elements(s) removed for the analyzed event.** For P7 events, the BES level of the event is determined by the highest System voltage level of the element(s) removed for the analyzed event.

EEI suggests that Footnote 6 (Page 12) be modified by deleting the first sentence because it is duplicative of the language already contained in Requirement R9. See below (*First Sentence Removed*):

In benchmark planning cases, Non-Consequential Load Loss is not permitted for category P0 and requires notification of applicable regulatory authorities or governing bodies responsible for retail electric service issues when utilized as an element of a Corrective Action Plan for P1 Contingencies. *See Requirement R9 for the relevant requirements.*

Likes 0	
Dislikes 0	
Response	

Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	

N/A

Likes 0	
Dislikes 0	

Response

Michael Brytowski - Great River Energy - 3	
Answer	
Document Name	

Comment

The current ordering of requirements R1, R2, & R3 creates confusion when reading the responsibilities of requirements 4-11. Consider reordering – R2, R3 then R1. Coordinating Zones, develop benchmark planning then conducting the assessments. The Transmission Planner (TP) is not referenced in R2 or R3.

R2 currently – Coordinating Zones

Each Planning Coordinator shall identify the zone(s) to which the Planning Coordinator belongs to under Attachment 1, and shall coordinate with all Planning Coordinators within each of its identified zone(s), to select one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event for each of its identified zone(s) when completing the Extreme Temperature Assessment.

R3 currently – a process for developing benchmark planning

Each Planning Coordinator shall coordinate with all Planning Coordinators within each of its zone(s) identified in Requirement R2, to implement a process for developing benchmark planning cases for the Extreme Temperature Assessment that represent the benchmark temperature events selected in Requirement R2 and sensitivity cases to demonstrate the impact of changes to the basic assumptions used in the benchmark planning cases.

R1 currently – The assessments

Each Planning Coordinator shall identify, in conjunction with its Transmission Planner(s), each entity's individual and joint responsibilities for completing the Extreme Temperature Assessment, which shall include each of the responsibilities described in Requirements R2 through R11. Each responsible entity shall complete its responsibilities such that the Extreme Temperature Assessment is completed at least once every five calendar years.

Likes 1	Scott Brame, N/A, Brame Scott
Dislikes 0	

Response

Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	
Document Name	

Comment	
Our understanding of the Benchmark Process is that the Weather Zones were used to develop the lists (library) of Benchmark Events, and therefore each Weather Zone has its library. Our interpretation of the current document would be that Québec shares the same library "Eastern Canada" as our Canadian neighbors, without however having to choose the same events every 5 years because we are alone in our ETA Zone as per the table in Attachment 1. However, the Quebec zone vs. Eastern Canada zone should be clarified because the Technical Rationale does not distinguish between the two types of zones (Weather Zones and ETA Zones), and rather gives the impression that it would normally be the same zone while the list under "Benchmark Event Data" on the Project page give the impression that the Québec zone is included with the Eastern Canada zone. To be consistent with the table and the map in Attachment 1, if we decided that we did not need to coordinate with our neighbors for the ETA, there is no reason for us to share the same library, Québec should have a separate library.	
Likes 0	
Dislikes 0	
Response	

Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	
Document Name	
Comment	

AZPS supports the following comments submitted by EEI on behalf of its members:

EEI suggests the following changes to Table 1 – Steady State & Stability Performance Events as follows:

Formatting issue with P7 (Sensitivity Cases): The “Yes” statement is out of alignment with the other cells.

Page 10 (Steady State only Section)

Item h. from TPL-001-5.1 should be added to Table 1 of TPL-008-1 (see below):

h. Planning event P0 is applicable to Steady State only.

EEI asks for clarity regarding Stability Only Events, noting that in TPL-001-5.1 - Item j (Stability Only) was not included in Table 1 of TPL-008-1. It is unclear whether the exclusion of Stability Only events was intentional or an unintentional omission. If this was unintentional, we suggest adding the following:

EEI offers the following edits to Footnote 1 (Page 12), which we believe provides greater clarity to the footnote (proposed changes in boldface below):

For P1 events, the BES level of the event is determined by the lowest System voltage level of the elements(s) removed for the analyzed event. For P7 events, the BES level of the event is determined by the highest System voltage level of the element(s) removed for the analyzed event.

EEI suggests that Footnote 6 (Page 12) be modified by deleting the first sentence because it is duplicative of the language already contained in Requirement R9. See below:

In benchmark planning cases, Non-Consequential Load Loss is not permitted for category P0 and requires notification of applicable regulatory authorities or governing bodies responsible for retail electric service issues when utilized as an element of a Corrective Action Plan for P1 Contingencies. *See Requirement R9 for the relevant requirements.*

Likes 0	
Dislikes 0	

Response

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	
Document Name	

Comment

No additional comments.

Likes 0	
Dislikes 0	

Response

Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC) Project 2023-07 TPL-008-1 Draft #3

Answer	
Document Name	

Comment

For purposes of posterity, the SRC requests the standard drafting team provide a supporting explanation in the Technical Rationale justifying why P1 and P7 events are limited to >200 kV. Consider revising the Extreme Temperature Assessment definition to make it easier to read. The SRC proposes the following language:

Extreme Temperature Assessment – Documented ***benchmark and sensitivity*** evaluation of future Bulk Electric System performance for extreme heat and extreme cold benchmark temperature events.

The SRC recommends adding language for clarity of the number of cases needed. As currently drafted, TPL-008 R2 (winter / summer), R3 (benchmark / sensitivity), R4 & R5 (power flow), and R6 (dynamics) requires eight cases, however, this information is not straight forward and may lead to missed cases.

The SRC requests clarification regarding R3.3 [Assumed seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers in areas outside the zone, as needed.] In the event an area is lacking in resources to meet an extreme future case load, is the PC to assume reliance on neighboring zones to import (and assume import capability) or can the CAP be to establish more resources (dependency or self-sufficiency)?

Please confirm that the PC selects which future year (within the long-term planning horizon) is studied, as long as it is greater than one year.

Likes 0	
Dislikes 0	

Response

Kinte Whitehead - Exelon - 3

Answer	
Document Name	

Comment

Exelon supports the clarification suggested by the EEI for Table 1.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC

Answer	
Document Name	

Comment

Attachment 1 – Extreme Temperature Assessment Zones in accordance with Requirement R2: We agree with Québec being its own Interconnection in the map and in the table, however Québec is the only area that has its own zone in the table which does not correspond to a Weather Zone identified in the Benchmark Process. Similarly, it is not in the list of benchmark temperature event data on the project page under “Benchmark Event Data”. For example, ERCOT is identified as its own Interconnection and has its own list of benchmark temperature events. Another example is Florida in the SERC region warrants a separate treatment and has its own benchmark temperature event data.

Our understanding of the Benchmark Process is that the Weather Zones were used to develop the lists (library) of Benchmark Events, and therefore each Weather Zone has its library. Our interpretation of the current document would be that Québec shares the same library "Eastern Canada" as our Canadian neighbors, without however having to choose the same events every 5 years because we are alone in our ETA Zone as per the table in Attachment 1.

However, the Quebec zone vs. Eastern Canada zone should be clarified because the Technical Rationale does not distinguish between the two types of zones (Weather Zones and ETA Zones), and rather gives the impression that it would normally be the same zone while the list under "Benchmark Event Data" on the Project page give the impression that the Québec zone is included with the Eastern Canada zone. To be consistent with the table and the map in Attachment 1, if we decided that we did not need to coordinate with our neighbors for the ETA, there is no reason for us to share the same library, Québec should have a separate library.

Lastly, the Quebec zone does not appear in the TPL-008 Attachment 1 map, while it is in the table just above. We suggest adding the label “Québec” or “Quebec Interconnection” in white font in the dark blue space represented by the province of Quebec.

Likes 0	
Dislikes 0	

Response

Stephanie Kenny - Edison International - Southern California Edison Company - 6

Answer	
Document Name	

Comment

See EEI Comments

Likes 0	
Dislikes 0	

Response

Romel Aquino - Edison International - Southern California Edison Company - 3

Answer	
Document Name	Project 2023-07 TPL-008 Draft 3 Near Final Comments Rev. 0d 10_18_2024 (1).docx

Comment

Refer to Edison Electric comments.

Likes 0	
Dislikes 0	

Response

Selene Willis - Edison International - Southern California Edison Company - 5

Answer	
Document Name	

Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	
Document Name	
Comment	
OPG supports NPCC Regional Standards Committee’s comments.	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	
Document Name	
Comment	
Additional comments regarding the listed requirements are as follows: R5: • The recently adopted NERC Glossary term, System Voltage Limits, should be referenced in this requirement instead of the outdated wording “System steady state voltage limits”. “…shall have criteria for acceptable System Voltage Limits …” • Since this requirement appears to refer to steady-state voltage, the post contingency voltage deviation portion of the existing requirement should be removed. The resultant steady-state voltage level being outside of acceptable high and low limits is the point of concern. For example, if a low voltage criterion is 0.92 p.u., then voltages below this limit would violate this particular criterion regardless of whether the beginning voltage was 0.95 p.u., 0.98 p.u., or any other voltage level. R6: • The inclusion of “within an Interconnection” is not appropriate as the PC or TP should not be required to assess outside of its applicable area. Note the inclusion of more appropriate language referring to the PC’s or TP’s planning area (its portion of the Bulk Electric System) in this draft so it is not clear why some requirements refer to an Interconnection while others, more correctly, refer to the area of actual responsibility for the PC or TP.	

• The following bullet contains a wording addition to clarify the applicability of this requirement to System-wide impacts. This is also consistent with wording in other Reliability Standards when referencing these types of impacts.

• “Each responsible entity, as identified in Requirement R1, shall define and document the criteria or methodology used in the Extreme Temperature Assessment analysis to identify instability, uncontrolled separation, or Cascading of the Bulk Electric System.”

Likes 0	
Dislikes 0	

Response

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	
Document Name	2023-07_Unofficial_Comment_Form_Draft 3_100724 ITC (002).docx

Comment

See attachment

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - ReliabilityFirst - 10 - RF

Answer	
Document Name	

Comment

The wording in R6 is similar to CIP-014 in that it could be more prescriptive in describing how an entity should study instability, uncontrolled separation, or Cascading within an Interconnection. ReliabilityFirst and the other regions will assess the validity of judgments made by Registered Entities when assessing this requirement.

Likes 0	
Dislikes 0	

Response

Robert Blackney - Edison International - Southern California Edison Company - 1

Answer	
Document Name	

Comment

See comments submitted by Edison Electric Institute.

Likes 0	
Dislikes 0	

Response

Michael Goggin - Grid Strategies LLC - 5

Answer	
Document Name	

Comment

We appreciate the Implementation Plan shortening of the compliance timeline for requirements R2-11 by one year. However, even with that change, the draft Implementation Plan proposes that requirements R7-R11, which require the Extreme Temperature Assessment and any resulting Corrective Action Plan and therefore constitute the substantive requirement of TPL-008, do not take effect until more than 5 years after the Standard is approved by FERC. While this is an improvement relative to the 6-year delay in the prior draft, this timeframe is still excessive. This unnecessary delay is contrary to FERC's directive in Order 896 and the urgent importance of planning for extreme heat and cold events.

NERC's 2023 State of Reliability Overview concluded that "extreme weather events continue to pose the greatest risk to reliability due to the increase in frequency, footprint, duration, and severity." FERC Order 896 was also clear that the increasing frequency and magnitude of extreme weather events "have created an urgency to address the negative impact of extreme weather on the reliability of the Bulk-Power System" (at paragraphs 21-22). Waiting until 2030 to address the largest threat to grid reliability does not make sense. Such a delay is also unnecessary, as entities responsible for TPL-008 already conduct nearly all of the elements of TPL-008 today to comply with TPL-001. TPL-008 effectively requires running similar analyses as TPL-001, but for extreme heat and cold scenarios. As a result, it should be straightforward for responsible entities to modify their existing planning practices to incorporate the two additional scenarios.

This unnecessary delay is also at odds with FERC's directive in Order 896. At paragraph 188, FERC directed "NERC to propose an implementation timeline for the new or modified Reliability Standard, with implementation beginning no later than 12 months after the effective date of a Commission order approving the proposed Reliability Standard." Under the draft Implementation Plan, the only requirement of TPL-008 that comes close to falling within the 12-month timeline FERC directed is compliance with R1, which begins “the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority’s order approving the standard.”

More importantly, R1 only requires that “Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall determine and identify each entity’s individual and joint responsibilities for performing the studies needed to complete the Extreme Temperature Assessment,” and as such is a minor procedural step towards implementing the actual Extreme Temperature Assessment and any resulting Corrective Action Plan in R7-R11. As noted above, those meaningful requirements do not begin until more than 5 years after the standard is approved by FERC in the current draft. To comply with FERC’s directive and the urgency of addressing extreme weather events, the drafting team should require compliance with R7-R11 to begin at the effective date of the standard (around 12 months after FERC approval of the standard), and the interim steps in R2-R6 should also be moved up from the current Implementation Plan’s proposed deadline of 24 months after the effective date of the standard.

Likes 0	
Dislikes 0	

Response

Summary Response to TPL-008-1 Draft 3 Comments Received

NERC Project 2023-07 Transmission Planning Performance Requirements for Extreme Weather | November 2024

Comments Received Summary

There were 66 sets of responses, including comments from approximately 156 different people from approximately 101 companies representing 10 of the Industry Segments. A summary of comments submitted can be reviewed on the project page.

If you have an interest in joining the distribution list for this project, please reach out to Senior Standards Developer, Jordan Mallory.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact Manager of Standards Jamie Calderon (via email) or at (404) 960-0568.

Consideration of Comments

The NERC Project 2023-07 thanks all of industry for your time and comments. The drafting team (DT) feels that many great points have been provided for the DT to consider during the drafting phase of this project. High level themes received from industry are located below (bolded is the high-level theme followed by the DT's response).

Zones

Many commenters continued to express concerns that the temperature regions as proposed in the map (and elsewhere) are in several cases far too large to provide meaningful analysis (e.g., MISO and SPP in particular). Additionally, the benchmark temperature events identified for both MISO and SPP do not represent what would be considered extreme temperature events due to their large geographically diverse regions.

The zones shown in Attachment 1 lumps Ontario with the Maritimes (New Brunswick, Nova Scotia, and parts of Northern Maine); however, practical experience has shown that there is no reliability benefit to coordinating the extreme weather planning assessments for two reasons:

- Experience has shown that Ontario and the Maritimes are sufficiently distant from each other as to experience extreme temperature conditions at different times. An extreme temperature event in Ontario would not occur at the same time as an extreme temperature event in the Maritimes.
- The balancing areas of Ontario and the Maritimes are not adjacent and the capacity of the transmission system to transfer power between Ontario and the Maritimes is small enough that

the power transferred between Ontario and the Maritimes would most likely be negligible during an extreme temperature event.

For the NPCC region, it would make the most sense to divide the weather zones for extreme weather planning assessments along the boundaries of the existing Reliability Coordinator areas, resulting in five different weather zones:

- ISO New York
- ISO New England
- Ontario
- Quebec
- The Maritimes, including New Brunswick, Nova Scotia, and Northern Maine

In addition to the foregoing, New Brunswick Power would like to support the comments of Helen Lainis, Independent Electricity System Operator.

Drafting team response:

The DT agrees and NERC staff will work to get the zones modified to address the concerns received regarding splitting certain zones into further sections. Below lists out the zones that have been split further. This will be reflected in the map and Table 1 draft 4 posting of the TPL-008-1.

- SPP (north and south)
- MISO (north and south)
- Ontario
- Quebec
- New Brunswick, Nova Scotia, Prince Edward Island, and Northern Maine

Overlapping Zones

A commenter expressed concern with overlapping zones within neighboring entities and should be allowed to meet the requirements of extreme weather conditions. Although we agree that the focus of the study is within the boundary, PCs should have the flexibility to consider maybe a little bit past the confines of the identified zone as identified in Attachment 1.

Drafting team response:

The TPL-008-1 is the bare minimum of what is required. If a PC determines that it needs to coordinate with PCs in other zones, it is more than welcome to coordinate.

Weather Data

One commenter expressed concern with picking weather data that is comparable between New Mexico and Arizona. We believe differences in weather patterns would impact New Mexico study if building that study to Arizona's summer temperatures.

Drafting team response:

The ERO benchmark data provided is aggregated for that zone and not specific areas. Therefore, you would not be subject to the summer temperatures of Arizona. Data used to make this inclusion uses zip code by zip code data.

Benchmark Events

Some commenters expressed that the benchmark events should be included as an attachment to the TPL-008-1 Standard.

Drafting team response:

The DT disagrees with this route for multiple reasons listed below.

1. There will be around 59 plus tables needed to be created, which will make for a 100-plus page standard.
2. Feedback received is that entities appreciate the Excel option to be able to filter and sort, where necessary, when sorting through all the data provided in the benchmark temperature.
3. NERC will need to put together a DT and open the TPL-008-1 standard to update the attachment with ERO benchmark event data every five years and complete this in a timely manner for industry. With Requirement R2 being updated, the DT does not see the need for all benchmark events to be added as an attachment to TPL-008-1.

How to use Benchmark Events

A commenter requested that the drafting team clarify how the event temperature information (available on NERC's website) is intended to be used, and more specifically, whether it is to be applied across the entire zone.

Drafting team response:

The data provided has been calculated via the entire zone identified in table 1. This is no different from other studies that have been completed.

Requirement Order Confusion

Requirement R2 and R3 following R1 creates confusion when reading the responsibilities of requirements 4-11. Consider reordering – R2, R3 then R1. Coordinating Zones, develop benchmark planning then conducting the assessments. The Transmission Planner (TP) is not referenced in R2 or R3.

Drafting team response:

The drafting team determined R1, R2, and R3 are in the appropriate order. R1 requires the PCs and its TP(s) to discuss and identify responsibilities. Although R2 and R3 are applicable to the PC only, TPs may want to inform their PC they want to be included in R2 and R3 activities during the initial R1 discussions. For instance, TPs may want to provide feedback to their PCs with respect to the selection of the benchmark temperature events and/or the implementation of the process for developing benchmark planning cases.

Requirement R1

Document

A commenter requested the drafting team (DT) add document to Requirement R1.

Drafting team response:

The DT followed TPL-007-4 and how it was drafted and did not add "document" to Requirement R1. The DT recognizes there has been a lot of back and forth as to whether document is needed in various standards and does not feel it is necessary to be used in this instance.

Requirement R2

Planning Coordinator Development Benchmark Events

Some commenters expressed that Requirement R2 be made clear that Planning Coordinators are allowed to develop their own benchmark events should the benchmark events provided by the ERO are not sufficient for its zone.

Drafting team response:

FERC Order 896 recognizes that historical events may span across regions and therefore, the ERO is in the best position to develop benchmark events. The DT updated the TPL-008-1 Standard to ensure it is clear that TPL-008-1 allows Planning Coordinators, in coordination with other Planning Coordinators, to develop benchmark events, should the events provided by the ERO not be adequate for Planning Coordinators to consider. As a reminder, one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event are to be identified and studied among the PCs within the zone identified in Attachment 1 of the TPL-008-1 Standard.

Requirement for NERC to Coordinate with PCs

Some commenters expressed that a requirement should be added to the TPL-008-1 standard requiring NERC to coordinate with Planning Coordinators when developing benchmark events.

Drafting team response:

A NERC Process[1] has been developed and posted to the NERC Project 2023-07 page laying out the process for the 5-year iteration of benchmark events being developed. Please see this document for next steps on future benchmark event development.

[1] Link to NERC Process document: NERC Standards Development Process Document

Year Events

A commenter suggested that if the goal is for the PCs to study a one in 40-year event for temperature that each PC perform a study for their footprint and share results to the adjacent PCs, similar to the way existing NERC standards are coordinated. For instance, there are other standards that utilize language for the applicable entity to study its PC footprint and coordinate with 1st tier entities. SPP believes that language similar to this can accomplish the intended goal without creating a burden if the boundaries change in the Map.

Drafting team response:

The goal is not for the PC to study a one in 40-year event. TPL-008-1 is to study an extreme cold or extreme heat event considered no less than a 40-year period of temperature data.

Years Used for Benchmark Events

40 years of temperature data is an immense amount of data. The data collected 40 years ago compared to today's temperatures may not be accurate and could construe the data from the last 20-25 years. We believe that there have been enough recent extreme weather events in the last 25 years to accurately consider extreme heat and extreme cold benchmark temperatures. We recommend that the drafting team consider utilizing a timeline closer to 20 years and not 40 years.

Another commenter proposed 50 years should be used.

Drafting team response:

The requirement to consider no less than 40 years of temperature data was established based on the observation that many of the worst events identified in various regions of North America occurred in the 1980s and 1990s. For example, preliminary data indicated that the five worst extreme cold temperature events in the PJM region over the last 43 years occurred between 1983 and 1994. Similar results were seen in other regions for both extreme heat and extreme cold temperature events. Thus, the SDT determined that a minimum of 40 years of temperature data should be used to ensure more extreme events weren't excluded by using a shorter duration of temperature data.

Regarding 50-year proposal. There is nothing that precludes an entity from pulling 50-years of data, should they find this more beneficial. A standard provides the bare minimum of what is required and anything above and beyond is not precluded from an entity from considering.

Disagreements during coordination

There should be some method to help ensure coordination on scenario selection and case data submittal among all PCs in a zone. How will disagreements among PC's be resolved? Voting? Regions can probably resolve this on their own most of the time, but there may be disputes that need to be resolved somehow.

Drafting Team Response:

The DT understands that this may happen and enough time during implementation has been provided for additional meetings to work through disagreements. In addition, if majority of the PCs within the zone agree, then the team would recommend going the route of majority and let the entity who is in disagreement work through their justification when it comes time for them to be audited. Lastly, entities are welcome to reach out to their Regional Entities if a disagreement comes up to guidance, if needed.

Requirement R2 Subparts – Too Prescriptive

One commenter believes the language in sections 2.1 and 2.2 are too prescriptive. We believe the Planning Coordinator should work with stakeholders to determine the data set that will be used to derive extreme heat and cold weather temperatures. Does the planning coordinator have the ability to carve the zones?

Drafting team response:

Benchmark event data provided by the ERO are there for entities to review and determine what data works for their zone. R2 also allows entities to develop their own benchmark temperature event, should the data provided not be allowed. In addition, criteria is needed per FERC Order 896 and Parts 2.1 and 2.2 to complete this. Order 896: "We also direct NERC to include in the Reliability Standard the framework and criteria that responsible entities shall use to develop from the relevant benchmark event planning cases to represent potential weather-related contingencies".

Extreme Event selection

The new requirement proposed in R2 2.1 in the updated draft that the event selected represent "one of the 20 most extreme temperature conditions" may result in entities selecting events that are not representative of the most severe generation shortfalls they are likely to experience. First, entities should be required to select from a smaller number of most severe events, like the three most severe events. Second, the ranking of events should not be based on most extreme temperature, but rather most severe generation shortage, accounting for both higher demand and higher generator outage rates during the event. This will accurately reflect that temperature alone does not determine the severity of an event, as wind speed, insulation, and other factors affect how extreme cold and heat affect both generator outages and the need for building heating or cooling.

Drafting team response:

The DT understands the concern. However, when considering extreme events over a 3-day rolling average over 40-years does not provide a ton of data to work from. While yes, extreme events have become more common in recent years, it is important for an entity to be able to evaluate events that happened over 40-years as some of the events may not be extreme compared to other events. It is important to collect 20 extreme events to review and consider which event to study for further studies. Pulling data for 10 most extreme events may not provide the full picture of events to review and select from.

Requirement R3/R4

Transmission Planners Missing

The prior draft of TPL-008 contained language in R3 that required “Planning Coordinator(s), Transmission Planner(s), and other designated study entities” to collectively implement the requirement. The SRC requests language along these lines be reinstated such that all parties that play a role in implementing the process for developing benchmark planning cases must comply.

Drafting team response:

Coordination is at the PC level and not the TP level. Therefore, the team removed this from the last draft, and it does not need to be added back in.

Benchmark Event Framework

Some commenters requested the DT to clarify “other designated entities.”

Drafting team response:

The DT removed “other designated entities” from the TPL-008-1 Standard.

Number of Studies Required

Some commenters expressed concern regarding the number of studies which must be performed, particularly when a Planning Coordinator (PC) selects a benchmark temperature event that is different from that of its adjacent PC(s). In that situation, each benchmark temperature event may necessitate a significant coordination effort. It was recommended that a governing body identify the scenarios. Extreme temperature events will typically extend beyond the footprint of a single Planning Coordinator. To avoid putting the PCs in a position where they are required to agree on a scenario, a year and the sensitivity to be studied, NERC or other (e.g. ERAG) should identify the extreme heat and extreme cold temperature events to be studied. This is necessary for consistent modeling results across adjacent planning entities. Also, as a benchmark temperature event may extend across several planning areas, the governing body must take this into consideration when determining which extreme heat and extreme cold temperature events are to be studied so that no planning entity is assigned more than one of each.

Drafting team response:

The DT updated the TPL-008-1 Standard to identify that one common extreme heat and one common extreme cold benchmark planning case must be developed, as well as at least one common extreme heat and one common extreme cold sensitivity case. This does not preclude entities from developing more cases, but requires a minimum of one each. Per the FERC Order 896, it is important that entities are studying common historical events in preparation for future events. The ERO will provide entities with one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event for PCs to study within their zones. In addition, the TPL-008-1 Standard has been updated to allow PCs to coordinate with other PCs to develop their own benchmark event should the events provided by the ERO not be adequate for Planning Coordinators to consider.

Extreme Weather is a Sensitivity

Some commenters expressed that Extreme Temperature Events are already a "sensitivity" to normal long-term planning cases and are built with Gen/Load/Transfer based on the extreme weather conditions of an entity's territory. Additionally, mandatory "sensitivity cases" seem redundant in nature. In addition, another commenter asked if sensitivity cases could be baked-in with the benchmark temperature event.

Drafting team response:

TPL-008-1 is different than TPL-001-5.1. The TPL-008-1 Standard focuses on extreme heat and extreme cold temperature events. Entities are to select an extreme heat and cold benchmark event, develop planning cases, and then develop sensitivity cases from that, which may indicate a different approach on how to handle certain scenarios.

Additionally, FERC Order 896 P124 states that "we adopt the NOPR proposal and direct NERC to require the use of sensitivity cases to demonstrate the impact of changes to the assumptions used in the benchmark planning case. Sensitivity analyses help a transmission planner to determine if the results of the base case are sensitive to changes in the inputs. The use of sensitivity analyses is particularly necessary when studying extreme heat and cold events because some of the assumptions made when developing a base case may change if temperatures change – for example, during extreme cold events, load may increase as temperatures decrease, while a decrease in temperature may result in a decrease in generation. We agree with AEP, and we direct NERC to define during the Reliability Standard development process a baseline set of sensitivities for the new or modified Reliability Standard. While we do not require the inclusion of any specific sensitivity in this final rule, NERC should consider including conditions that vary with temperature such as load, generation, and system transfers." P126 continues to explain that "[w]e disagree with NYISO and LCRA that extreme heat and cold weather impacts are already studied as sensitivities under Reliability Standard TPL-001-5.1. Although TPL-001-5.1 mandates sensitivity analysis by varying one or more conditions specified in the standard such as load, generation, and transfers, this analysis alone cannot capture the complexities of extreme heat and cold weather conditions. Sensitivity analyses consider the impact on a base case of the variability of discrete variables. Extreme heat and cold weather impacts, on the other hand, may include numerous concurrent outages and derates which cannot be studied as part of a single-variable sensitivity analysis."

TPL-008-1 Cases Used for TPL-001-5.1

One commenter asked whether language can be added to ensure that entities can take credit for studies that are run as part of the Sensitivity analysis, rather than running those studies again as part of the assessment to be conducted under TPL-001. For example, the Extreme Temperature Assessment could take the place of the sensitivity analysis required within the TPL-001 assessment for both the steady state and stability analyses. Moreover, if the Extreme Temperature Assessment is essentially a type of sensitivity analysis already, the commenter advised removing R4.2 because this would create a sensitivity case based on a sensitivity case.

Drafting team response:

A Planning Assessment must be completed annually in accordance with TPL-001-5.1, while an Extreme Temperature Assessment must be completed at least once every five calendar years in accordance with the TPL-008-1 Standard. Time will be required to coordinate and develop the common cases and therefore, may not meet what is required in TPL-001. TPL-008-1 does not speak to TPL-001; however, both standards have different expectations. The DT does not encourage this, but if an entity decided to go this route, it would be up to that entity to explain and demonstrate compliance with the TPL-008-1 Standard.

Concurrent/Correlated Outage Language

Some commenters expressed that in Order 896 paragraph 88, FERC directs "NERC to require under the new or revised Reliability Standard the study of concurrent/correlated generator and transmission outages due to extreme heat and cold events in benchmark events," explaining in paragraph 89 that "it is necessary that responsible entities evaluate the risk of correlated or concurrent outages and derates of all types of generation resources and transmission facilities as a result of extreme heat and cold events." Commenters suggested modifying "Benchmark planning cases that include seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers" to include "concurrent/correlated generator and transmission outages."

Drafting team response:

Concurrent/correlated outages are addressed through the standard. The DT did not use language verbatim, but the standard is laid out on adjustment of temperature data that is provided by the event selection. Aligning with the directives set forth in FERC Order 896, which emphasizes the importance of incorporating derated generation, transmission capacity, and the availability of generation and transmission in the development of benchmark planning cases, it becomes imperative for responsible entities to consider potential concurrent or correlated generation and transmission outages and/or derates within relevant benchmark planning cases. This ensures that the benchmark planning case accurately reflects System conditions under extreme temperatures, with generation and transmission derates and/or outages already factored.

MOD-032 Data

Some commenters asked if the DT feels it would be necessary to add any additional data to the table in MOD-032 to complete this work. In addition, some sought clarification on how MOD-032 will allow for the collection of additional information related to extreme heat and cold events.

Drafting team response:

MOD-032 ensures an adequate means of data collection for transmission planning and requires applicable registered entities to provide steady-state, dynamic, and short circuit modeling data to their Transmission Planner(s) and Planning Coordinator(s). As outlined in R1 and Attachment 1 of MOD-032, MOD-032 allows various data collection such as in-service status and capability associated with demand, generation, and transmission associated with various case types, scenarios, system operating states, or conditions for the long-term planning horizon. MOD-032 also requires applicable registered entities to provide "other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes" for each of the three types of data required. Because the DT determined the responsible entities that will be developing benchmark planning cases are limited to Planning Coordinators and Transmission Planners, they will be able to request and receive needed data pursuant to MOD-032. Thus, the DT believes that there is no need to update MOD-032 because it allows Planning Coordinators and Transmission Planners to request any specific data needed for developing benchmark planning cases and sensitivity cases required in R4 of TPL-008-1.

Contingencies

In FERC Order 896, paragraph 39, there is a Commission Determination as follows:

"We also direct NERC to include in the Reliability Standard the framework and criteria that responsible entities shall use to develop from the relevant benchmark event planning cases to represent potential weather-related contingencies (e.g., concurrent/correlated generation and transmission outages, derates) and expected future conditions of the system such as changes in load, transfers, and generation resource mix, and impacts on generators sensitive to extreme heat or cold, due to the weather conditions indicated in the benchmark events. Developing such a framework would provide a common design basis for responsible entities to follow when creating benchmark planning cases. This would not only help establish a clear set of expectations for responsible entities to follow when developing benchmark planning events, but also facilitate auditing and enforcement of the Standard."

In review of Order 896, we find the term "contingencies" is used two different ways. Paragraph 39 describes things that are in the base or N-0 state – for example, a cold weather event occurs, and certain wind generators can no longer operate – this as a base contingency. Similarly, in paragraph 88, there is an additional Commission Determination as follows, in further support of these baseline "contingency" outages:

"Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to require under the new or revised Reliability Standard the study of concurrent/correlated generator and transmission outages due to extreme heat and cold events in benchmark events as described in more detail below."

Then later, in Paragraph 92 (still under the Commission Determination), FERC further clarifies:

"Regarding the comments of NYISO and EPRI on the difference between extreme events and contingencies covered under Reliability Standard TPL-001-5.1, we clarify that all contingencies included in benchmark planning cases under the new or modified Reliability Standard will represent initial conditions for extreme weather event planning and analysis. These contingencies (i.e., correlated/concurrent, temperature sensitive outages, and derates) shall be identified based on similar contingencies that occurred in recent extreme weather events or expected to occur in future forecasted events."

From these, it is clear that Order 896 is expecting "contingencies" of weather-based equipment outages to be part of the base or N-0 system state. The more traditional "contingencies" are then addressed on top of this condition, as presented in Order 896, Section G, starting at Paragraph 95.

The specific request from this comment is for the SDT to clarify how it expects such base "contingencies" to be included in the model. There does not appear to be language currently in the standard in support of this, and it is clear from Order 896 that it is expected both the base model outage "contingencies" and then subsequent contingency events to test system performance.

Drafting team response:

The SDT drafted Requirement R4 to require the responsible entity to use data consistent with Reliability Standard MOD-032, supplemented by other sources as needed, for developing benchmark planning cases that represent System conditions based on selected benchmark temperature events. This aligns with directives in FERC Order No. 896, paragraph 30, emphasizing the requirement of developing both benchmark planning cases and sensitivity study cases. Requirement R4 is consistent with Reliability Standard TPL-001-5.1 in cross-referencing Reliability Standard MOD-032, which establishes consistent modeling data requirements and reporting procedures for the development of planning horizon cases necessary to support analysis of the reliability of the interconnected System. It is also consistent with Reliability Standard TPL-001-5.1 in acknowledging that data from other sources may be required to supplement the data collected through Reliability Standard MOD-032 procedures.

The benchmark planning cases and sensitivity cases developed in Requirements R4.1 and R4.2, respectively, shall include forecasted seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers within the zone in accordance with Requirement R3.2, and assumed seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers in areas outside the zone, as needed, in accordance with Requirement R3.3. The seasonal and temperature dependent adjustments included during the development of the benchmark planning cases and sensitivity cases establish category P0 as the normal System condition in Table 1. Subsequently, the Contingencies for each category in Table 1 that are expected to produce more severe System impacts on the responsible entity's portion of the Bulk Electric System shall be identified in accordance with Requirement R7 and evaluated in both steady state and transient stability analyses in accordance with Requirement R8 for the benchmark planning cases and sensitivity cases developed in Requirements R4.1 and R4.2, respectively.

Requirement R5

Use of "System Voltage Limits"

Some comments suggested using the recently adopted NERC Glossary term "System Voltage Limits."

Drafting team response:

The DT determined "System Voltage Limits" focuses on operations and planning information and differs from what is used in the standard. The DT concluded to maintain the proposed language consistent with Reliability Standard TPL-001-5.1.

Requirement R6

Violation Risk Factor

The risk factor should be Medium to match TPL 001-5.1. Concern that level of coordination needed to affect the standard will be significant, particularly for "smaller" entities.

Drafting team response:

The DT determined that based on the planning for events such as instability, uncontrolled separation, or Cascading events would consist of a high VRF and therefore, kept the VRF as high. This is consistent with the definition of a high VRF in the justification document provided on the NERC website.

Requirement R8

Performance of Steady State and/or Stability Analysis

The standard does not clearly and specifically state whether steady-state and/or stability analysis is to be performed for the identified events as TPL-001 does, for instance. The DT should consider modifying R7 to allow the responsible entity to develop a methodology or rationale in the performance of a benchmark event to appropriately assess it for that entity's planning area, otherwise, additional clarity in the analysis expectations is needed. Different weather events would require a different consideration of applicable contingencies and analysis approaches.

Drafting team response:

Requirement 4 has been updated to state one common extreme heat and one common extreme cold. In addition, R8 has been updated to clarify that steady state and transient stability analyses are to be performed.

Additional Sensitivity Cases

Additional sensitivity studies required in R8.2 would add a significant administrative burden without more clarification to how it benefits the long-term planning horizon.

Drafting team response:

Table 1 has been updated to require P0, P1, and P7 Contingencies. R4 has also been updated to clarify that it is one common extreme heat and one common extreme cold benchmark planning case, as well as at least one common extreme heat and one common extreme cold sensitivity case. In addition, this is a directive from the FERC Order 896 P124 which states "we adopt the NOPR proposal and direct NERC to require the use of sensitivity cases to demonstrate the impact of changes to the assumptions used in the benchmark planning case. Sensitivity analyses help a transmission planner to determine if the results of the base case are sensitive to changes in the inputs. The use of sensitivity analyses is particularly necessary when studying extreme heat and cold events because some of the assumptions made when developing a base case may change if temperatures change – for example, during extreme cold events, load may increase as temperatures decrease, while a decrease in temperature may result in a decrease in generation. We agree with AEP, and we direct NERC to define during the Reliability Standard development process a baseline set of sensitivities for the new or modified Reliability Standard. While we do not require the inclusion of any specific sensitivity in this final rule, NERC should consider including conditions that vary with temperature such as load, generation, and system transfers."

Requirement R9

Regulatory Burden

Some commenters raised concerns about the requirement to submit CAPs to regulatory authorities, suggesting it could delay approval, lacks justification, need clearer definitions, and should be limited or removed.

Drafting team response

The DT reviewed the comments and determined that the requirement is necessary to address the directives of Order 896, specifically the directives mentioned in the paragraphs 152 (i.e., "we direct NERC to develop certain processes to facilitate interaction and coordination with applicable regulatory authorities or governing bodies responsible for retail electric service as appropriate in implementing a corrective action plan") and 165 (i.e., "we direct NERC to require in the new or modified Reliability Standard that responsible entities share their corrective action plans with, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues").

Clarity on Sensitivity Analysis

Various commenters questioned the necessity of a Corrective Action Plan for issues identified in sensitivity analysis, seeking clarity on how sensitivity analysis is handled.

Drafting team response

The DT updated Requirement R9 to clarify that Corrective Action Plans are not required specifically for addressing performance requirements related to sensitivity cases. The responsible entity must develop Corrective Action Plan(s) when the analysis of a benchmark planning case indicates its portion of the Bulk Electric System is unable to meet performance requirements for Table 1 P0 or P1 Contingencies.

CAP Request

A commenter requested the DT to 'make their CAP available' in R9.1 to 'make available on request.'

Drafting team response

FERC Order 896 P153 states: "We adopt our rationale set forth in the NOPR and conclude that the directive to require the development of corrective action plans is needed for Reliable Operation of the Bulk-Power System. Under the currently effective Reliability Standard TPL-001-5.1, planning coordinators and transmission planners are required to evaluate possible actions to reduce the likelihood or mitigate the consequences of extreme weather events, but are not obligated to develop corrective action plans, even if such events are found to cause cascading outages. Experience over the past decade has demonstrated that the potential severity of extreme heat and cold weather events exacerbates the likelihood to cause system instability, uncontrolled separation, or cascading failures as a result of a sudden disturbance or unanticipated failure of system elements. Thus, we conclude that entities should proactively address known system vulnerabilities by developing corrective action plans that include mitigation for specified instances where performance requirements for extreme heat and cold events are not met." Therefore, it is the responsibility of the PC or TP developing the CAPs to provide this information to the respective governing bodies and solicit feedback per the FERC Order.

CAP Process

There are already existing processes for interactions with applicable regulatory authorities and governing bodies regarding CAP for many other issues and items. Extreme weather CAPs are not exceptions and do not need a new way to solicit feedback. R9.1 should be removed because it also creates a compliance requirement without any benefit to reliability and would be confusing. In addition, a commenter requested 9.1 subpart be removed because it creates a compliance requirement without any incremental benefit to reliability and further conflicts with existing planning requirements and processes. In addition, some entities felt the way Requirement R9 was drafted out was providing some confusion and requested re-order of the sub-parts.

Drafting team response

An entity may use what is already in place to be compliant with this requirement. This requirement is addressing the FERC Order 896 directive in P152 that states "we direct NERC to develop certain processes to facilitate interaction and coordination with applicable regulatory authorities or governing bodies responsible for retail electric service as appropriate in implementing a corrective action plan." Lastly, the TPL-008-1 Standard is aligning with what the FERC Order 896 directs. The DT did its best to align with TPL-001 while meeting the FERC Order 896 directives.

The DT re-order the CAP process within Requirement R9 to provide clarity. Please see the updated standard.

Include Threshold

One commenter believes the requirement for the notification to an applicable regulatory entity should also include a threshold. As written, an entity would need to make a notification if a proposal tripped 0.1 MW of non-consequential load. Recommend the DT add a threshold in a similar way as is included in TPL-001 Attachment 1.

Drafting team response

The DT does not feel that a threshold is needed in the TPL-008-1 Standard. An entity only has report obligations if it is a part of a CAP. Depending on the mechanism used, you may not be required to report smaller amounts of load.

Jurisdiction

One commenter expressed that the "applicable regulatory authorities... electric service" needs better clarification and questioned what this looks like for Jurisdictional vs non-Jurisdictional. The commenter asked the DT to provide better guidance and examples, and highly recommended using operation procedures instead of CAPs since operation procedures have more flexibility to respond to a system's needs and adapt proactively.

Drafting team response

Per FERC Order 896 P165, building generation and transmission is outside the jurisdiction and left up to the states. FERC Order 896 provides some examples of various activities that would be appropriate in P155: "As noted by commenters, the NOPR provided examples of various activities that may be appropriate under a corrective action plan, some of which may require state or local authorizations (e.g., generation or transmission development). Other examples mentioned in the NOPR include "implementing new energy efficiency programs to decrease load, . . . transmission switching, or adjusting transmission and generation maintenance outages based on longer-lead forecasts," none of which involve the construction of generation or transmission capacity. In addition, responsible entities have the option to use controlled load shed as a mitigation measure. In sum, while responsible entities would have the obligation to develop and implement a corrective action plan, the Commission is not directing any specific result or content of the corrective action plan. In such circumstances, the Commission's directive does not exceed the jurisdictional limits set forth in section 215(i) of the FPA0." Also, "applicable regulatory authorities or governing bodies responsible for retail electric service issues" is in TPL-001; therefore, the same entities may be used. Finally, this language was added based on FERC Order 896 P165: "We direct NERC to require in the new or modified Reliability Standard that responsible entities share their corrective action plans with, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues. We agree with commenters that relevant state entities should have the opportunity to provide input during the development of corrective action plans. Just as this final rule seeks to ensure Reliable Operation of the Bulk-Power System during extreme heat and cold weather events, regulatory authorities and governing bodies responsible for retail electric service are taking actions to ensure reliability for local stakeholders. As such, we believe that requiring responsible entities to seek input from applicable regulatory authorities or governing bodies responsible for retail electric service issues when developing corrective action plans could help ensure that shared opportunities to increase system reliability are not missed. Further, as NESCOE points out, such consultation may allow these entities to better understand "the cost implications of various approaches" and, therefore, provide "better insight into the considerations and tradeoffs inherent in the options available."

Requirement R10

Clarity and Communication on Possible Actions

A commenter questioned what actions the responsible entity intends to take based on the identified "possible actions." There is uncertainty about how these actions will be executed. In addition, the commenter suggested that these possible actions should be communicated to the operators so they can prepare necessary plans and processes accordingly.

Drafting team response

The DT acknowledges the commenter's concerns regarding implementing possible actions and their communication to operators. The DT asserts that R11 outlines the expected actions, mandating responsible entities to share Extreme Temperature Assessment results with any functional entities that has a reliability-related need to enhance readiness for extreme temperature events.

TPs Ability to Create CAPs

A commenter disagrees with R10 because the requirement does not give TPs the ability to create CAPs for the listed contingencies.

Drafting team response

Requirement 10 does not preclude Transmission Planners from developing CAPs; however, possible actions would be required should a Transmission Planner determine that a CAP is not required.

Requirement R11

Timeline for Distributing Assessment Results

Some commenters questioned if the 60 calendar days was appropriate and should align with TPL-001-5 that states 90-days.

Drafting team response:

The DT determined to keep the requirement unchanged as this strikes a good balance between allowing enough time for the responsible entity to distribute the results and the functional entity requesting the information to receive them.

Stability Performance

A commenter asked the DT how to determine stability performance requirements for P0 events. Currently, Table 1 says that the system shall remain stable, and that instability, uncontrolled separation and cascading shall not occur, but the commenters asked how those would occur for a P0 event.

Drafting team response:

Instability can occur during P0 conditions due to various factors like oscillations, renewable generation behavior, and excessive power transfers. For example, poorly damped oscillations between generators in different areas can grow and destabilize the system if not properly controlled. High levels of wind, solar, or energy storage may also cause instability if these resources don't adequately support grid stability. Additionally, excessive power transfers on key transmission lines can lead to voltage instability and potential voltage collapse.

Implementation Plan

One entity disagreed with the amount of time allowed for entities to implement TPL-008-1.

Drafting team response:

The DT appreciates the interest in making the turnaround transition complete in a quicker manner. However, TPL-008-1 has many factors at play, for example: locating and coordinating with other PCs within its zone, hosting meetings to determine the common factor that works for all PCs within its zone, etc. The

DT feels it is important to provide entities with adequate time to sort things out with these new requirements in place to ensure each entity is successful in the end.

Map

A request was made to disconnected portions of SERC and PJM be included into zones that more closely align with their temperature regions.

Drafting team response:

The “disconnected portions” of PJM and SERC are electrically connected via AC ties and should be studied together as a zone. In addition, the map is not an accurate depiction, and the disconnected portions are closer to the PJM and SERC zones than displayed on the map. As a reminder, the map is a visual assistance and not to be used for compliance purposes.

Update Map and Table 1

Some commenters requested the map be updated to accurately reflect the updated zones.

Drafting team response:

The DT updated the map and Table 1 accordingly.

Coordination via Map and Table 1

One commenter expressed concern with the western portion of the Table and Map. The Table and Map seem to group together PCs in a way that could create issues when trying to identify which PCs belong to those zones. There is currently no requirement to post publicly which zone a PC is within, therefore knowing which PC belongs to each zone is not possible.

Drafting team response:

Coordination with other PCs should be no different than coordinating with the PCs in TPL-001-5. An entity could reach out to its Regional Entity or coordinate with the larger PC within its zone. The DT recognizes this may take some time to research and figure out up front but is needed to meet FERC Order 896.

Add State Boundaries to Map

Some commenters support the zones outlined in the map provided in Attachment 1. However, the graphic would be significantly improved by incorporating state boundaries and referencing the NERC benchmark library.

Drafting team response:

The DT attempted to add state boundaries and found that the map is not an accurate depiction of zones when state boundaries are added. This is why Table 1 was developed and the map was added as a visual, but to be used for compliance purposes.

Technical Rationale

One comment was that the technical rationale states the zones have been determined by the Reliability Coordinator (RC) area. SPP believes that breaking the zone by RC footprint is not accurate and should be divided by the PC footprint especially considering that the standard only applies to the PC. PC and RC footprints can be drastically different across the grid.

Drafting team response:

The DT recognizes this causes confusion and has updated the Technical Rationale to remove RC.

Please see many updates to the Technical Rationale made by the team during this draft.

Reminder

Standards Announcement

Project 2023-07 Transmission Planning Performance Requirements for Extreme Weather

Additional Ballots and Non-binding Poll Open through October 21, 2024

Now Available

Additional ballots for draft three of **TPL-008-1 – Transmission System Planning Performance Requirements for Extreme Temperature Events** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels are open through **8 p.m. Eastern, Monday, October 21, 2024**.

The Standards Committee approved waivers to the Standards Process Manual at their December 2023 meeting. These waivers were sought by NERC Standards for reduced formal comment and ballot periods to assist the drafting teams in expediting the standards development process due to firm timeline expectations set by FERC Order 896.

The standard drafting team's considerations of the responses received from the last comment period are reflected in this draft of the standard.

Reminder Regarding Corporate RBB Memberships

Under the NERC Rules of Procedure, each entity and its affiliates is collectively permitted one voting membership per Registered Ballot Body Segment. Each entity that undergoes a change in corporate structure (such as a merger or acquisition) that results in the entity or affiliated entities having more than the one permitted representative in a particular Segment must withdraw the duplicate membership(s) prior to joining new ballot pools or voting on anything as part of an existing ballot pool. Contact ballotadmin@nerc.net to assist with the removal of any duplicate registrations.

Balloting

Members of the ballot pools associated with this project can log in and submit their votes by accessing the Standards Balloting and Commenting System (SBS) here.

Note: Votes cast in previous ballots, will not carry over to additional ballots. It is the responsibility of the registered voter in the ballot pools to place votes again. To ensure a quorum is reached, if you do not want to vote affirmative or negative, cast an abstention.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*

- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps
The ballot results will be announced and posted on the project page. The drafting team will review all responses received during the comment period and determine the next steps of the project.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Jordan Mallory (via email) or at 404-479-7358. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2023-07 Transmission Planning Performance Requirements for Extreme Weather observer list” in the Description Box.

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NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2023-07 Transmission Planning Performance Requirements for Extreme Weather

Formal Comment Period Open through October 21, 2024

Now Available

A 15-day formal comment period for draft three of **TPL-008-1 – Transmission System Planning Performance Requirements for Extreme Temperature Events** is open through **8 p.m. Eastern, Monday, October 21, 2024**.

The Standards Committee approved waivers to the Standards Process Manual at their December 2023 meeting. These waivers were sought by NERC Standards for reduced formal comment and ballot periods to assist the drafting teams in expediting the standards development process due to firm timeline expectations set by FERC Order 896.

The standard drafting team's considerations of the responses received from the previous comment period are reflected in this draft of the standard.

Reminder Regarding Corporate RBB Memberships
Under the NERC Rules of Procedure, each entity and its affiliates is collectively permitted one voting membership per Registered Ballot Body Segment. Each entity that undergoes a change in corporate structure (such as a merger or acquisition) that results in the entity or affiliated entities having more than the one permitted representative in a particular Segment must withdraw the duplicate membership(s) prior to joining new ballot pools or voting on anything as part of an existing ballot pool. Contact ballotadmin@nerc.net to assist with the removal of any duplicate registrations.

Commenting
Use the Standards Balloting and Commenting System (SBS) to submit comments. An unofficial Word version of the comment form is posted on the project page.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps
Additional ballots for the standard and implementation plan, as well as a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **October 11-21, 2024**.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Jordan Mallory (via email) or at 404-479-7358. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2023-07 Transmission Planning Performance Requirements for Extreme Weather observer list” in the Description Box.

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BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/353)
Ballot Name: 2023-07 Transmission Planning Performance Requirements for Extreme Weather TPL-008-1 AB 3 ST
Voting Start Date: 10/11/2024 12:01:00 AM
Voting End Date: 10/21/2024 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 3
Total # Votes: 265
Total Ballot Pool: 314
Quorum: 84.39
Quorum Established Date: 10/21/2024 5:53:34 PM
Weighted Segment Value: 51.9

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	89	1	33	0.516	31	0.484	0	13	12
Segment: 2	8	0.8	3	0.3	5	0.5	0	0	0
Segment: 3	68	1	28	0.56	22	0.44	0	8	10
Segment: 4	18	1	4	0.4	6	0.6	0	2	6
Segment: 5	76	1	25	0.521	23	0.479	0	13	15
Segment: 6	47	1	23	0.622	14	0.378	0	6	4
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	1	0	0	0	0	0	0	0	1

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	7	0.4	3	0.3	1	0.1	0	2	1
Totals:	314	6.2	119	3.218	102	2.982	0	44	49

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
1	American Transmission Company, LLC	Amy Wilke		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Black Hills Corporation	Travis Grablander		Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
1	Central Electric Power Cooperative (Missouri)	Michael Bax		None	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Third-Party Comments
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	Third-Party Comments
1	Colorado Springs Utilities	Corey Walker		Negative	Third-Party Comments
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Third-Party Comments
1	Dominion - Dominion Virginia Power	Steven Belle		Negative	Comments Submitted
1	Duke Energy	Katherine Street		Affirmative	N/A
1	Edison International - Southern California Edison Company	Robert Blackney		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Eversource Energy	Joshua London		Affirmative	N/A
1	Exelon	Daniel Gacek		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Negative	Comments Submitted
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
1	Great River Energy	Gordon Pietsch		Negative	Comments Submitted
1	Hydro One Networks, Inc.	Emma Halilovic	Lidija Efremova	Abstain	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Abstain	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
1	JEA	Joseph McClung		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Josh Johnson		None	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Matt Lewis		Abstain	N/A
1	LS Power Transmission, LLC	Jennifer Richardson		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
1	MEAG Power	David Weekley	Rebika Yitna	Abstain	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Nikki Carson-Marquis	Negative	Third-Party Comments
1	Muscatine Power and Water	Andrew Kurriger		Negative	Third-Party Comments
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	NB Power Corporation	Jeffrey Streifling		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
1	New York Power Authority	Daniel Valle		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
1	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Negative	Comments Submitted
1	Orlando Utilities Commission	Aaron Staley		None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Negative	Comments Submitted
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
1	Portland General Electric Co.	Brooke Jockin		Abstain	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		None	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Negative	Comments Submitted
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Negative	Comments Submitted
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Abstain	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Laura Somak	Israel Perez	Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		None	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Negative	Comments Submitted
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Negative	Comments Submitted
1	VELCO -Vermont Electric Power Company, Inc.	Randall Buswell		Abstain	N/A
1	Western Area Power Administration	Ben Hammer		Affirmative	N/A
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
2	California ISO	Darcy O'Connell		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
2	Independent Electricity System Operator	Helen Lainis		Negative	Comments Submitted
2	ISO New England, Inc.	John Pearson	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Negative	Comments Submitted
2	New York Independent System Operator	Gregory Campoli		Negative	Third-Party Comments
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips	Shannon Mickens	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	AEP	Leshel Hutchings		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr	Danielle Moskop	Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs	Carly Miller	Affirmative	N/A
3	Bonneville Power Administration	Ron Sporseen		Affirmative	N/A
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Jessica Morrissey		None	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
3	Colorado Springs Utilities	Hillary Dobson		Negative	Third-Party Comments
3	Con Ed - Consolidated Edison Co. of New York	Lincoln Burton		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Victoria Crider		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Abstain	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Hayden Maples	Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		None	N/A
3	Great River Energy	Michael Brytowski		Negative	Comments Submitted
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
3	JEA	Marilyn Williams		None	N/A
3	Lakeland Electric	Steven Marshall		None	N/A
3	Lincoln Electric System	Sam Christensen		Abstain	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		Abstain	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
3	MEAG Power	Roger Brand	Rebika Yitna	Abstain	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
3	New York Power Authority	Richard Machado		Affirmative	N/A
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
3	Northern California Power Agency	Michael Whitney		None	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
3	Omaha Public Power District	David Heins		Negative	Third-Party Comments
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party Comments
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted
3	Portland General Electric Co.	Mayra Franco		Abstain	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Negative	Comments Submitted
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Santee Cooper	Vicky Budreau		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Usama Tahir		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Negative	Third-Party Comments
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Abstain	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
3	Tri-State G and T Association, Inc.	Ryan Walter		None	N/A
3	Xcel Energy, Inc.	Nicholas Friebel	Joseph Gatten	None	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Third-Party Comments
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		None	N/A
4	Austin Energy	Tony Hua		None	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	None	N/A
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	CMS Energy - Consumers Energy Company	Aric Root		None	N/A
4	DTE Energy	Patricia Ireland		Abstain	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Georgia System Operations Corporation	Katrina Lyons		Negative	Third-Party Comments
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Third-Party Comments
4	Northern California Power Agency	Marty Hostler	Mason Jones	None	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Negative	Comments Submitted
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	George Pino		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Negative	Comments Submitted
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
4	Western Power Pool	Kevin Conway		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		None	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
5	Bonneville Power Administration	Milli Chennell		Affirmative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	None	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Colorado Springs Utilities	Jeffrey Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
5	Constellation	Alison MacKellar		Abstain	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Third-Party Comments
5	Dominion - Dominion Resources, Inc.	Barbara Marion		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Abstain	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Evergy	Jeremy Harris	Hayden Maples	Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A
5	Great River Energy	Jacalynn Bentz	Joseph Knight	None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Abstain	N/A
5	Grid Strategies LLC	Michael Goggin		Negative	Comments Submitted
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Abstain	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	Invenergy LLC	Rhonda Jones		None	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		None	N/A
5	LS Power Development, LLC	C. A. Campbell		None	N/A
5	Manitoba Hydro	Kristy-Lee Young	Helen Zhao	Affirmative	N/A
5	Muscatine Power and Water	Chance Back		Negative	Third-Party Comments
5	National Grid USA	Robin Berry		Negative	Comments Submitted
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Erin Wilson		Negative	Comments Submitted
5	Nebraska Public Power District	Ronald Bender		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	NextEra Energy	Richard Vendetti		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Third-Party Comments
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Third-Party Comments
5	Oglethorpe Power Corporation	Donna Johnson		Negative	Third-Party Comments
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Third-Party Comments
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
5	Orlando Utilities Commission	Dania Colon		None	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	Third-Party Comments
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Negative	Comments Submitted
5	Pattern Operators LP	George E Brown		Negative	Third-Party Comments
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Abstain	N/A
5	PSEG Nuclear LLC	Tim Kucey		None	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Negative	Comments Submitted
5	Public Utility District No. 2 of Grant County, Washington	Loren Harbachuk		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
5	Santee Cooper	Carey Salisbury		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		None	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Comments Submitted
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Abstain	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Negative	Comments Submitted
5	Talen Generation, LLC	Donald Lock		Negative	Comments Submitted
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Abstain	N/A
5	Tennessee Valley Authority	Darren Boehm		None	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP	Mathew Miller		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Austin Energy	Imane Mrini		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A
6	Black Hills Corporation	Rachel Schuldt		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Negative	Third-Party Comments
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
6	Constellation	Kimberly Turco		Abstain	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	John Sturgeon		Affirmative	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
6	Great River Energy	Brian Meloy		Negative	Comments Submitted
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Negative	Third-Party Comments
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Manitoba Hydro	Brandin Stoesz		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Muscatine Power and Water	Nicholas Burns		Negative	Third-Party Comments
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Rebecca Blair		Negative	Comments Submitted
6	Northern California Power Agency	Dennis Sismaet		None	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Third-Party Comments
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Stefanie Burke		Abstain	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		None	N/A
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie		Negative	Comments Submitted
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
6	Snohomish County PUD No. 1	John Liang		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Southern Company - Southern Company Generation and Energy Marketing	Matthew O'neal		Negative	Comments Submitted
6	Southern Indiana Gas and Electric Co.	Kati Barr		Abstain	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Negative	Comments Submitted
6	Western Area Power Administration	Jennifer Neville		Affirmative	N/A
6	Xcel Energy, Inc.	Steve Szablya		Affirmative	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		None	N/A
10	Midwest Reliability Organization	Mark Flanary		Negative	Comments Submitted
10	New York State Reliability Council	Wesley Yeomans		None	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Tremayne Brown	Greg Sorenson	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Showing 1 to 314 of 314 entries

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BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/353)
Ballot Name: 2023-07 Transmission Planning Performance Requirements for Extreme Weather Implementation Plan AB 3 OT
Voting Start Date: 10/11/2024 12:01:00 AM
Voting End Date: 10/21/2024 8:00:00 PM
Ballot Type: OT
Ballot Activity: AB
Ballot Series: 3
Total # Votes: 264
Total Ballot Pool: 314
Quorum: 84.08
Quorum Established Date: 10/21/2024 5:57:24 PM
Weighted Segment Value: 63.34

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	89	1	38	0.594	26	0.406	0	13	12
Segment: 2	8	0.8	6	0.6	2	0.2	0	0	0
Segment: 3	68	1	31	0.62	19	0.38	0	8	10
Segment: 4	18	1	5	0.5	5	0.5	0	2	6
Segment: 5	76	1	27	0.574	20	0.426	0	13	16
Segment: 6	47	1	25	0.676	12	0.324	0	6	4
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	1	0	0	0	0	0	0	0	1

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	7	0.3	3	0.3	0	0	0	3	1
Totals:	314	6.1	135	3.864	84	2.236	0	45	50

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
1	American Transmission Company, LLC	Amy Wilke		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Black Hills Corporation	Travis Grablander		Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
1	Central Electric Power Cooperative (Missouri)	Michael Bax		None	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Third-Party Comments
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	Third-Party Comments
1	Colorado Springs Utilities	Corey Walker		Negative	Third-Party Comments
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Third-Party Comments
1	Dominion - Dominion Virginia Power	Steven Belle		Negative	Comments Submitted
1	Duke Energy	Katherine Street		Affirmative	N/A
1	Edison International - Southern California Edison Company	Robert Blackney		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Eversource Energy	Joshua London		Affirmative	N/A
1	Exelon	Daniel Gacek		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
1	Great River Energy	Gordon Pietsch		Negative	Comments Submitted
1	Hydro One Networks, Inc.	Emma Halilovic	Lidija Efremova	Abstain	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Abstain	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
1	JEA	Joseph McClung		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Josh Johnson		None	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Matt Lewis		Abstain	N/A
1	LS Power Transmission, LLC	Jennifer Richardson		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
1	MEAG Power	David Weekley	Rebika Yitna	Abstain	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Nikki Carson-Marquis	Negative	Third-Party Comments
1	Muscatine Power and Water	Andrew Kurriger		Negative	Third-Party Comments
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	NB Power Corporation	Jeffrey Streifling		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
1	New York Power Authority	Daniel Valle		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
1	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Affirmative	N/A
1	Orlando Utilities Commission	Aaron Staley		None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Negative	Comments Submitted
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Abstain	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		None	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Negative	Comments Submitted
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Abstain	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Laura Somak	Israel Perez	Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		None	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Negative	Comments Submitted
1	VELCO -Vermont Electric Power Company, Inc.	Randall Buswell		Abstain	N/A
1	Western Area Power Administration	Ben Hammer		Affirmative	N/A
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
2	California ISO	Darcy O'Connell		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A
2	Independent Electricity System Operator	Helen Lainis		Affirmative	N/A
2	ISO New England, Inc.	John Pearson	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Negative	Third-Party Comments
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips	Shannon Mickens	Negative	Comments Submitted
3	AEP	Leshel Hutchings		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Ameren - Ameren Services	David Jendras Sr	Danielle Moskop	Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs	Carly Miller	Affirmative	N/A
3	Bonneville Power Administration	Ron Sporseen		Affirmative	N/A
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Jessica Morrissey		None	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Lincoln Burton		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Victoria Crider		Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Hayden Maples	Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		None	N/A
3	Great River Energy	Michael Brytowski		Negative	Comments Submitted
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
3	JEA	Marilyn Williams		None	N/A
3	Lakeland Electric	Steven Marshall		None	N/A
3	Lincoln Electric System	Sam Christensen		Abstain	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		Abstain	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
3	MEAG Power	Roger Brand	Rebika Yitna	Abstain	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	Third-Party Comments
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
3	New York Power Authority	Richard Machado		Affirmative	N/A
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
3	Northern California Power Agency	Michael Whitney		None	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
3	Omaha Public Power District	David Heins		Negative	Third-Party Comments
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party Comments
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Negative	Comments Submitted
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
3	Portland General Electric Co.	Mayra Franco		Abstain	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Negative	Third-Party Comments
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Santee Cooper	Vicky Budreau		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Usama Tahir		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Negative	Third-Party Comments
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Abstain	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
3	Tri-State G and T Association, Inc.	Ryan Walter		None	N/A
3	Xcel Energy, Inc.	Nicholas Friebel	Joseph Gatten	None	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Third-Party Comments
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		None	N/A
4	Austin Energy	Tony Hua		None	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	None	N/A
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		Negative	Third-Party Comments
4	CMS Energy - Consumers Energy Company	Aric Root		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	DTE Energy	Patricia Ireland		Abstain	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Georgia System Operations Corporation	Katrina Lyons		Negative	Third-Party Comments
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Third-Party Comments
4	Northern California Power Agency	Marty Hostler	Mason Jones	None	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Negative	Comments Submitted
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	George Pino		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
4	Western Power Pool	Kevin Conway		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		None	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
5	Bonneville Power Administration	Milli Chennell		Affirmative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	None	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Colorado Springs Utilities	Jeffrey Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
5	Constellation	Alison MacKellar		Abstain	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Third-Party Comments
5	Dominion - Dominion Resources, Inc.	Barbara Marion		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Abstain	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A
5	Great River Energy	Jacalynn Bentz	Joseph Knight	None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Abstain	N/A
5	Grid Strategies LLC	Michael Goggin		Negative	Comments Submitted
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Abstain	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	Invenergy LLC	Rhonda Jones		None	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		None	N/A
5	LS Power Development, LLC	C. A. Campbell		None	N/A
5	Manitoba Hydro	Kristy-Lee Young	Helen Zhao	Affirmative	N/A
5	Muscatine Power and Water	Chance Back		Negative	Third-Party Comments
5	National Grid USA	Robin Berry		Negative	Comments Submitted
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Erin Wilson		Negative	Comments Submitted
5	Nebraska Public Power District	Ronald Bender		Negative	Third-Party Comments
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	NextEra Energy	Richard Vendetti		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Third-Party Comments
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Third-Party Comments
5	Oglethorpe Power Corporation	Donna Johnson		Negative	Third-Party Comments
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Third-Party Comments
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
5	Orlando Utilities Commission	Dania Colon		None	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	Third-Party Comments
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Negative	Comments Submitted
5	Pattern Operators LP	George E Brown		Negative	Third-Party Comments
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Abstain	N/A
5	PSEG Nuclear LLC	Tim Kucey		None	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Negative	Comments Submitted
5	Public Utility District No. 2 of Grant County, Washington	Loren Harbachuk		Abstain	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
5	Santee Cooper	Carey Salisbury		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		None	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Comments Submitted
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Abstain	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Abstain	N/A
5	Tennessee Valley Authority	Darren Boehm		None	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP	Mathew Miller		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Imane Mrini		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Black Hills Corporation	Rachel Schuldt		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Negative	Third-Party Comments
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
6	Constellation	Kimberly Turco		Abstain	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	John Sturgeon		Affirmative	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
6	Great River Energy	Brian Meloy		Negative	Comments Submitted
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Negative	Third-Party Comments
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Manitoba Hydro	Brandin Stoesz		Affirmative	N/A
6	Muscatine Power and Water	Nicholas Burns		Negative	Third-Party Comments
6	New York Power Authority	Shelly Dineen		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Rebecca Blair		Negative	Comments Submitted
6	Northern California Power Agency	Dennis Sismaet		None	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Third-Party Comments
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Stefanie Burke		Abstain	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		None	N/A
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
6	Snohomish County PUD No. 1	John Liang		Negative	Comments Submitted
6	Southern Company - Southern Company Generation and Energy Marketing	Matthew O'neal		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Southern Indiana Gas and Electric Co.	Kati Barr		Abstain	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	Western Area Power Administration	Jennifer Neville		Affirmative	N/A
6	Xcel Energy, Inc.	Steve Szablya		Affirmative	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		None	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		None	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Tremayne Brown	Greg Sorenson	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A

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Showing 1 to 314 of 314 entries

BALLOT RESULTS

Ballot Name: 2023-07 Transmission Planning Performance Requirements for Extreme Weather TPL-008-1 | Non-binding Poll AB 3 NB
Voting Start Date: 10/11/2024 12:01:00 AM
Voting End Date: 10/21/2024 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 3
Total # Votes: 249
Total Ballot Pool: 297
Quorum: 83.84
Quorum Established Date: 10/21/2024 5:59:32 PM
Weighted Segment Value: 55.19

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	86	1	28	0.519	26	0.481	19	13
Segment: 2	7	0.4	2	0.2	2	0.2	3	0
Segment: 3	63	1	23	0.561	18	0.439	13	9
Segment: 4	18	1	5	0.5	5	0.5	2	6
Segment: 5	72	1	22	0.537	19	0.463	16	14
Segment: 6	44	1	18	0.6	12	0.4	9	5
Segment: 7	0	0	0	0	0	0	0	0
Segment: 8	1	0	0	0	0	0	0	1
Segment: 9	0	0	0	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 10	6	0.3	3	0.3	0	0	3	0
Totals:	297	5.7	101	3.216	82	2.484	65	48

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		Abstain	N/A
1	American Transmission Company, LLC	Amy Wilke		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Black Hills Corporation	Travis Grablander		Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
1	Central Electric Power Cooperative (Missouri)	Michael Bax		None	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Comments Submitted
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	Comments Submitted
1	Colorado Springs Utilities	Corey Walker		Negative	Comments Submitted
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Steven Belle		Negative	Comments Submitted
1	Duke Energy	Katherine Street		Affirmative	N/A
1	Edison International - Southern California Edison Company	Robert Blackney		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Negative	Comments Submitted
1	Eversource Energy	Joshua London		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Exelon	Daniel Gacek		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Negative	Comments Submitted
1	Glencoe Light and Power Commission	Terry Volkmann		Abstain	N/A
1	Great River Energy	Gordon Pietsch		Negative	Comments Submitted
1	Hydro One Networks, Inc.	Emma Halilovic	Lidija Efremova	Abstain	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Abstain	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
1	JEA	Joseph McClung		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Josh Johnson		None	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Matt Lewis		Abstain	N/A
1	LS Power Transmission, LLC	Jennifer Richardson		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	MEAG Power	David Weekley	Rebika Yitna	Abstain	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Nikki Carson-Marquis	Negative	Comments Submitted
1	Muscatine Power and Water	Andrew Kurriger		Negative	Comments Submitted
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	NB Power Corporation	Jeffrey Streifling		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Daniel Valle		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Affirmative	N/A
1	Orlando Utilities Commission	Aaron Staley		None	N/A
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
1	Portland General Electric Co.	Brooke Jockin		Abstain	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		None	N/A
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		None	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Negative	Comments Submitted
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Negative	Comments Submitted
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Abstain	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Laura Somak	Israel Perez	Affirmative	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		None	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Negative	Comments Submitted
1	VELCO -Vermont Electric Power Company, Inc.	Randall Buswell		Abstain	N/A
1	Western Area Power Administration	Ben Hammer		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
2	Independent Electricity System Operator	Helen Lainis		Abstain	N/A
2	ISO New England, Inc.	John Pearson	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips	Shannon Mickens	Negative	Comments Submitted
3	AEP	Leshel Hutchings		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr	Danielle Moskop	Abstain	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs	Carly Miller	Affirmative	N/A
3	Bonneville Power Administration	Ron Sporseen		Affirmative	N/A
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Jessica Morrissey		None	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
3	Colorado Springs Utilities	Hillary Dobson		Negative	Comments Submitted
3	Con Ed - Consolidated Edison Co. of New York	Lincoln Burton		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Victoria Crider		Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Abstain	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Hayden Maples	Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Negative	Comments Submitted
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
3	JEA	Marilyn Williams		None	N/A
3	Lakeland Electric	Steven Marshall		None	N/A
3	Lincoln Electric System	Sam Christensen		Abstain	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
3	MEAG Power	Roger Brand	Rebika Yitna	Abstain	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Negative	Comments Submitted
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	Richard Machado		Affirmative	N/A
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
3	Northern California Power Agency	Michael Whitney		None	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
3	Omaha Public Power District	David Heins		Negative	Comments Submitted
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Negative	Comments Submitted
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted
3	Portland General Electric Co.	Mayra Franco		Abstain	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Abstain	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Negative	Comments Submitted
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Santee Cooper	Vicky Budreau		Abstain	N/A
3	Seminole Electric Cooperative, Inc.	Usama Tahir		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Abstain	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		None	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Comments Submitted
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		None	N/A
4	Austin Energy	Tony Hua		None	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	None	N/A
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		Negative	Comments Submitted
4	CMS Energy - Consumers Energy Company	Aric Root		None	N/A
4	DTE Energy	Patricia Ireland		Abstain	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Georgia System Operations Corporation	Katrina Lyons		Negative	Comments Submitted
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Comments Submitted
4	Northern California Power Agency	Marty Hostler	Mason Jones	None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Negative	Comments Submitted
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	George Pino		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
4	Western Power Pool	Kevin Conway		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		None	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
5	Bonneville Power Administration	Milli Chennell		Affirmative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Colorado Springs Utilities	Jeffrey Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
5	Constellation	Alison MacKellar		Abstain	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Barbara Marion		Negative	No Comment Submitted
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Abstain	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Abstain	N/A
5	Grid Strategies LLC	Michael Goggin		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Abstain	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		None	N/A
5	Lower Colorado River Authority	Teresa Krabe		None	N/A
5	LS Power Development, LLC	C. A. Campbell		None	N/A
5	Muscatine Power and Water	Chance Back		Negative	Comments Submitted
5	National Grid USA	Robin Berry		Negative	Comments Submitted
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Erin Wilson		Negative	Comments Submitted
5	Nebraska Public Power District	Ronald Bender		Abstain	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	NextEra Energy	Richard Vendetti		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Comments Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Comments Submitted
5	Oglethorpe Power Corporation	Donna Johnson		Negative	Comments Submitted
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
5	Orlando Utilities Commission	Dania Colon		None	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	Comments Submitted
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Negative	Comments Submitted
5	Pattern Operators LP	George E Brown		Negative	Comments Submitted
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Abstain	N/A
5	PSEG Nuclear LLC	Tim Kucey		None	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Negative	Comments Submitted
5	Public Utility District No. 2 of Grant County, Washington	Loren Harbachuk		Abstain	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
5	Santee Cooper	Carey Salisbury		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		None	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Abstain	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Abstain	N/A
5	Tennessee Valley Authority	Darren Boehm		None	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Abstain	N/A
6	AEP	Mathew Miller		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Imane Mrini		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A
6	Black Hills Corporation	Rachel Schuldt		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
6	Constellation	Kimberly Turco		Abstain	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	John Sturgeon		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
6	Great River Energy	Brian Meloy		Negative	Comments Submitted
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Negative	Comments Submitted
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Muscatine Power and Water	Nicholas Burns		Negative	Comments Submitted
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Rebecca Blair		Negative	Comments Submitted
6	Northern California Power Agency	Dennis Sismaet		None	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Comments Submitted
6	Omaha Public Power District	Shonda McCain		Negative	Comments Submitted
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Portland General Electric Co.	Stefanie Burke		Abstain	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		None	N/A
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie		Negative	Comments Submitted
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Santee Cooper	Marty Watson		Abstain	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
6	Snohomish County PUD No. 1	John Liang		Negative	Comments Submitted
6	Southern Company - Southern Company Generation and Energy Marketing	Matthew O'neal		Negative	Comments Submitted
6	Southern Indiana Gas and Electric Co.	Kati Barr		Abstain	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	Western Area Power Administration	Jennifer Neville		Affirmative	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		None	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	ReliabilityFirst	Tremayne Brown	Greg Sorenson	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A

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Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the fourth draft of the proposed standard posted for a 15-day formal comment period with additional ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	July 19, 2023
SAR posted for comment	August 8–September 27, 2023
45-day formal comment period with initial ballot	March 20–May 3, 2024
38-day formal comment period with additional ballot	July 16–August 22, 2024
15-day formal comment period with additional ballot	October 7–21, 2024

Anticipated Actions	Date
15-day formal comment period with additional ballot	November 7–21, 2024
5-day final ballot	December 2–6, 2024
Board adoption	December 11, 2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

Extreme Temperature Assessment – Documented evaluation of future Bulk Electric System performance for extreme heat and extreme cold benchmark temperature events.

A. Introduction

1. **Title:** Transmission System Planning Performance Requirements for Extreme Temperature Events

2. **Number:** TPL-008-1

3. **Purpose:** Establish Transmission system planning performance requirements to develop a Bulk Power System (BPS) that will operate reliably during extreme heat and extreme cold temperature events.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Transmission Planner

   4.1.2. Planning Coordinator

5. **Effective Date:** See Implementation Plan for Project 2023-07.

B. Requirements and Measures

R1. Each Planning Coordinator shall identify, in conjunction with its Transmission Planner(s), each entity's individual and joint responsibilities for completing the Extreme Temperature Assessment, which shall include each of the responsibilities described in Requirements R2 through R11. Each responsible entity shall complete its responsibilities such that the Extreme Temperature Assessment is completed at least once every five calendar years. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M1. Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall provide dated documentation of each entity's individual and joint responsibilities, such as meeting minutes, agreements, copies of procedures, or protocols in effect between entities or between departments of a vertically integrated system, or email correspondence that identifies an agreement has been reached on individual and joint responsibilities for completing the Extreme Temperature Assessment, and that these responsibilities were completed such that the Extreme Temperature Assessment was completed once every five calendar years.

R2. Each Planning Coordinator shall identify the zone(s) to which the Planning Coordinator belongs to under Attachment 1 and shall coordinate with all Planning Coordinators within each of its identified zone(s), to identify one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event for each of its identified zone(s) when completing the Extreme Temperature Assessment. The benchmark temperature events shall be obtained from the benchmark library maintained by the ERO or developed by the Planning Coordinators. Each benchmark temperature event shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. Consider no less than a 40-year period of temperature data ending no more than five years prior to the time the benchmark temperature events are selected; and

2.2. Represent one of the 20 most extreme temperature conditions based on the three-day rolling average of daily maximum (heat) or daily minimum (cold) temperature across the zone.

M2. Each Planning Coordinator shall have evidence in either electronic or hard copy format that it identified the zone(s) to which it belongs to, under Attachment 1, and that it coordinated with all other Planning Coordinators within each of its identified zone(s) to select one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event meeting the criteria of Requirement R2 for each of their identified zone(s) when completing the Extreme Temperature Assessment.

R3. Each Planning Coordinator shall coordinate with all Planning Coordinators within each of its zone(s) identified in Requirement R2, to implement a process for developing

benchmark planning cases for the Extreme Temperature Assessment that represent the benchmark temperature events selected in Requirement R2 and sensitivity cases to demonstrate the impact of changes to the basic assumptions used in the benchmark planning cases. This process shall include the following: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Selection of System models within the Long-Term Transmission Planning Horizon to form the basis for the benchmark planning cases.

3.2. Forecasted seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers within the zone.

3.3. Assumed seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers in areas outside the zone, as needed.

3.4. Identification of changes to at least one of the following conditions for sensitivity cases: generation, real and reactive forecasted Load, or transfers.

M3. Each Planning Coordinator shall have dated evidence that it implemented a process for coordinating the development of benchmark planning cases and sensitivity cases for the Extreme Temperature Assessment as specified in Requirement R3.

R4. Each responsible entity, as identified in Requirement R1, shall use the coordination process developed in Requirement R3 and data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, to develop the following and establish category P0 as the normal System condition in Table 1: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

4.1. One common extreme heat and one common extreme cold benchmark planning case.

4.2. One common extreme heat and one common extreme cold sensitivity case.

M4. Each responsible entity, as identified in Requirement R1, shall have dated evidence in either electronic or hard copy format that it developed benchmark planning cases and sensitivity cases in accordance with Requirement R4.

R5. Each responsible entity, as identified in Requirement R1, shall have criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations for completing the Extreme Temperature Assessment. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M5. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of the documentation, specifying the criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations for completing the Extreme Temperature Assessment.

R6. Each responsible entity, as identified in Requirement R1, shall define and document the criteria or methodology to be used in the Extreme Temperature Assessment to

identify instability, uncontrolled separation, or Cascading within an Interconnection. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M6. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of documentation, specifying the criteria or methodology to be used in the Extreme Temperature Assessment to identify instability, uncontrolled separation, or Cascading within an Interconnection in accordance with Requirement R6.

R7. Each responsible entity, as identified in Requirement R1, shall identify the Contingencies for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System. The rationale for those Contingencies selected for evaluation shall be available as supporting information. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M7. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of documentation, of the Contingencies for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System along with supporting rationale.

R8. Each responsible entity, as identified in Requirement R1, shall complete steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, and shall document the assumptions and results. Steady state and transient stability analyses shall be performed for the following: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

8.1. Benchmark planning cases developed in accordance with Requirement R4 Part 4.1.

8.2. Sensitivity cases developed in accordance with Requirement R4 Part 4.2.

M8. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of documentation, of the assumptions and results of the steady state and transient stability analyses completed in the Extreme Temperature Assessment.

R9. Each responsible entity, as identified in Requirement R1, shall develop a Corrective Action Plan(s) when the analysis of a benchmark planning case, in accordance with Requirement R8 Part 8.1, indicates its portion of the Bulk Electric System is unable to meet performance requirements for category P0 or P1 in Table 1. For each Corrective Action Plan, the responsible entity shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

9.1. Document alternative(s) considered when Non-Consequential Load Loss is utilized as an element of a Corrective Action Plan for a Table 1 P1 Contingency.

9.2. Be permitted to utilize Non-Consequential Load Loss as an interim solution, which normally is not permitted for category P0 in Table 1 for situations that are

beyond the control of the Planning Coordinator or Transmission Planner that prevent the implementation of a Corrective Action Plan in the required timeframe, provided that the responsible entity documents the situation causing the problem, alternatives evaluated, and takes actions to resolve the situation.

9.3. Make its Corrective Action Plan available to, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.

9.4. Be permitted to have revisions to the Corrective Action Plan in subsequent Extreme Temperature Assessments, provided that the planned Bulk Electric System shall continue to meet the performance requirements of Table 1.

M9. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of documentation, of each Corrective Action Plan developed in accordance with Requirement R9 when the analysis of a benchmark planning case indicates its portion of the Bulk Electric System is unable to meet performance requirements for category P0 or P1 in Table 1. Evidence shall include documentation of correspondence with applicable regulatory authorities or governing bodies responsible for retail electric service issues and any revision history.

R10. Each responsible entity, as identified in Requirement R1, shall evaluate and document possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) if analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection, for the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

10.1. Table 1 P7 Contingencies in benchmark planning cases analyzed in accordance with Requirement R8 Part 8.1.

10.2. Categories P0, P1, and P7 in Table 1 in sensitivity cases analyzed in accordance with Requirement R8 Part 8.2.

M10. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of documentation that it evaluated and documented possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts when the analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection for Table 1 P7 Contingencies in benchmark planning cases or categories P0, P1, or P7 in Table 1 in sensitivity cases.

R11. Each responsible entity, as identified in Requirement R1, shall provide its Extreme Temperature Assessment results within 60 calendar days of a request to any functional entity that has a reliability related need and submits a written request for the information. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M11. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as email notices, documentation of updated web pages, or postal receipts showing recipient, that it provided its Extreme Temperature Assessment to any

functional entity who has a reliability need within 60 calendar days of a written request.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: “Compliance Enforcement Authority” means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. 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.

- Each responsible entity shall retain evidence of compliance with each requirement in this standard for five calendar years or one complete Extreme Temperature Assessment cycle, whichever is longer.

1.3. Compliance Monitoring and Enforcement Program: “Compliance Monitoring Enforcement Program” or “CMEP” means, depending on the context (1) the NERC Compliance Monitoring and Enforcement Program (Appendix 4C to the NERC Rules of Procedure) or the Commission-approved program of a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that is responsible for performing compliance monitoring and enforcement activities with respect to Registered Entities’ compliance with Reliability Standards.

Table 1 – Steady State & Stability Performance Events
Steady State & Stability: a. Instability, uncontrolled separation, or Cascading within an Interconnection, defined in accordance with Requirement R6, shall not occur. b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0. c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event. d. Simulate Normal Clearing unless otherwise specified. e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings. **Steady State Only:** f. Applicable Facility Ratings shall not be exceeded. g. System steady state voltages and post-Contingency voltage deviations shall meet the criteria identified in Requirement R5.

Table 1 – Steady State & Stability Performance Events

Category	Initial Condition	Event[1]	Fault Type[3]	Contingency BES Level	Interruption of Firm Transmission Service Allowed	Non-Consequential Load Loss Allowed	
						Benchmark Planning Cases	Sensitivity Cases
P0 No Contingency	Normal System	None	N/A	N/A	Yes	No[6]	Yes
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[2] 4. Shunt Device[4]	3Ø	≥ 200 kV	Yes	Yes[6]	Yes
		5. Single Pole of a DC line	SLG				
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure[5] 2. Loss of a bipolar DC line	SLG	≥ 200 kV	Yes	Yes	Yes

Table 1 – Steady State & Stability Performance Events
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the BES level of the event. For P7 events, the BES level of the event is the highest System voltage level of the element(s) removed for the analyzed event. 2. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers. 3. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria. 4. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground. 5. Excludes circuits that share a common structure for 1 mile or less. 6. Benchmark planning cases require the development of a Corrective Action Plan when the responsible entity's portion of the BES is unable to meet the performance requirements for categories P0 or P1. Additionally, in benchmark planning cases, Non-Consequential Load Loss is not permitted for category P0 except where permitted as an interim solution in a Corrective Action Plan in accordance with Requirement R9 Part 9.2.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed less than or equal to six months late.	The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed more than six months but less than or equal to 12 months late.	The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed more than 12 months but less than or equal to 18 months late.	The Planning Coordinator, in conjunction with its Transmission Planner(s), failed to identify individual and joint responsibilities for completing the Extreme Temperature Assessment. OR The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed more than 18 months late.
R2.	N/A	N/A	The Planning Coordinator coordinated with all Planning Coordinators within each identified zone to identify one common extreme heat and one common extreme cold benchmark temperature event for completing the Extreme Temperature Assessment, but one of the identified events	The Planning Coordinator coordinated with all Planning Coordinators within each identified zone to identify one common extreme heat and one common extreme cold benchmark temperature event for completing the Extreme Temperature Assessment, but both of the identified events

			failed to meet all the criteria of Requirement R2.	failed to meet all of the criteria of Requirement R2. OR The Planning Coordinator failed to coordinate with all Planning Coordinators within each identified zone to identify one common extreme heat and one common extreme cold benchmark temperature event for completing the Extreme Temperature Assessment.
R3.	N/A	N/A	N/A	The Planning Coordinator did not coordinate with all Planning Coordinators within each of its identified zone(s) to implement a process for developing benchmark planning cases. OR The Planning Coordinator coordinated with all Planning Coordinators within each of its identified zone(s) to implement a process for developing benchmark planning cases, but the process did not include all of the required elements.

R4.	N/A	N/A	N/A	The responsible entity, as identified in Requirement R1, did not use the coordination process to develop benchmark planning cases or sensitivity cases. OR The responsible entity, as identified in Requirement R1, used the coordination process to develop benchmark planning cases and sensitivity cases, but did not use data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, for one or more of the required cases. OR The responsible entity, as identified in Requirement R1, used the coordination process and data consistent with that provided in accordance with the MOD-032 standard, supplemented as needed, but failed to develop one or more of the required planning or sensitivity cases.

R5.	N/A	N/A	N/A	The responsible entity, as identified in Requirement R1, did not have criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations for completing the Extreme Temperature Assessment.
R6.	N/A	N/A	N/A	The responsible entity, as identified in Requirement R1, failed to define or document the criteria or methodology to be used in the Extreme Temperature Assessment to identify instability, uncontrolled separation, or Cascading within an Interconnection.
R7.	N/A	N/A	The responsible entity, as identified in Requirement R1, identified Contingencies for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System, but did not include the rationale for those Contingencies selected for evaluation as supporting information.	The responsible entity, as identified in Requirement R1, did not identify Contingencies for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System.

R8.	The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to document the assumptions for one or more sensitivity cases in accordance with Requirement R8.	The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to document the assumptions for one or more benchmark planning cases in accordance with Requirement R8.	The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to evaluate and document results for one or more of the sensitivity cases in accordance with Requirement R8.	The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to evaluate and document results for one or more of the benchmark planning cases in accordance with Requirement R8. OR The responsible entity, as identified in Requirement R1, failed to complete steady state or transient stability analyses and document results in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, in accordance with Requirement R8.
R9.	N/A	N/A	The responsible entity, as identified in Requirement R1, developed a Corrective Action Plan in accordance with Requirement R9, but failed to make its Corrective Action Plan available to, or solicit	The responsible entity, as identified in Requirement R1, failed to develop a Corrective Action Plan when the benchmark planning case study results indicate the System is unable to meet

			feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.	performance requirements for the Table 1 P0 or P1 Contingencies. OR The responsible entity, as identified in Requirement R1, developed a Corrective Action Plan, but it was missing one or more of the elements of Requirement R9 Part 9.1, 9.3 and 9.4 (as applicable).
R10.	N/A	N/A	The responsible entity, as identified in Requirement R1, evaluated and documented possible actions to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection where required under Requirement R10 Part 10.1, but failed to evaluate and document possible actions where required under Requirement R10 Part 10.2.	The responsible entity, as identified in Requirement R1, evaluated and documented possible actions to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection where required under Requirement R10 Part 10.2, but failed to evaluate and document possible actions where required under Requirement R10 Part 10.1. OR The responsible entity, as identified in Requirement R1, failed to evaluate and

				document possible actions to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection where required under Requirement R10 Parts 10.1 and 10.2.
R11.	The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 60 days but less than or equal to 80 days following the request.	The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 80 days but less than or equal to 100 days following the request.	The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 100 days but less than or equal to 120 days following the request.	The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 120 days following the request. OR The responsible entity, as identified in Requirement R1, did not provide its Extreme Temperature Assessment results to functional entities having a reliability related need who submitted a written request for the information.

D. Regional Variances

None.

E. Associated Documents

- Implementation Plan for Project 2023-07
- Technical Rationale Document
- Consideration of Issues and Directives for FERC Order 896.
- ERO Benchmark Event Library

Version History

Version	Date	Action	Change Tracking
1	TBD	Addressing FERC Order 896	New Standard

Attachment 1: Extreme Temperature Assessment Zones

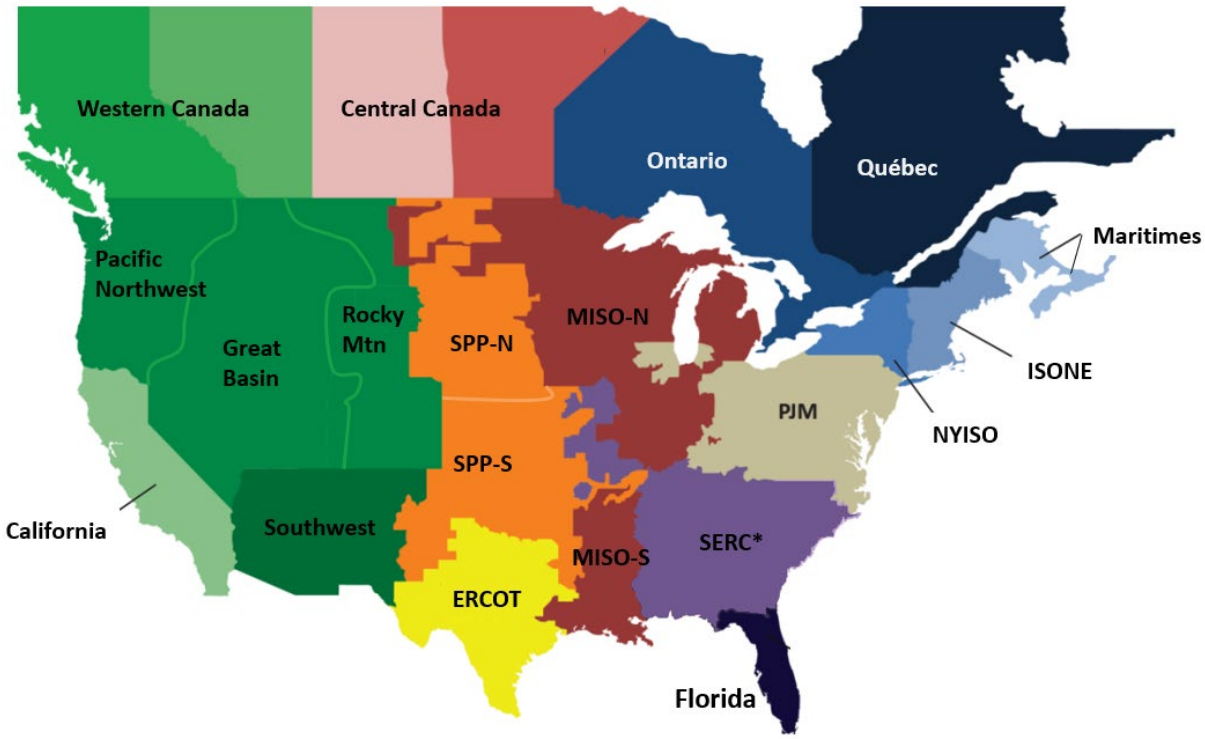
The table below lists the zones to be used in the Extreme Temperature Assessment and identifies the Planning Coordinators that belong to each zone. In accordance with Requirement R2, each Planning Coordinator is required to identify the zone(s) to which it belongs.

Zone	Planning Coordinators
Eastern Interconnection	
MISO North	Planning Coordinator(s) in MISO that serve portions of MISO in Montana, North Dakota, South Dakota, Minnesota, Iowa, Wisconsin, Michigan, Indiana, Illinois, Missouri, and Kentucky
MISO South	Planning Coordinator(s) in MISO that serve portions of Arkansas, Mississippi, Louisiana, and Texas
SPP North	Planning Coordinator(s) in portions of SPP that serve Iowa, Montana, Nebraska, North Dakota, and South Dakota.
SPP South	Planning Coordinator(s) in portions of SPP that serve Arkansas, Kansas, Louisiana, Missouri, New Mexico, Oklahoma, and Texas.
PJM	Planning Coordinator(s) that serves PJM
New England	Planning Coordinator(s) in NPCC that serve the six New England States
New York	Planning Coordinator(s) in NPCC that serve New York
SERC	Planning Coordinator(s) in SERC, excluding those that serve Florida and those in MISO, SPP, and PJM
Florida	Planning Coordinator(s) in SERC that serve Florida
Central Canada	Planning Coordinator(s) that serve Saskatchewan and Manitoba region of MRO
Ontario	Planning Coordinator(s) in NPCC that serve Ontario
Maritimes	Planning Coordinator(s) in NPCC that primarily serve New Brunswick, Nova Scotia, Prince Edward Island, and Northern Maine
Western Interconnection	
WECC Southwest	Planning Coordinator(s) in the Southwest region of WECC, including El Paso in West Texas
Pacific Northwest	Planning Coordinator(s) in the Pacific Northwest region of WECC
Great Basin	Planning Coordinator(s) in the Great Basin region of WECC
Rocky Mountain	Planning Coordinator(s) in the Rocky Mountain region of WECC

Zone	Planning Coordinators
California/Mexico	Planning Coordinator(s) in the California/Mexico region of WECC
Western Canada	Planning Coordinator(s) that primarily serve British Columbia and Alberta region of WECC
ERCOT Interconnection	
ERCOT	Planning Coordinator(s) in Texas that are part of the ERCOT Interconnection
Quebec Interconnection	
Quebec	Planning Coordinator(s) that serve Quebec in the NPCC Region.

The map below depicts an approximation of the zones to be used in the Extreme Temperature Assessment and is provided as a visual aid; to the extent that there is a conflict between the map and the table, the table controls. This map is not to be used for compliance purposes.

TPL-008-1 Weather Zones Map



Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the fourth draft of the proposed standard posted for a 15-day formal comment period with additional ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	July 19, 2023
SAR posted for comment	August 8–September 27, 2023
45-day formal comment period with initial ballot	March 20–May 3, 2024
38-day formal comment period with additional ballot	July 16–August 22, 2024
15-day formal comment period with additional ballot	October 7–21, 2024

Anticipated Actions	Date
15-day formal comment period with additional ballot	November 7–21, 2024
5-day final ballot	December 2–6, 2024
Board adoption	December 11, 2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

Extreme Temperature Assessment – Documented evaluation of future Bulk Electric System performance for extreme heat and extreme cold benchmark temperature events.

A. Introduction

1. **Title:** Transmission System Planning Performance Requirements for Extreme Temperature Events
2. **Number:** TPL-008-1
3. **Purpose:** Establish Transmission system planning performance requirements to develop a Bulk Power System (BPS) that will operate reliably during extreme heat and extreme cold temperature events.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Transmission Planner
     - **4.1.2.** Planning Coordinator
5. **Effective Date:** See Implementation Plan for Project 2023-07.

B. Requirements and Measures

R1. Each Planning Coordinator shall identify, in conjunction with its Transmission Planner(s), each entity's individual and joint responsibilities for completing the Extreme Temperature Assessment, which shall include each of the responsibilities described in Requirements R2 through R11. Each responsible entity shall complete its responsibilities such that the Extreme Temperature Assessment is completed at least once every five calendar years. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M1. Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall provide dated documentation of each entity's individual and joint responsibilities, such as meeting minutes, agreements, copies of procedures, or protocols~~,~~ in effect between entities or between departments of a vertically integrated system, or email correspondence that identifies an agreement has been reached on individual and joint responsibilities for completing the Extreme Temperature Assessment, and that these responsibilities were completed such that the Extreme Temperature Assessment was completed once every five calendar years.

R2. Each Planning Coordinator shall identify the zone(s) to which the Planning Coordinator belongs to under Attachment 1~~,~~ and shall coordinate with all Planning Coordinators within each of its identified zone(s), to ~~select~~identify one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event for each of its identified zone(s) when completing the Extreme Temperature Assessment.~~[1] Selected~~ The benchmark temperature events shall be obtained from the benchmark library maintained by the ERO or developed by the Planning Coordinators. Each benchmark temperature event shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. Consider no less than a 40-year period of temperature data ending no more than five years prior to the time the benchmark temperature events are selected; and

2.2. Represent one of the 20 most extreme temperature conditions based on the three-day rolling average of daily maximum (heat) or daily minimum (cold) temperature across the zone.

M2. Each Planning Coordinator shall have evidence in either electronic or hard copy format that it identified the zone(s) to which it belongs to, under Attachment 1, and that it coordinated with all other Planning Coordinators within each of its identified zone(s) to select one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event meeting the criteria of Requirement R2 for each of their identified zone(s) when completing the Extreme Temperature Assessment.

~~[1] The Electric Reliability Organization (ERO) will maintain a library of benchmark temperature events that meet the criteria of Requirement R2.~~

R3. Each Planning Coordinator shall coordinate with all Planning Coordinators within each of its zone(s) identified in Requirement R2, to implement a process for developing benchmark planning cases for the Extreme Temperature Assessment that represent the benchmark temperature events selected in Requirement R2 and sensitivity cases to demonstrate the impact of changes to the basic assumptions used in the benchmark planning cases. This process shall include the following: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- **3.1.** Selection of System models within the Long-Term Transmission Planning Horizon to form the basis for the benchmark planning cases.
- **3.2.** Forecasted seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers within the zone.
- **3.3.** Assumed seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers in areas outside the zone, as needed.
- **3.4.** Identification of changes to at least one of the following conditions for sensitivity cases: generation, real and reactive forecasted Load, or transfers.

M3. Each Planning Coordinator shall have dated evidence that it implemented a process for coordinating the development of benchmark planning cases and sensitivity cases for the Extreme Temperature Assessment as specified in Requirement R3.

R4. Each responsible entity, as identified in Requirement R1, shall use the coordination process developed in Requirement R3 and data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, to develop the following and establish category P0 as the normal System condition in Table 1: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

- **4.1.** One common extreme heat and one common extreme cold benchmark planning case.
- **4.2.** One common extreme heat and one common extreme cold sensitivity case.

M4. Each responsible entity, as identified in Requirement R1, shall have dated evidence in either electronic or hard copy format that it developed benchmark planning cases and sensitivity cases in accordance with Requirement R4.

R5. Each responsible entity, as identified in Requirement R1, shall have criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations for completing the Extreme Temperature Assessment. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M5. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of the documentation, specifying the criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations for completing the Extreme Temperature Assessment.

R6. Each responsible entity, as identified in Requirement R1, shall define and document the criteria or methodology to be used in the Extreme Temperature Assessment to identify instability, uncontrolled separation, or Cascading within an Interconnection. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M6. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of documentation, specifying the criteria or methodology to be used in the Extreme Temperature Assessment to identify instability, uncontrolled separation, or Cascading within an Interconnection in accordance with Requirement R6.

R7. Each responsible entity, as identified in Requirement R1, shall identify the Contingencies for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System. The rationale for those Contingencies selected for evaluation shall be available as supporting information. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M7. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of documentation, of the Contingencies for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System along with supporting rationale.

R8. Each responsible entity, as identified in Requirement R1, shall complete steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, and shall document the assumptions and results. Steady state and transient stability analyses shall be performed for the following: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

8.1. Benchmark planning cases developed in accordance with Requirement R4 Part 4.1.

8.2. Sensitivity cases developed in accordance with Requirement R4 Part 4.2.

M8. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of documentation, of the assumptions and results of the steady state and transient stability analyses completed in the Extreme Temperature Assessment.

R9. Each responsible entity, as identified in Requirement R1, shall develop a Corrective Action Plan(s) when the analysis of a benchmark planning case, in accordance with Requirement R8 Part 8.1, indicates its portion of the Bulk Electric System is unable to meet performance requirements for category P0 or P1 in Table 1. For each Corrective Action Plan, the responsible entity shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

~~**9.1.** Make its Corrective Action Plan available to, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.~~

~~**9.2.**~~**9.1.** Document alternative(s) considered~~, and notify the applicable regulatory authorities or governing bodies responsible for retail electric service issues~~ when Non-Consequential Load Loss is utilized as an element of a Corrective Action Plan for a Table 1 P1 Contingency.

~~**9.3.**~~**9.2.** Be permitted to utilize Non-Consequential Load Loss as an interim solution, which normally is not permitted for category P0 in Table 1~~, in~~ for situations that are beyond the control of the Planning Coordinator or Transmission Planner that prevent the implementation of a Corrective Action Plan in the required timeframe, provided that the responsible entity documents the situation causing the problem, alternatives evaluated, and takes actions to resolve the situation.

9.3. Make its Corrective Action Plan available to, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.

9.4. Be ~~allowed~~permitted to have revisions to the Corrective Action Plan in subsequent Extreme Temperature Assessments, provided that the planned Bulk Electric System shall continue to meet the performance requirements of Table 1.

M9. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of documentation, of each Corrective Action Plan developed in accordance with Requirement R9~~, including dated documentation of correspondence with applicable regulatory authorities or governing bodies responsible for retail electric service issues and any revision history,~~ when the analysis of a benchmark planning case indicates its portion of the Bulk Electric System is unable to meet performance requirements for category P0 or P1 in Table 1. Evidence shall include documentation of correspondence with applicable regulatory authorities or governing bodies responsible for retail electric service issues and any revision history.

R10. Each responsible entity, as identified in Requirement R1, shall evaluate and document possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) if analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection, for the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

10.1. Table 1 P7 Contingencies in benchmark planning cases analyzed in accordance with Requirement R8 Part 8.1.

10.2. Categories P0, P1, and P7 in Table 1 in sensitivity cases analyzed in accordance with Requirement R8 Part 8.2.

M10. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of documentation that it evaluated and documented possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts when the analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection for Table 1 P7 Contingencies in benchmark planning cases or categories P0, P1, or P7 in Table 1 in sensitivity cases.

R11. Each responsible entity, as identified in Requirement R1, shall provide its Extreme Temperature Assessment results within 60 calendar days of a request to any functional entity that has a reliability related need and submits a written request for the information. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M11. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as email notices, documentation of updated web pages, or postal receipts showing recipient~~, or a demonstration of a public posting~~, that it provided its Extreme Temperature Assessment to any functional entity who has a reliability need within 60 calendar days of a written request.

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~~the NERC Reliability Standards~~ in their respective jurisdictions~~.

1.2. 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.

- Each responsible entity shall retain evidence of compliance with each requirement in this standard for five calendar years or one complete Extreme Temperature Assessment cycle, whichever is longer.

1.3. Compliance Monitoring and Enforcement Program: ~~As defined in the NERC Rules of Procedure, ~~"Compliance Monitoring Enforcement Program" or "CMEP" means, depending on the context (1) the NERC Compliance Monitoring and Enforcement Program~~" refers~~ (Appendix 4C to the ~~identification~~NERC Rules of Procedure) or the Commission-approved program of ~~the processes~~a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that ~~will be used to evaluate data or information~~is responsible for ~~the purpose of assessing performance or outcomes~~performing compliance monitoring and enforcement activities with ~~the associated~~respect to Registered Entities' compliance with Reliability ~~Standard~~Standards.

Table 1 – Steady State & Stability Performance Events
Steady State & Stability: a. Instability, uncontrolled separation, or Cascading within an Interconnection, defined in accordance with Requirement R6, shall not occur. b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0. c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event. d. Simulate Normal Clearing unless otherwise specified. e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings. **Steady State Only:** f. Applicable Facility Ratings shall not be exceeded. g. System steady state voltages and post-Contingency voltage deviations shall meet the criteria identified in Requirement R5.

Table 1 – Steady State & Stability Performance Events							
Category	Initial Condition	Event[1]	Fault ~~Type[2]~~Type[3]	Contingency BES Level	Interruption of Firm Transmission Service Allowed	Non-Consequential Load Loss Allowed	
						Benchmark Planning Cases	Sensitivity Cases
P0 No Contingency	Normal System	None	N/A	~~≥ 200 kV~~N/A	Yes	No[6]	Yes
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit ~~3. Transformer[3]~~ 3. Transformer[2] 4. Shunt Device[4]	3Ø	≥ 200 kV	Yes	Yes[6]	Yes
		5. Single Pole of a DC line	SLG				
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure[5] 2. Loss of a bipolar DC line	SLG	≥ 200 kV	Yes	Yes	Yes

Table 1 – Steady State & Stability Performance Events
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the BES level of the event. For P7 events, the BES level of the event is the highest System voltage level of the element(s) removed for the analyzed event. ~~2.~~1.~~Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.~~ ~~3.~~2. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers. 3. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria. 4. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground. 5. Excludes circuits that share a common structure for 1 mile or less. 6. Benchmark planning cases require the development of a Corrective Action Plan when the responsible entity's portion of the BES is unable to meet the performance requirements for categories P0 or P1. Additionally, in benchmark planning cases, Non-Consequential Load Loss is not permitted for category P0 ~~and requires notification of applicable regulatory authorities or governing bodies responsible for retail electric service issues when utilized~~except where permitted as an ~~element of~~interim solution in a Corrective Action Plan ~~for P1 Contingencies. See~~in accordance with Requirement R9 ~~for the relevant requirements~~Part 9.2.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed less than or equal to six months late.	The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed more than six months but less than or equal to 12 months late.	The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed more than 12 months but less than or equal to 18 months late.	The Planning Coordinator, in conjunction with its Transmission Planner(s), failed to identify individual and joint responsibilities for completing the Extreme Temperature Assessment. OR The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed more than 18 months late.
R2.	N/A	N/A	The Planning Coordinator coordinated with all Planning Coordinators within each identified zone to ~~select~~identify one common extreme heat and one common extreme cold benchmark temperature event for completing the Extreme Temperature Assessment, but one of the ~~selected~~identified	The Planning Coordinator coordinated with all Planning Coordinators within each identified zone to ~~select~~identify one common extreme heat and one common extreme cold benchmark temperature event for completing the Extreme Temperature Assessment, but both of the ~~selected~~identified

			events failed to meet all the criteria of Requirement R2.	events failed to meet all of the criteria of Requirement R2. OR The Planning Coordinator failed to coordinate with all Planning Coordinators within each identified zone to ~~select~~identify one common extreme heat and one common extreme cold benchmark temperature event for completing the Extreme Temperature Assessment.
R3.	N/A	N/A	N/A	The Planning Coordinator did not coordinate with all Planning Coordinators within each of its identified zone(s) to implement a process for developing benchmark planning cases. OR The Planning Coordinator coordinated with all Planning Coordinators within each of its identified zone(s) to implement a process for developing benchmark planning cases, but the process did not include all of the required elements.

R4.	N/A	N/A	N/A	The responsible entity, as identified in Requirement R1, did not use the coordination process to develop benchmark planning cases or sensitivity cases. OR The responsible entity, as identified in Requirement R1, used the coordination process to develop benchmark planning cases and sensitivity cases, but did not use data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, for one or more of the required cases. OR The responsible entity, as identified in Requirement R1, used the coordination process and data consistent with that provided in accordance with the MOD-032 standard, supplemented as needed, but failed to develop one or more of the required planning or sensitivity cases.

R5.	N/A	N/A	N/A	The responsible entity, as identified in Requirement R1, did not have criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations for completing the Extreme Temperature Assessment.
R6.	N/A	N/A	N/A	The responsible entity, as identified in Requirement R1, failed to define or document the criteria or methodology to be used in the Extreme Temperature Assessment to identify instability, uncontrolled separation, or Cascading within an Interconnection.
R7.	N/A	N/A	The responsible entity, as identified in Requirement R1, identified Contingencies for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System, but did not include the rationale for those Contingencies selected for evaluation as supporting information.	The responsible entity, as identified in Requirement R1, did not identify Contingencies for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System.

R8.	The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to document the assumptions for one or more sensitivity cases in accordance with Requirement R8.	The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to document the assumptions for one or more benchmark planning cases in accordance with Requirement R8.	The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to evaluate and document results for one or more of the sensitivity cases in accordance with Requirement R8.	The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to evaluate and document results for one or more of the benchmark planning cases in accordance with Requirement R8. OR The responsible entity, as identified in Requirement R1, failed to complete steady state or transient stability analyses and document results in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, in accordance with Requirement R8.
R9.	N/A	N/A	The responsible entity, as identified in Requirement R1, developed a Corrective Action Plan in accordance with Requirement R9, but failed to make its Corrective Action Plan available to, or solicit	The responsible entity, as identified in Requirement R1, failed to develop a Corrective Action Plan when the benchmark planning case study results indicate the System is unable to meet

			feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.	performance requirements for the Table 1 P0 or P1 Contingencies. OR The responsible entity, as identified in Requirement R1, developed a Corrective Action Plan, but it was missing one or more of the elements of Requirement R9 Part 9.~~2~~1, 9.3 and 9.4 (as applicable).
R10.	N/A	N/A	The responsible entity, as identified in Requirement R1, evaluated and documented possible actions to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection where required under Requirement R10 Part 10.1, but failed to evaluate and document possible actions where required under Requirement R10 Part 10.2.	The responsible entity, as identified in Requirement R1, evaluated and documented possible actions to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection where required under Requirement R10 Part 10.2, but failed to evaluate and document possible actions where required under Requirement R10 Part 10.1. OR The responsible entity, as identified in Requirement R1, failed to evaluate and

				document possible actions to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection where required under Requirement R10 Parts 10.1 and 10.2.
R11.	The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 60 days but less than or equal to 80 days following the request.	The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 80 days but less than or equal to 100 days following the request.	The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 100 days but less than or equal to 120 days following the request.	The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 120 days following the request. OR The responsible entity, as identified in Requirement R1, did not provide its Extreme Temperature Assessment results to functional entities having a reliability related need who submitted a written request for the information.

D. Regional Variances

None.

E. Associated Documents

- Implementation Plan for Project 2023-07
- Technical Rationale Document
- Consideration of Issues and Directives for FERC Order 896.
- ERO Benchmark Event Library

Version History

Version	Date	Action	Change Tracking
1	TBD	Addressing FERC Order 896	New Standard

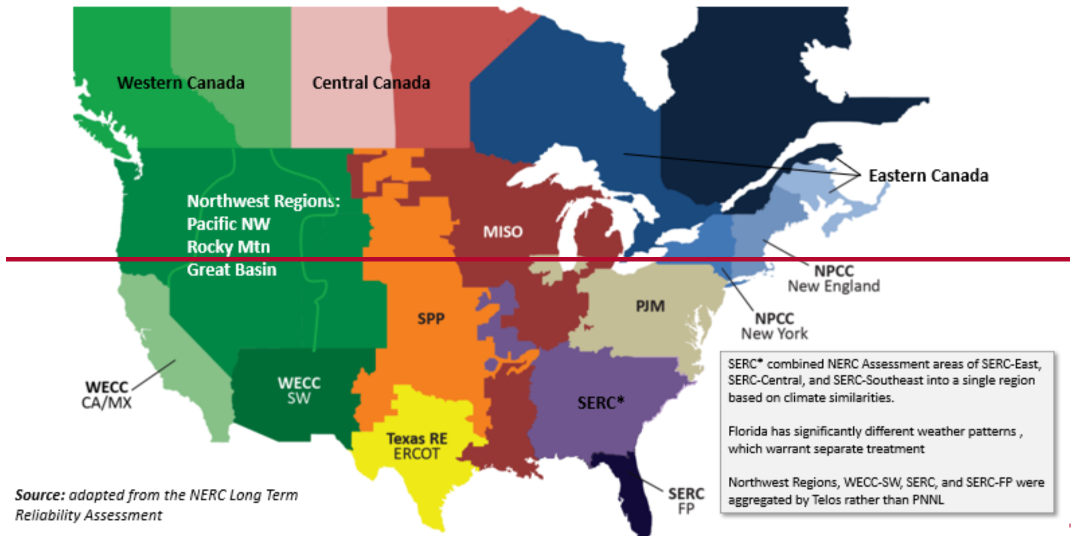
Attachment 1: Extreme Temperature Assessment Zones

The table below lists the zones to be used in the Extreme Temperature Assessment and identifies the Planning Coordinators that belong to each zone. In accordance with Requirement R2, each Planning Coordinator is required to identify the zone(s) to which it belongs.

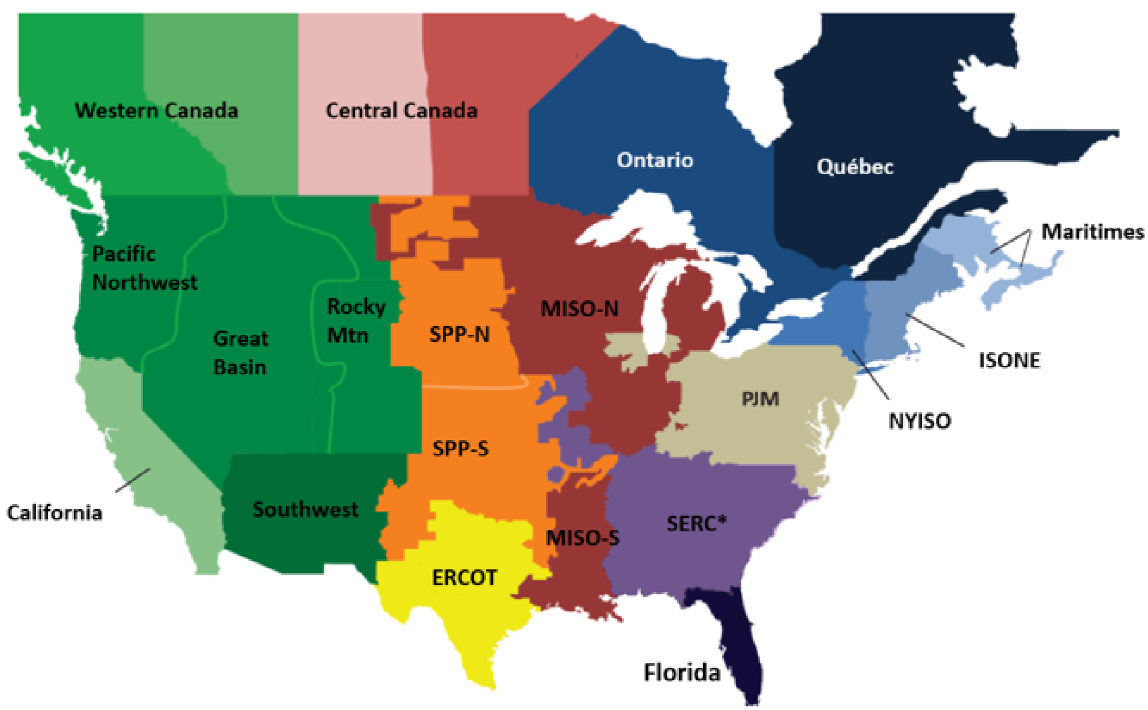
Zone	Planning Coordinators
Eastern Interconnection	
MISO North	~~MISO~~Planning Coordinator(s) in MISO that serve portions of MISO in Montana, North Dakota, South Dakota, Minnesota, Iowa, Wisconsin, Michigan, Indiana, Illinois, Missouri, and Kentucky
MISO South	Planning Coordinator(s) in MISO that serve portions of Arkansas, Mississippi, Louisiana, and Texas
SPP North	~~SPP~~Planning Coordinator(s) in portions of SPP that serve Iowa, Montana, Nebraska, North Dakota, and South Dakota.
SPP South	Planning Coordinator(s) in portions of SPP that serve Arkansas, Kansas, Louisiana, Missouri, New Mexico, Oklahoma, and Texas.
PJM	~~PJM~~Planning Coordinator(s) that serves PJM
~~NPCC (~~New England~~)~~	Planning ~~Coordinators~~Coordinator(s) in NPCC that ~~primarily~~ serve the six New England States
~~NPCC (~~New York~~)~~	Planning ~~Coordinators~~Coordinator(s) in NPCC that ~~primarily~~ serve New York
SERC	Planning ~~Coordinators~~Coordinator(s) in SERC, excluding those that ~~primarily~~ serve Florida and those in MISO, SPP, ~~or~~and PJM
~~SERC (~~Florida~~)~~	Planning ~~Coordinators~~Coordinator(s) in SERC that ~~primarily~~ serve Florida
Central Canada	Planning ~~Coordinators~~Coordinator(s) that ~~primarily~~ serve Saskatchewan and~~/or~~ Manitoba region of MRO
Ontario	Planning Coordinator(s) in NPCC that serve Ontario
~~Eastern Canada~~Maritimes	Planning ~~Coordinators~~Coordinator(s) in NPCC that primarily serve ~~Ontario,~~ New Brunswick, ~~and~~ Nova Scotia, Prince Edward Island, and Northern Maine
Western Interconnection	
WECC Southwest	Planning ~~Coordinators~~Coordinator(s) in the Southwest region of WECC, including El Paso in West Texas
Pacific Northwest	Planning ~~Coordinators~~Coordinator(s) in the Pacific Northwest region of WECC

Zone	Planning Coordinators
Great Basin	Planning ~~Coordinators~~Coordinator(s) in the Great Basin region of WECC
Rocky Mountain	Planning ~~Coordinators~~Coordinator(s) in the Rocky Mountain region of WECC
California/Mexico	Planning ~~Coordinators~~Coordinator(s) in the California/Mexico region of WECC
Western Canada	Planning ~~Coordinators~~Coordinator(s) that primarily serve British Columbia and~~/or~~ Alberta region of WECC
ERCOT Interconnection	
ERCOT	~~Areas~~Planning Coordinator(s) in Texas ~~subject to ERCOTs jurisdiction.~~that are part of the ERCOT Interconnection
Quebec Interconnection	
Quebec	Planning ~~Coordinators~~Coordinator(s) that ~~primarily~~ serve Quebec in the NPCC Region.

The map below depicts an approximation of the zones to be used in the Extreme Temperature Assessment and is provided as a visual aid; to the extent that there is a conflict between the map and the table, the table controls. This map is not to be used for compliance purposes.



TPL-008-1 Weather Zones Map



NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2023-07 Transmission System Planning Performance Requirements for Extreme Weather
Reliability Standard TPL-008-1

Applicable Standard

- TPL-008-1 – Transmission System Planning Performance Requirements for Extreme Temperature Events

Requested Retirement

- Not applicable

Prerequisite Standard

- Not applicable

Applicable Entities

- Planning Coordinators
- Transmission Planners

New Term in the NERC Glossary of Terms

This section includes all newly defined, revised, or retired terms used or eliminated in the NERC Reliability Standard. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

- **Extreme Temperature Assessment** – Documented evaluation of future Bulk Electric System performance for extreme heat and extreme cold benchmark temperature events.

Background

On June 15, 2023, the U.S. Federal Energy Regulatory Commission ("FERC") issued Order No. 896, a final rule directing NERC to develop a new or modified Reliability Standard to address the lack of a long-term planning requirement(s) for extreme heat and cold weather events.[1] Specifically, FERC directed NERC to develop modifications to Reliability Standard TPL-001-5.1 or develop a new Reliability Standard that requires the following: (1) development of benchmark planning cases based on major prior extreme heat and cold weather events and/or meteorological projections; (2) planning for extreme heat and cold weather

[1] *Transmission System Planning Requirements for Extreme* Weather, Order No. 896, 183 FERC ¶ 61,191 (2023).

events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios including the expected resource mix's availability during extreme heat and cold weather conditions, and including the wide-area impacts of extreme heat and cold weather; and (3) development of Corrective Action Plans that mitigate any instances where performance requirements for extreme heat and cold weather events are not met. FERC further directed NERC to ensure that the proposed new or modified Reliability Standard becomes mandatory and enforceable beginning no later than 12 months from the effective date of FERC approval.

General Considerations

Proposed Reliability Standard TPL-008-1 would require the performance of an Extreme Temperature Assessment at least once every five calendar years (Requirement R1). This implementation plan provides a staggered approach for the performance of the first Extreme Temperature Assessment, with phased-in compliance dates beginning 12 months from the effective date of regulatory approval consistent with Order No. 896. For subsequent Extreme Temperature Assessments, entities may establish timeframes appropriate to their facts and circumstances for carrying out their responsibilities under the standard, provided that the Extreme Temperature Assessment is completed no later than five calendar years following the previous Extreme Temperature Assessment.

Effective Date

The effective date for the proposed Reliability Standard is provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of the proposed Reliability Standard (e.g., an entire Requirement or a portion thereof), the additional time for compliance with that section is specified below. These phased-in compliance dates represent the dates that entities must begin to comply with that particular section of the Reliability Standard, even where the Reliability Standard goes into effect at an earlier date.

TPL-008-1 and Definition

Where approval by an applicable governmental authority is required, the standard and definition of Extreme Temperature Assessment shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard and definition of Extreme Temperature Assessment is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Phased-In Compliance Dates

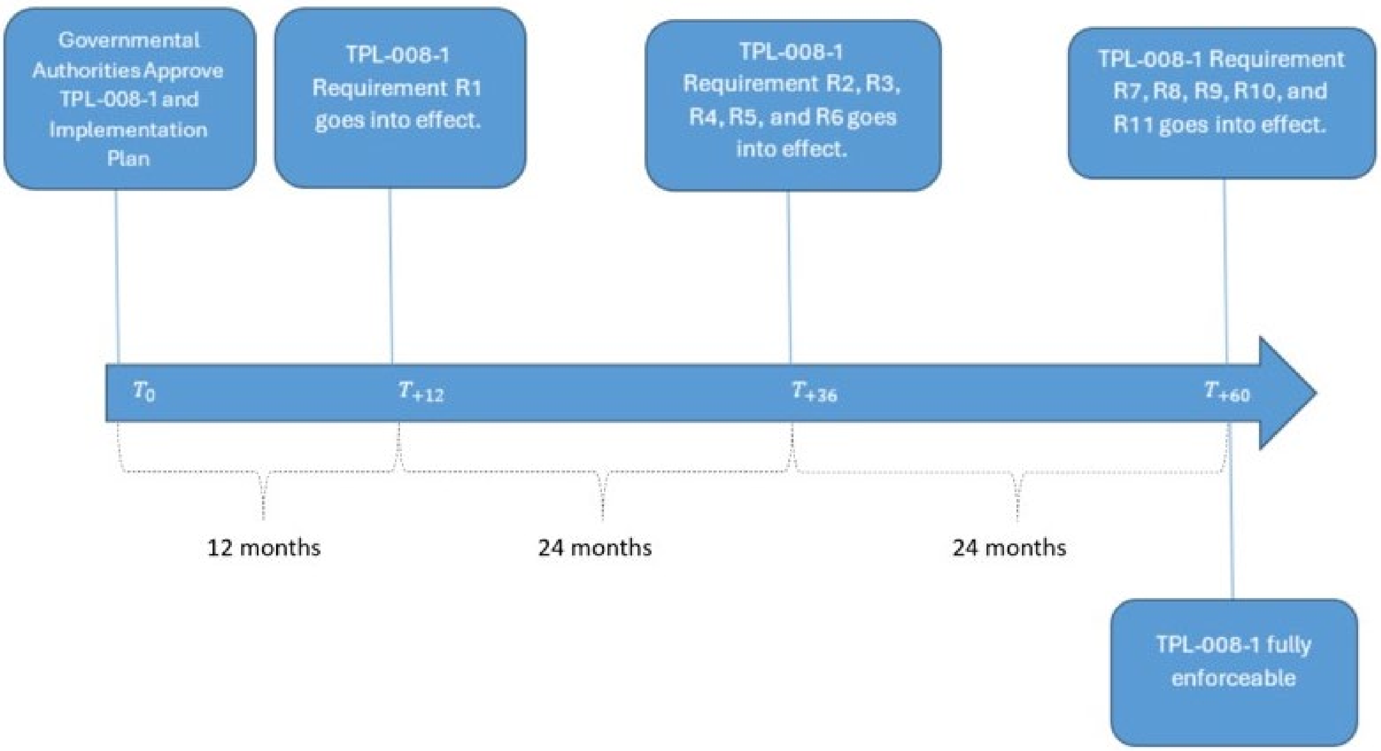
Compliance Date for TPL-008-1 Requirement R1

Entities shall be required to comply with Requirement R1, pertaining to the identification of individual and joint responsibilities for completing the Extreme Temperature Assessment, upon the effective date of Reliability Standard TPL-008-1.

Compliance Date for TPL-008-1 Requirements R2, R3, R4, R5, R6
Entities shall not be required to comply with Requirements R2, R3, R4, R5, and R6 until twenty-four (24) months after the effective date of Reliability Standard TPL-008-1.

Compliance Date for TPL-008-1 Requirements R7, R8, R9, R10, R11
Entities shall not be required to comply with Requirements R7, R8, R9, R10, and R11 until forty-eight (48) months after the effective date of Reliability Standard TPL-008-1.

Figure 1: Implementation Plan, Demonstrating Effective Date and Phased-in Compliance Dates from the effective date of the governmental authority's order approving this standard



Initial Performance of Periodic Requirements
Entities shall complete the Extreme Temperature Assessment no later than forty-eight (48) months after the effective date of Reliability Standard TPL-008-1. Subsequent Extreme Temperature Assessments shall be completed by no later than five calendar years following the completion of the previous Extreme Temperature Assessment.

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Technical Rationale and Justification for TPL-008-1

Project 2023-07 Transmission Planning Performance Requirements for Extreme Weather

November 2024

RELIABILITY | RESILIENCE | SECURITY




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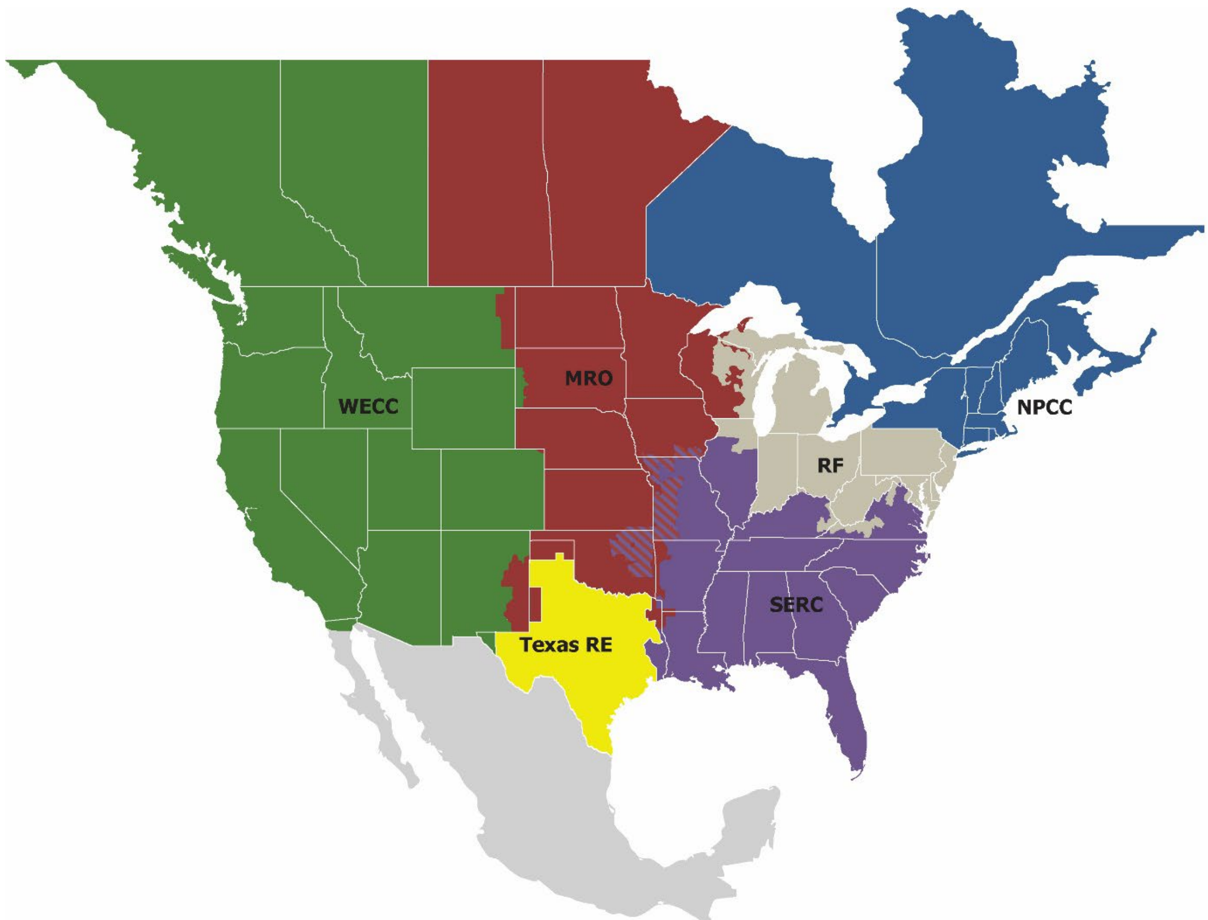
Table of Contents

Preface

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

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

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



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

Introduction

This document explains the technical rationale and justification for the proposed Reliability Standard TPL-008-1. It provides stakeholders and the ERO Enterprise with an understanding of the technology and technical requirements in the Reliability Standard. This Technical Rationale and Justification for TPL-008-1 is not a Reliability Standard and should not be considered mandatory and enforceable.

Background

On June 15, 2023, FERC issued FERC Order No. 896 that acknowledges the "challenges associated with planning for extreme heat and cold weather events, particularly those that occur during periods when the Bulk-Power System must meet unexpectedly high demand. Extreme heat and cold weather events have occurred with greater frequency in recent years and are projected to occur with even greater frequency in the future. These events have shown that load shed during extreme temperatures result in unacceptable risk to life and have extreme economic impact. As such, the impact of concurrent failures of Bulk-Power System generation and transmission equipment and the potential for cascading outages that may be caused by extreme heat and cold weather events should be studied and corrective actions should be identified and implemented."[1]

Therefore, the Commission directed in FERC Order No. 896 to develop a new or modified Reliability Standard to address a lack of long-term planning requirement(s) for extreme heat and cold weather events. Specifically, FERC directed NERC to develop modifications to Reliability Standard TPL-001-5.1 or a new Reliability Standard, to require the following: (1) development of benchmark planning cases based on major prior extreme heat and cold weather events and/or meteorological projections; (2) planning for extreme heat and cold weather events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios including the expected resource mix's availability during extreme heat and cold weather conditions, and including the wide-area impacts of extreme heat and cold weather; and (3) development of corrective action plans that mitigate any instances where performance requirements for extreme heat and cold weather events are not met.

[1] N. Am. Elec. Reliability Corp., 183 FERC ¶ 61,191 (2023) (FERC Order), Final Rule. eLibrary | File List (ferc.gov)

Defined Terms

The Standard Drafting Team (SDT) defined one term to be added to the NERC Glossary of Terms to make the requirements easier to read and understand.

Extreme Temperature Assessment
Documented evaluation of future Bulk Electric System performance for extreme heat and extreme cold benchmark temperature events.

The definition of Extreme Temperature Assessment was developed by the SDT to limit wordiness throughout the requirements.

TPL-008-1 Standard

The FERC Order No. 896 directed NERC to submit a new Reliability Standard or modifications to Reliability Standard TPL-001-5.1 to address the concerns pertaining to transmission system planning for extreme heat and cold weather events that impact the Reliable Operation of the Bulk-Power System.

The SDT determined that a new Reliability Standard was the cleanest way to address FERC's directives versus modifying Reliability Standard TPL-001-5.1. While the TPL-008-1 standard uses similar requirements, this allows industry to have one standard that focuses on extreme heat and extreme cold benchmark temperature events.

The purpose of TPL-008-1 is to "Establish Transmission system planning performance requirements to develop a Bulk Power System (BPS) that will operate reliably during extreme heat and extreme cold temperature events." The directives in FERC Order No. 896 pertain to the reliable operation of the BPS, and the requirements of TPL-008-1 support that by ensuring Planning Coordinators and Transmission Planners are planning their portions of the Bulk Electric System to meet performance requirements in extreme heat and extreme cold benchmark temperature events.

Requirement R1

Requirement R1 requires each Planning Coordinator (PC) and the Transmission Planner(s) (TP) within the PC's footprint to identify each entity's individual and joint responsibilities when completing the Extreme Temperature Assessment at least once every five calendar years. Due to significant level of data collection and coordination between the Planning Coordinator(s) and Transmission Planner(s) for the potential wide-area extreme heat and extreme cold benchmark events, as well as the need to document the assumptions and study results, the drafting team opined that completing the Extreme Temperature Assessment once every five calendar years is a reasonable timeframe to allow responsible entities to coordinate, prepare, perform, and document the study results. To the extent that responsible entities want to complete more than one set of the Extreme Temperature Assessment for an extreme heat and extreme cold benchmark event, they can do so, but the minimum requirement is once every five calendar years to complete one set of the Extreme Temperature Assessment.

The purpose of this requirement is to have the PC and its TP(s) identify their individual and joint responsibilities for the following activities:

- Identifying the PC's zone(s) and coordinating with all PCs in each of its identified zone(s) to select one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event (Requirement R2),
- Implementing a process for developing benchmark planning cases and sensitivity cases (Requirement R3),
- Developing benchmark planning cases and sensitivity cases (Requirement R4),
- Having acceptable criteria (Requirements R5 and R6),
- Identifying Contingencies for evaluation (Requirement R7),
- Performing steady state and transient stability analyses (Requirement R8),
- Developing Corrective Action Plans when required (Requirement R9),
- Evaluating and documenting possible actions for performance deficiencies that do not require Corrective Action Plans (Requirement R10), and
- Providing study results to any functional entity that has a reliability related need (Requirement R11).

The responsibilities described in Requirements R2 and R3 are explicitly assigned to the PC. The responsibilities described in Requirements R4 through R11 may be completed by either the PC or one or more of its TPs. Requirement R1 requires that an agreement is reached on the individual and joint responsibilities for completing the Extreme Temperature Assessment between the PC and its TPs.

Requirement R2

Requirement R2 requires each Planning Coordinator (PC) to identify the zone(s) it will participate in for the components of the Extreme Temperature Assessment that require coordination. PCs in the same zone are required to coordinate to:

- Select one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event (Requirement R2), and
- Implement a process for developing benchmark planning cases and sensitivity cases (Requirement R3).

FERC Order No. 896 directed NERC to require that transmission planning studies under the new or revised Reliability Standard consider the wide-area impacts of extreme heat and cold weather. Considering this directive, the SDT identified the zones depicted in Attachment 1 as reasonable boundaries that balance the need for studies to cover large regions with similar weather patterns with the need for a manageable level of coordination. An earlier proposal to limit coordination to only adjacent PCs was not adequate for meeting FERC's directives. While the zones depicted in Attachment 1 will require some PCs to coordinate with many other PCs, the industry has demonstrated, through various working groups and organizations, that it is capable of cooperating to build models that represent larger areas. The zones depicted in Attachment 1 are either aligned with existing PC boundaries or boundaries of a group of PCs with similar weather patterns.

Requirement R2 describes the need to select extreme benchmark temperature events necessary for the creation of benchmark planning cases. Specifically, extreme hot and cold temperatures experienced during benchmark events are assumed to be outside the ranges used as the basis of planning cases studied under Reliability Standard TPL-001-5.1. Since temperature levels and associated weather conditions affect load levels, generation performance, and transfer levels, the selection of benchmark events is critical to ensuring the Extreme Temperature Assessment appropriately evaluates probable System conditions.

Since any region can experience temperatures that are higher or lower than normal, PCs within the same zone must coordinate to select one common temperature event that includes hotter temperature assumptions and one common temperature event that includes colder temperature assumptions. While it is understood that, for example, one region may typically experience hotter summers and milder winters than another region, both a hotter than average summer and a colder than average winter could result in reliability concerns. Therefore, the requirement is for one common case specific to extreme heat and one common case specific to extreme cold conditions to be studied for the Extreme Temperature Assessment. By selecting the same, common events, PCs ensure that extreme temperatures are studied over the entire zone. The evaluation of a common event taking place over a wide area is foundational to FERC Order No. 896. Furthermore, selecting the same, common events reasonably limits coordination requirements. PCs are required to participate in the selection of events for their zone(s), but have no responsibilities for the selection of events in other zones.

The SDT determined that the extreme heat and extreme cold temperatures selected must have a verified statistical basis based on weather data from credible sources. The SDT has identified several key features that are used to determine when a temperature event will constitute a valid extreme benchmark temperature event for the purposes of completing the Extreme Temperature Assessment. Specifically, extreme benchmark temperature events must:

- Consider no less than 40 years of temperature data,
- Utilize data ending no more than five years prior to the time benchmark temperature events are selected, and
- Represent one of the worst 20 extreme temperature conditions within the zone.

Temperature events are ranked by computing the 3-day rolling average of daily maximum temperatures (for extreme heat) or daily minimum temperatures (for extreme cold). The 3-day rolling average temperatures are calculated for both extreme heat and extreme cold to identify multi-day periods of extreme heat or extreme cold temperature events. The ERO will maintain a library of benchmark events to provide responsible entities access to vetted benchmark temperature events that meet the criteria of Requirement R2. While selection of events from the ERO's provided library assures entities they are selecting valid events, Requirement R2 does not preclude entities from collecting temperature data and identifying benchmark temperature events through their own process. Entities that elect to develop their own benchmark temperature events are responsible for ensuring the input temperature data and selected benchmark temperature events meet the criteria of Requirement R2. Additionally, because Requirement R2 requires PCs within a zone to coordinate in the selection of the benchmark temperature events, the process used to identify these events must be agreeable to those PCs.

The requirement to consider no less than 40 years of temperature data was established based on the observation that many of the worst events identified in various regions of North America occurred in the 1980s and 1990s. For example, preliminary data indicated that the five worst extreme cold temperature events in the PJM region over the last 43 years occurred between 1983 and 1994. Similar results were seen in other regions for both extreme heat and extreme cold temperature events. Thus, the SDT determined that a minimum of 40 years of temperature data should be used to ensure more extreme events weren't excluded by using a shorter duration of temperature data.

Requirement R3

Requirement R3 aligns with directives in FERC Order No. 896, emphasizing the importance of coordinating the development of benchmark planning cases and sensitivity cases amongst PCs within a zone, where the scope of extreme temperature event studies will likely cover large geographical areas exceeding smaller individual planning areas. The SDT considered comments from the industry expressing concerns regarding the necessity to coordinate among all impacted PCs in developing benchmark planning cases and sensitivity cases for various extreme benchmark temperature events. Recognizing that coordination among all impacted PCs may not be necessary to ensure reliability within an individual planning area, the SDT drafted Requirement R3 to require each PC to coordinate with all PCs within a zone to implement a process for the development of benchmark planning cases and sensitivity cases. The SDT believes this change balances the need to ensure the planning cases capture impacts to/from entities affected by the same benchmark temperature event, while recognizing that reliability will be less impacted by system changes far removed from the zone.

PCs within a zone must coordinate to implement a process that results in the development of benchmark planning cases that represent the benchmark temperature events selected in accordance with Requirement R2, and sensitivity cases that demonstrate the impact of changes to the basic assumptions used in the benchmark planning cases. This process requires several components, outlined in the sub-requirements of Requirement R3.

First, Requirement R3 Part 3.1 requires PCs within a zone to identify System models form the basis for developing the benchmark planning cases. These models must represent one of the years in the Long-Term Transmission Planning Horizon. PCs will also need to ensure models include stability modeling data to provide for the performance of stability analysis later in the process. It is reasonably anticipated that PCs will likely utilize a summer peak model as the starting point for the extreme heat benchmark temperature event and a winter peak model as the starting point for the extreme cold benchmark temperature event.

Secondly, Requirement R3 Part 3.2 requires that PCs within a zone provide forecasted data for their area within the zone that represents the benchmark temperature events selected in accordance with Requirement R2. Each PC must provide data for their area within the zone that represents seasonal and temperature adjustments for Load, generation, Transmission, and transfers. The provided data should be used to update the starting point models to reflect the selected benchmark temperature events.

Thirdly, Requirement R3 Part 3.3 allows PCs to agree on assumptions for seasonal and temperature adjustments for Load, generation, Transmission, and transfers in areas *outside* of the zone. As a sub-requirement of Requirement R3, these assumptions must be coordinated among PCs in the zone, as needed. As an example, PCs within the zone may identify the need for imported power during a benchmark event. The PCs may evaluate historical import availability and assume an import from an area outside of the zone is reasonable and should be modeled.

Finally, Requirement R3 Part 3.4 requires PCs to coordinate and identify changes to generation, real and reactive forecasted Load, or transfers that should be reflected in sensitivity cases. Sensitivity cases are intended to demonstrate the impact of changes to the basic assumptions used in the benchmark planning cases, and Requirement R3 Part 3.4 ensures PCs are cooperating to identify changes that sufficiently alter the assumptions reflected in the benchmark planning cases. For example, PCs that identified an import external source to the zone for a benchmark planning case may elect to alter the source of that import in the sensitivity case.

Requirement R4

The SDT drafted Requirement R4 to require the responsible entity to use data consistent with Reliability Standard MOD-032, supplemented by other sources as needed, for developing benchmark planning cases that represent System conditions based on selected benchmark temperature events. This aligns with directives in FERC Order No. 896, paragraph 30, emphasizing the requirement of developing both benchmark planning cases and sensitivity study cases. Requirement R4 is consistent with Reliability Standard TPL-001-5.1 in cross-referencing Reliability Standard MOD-032, which establishes consistent modeling data requirements and reporting procedures for the development of planning horizon cases necessary to support analysis of the reliability of the interconnected System. It is also consistent with Reliability Standard TPL-001-5.1 in acknowledging that data from other sources may be required to supplement the data collected through Reliability Standard MOD-032 procedures.

Requirement R4 requires entities to use the coordination process developed in accordance with Requirement R3 to develop the following four cases:

- One common extreme heat benchmark planning case (Requirement R4 Part 4.1),
- One common extreme cold benchmark planning case (Requirement R4 Part 4.1),
- One common extreme heat sensitivity case (Requirement R4 Part 4.2), and
- One common extreme cold sensitivity case (Requirement R4 Part 4.2).

At the completion of the case development process, implemented in accordance with Requirement R3, and executed in Requirement R4, responsible entities will have the four cases listed above. This establishes category P0 as the normal System condition in Table 1 for each case. Requirement R3 does not preclude PCs from implementing a process that develops cases for multiple benchmark temperature events or additional sensitivity cases. Moreover, entities may elect to develop additional cases for their internal use.

As per FERC Order No. 896, paragraph 94, it is clarified that resource adequacy benchmarks are not within the scope of TPL-008-1. The intent of the standard is to evaluate benchmark events where sufficient generation is available to supply load. However, under an extreme heat or extreme cold temperature condition, there may be instances where the benchmark planning cases and/or sensitivity cases may not have sufficient available generation to supply the load. In these scenarios, it may be acceptable for the responsible entity to revise the model to reduce the forecasted Load, or include forecasted generation, to achieve a solution for the benchmark planning cases and/or sensitivity cases and evaluate future Bulk Electric System performance for extreme temperature events. Each responsible entity, as identified in Requirement R1, shall have dated evidence in either electronic or hard copy format that it developed benchmark planning cases and sensitivity cases in accordance with Requirement R4.

Requirement R5

Requirement R5 was drafted to require each responsible entity to set the criteria needed for limits that will be used to evaluate System steady state voltage and post-Contingency voltage deviations for completing the Extreme Temperature Assessment. The establishment of these criteria allows auditors to compare the results of the Extreme Temperature Assessment with the established criteria.

Requirement R6

Requirement R6 was drafted to require the responsible entity to define and document the criteria or methodology used in evaluating the Extreme Temperature Assessment analysis to identify instability, uncontrolled separation, or Cascading within an Interconnection. Adequate and thorough criteria should be built into the Extreme Temperature Assessment to help identify instability, uncontrolled separation, and Cascading conditions. The establishment of these criteria allows auditors to compare the results of the Extreme Temperature Assessment with the established criteria.

Requirement R7

This requirement addresses directives in FERC Order No. 896 to define a set of Contingencies that responsible entities will be required to consider when conducting wide-area studies of extreme heat and cold weather events. FERC's preference to rely on established Contingency definitions, "[w]e believe that it is necessary to establish a set of common contingencies for all responsible entities to analyze. Required contingencies, such as those listed in Table 1 of Reliability Standard TPL-001-5.1 (i.e., category P1 through P7), establish common planning events that set the starting point for transmission system planning assessments," was also considered by the SDT. It is necessary to establish a set of common Contingencies for all responsible entities to analyze. Requiring the study of predefined Contingencies, such as those listed in Table 1, will ensure a level of uniformity across planning regions, considering that extreme heat and cold weather events often exceed the geographic boundaries of most existing planning footprints. Defining the Contingencies in Table 1 consistently with Table 1 of Reliability Standard TPL-001-5.1 meets FERC's preference for commonality.

If feasible, all Contingencies listed in Table 1 should be considered for evaluation by the responsible entity; however, the language affords flexibility in identifying the most appropriate Contingencies. As such, the responsible entity should implement a method and establish sufficient supporting rationale to ensure Contingencies within each category of Table 1, that are expected to produce more severe System impacts within its planning area, are adequately identified. It is noted that since the benchmark planning cases are developed from the extreme temperature benchmark events, they already represent extreme System conditions and thus not all Contingencies from Reliability Standard TPL-001-5.1 Table 1 are included in the TPL-008-1 Table 1 for assessment. The Events included in TPL-008-1 Table 1 represent the more likely Contingencies to occur.

The SDT included categories P0, P1, and P7 in Table 1 of TPL-008-1. The SDT finds it reasonable to exclude P2, P3, P4, P5 and P6 Contingencies from the Extreme Temperature Assessment. Studying categories P0, P1 and P7 is the minimum requirement of TPL-008-1. The standard does not preclude entities from studying additional Contingencies if desired. The following discusses the rationale for excluding P2 through P6 Contingencies for TPL-008-1:

1. Excluding P2 and P4 Contingencies:

   After consideration of comments received from the industry, the SDT removed P2 and P4 Contingencies due to lower probability of occurrence than P1 and P7 Contingencies. The standard establishes minimum requirement for Contingencies with higher probability of occurrence. To the extent that the responsible entity determines the need for studying beyond the minimum requirements, the standard does not preclude the entity from doing so.

2. Excluding P3 and P6 Contingencies:

   Part of the decision stems from the complexity of P3 and P6 Contingencies, which involve multiple element outages triggered by multiple Contingencies, with System adjustments allowed between them. Consequently, the occurrence likelihood of P3 and P6 Contingencies could be even lower compared to P1 and P7 Contingencies. Moreover, aligning with the directives set forth in FERC Order 896, which emphasizes the importance of incorporating derated generation, transmission capacity, and the availability of generation and transmission in the development of benchmark planning cases, it becomes imperative for responsible entities to consider potential concurrent or correlated generation and transmission outages and/or derates within relevant benchmark planning cases. This ensures that the benchmark planning case accurately reflects System conditions under extreme temperatures, with generation and transmission derates and/or outages already factored. Therefore, the SDT believes excluding P3 and P6 is justified, as generation and transmission derates and/or outages are already accounted for within the benchmark planning cases. Excluding P5 Contingencies:

After consideration of comments received from the industry, the SDT removed P5 Contingency (Delayed Fault Clearing due to failure of non-redundant component of a Protection System). This is because while some categories of Contingencies may be assessed in a straightforward approach, category P5 Contingency events often require a significant level of engineering analysis (including protection and/or control analysis). These analyses are sensitive to the System topology and expected dispatch. As the planning benchmark cases are developed for TPL-008-1 that represent System conditions that are different than the typical summer or winter peak conditions, the development of category P5 Contingency events is expected to be a significant burden. Since these events only require evaluations of possible mitigations (and not Corrective Action Plans), violations resulting from these events are unlikely to result in significant transmission System investment. Furthermore, any violations resulting from category P5 events may be mitigated by eliminating and addressing the single point of failure included in the event definition. Thus, the evaluation of possible actions is unlikely to result in further insight beyond the general reliability improvements associated with eliminating single points of failure.

The SDT discussed and decided to keep the P7 Contingency category because common structure Contingencies are often evaluated after categories P0 and P1 as the most common minimum level of transmission reliability assessment. These events have a high likelihood of occurrence due to the following reasons:

- Historical events that include simultaneous forced outage due to tripping of the double-circuit power lines due to electrical storm events;
- Environment-caused factors include pollution buildup, such as dust, that could cause faulted condition that trips both transmission lines on a common tower;
- Avian-caused outages that impact both transmission lines on a common tower;
- Smoke from nearby wildfires can cause simultaneous tripping of both circuits on a common tower;
- Nearby wildfires can impact System Operation as System Operators proactively de-energize both lines on a common tower to avoid further impact to the transmission grid in the event of a simultaneous tripping of both lines that may be carrying high power transfer between areas;
- Weather-related causes such as lightning, flooding, wind, or icing can cause tripping of both transmission lines on a common tower;
- Natural disaster such as winter storm can cause transmission tower to collapse, taking out both lines strung on the same tower;
- Other incidents such as vehicle accident, aircraft accident, vandalism, or animal contact can adversely impact both transmission lines on the common tower.
- Loss of two circuits running in parallel, simultaneously, is likely to have a greater system impact versus loss of two unrelated or geographically separated circuits. Therefore, there is greater potential for reliability concerns, especially during heavy transfers that are likely during periods of extreme weather, due to loss of both circuits of a double-circuit line.
- Due to the reasons above, Contingencies that involve double-line circuits on a common tower are mostly included in the critical multiple Contingency list in System Operations reliability assessment.

Some, but not all, items to consider when developing the rationale for selecting Contingencies are:

- Past studies,
- Subject matter expert knowledge of the responsible entity’s System (to be supplemented with data or analysis), and

- Historical data from past operating events.

Lastly, regarding the Bulk Electric System (BES) voltage levels for the Contingencies, the SDT reviewed previous major wide-area benchmark events and found that the Facilities that were out of service by these events have voltages that are 200 kV and above. Thus, it is the reason for establishing voltages of 200 kV and above for Contingencies in Table 1 of TPL-008-1. The monitoring of potential impact is still applicable to Facilities with all BES voltage levels. However, with that said, the SDT recognized that many PCs and TPs have Contingencies that include all BES levels. Responsible entities may elect to use the existing Contingencies that they already have and report the criteria violations for the categories in TPL-008-1 Table 1.

Requirement R8

Requirement R8 was drafted to provide clarity on the following:

1. What planning study cases are required?

   The Requirement R8 includes the following number of assessments to complete the Extreme Temperature Assessment and address FERC Order No. 896 directives per paragraph 111 that "direct NERC to require in the proposed new or modified Reliability Standard that responsible entities perform both steady state and transient stability (dynamic) analyses in the extreme heat and cold weather planning studies". In addition, Requirement R8 also addresses FERC Order No. 896 directives per paragraph 124 that "require the use of sensitivity cases to demonstrate the impact of changes to the assumptions used in the benchmark planning case". Requirement R8 also addresses FERC Order No. 896 directives per paragraph 124 that sensitivity cases "should consider including conditions that vary with temperature such as load, generation, and system transfers." Since the benchmark planning case(s) already include System conditions under extreme heat or extreme cold events, the sensitivity analysis is to include changes to at least one of the following conditions: generation, real and reactive forecasted Load, or transfers. Since the minimum requirement includes changes to one of these conditions, the PCs and the TPs can include further sensitivity assessments to change more conditions if they choose to do so.

   The following provides the number of assessments required for the benchmark planning and sensitivity cases to complete the Extreme Temperature Assessment.

Type of Extreme Temperature Assessment	Extreme Cold Temperature Event	Extreme Heat Temperature Event	Total
Benchmark Planning Case Analysis	One extreme cold benchmark planning case assessment	One extreme heat benchmark planning case assessment	Two benchmark planning case assessments
Sensitivity Case Analysis	One sensitivity case with changes to at least one of the following conditions: generation, real and reactive forecasted Load, or transfers	One sensitivity case with changes to at least one of the following conditions: generation, real and reactive forecasted Load, or transfers	Two sensitivity case assessments
Total			A total of four assessments to complete the Extreme Temperature Assessment

2. What are the types of analyses required?

   There are two types of analyses required: steady-state and transient stability. Each type of analysis must be completed for each of the four cases described in the table above. This requirement is to satisfy FERC Order No. 896 directive paragraph 111.

Requirement R9

FERC Order No. 896 identifies a deficiency in the existing Reliability Standard TPL-001-5.1 where “planning coordinators and transmission planners are required to evaluate possible actions to reduce the likelihood or mitigate the consequences of extreme temperature events but are not obligated to develop corrective action plans” (¶139).

Given potential severe consequences of extreme cold and extreme heat events, FERC Order No. 896 raises the bar and “directs NERC to require in the new or modified Reliability Standard the development of extreme weather corrective action plans for specified instances when performance standards are not met” (¶152).

Due to higher likelihood of categories P0 and P1, these categories are held to a higher performance requirement in benchmark planning cases. Corrective Action Plans are required to address performance deficiencies for categories P0 and P1 in benchmark planning cases analyzed in the Extreme Temperature Assessment.

Furthermore, having a Corrective Action Plan requirement for categories P0 and P1 in benchmark planning cases ensures resilience during future extreme cold and extreme heat temperature events, when the transmission System is required to be P1 Contingency-secure (for steady-state and transient stability).

Given that a category P0 represents a continuous System condition without any system disturbances, the SDT determined that load shedding should not be considered as a Corrective Action Plan. However, the SDT has determined that load curtailment may be considered for a P1 Contingency as a Corrective Action Plan where load shed is allowed to prevent system-wide failures and ensuring the continued operation of essential services under a critical P1 Contingency in the extreme heat and cold temperature events. The SDT also emphasizes that alternative solutions, other than firm load curtailment, are evaluated in higher priorities. Non-Consequential Load Loss is permitted as an interim solution in situations that are beyond the control of the Planning Coordinator or Transmission Planner that prevent the implementation of a Corrective Action Plan in the required timeframe; however, the responsible entity must document the situation causing the problem, alternatives evaluated, and take actions to resolve the situation. Future revisions to the Corrective Action Plan are allowed, provided that the planned Bulk Electric System continues to meet the performance requirements of Table 1.

FERC Order No. 896 also directs NERC “to develop certain processes to facilitate interaction and coordination with applicable regulatory authorities or governing bodies responsible for retail electric service as appropriate in implementing a corrective action plan” (¶152). In the event that Non-Consequential Load Loss is included in the Corrective Action Plan for a P1 Contingency, the responsible entity shall document alternative(s) considered, make the Corrective Action Plan available to, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.

Requirement R10

The requirement for responsible entities to evaluate and document possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts when the study results in the benchmark planning cases analyses conclude there could be instability, uncontrolled separation, or Cascading for P7 Contingencies is in response to directives outlined in FERC Order No. 896.

P7 Contingencies involve multiple element outages resulting from a single event, making them relatively less likely to occur, compared to categories P0 and P1, but potentially causing more severe system impacts. Considering both the likelihood of these Contingencies, and the fact that the Extreme Temperature Assessment already addresses low-probability System conditions, the SDT determined that Corrective Action Plans should not be required for P7 Contingencies. However, due to the potential severity resulting from single-Contingency multiple element outages, the SDT believes it is appropriate for responsible entities to at least evaluate and document possible mitigation actions to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses conclude there could be instability, uncontrolled separation, or Cascading. The biggest benefit from the evaluation and documentation of the possible mitigating actions is it allows a responsible entity to see where major reliability concerns exist that may need to be addressed; and, if a sufficiently large number of reliability concerns are identified, it may encourage transmission upgrade mitigation option(s) to be considered and implemented without it being strictly called for in the standard. Not requiring Corrective Action Plans for these Contingencies, but requiring the evaluation, is a compromise from having Corrective Action Plans for all studied Contingencies.

Furthermore, FERC Order No. 896 requires “the use of sensitivity cases to demonstrate the impact of changes to the assumptions used in the benchmark planning case” (¶124). FERC Order No. 896 also states: “NERC should determine whether corrective action plans should be required for single or multiple sensitivity cases, and whether corrective action plans should be developed if a contingency event that is not already included in benchmark planning case would result in cascading outages, uncontrolled separation, or instability” (¶158). The SDT acknowledges that sensitivity analysis is an important component of a robust transmission planning study. A requirement to develop and implement Corrective Action Plans for sensitivity cases may incentivize responsible entities to select fewer or less severe sensitivities. An incentive to select fewer sensitivities is undesirable because sensitivity study results are used to identify constraints and initiate deeper analysis into the variables that impact those constraints. The study results of sensitivity cases are also important to inform the development of Corrective Action Plans in the benchmark planning cases. Therefore, the SDT determined the responsible entity must evaluate and document possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses of sensitivity cases conclude there could be instability, uncontrolled separation, or Cascading for categories P0, P1, and P7. Finally, TPL-008-1 does not preclude the responsible entity from developing Corrective Action Plans for sensitivity cases beyond what is required in the standard.

Requirement R11

The requirement for responsible entities to share Extreme Temperature Assessment results aligns with directives in FERC Order No. 896, emphasizing coordination and sharing of study findings. It ensures collaboration among stakeholders and timely dissemination of critical information to entities with reliability-related needs. This fosters a collective understanding of reliability concerns identified in wide-area studies, thereby enhancing overall grid reliability.

Attachment 1: Extreme Temperature Assessment Zones

The map depicts an approximation of the zones to be used in the Extreme Temperature Assessment and is provided as a visual aid for each Planning Coordinator to identify the zone(s) to which the Planning Coordinator belongs to under Attachment 1. The zone topology is a function of balancing authority jurisdiction and general knowledge of zonal weather patterns. The goal of the topology was to split the North American System into several distinct zones that have similar electric power system properties (i.e., balancing authority and interconnections) and similar weather or climatological patterns. Balancing authorities with large areas of jurisdiction, exclusively ISOs and RTOs, are assigned their own weather zone. In geographical areas comprised of multiple balancing authorities, generalized weather zones are created to best represent zonal weather patterns.

The NPCC region of the Eastern Interconnection was divided into New England, New York, Quebec Interconnection, Ontario, and Maritimes. The Planning Coordinators for the NPCC region of the Eastern Interconnection are listed below:

- New England: Planning Coordinators in NPCC that primarily serve the six New England States.
- New York: Planning Coordinators in NPCC that primarily serve New York.
- Quebec: Planning Coordinators that primarily serve Quebec in the NPCC Region.
- Ontario: Planning Coordinators in NPCC that primarily serve Ontario.
- Maritimes: Planning Coordinators in NPCC that primarily serve New Brunswick, Nova Scotia, Prince Edward Island, and the Northern Maine Independent System Administrator (NMISA). The NMISA is responsible for the administration of the northern Maine transmission system and electric power markets in Aroostook and Washington counties, with the load served radially from New Brunswick. It was not included in the New England division since there are no physical ties between NMISA and ISO-NE which is the Planning Coordinator serving the remainder of the six New England States.

Additionally, SERC combined NERC Assessment areas of SERC-East, SERC-Central, and SERC-Southeast into a single zone based on climate similarities. Northwest Regions, WECC-SW, SERC, and SERC-FP were based on balancing authority PNNL data. SPP-N, SPP-S, MISO-N, and MISO-S were aggregated based on county-level PNNL data.

Unofficial Comment Form – Draft 4

Project 2023-07 Transmission Planning Performance Requirements for Extreme Weather

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on draft four of **TPL-008-1 – Transmission System Planning Performance Requirements for Extreme Temperature Events** by **8 p.m. Eastern, November 21, 2024.**

Additional information is available on the project page. If you have questions, contact Senior Standards Developer, Jordan Mallory (via email), or at 470-479-7538.

Background Information

On June 15, 2023, FERC issued FERC Order No. 896 that acknowledges the "challenges associated with planning for extreme heat and cold weather events, particularly those that occur during periods when the Bulk-Power System must meet unexpectedly high demand. Extreme heat and cold weather events have occurred with greater frequency in recent years and are projected to occur with even greater frequency in the future. These events have shown that load shed during extreme temperature result in unacceptable risk to life and have extreme economic impact. As such, the impact of concurrent failures of Bulk-Power System generation and transmission equipment and the potential for cascading outages that may be caused by extreme heat and cold weather events should be studied and corrective actions should be identified and implemented."[1]

Therefore, the Commission directed, in FERC Order No. 896, to develop a new or modified Reliability Standard to address a lack of long-term planning requirement(s) for extreme heat and cold weather events. Specifically, FERC directed NERC to develop modifications to Reliability Standard TPL-001-5.1 or a new Reliability Standard, to require the following: (1) development of benchmark planning cases based on major prior extreme heat and cold weather events and/or meteorological projections; (2) planning for extreme heat and cold weather events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios including the expected resource mix's availability during extreme heat and cold weather conditions, and including the wide-area impacts of extreme heat and cold weather; and (3) development of corrective action plans that mitigate any instances where performance requirements for extreme heat and cold weather events are not met.

[1] N. Am. Elec. Reliability Corp., 183 FERC ¶ 61,191 (2023) (FERC Order), Final Rule. eLibrary | File List (ferc.gov)

Questions

1. The Drafting Team (DT) updated Requirement R2 based on comments received. Do you agree? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

   ☐ Yes
   ☐ No

   Comments:

2. The DT updated Requirement R9 based on comments received. Do you agree? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

   ☐ Yes
   ☐ No

   Comments:

3. The DT updated Attachment 1 based on comments received. Do you agree? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

   ☐ Yes
   ☐ No

   Comments:

4. The DT believes proposed modifications in TPL-008-1 provide entities with flexibility to meet the reliability objectives in a cost-effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost-effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

   ☐ Yes
   ☐ No

   Comments:

5. Provide any additional comments for the drafting team to consider, including the provided technical rationale document, if desired.

   Comments:

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Justifications

Project 2023-07 Transmission System Planning Performance Requirements for Extreme Weather

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Project 2023-07 Transmission System Planning Performance Requirements for Extreme Weather. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for TPL-008-1, Requirement R1	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to the fact that the Planning Coordinators, in conjunction with its Transmission Planner(s) will determine joint responsibilities for requirements throughout TPL-008-1.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed less than or equal to six months late.	The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed more than six months but less than or equal to 12 months late.	The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed more than 12 months but less than or equal to 18 months late.	The Planning Coordinator, in conjunction with its Transmission Planner(s), failed to identify individual and joint responsibilities for completing the Extreme Temperature Assessment. OR The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed more than 18 months late.

VSL Justifications for TPL-008-1, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL has been assigned as a binary due to the Planning Coordinator and Transmission Planner to determine who completes the responsibilities throughout TPL-008-1. The responsibilities documentation will either be developed or not.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R2	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of high is appropriate due to the fact that selecting a benchmark event to perform an extreme temperature assessment can affect the grid based on planning analysis for future events.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Planning Coordinator coordinated with all Planning Coordinators within each identified zone to identify one common extreme heat and one common extreme cold benchmark temperature event for completing the Extreme Temperature Assessment, but one of the identified events failed to meet all the criteria of Requirement R2.	The Planning Coordinator coordinated with all Planning Coordinators within each identified zone to identify one common extreme heat and one common extreme cold benchmark temperature event for completing the Extreme Temperature Assessment, but both of the identified events failed to meet all of the criteria of Requirement R2. OR The Planning Coordinator failed to coordinate with all Planning Coordinators within each identified zone to identify one common extreme heat and one common extreme cold benchmark temperature event for completing the Extreme Temperature Assessment.

VSL Justifications for TPL-008-1, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	This VSL has been assigned as a binary due to the benchmark event needing to be selected for benchmark planning cases to be completed. You either select a benchmark event or not.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R3	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of medium is appropriate due to the fact that it is important to develop and maintain System models within an entity's planning area for performing Extreme Temperature Assessments. Connecting to MOD-032 to provide important data needed to assist entities with System models is also important for accurate information to be used.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Planning Coordinator did not coordinate with all Planning Coordinators within each of its identified zone(s) to implement a process for developing benchmark planning cases. OR The Planning Coordinator coordinated with all Planning Coordinators within each of its identified zone(s) to implement a process for developing benchmark planning cases, but the process did not include all of the required elements.

VSL Justifications for TPL-008-1, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL has been assigned as a binary due to the responsible entity either develops and maintains the System models within its planning area or it does not develop and maintain the System models within its planning area.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R4	
Proposed VRF	**High**
NERC VRF Discussion	The VRF of High is appropriate because it could directly affect the electrical state or capability of the BPS if coordination is not completed for benchmark planning cases and sensitivity cases for the Extreme Temperature Assessment results.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity, as identified in Requirement R1, did not use the coordination process to develop benchmark planning cases or sensitivity cases. OR The responsible entity, as identified in Requirement R1, used the coordination process to develop benchmark planning cases and sensitivity cases, but did not use data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, for one or more of the required cases. OR The responsible entity, as identified in Requirement R1, used the coordination process and data consistent with that provided in accordance with the MOD-032 standard, supplemented as needed, but failed to develop one or more of the required planning or sensitivity cases.

VSL Justifications for TPL-008-1, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL has been assigned as a binary due to the Planning Coordinator to develop and implement a process for coordinating the development of benchmark planning cases. The benchmark planning cases will either be developed and implemented or not.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R5	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of medium is appropriate due to the importance of having criteria for acceptable System steady state voltage limits of post-Contingency voltage deviations for performing Extreme Temperature Assessments.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity, as identified in Requirement R1, did not have criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations for completing the Extreme Temperature Assessment.

VSL Justifications for TPL-008-1, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL has been assigned as a binary due to the responsible entity either having acceptable criteria for System steady state voltage limits and post-contingency voltage deviations or not.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R6	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate due to the importance of defining and documenting the criteria or methodology for System instability, uncontrolled separation, or Cascading.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity, as identified in Requirement R1, failed to define or document the criteria or methodology to be used in the Extreme Temperature Assessment to identify instability, uncontrolled separation, or Cascading within an Interconnection.

VSL Justifications for TPL-008-1, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R7	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of medium is appropriate for this requirement. Identifying Contingencies for performing Extreme Temperature Assessments for each of the event categories in Table 1 can indirectly impact the BES.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The responsible entity, as identified in Requirement R1, identified Contingencies for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System, but did not include the rationale for those Contingencies selected for evaluation as supporting information.	The responsible entity, as identified in Requirement R1, did not identify Contingencies for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System.

VSL Justifications for TPL-008-1, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R8	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate due to the importance of performing an Extreme Temperature Assessment every 5 years.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to document the assumptions for one or more sensitivity cases in accordance with Requirement R8.	The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to document the assumptions for one or more benchmark planning cases in accordance with Requirement R8.	The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to evaluate and document results for one or more of the sensitivity cases in accordance with Requirement R8.	The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to evaluate and document results for one or more of the benchmark planning cases in accordance with Requirement R8. OR The responsible entity, as identified in Requirement R1, failed to complete steady state or transient stability analyses and document results in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, in accordance with Requirement R8.

VSL Justifications for TPL-008-1, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R9	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate for this requirement. Developing a Corrective Action Plan is important to the BES as it assists entities when Systems are unable to meet performance requirements.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R9			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The responsible entity, as identified in Requirement R1, developed a Corrective Action Plan in accordance with Requirement R9, but failed to make its Corrective Action Plan available to, or solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.	The responsible entity, as identified in Requirement R1, failed to develop a Corrective Action Plan when the benchmark planning case study results indicate the System is unable to meet performance requirements for the Table 1 P0 or P1 Contingencies. OR The responsible entity, as identified in Requirement R1, developed a Corrective Action Plan, but it was missing one or more of the elements of Requirement R9 Part 9.1, 9.3 and 9.4 (as applicable).

VSL Justifications for TPL-008-1, Requirement R9	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL has been assigned as a binary due to the responsible entity either having acceptable criteria for System steady state voltage limits and post-contingency voltage deviations or not.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R10	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of lower has been assigned to Requirement R10. Documenting possible actions to reduce the likelihood or mitigate the consequences and adverse impacts are administrative in nature.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R10			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The responsible entity, as identified in Requirement R1, evaluated and documented possible actions to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection where required under Requirement R10 Part 10.1, but failed to evaluate and document possible actions where required under Requirement R10 Part 10.2.	The responsible entity, as identified in Requirement R1, evaluated and documented possible actions to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection where required under Requirement R10 Part 10.2, but failed to evaluate and document possible actions where required under Requirement R10 Part 10.1. OR The responsible entity, as identified in Requirement R1, failed to evaluate and document possible actions to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection where required under Requirement R10 Parts 10.1 and 10.2.

VSL Justifications for TPL-008-1, Requirement R10	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL has been assigned as a binary due to the fact that the responsible entity will have evaluated and documented possible actions to mitigate adverse impacts.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R11	
Proposed VRF	**Medium**
NERC VRF Discussion	The VRF of Medium is appropriate because it could directly affect the electrical state or capability of the BES if entities are not aware of the results from its Extreme Temperature Assessment results.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R11			
Lower	**Moderate**	**High**	**Severe**
The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 60 days but less than or equal to 80 days following the request.	The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 80 days but less than or equal to 100 days following the request.	The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 100 days but less than or equal to 120 days following the request.	The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 120 days following the request. OR The responsible entity, as identified in Requirement R1, did not provide its Extreme Temperature Assessment results to functional entities having a reliability related need who submitted a written request for the information.

VSL Justifications for TPL-008-1, Requirement R11	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

Consideration of FERC Order 896 Directives

Project 2023-07 Transmission System Planning Performance Requirements for Extreme Weather
November 2024

On June 15, 2023, FERC issued a Final Rule, Order No. 896, directing NERC to develop a new or modified Reliability Standard to address a lack of a long-term planning requirement(s) for extreme heat and cold weather events. Specifically, FERC directed NERC to develop modifications to Reliability Standard TPL-001-5.1 or to develop a new Reliability Standard to require the following: (1) development of benchmark planning cases based on major prior extreme heat and cold weather events and/or meteorological projections; (2) planning for extreme heat and cold weather events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios including the expected resource mix's availability during extreme heat and cold weather conditions, and including the wide-area impacts of extreme heat and cold weather; and (3) development of corrective action plans that mitigate any instances where performance requirements for extreme heat and cold weather events are not met. FERC directed NERC to submit a new or revised standard within 18 months, or by December 2024. The below provides the directives from FERC Order 896 along with the drafting team's consideration of the directives.

FERC Order 896 Directives	
Directive Language	**Consideration of Directives**
P35. "[W]e direct NERC to: (1) develop extreme heat and cold weather benchmark events, and (2) require the development of benchmark planning cases based on identified benchmark events." **P36**: "…As recommended by commenters, NERC should consider the examples of approaches for defining benchmark events identified in the NOPR (e.g., the use of projected frequency or probability distribution). NERC may also consider other approaches that achieve the objectives outlined in this final rule."	The ERO has worked with respective subject matter experts, including climate experts, the six regions, etc., to explore extreme heat and extreme cold benchmark temperature events. NERC, in consultation with climate data subject matter expert consultants on the benchmark events, utilized publicly available modeled data to address the requirements of TPL-008-1 that define extreme heat and extreme cold benchmark temperature events. Specifically, based on the available data, the drafting team determined that extreme benchmark temperature events must: 1) consider no less than forty years of historical temperature data, 2) include recent temperature

FERC Order 896 Directives	
Directive Language	**Consideration of Directives**
	data due to ongoing climate changes, and 3) represent one of the twenty worst extreme temperature conditions over the forty year period, based on a 3-day rolling average of daily maximum (heat) or minimum (cold) temperatures. The ERO will maintain a library of benchmark temperature events that meet these requirements. Responsible entities will be able to review and select benchmark temperature events from this library to assist with the development of benchmark planning cases. However, responsible entities may also identify benchmark temperature events via their own processes, provided that the event meets the criteria of Requirement R2 and is agreed upon by all PCs within the zone. Should the extreme heat and cold weather benchmark events provided not suffice for the entities zone, the Planning Coordinator (PC) in coordination with all PCs within its zone, may develop a common extreme heat and extreme cold weather benchmark event to use for the TPL-008-1 Standard. The drafting team developed requirements within TPL-008-1 to require PCs within zones to select one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event (Requirement R2). After selecting its benchmark events, the responsible entity is required to implement a process for coordinating the development of benchmark planning cases and sensitivity cases among the responsible entities (Requirement R3) and to develop benchmark planning cases and sensitivity cases (Requirement R4).

FERC Order 896 Directives	
Directive Language	**Consideration of Directives**
P37. "Because the impact of most extreme heat and cold events spans beyond the footprints of individual planning entities, it is important that all responsible entities likely to be impacted by the same extreme weather events use consistent benchmark events. Doing so is important to ensuring that neighboring planning regions are assuming similar weather conditions and are able to coordinate their assumptions accordingly. As a result, defining the benchmark event in a manner that provides responsible entities significant discretion to determine the applicable meteorological conditions would not meet the objectives of this final rule."	NERC, in consultation with climate data subject matter expert consultants on benchmark events, developed subregions or "zones" of North America that are likely to experience similar weather conditions. These zones also consider practical concerns with coordination such as the boundaries of Interconnections and Balancing Authority Areas. The drafting team developed Requirement R2 such that PCs within the same zone are required to select one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event. This process balances the opportunity to provide input with the need for common events to be modeled over wide areas.
P38. "[I]n developing extreme heat and cold benchmark events, NERC shall ensure that benchmark events reflect regional differences in climate and weather patterns."	NERC, in consultation with climate data subject matter expert consultants on benchmark events, has utilized publicly available modeled data in the last forty-three years (1980-2022), as well as more than eighty years of projected hourly meteorology data from PNNL to ensure regional differences in climate and weather patterns are reflected in the zones depicted in Attachment 1 of TPL-008-1. A Map has been added to the TPL-008-1 Standard showing the zones split throughout the US and Canada. These are to be considered wide area, and regional differences went into consideration when developing the data based on extreme historical events over the past 40 years.
P39. "We also direct NERC to include in the Reliability Standard the framework and criteria that responsible entities shall use to develop from the relevant benchmark event planning cases to represent potential weather-related contingencies (e.g., concurrent/correlated generation and transmission outages, derates) and expected future conditions of the system such as changes in load, transfers, and generation resource mix, and impacts on generators sensitive to extreme heat or cold, due to the weather conditions indicated in the benchmark events. Developing such a	The directive is addressed in Requirements R3 and R4 of the proposed TPL-008-1 standard. Requirement R3 obligates the PC to implement a process to coordinate the development of the benchmark planning cases and sensitivity cases. This process shall include: 1) the selection of System models within the Long-Term Transmission Planning Horizon to serve as a starting point for the benchmark planning cases, 2) forecasted seasonal and temperature

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framework would provide a common design basis for responsible entities to follow when creating benchmark planning cases. This would not only help establish a clear set of expectations for responsible entities to follow when developing benchmark planning events, but also facilitate auditing and enforcement of the Standard.”	dependent adjustments for Load, generation, Transmission, and transfers within the zone to represent the selected benchmark temperature events, 3) assumed seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers outside of the zone as needed, and 4) the identification of changes to at least one of generation, real and reactive forecasted load, or transfers to serve as a sensitivity case. Requirement R4 obligates the responsible entity to develop benchmark planning cases and sensitivity cases for performing the Extreme Temperature Assessment which reflects System conditions from the selected benchmark events. Requirement R4 also references the NERC MOD-032 Reliability Standard that provides PCs and Transmission Planners a mechanism for obtaining the data needed to develop the benchmark planning cases.
P40. “We also direct NERC to ensure the reliability standard contains appropriate mechanisms for ensuring the benchmark event reflects up-to-date meteorological data.”	Requirement R2 Part 2.1 requires that the temperature data collected to identify benchmark temperature events includes 40 years of data “ending no more than 5 years prior to the time the benchmark temperature events are selected”. This requirement ensures that the window of time considered for benchmark temperature events reflects up-to-date data. The up-to five-year gap was included due to potential lags in data sources.
P50. “[W]e…direct NERC to require that transmission planning studies under the new or revised Reliability Standard consider the wide-area impacts of extreme heat and cold weather. We direct NERC to clearly describe the process that an entity must use to define the wide-area boundaries. While commenters provide various views in favor of both a geographical approach and electrical approach to defining wide-area boundaries, we do not adopt any one approach in this final rule…NERC should consider the comments in this proceeding when developing a new or modified reliability standard that considers the broad area impacts of extreme heat and cold weather.”	To understand the complexities of defining wide-area boundaries, the drafting team reviewed the extreme weather events mentioned within FERC Order No. 896, as well as the comments received during the FERC Order proceeding. In addition, NERC consulted with climate data subject matter experts who evaluated publicly available modeled data in the last forty-three years (1980-2022) and more than eighty years of projected hourly meteorology data from PNNL. The drafting team struck a balance between a geographical approach and an electrical approach by dividing North America into zones that are likely to experience similar weather conditions but also consider practical

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	concerns with coordination such as the boundaries of Interconnections and Balancing Authority Areas. These zones are depicted in Attachment 1 of TPL-008-1, and PCs will be required to coordinate with all PCs in the zone(s) they belong to.
P58. "[W]e…direct NERC to develop benchmark events for extreme heat and cold weather events through the Reliability Standards development process. We agree … that the development of adequate benchmark events is critical and should be committed to the subject matter experts on the standards drafting team. "	The drafting team considered various approaches to developing benchmark temperature events. With assistance from NERC's subject matter expert consultants, the drafting team identified the key components of temperature events that are necessary for the event to constitute an adequate benchmark temperature event. These components were included in Requirement R2. Specifically, based on the available data, the drafting team determined that extreme benchmark temperature events must: 1) consider no less than forty years of historical temperature data, 2) include recent temperature data due to ongoing climate changes, and 3) represent one of the twenty worst extreme temperature conditions over the forty year period based on a 3-day rolling average of daily maximum (heat) or minimum (cold) temperatures. The ERO will maintain a library of benchmark temperature events that meet these requirements. Responsible entities will be able to review and select benchmark temperature events from this library to assist with the development of benchmark planning cases. However, responsible entities may also identify benchmark temperature events via their own processes provided that the event meets the criteria of Requirement R2 and is agreed upon by all PCs within the zone. In addition to describing the minimum requirements of a benchmark temperature event, Requirement R2 obligates PCs within the same zone to coordinate in selecting one common extreme heat benchmark temperature event and one common extreme cold benchmark

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	temperature event for completing the Extreme Temperature Assessment. This coordination is required to ensure the benchmark temperature event is reflected over a wide-area.
P60. "[W]e…direct NERC to designate the type(s) of entities responsible for developing benchmark planning cases and conducting wide-area studies under the new or modified Reliability Standard…benchmark planning cases should be developed by registered entities such as large planning coordinators, or groups of planning coordinators, with the capability of planning on a regional scope." **P61**: "We believe the designated responsible entities should have certain characteristics, including having a wide-area view of the Bulk-Power System and the ability to conduct long-term planning studies across a wide geographic area. The responsible entities should also have the planning tools, expertise, processes, and procedures to develop benchmark planning cases and analyze extreme weather events in the long-term planning horizon." **P62**: "To comply with this directive, NERC may designate the tasks of developing benchmark planning cases and conducting wide-area studies to an existing functional entity or a group of functional entities (e.g., a group of planning coordinators). NERC may also establish a new functional entity registration to undertake these tasks. In the petition accompanying the proposed Reliability Standard NERC should explain how the applicable registered entity or entities meet the objectives outlined above."	The drafting team discussed that the Transmission Planner (TP) and/or Planning Coordinator (PC) would be the responsible entities to address TPL-008-1 Requirements. Requirement R1 obligates both the TP and PC to identify their individual and joint responsibilities. Requirement R3 obligates each PC to implement a process for coordinating the development of benchmark planning cases and sensitivity cases, using the selected benchmark temperature events identified in Requirement R2. This process must be implemented in coordination with all PCs within the same zone. Requirement R4 obligates each responsible entity, as identified in Requirement R1, to use the coordination process developed in accordance with Requirement R3 and data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, to develop benchmark planning cases and sensitivity cases. The identification of joint and individual responsibilities in Requirement R1 provides a measure of flexibility for PCs and TPs to agree on a distribution of responsibilities. Thus, while PCs are responsible for implementing the case development process in Requirement R3, TPs may be responsible for providing data and completing the case development according to that process. The development of benchmark planning cases and sensitivity cases will require cooperation amongst many PCs and TPs. By requiring participation from all entities within a zone, TPL-008-1 ensures that the group of functional entities have a sufficient wide-area view of the Bulk Power

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	System and the planning tools, expertise, processes and procedures necessary for developing benchmark planning cases and sensitivity cases.
P72. "[W]e direct NERC to require functional entities to share with the entities responsible for developing benchmark planning cases and conducting wide-area studies the system information necessary to develop benchmark planning cases and conduct wide-area studies. Further, responsible entities must share the study results with affected transmission operators, transmission owners, generator owners, and other functional entities with a reliability need for the studies."	The directive is addressed in proposed TPL-008-1 in Requirements R3, R4 and R11. Requirement R3 obligates each PC to implement a process for coordinating the development of benchmark planning cases, using the selected benchmark temperature events identified in Requirement R2, among all Planning Coordinators within a zone. Requirement R4 obligates each responsible entity, as identified in Requirement R1, to use the coordination process implemented in accordance with Requirement R3 and data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, to develop benchmark planning cases and sensitivity cases. Requirement R11 obligates each responsible entity, as identified in Requirement R1, to provide its Extreme Temperature Assessment results within 60 calendar days of a request to any functional entity that has a reliability related need and submits a written request for the information.
P73. "Because in this final rule we direct NERC to determine the responsible entities that will be developing benchmark planning cases and conducting wide-area studies, it is possible that the selected responsible entities under the new or modified Reliability Standard will not be able to request and receive needed data pursuant to MOD-032-1, absent modification to that Standard."	The drafting team discussed and determined that data needed to address the Extreme Temperature Assessment would still be appropriate to receive through MOD-032. MOD-032 ensures an adequate means of data collection for transmission planning and requires applicable registered entities to provide steady-state, dynamic, and short circuit modeling data to their Transmission Planner(s) and Planning Coordinator(s). As outlined in Requirement R1 and Attachment 1 of MOD-032, MOD-032 allows various data collection such as in-service status and capability associated with demand, generation, and transmission associated with various case types, scenarios, system operating states, or conditions for the long-term planning horizon. MOD-032 also requires applicable registered entities to

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	provide "other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes" for each of the three types of data required. Because the drafting team determined the responsible entities that will be developing benchmark planning cases are limited to Planning Coordinators and Transmission Planners, they will be able to request and receive needed data pursuant to MOD-032. Thus, the drafting team believes that there is no need to update MOD-032.
P76: "[W]e…direct NERC to address the requirement for wide-area coordination through the standards development process, giving due consideration to relevant factors identified by commenters in this proceeding."	The drafting team reviewed all the extreme weather events mentioned within the FERC Order 896. For this project, the drafting team focused the scope of Requirement R3 to require each PC to implement a process for coordinating the development of benchmark planning cases and sensitivity cases, using the selected benchmark temperature events identified in Requirement R2, among all PCs within a zone.
P77. "[W]e direct NERC to require in the new or modified Reliability Standard that responsible entities share the results of their wide-area studies with other registered entities such as transmission operators, transmission owners, and generator owners that have a reliability related need for the studies."	This directive is addressed in proposed TPL-008-1 Requirement R11. Requirement R11 obligates each responsible entity to provide the wide-area study results within 60 calendar days of a request to any functional entity that has a reliability related need and has submitted a written request for the information.
P88. "[W]e direct NERC to require under the new or revised Reliability Standard the study of concurrent/correlated generator and transmission outages due to extreme heat and cold events in benchmark events as described in more detail below." **P92.** "These contingencies (i.e., correlated/concurrent, temperature sensitive outages, and derates) shall be identified based on similar contingencies that occurred in recent extreme weather events or expected to occur in future forecasted events."	This directive is addressed in proposed TPL-008-1 through Requirements R3 and R4. Per Requirement R3 Part 3.2, the benchmark planning case development process must include forecasted seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers within the zone. Per Requirement R4, the data necessary to build the benchmark planning cases must be provided via MOD-032, supplemented by other sources as needed. Any concurrent/correlated generator and transmission outages due to extreme heat and cold events in benchmark temperature events should be reflected in the model data and thus represented in the initial conditions of the benchmark planning cases.
P111. "[W]e direct NERC to require in the proposed new or modified Reliability Standard that responsible entities perform both steady state and	This directive is addressed in proposed TPL-008-1 through Requirement R8 and Table 1.

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transient stability (dynamic) analyses in the extreme heat and cold weather planning studies. In a steady state analysis, the system components are modeled as either in-service or out-of-service and the result is a single point-in-time snapshot of the system in a state of operating equilibrium. A transient stability (dynamic) analysis examines the system from the start to the end of a disturbance to determine if the system regains a state of operating equilibrium. Performing both analyses ensures that the system has been thoroughly assessed for instability, uncontrolled separation, and cascading failures in both the steady state and the transient stability realms." (internal citations omitted).	Requirement R8 requires the responsible entity to complete both steady state and transient stability analyses and document the assumptions and results. Table 1 obligates each responsible entity to perform both steady state and transient stability analyses and compare the study results against steady state and stability performance requirements.
P112. "[W]e direct NERC to define a set of contingencies that responsible entities will be required to consider when conducting wide-area studies of extreme heat and cold weather events under the new or modified Reliability Standard. We believe that it is necessary to establish a set of common contingencies for all responsible entities to analyze. Required contingencies, such as those listed in Table 1 of Reliability Standard TPL-001-5.1 (i.e., category P1 through P7), establish common planning events that set the starting point for transmission system planning assessments. Requiring the study of predefined contingencies will ensure a level of uniformity across planning regions—a feature that will be necessary in the new or revised Reliability Standard considering that extreme heat and cold weather events often exceed the geographic boundaries of most existing planning footprints." **P113:** "[T]he contingencies required in the new or revised Reliability Standards should reflect the complexities of transmission system planning studies for extreme heat and cold weather events."	This directive is addressed in proposed TPL-008-1 through Requirement R7 and Table 1. Requirement R7 requires the responsible entity to identify Contingencies for completing the Extreme Temperature Assessment. The rationale, for those Contingencies selected for evaluation, shall be available as supporting information. The Contingencies for each category in Table 1 of TPL-008-1 correspond to the well-established Contingencies defined in Reliability Standard TPL-001-5.1. Utilizing these well-established Contingencies will ensure a level of uniformity across planning regions.
P116. "[W]e direct NERC to require in the new or modified Reliability Standard that responsible entities model demand load response in their extreme weather event planning area. As indicated by several commenters, because demand load response is generally a mitigating	TPL-008-1 Requirement R4 meets this directive by requiring each responsible entity to develop benchmark planning cases using data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed.

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action that involves reducing distribution load during periods of stress to stabilize the Bulk-Power System, its effect during an extreme weather event should be modeled." **P 117:** "[I]n addressing this directive, we expect NERC to determine whether responsible entities will need to take additional steps to ensure that the impacts of demand load response are accurately modeled in extreme weather studies, such as by analyzing demand load response as a sensitivity, as is currently the case under Reliability Standard TPL-001-5.1."	Specifically, Attachment 1 of MOD-032 requires information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes.
P124. "[W]e direct NERC to require the use of sensitivity cases to demonstrate the impact of changes to the assumptions used in the benchmark planning case. Sensitivity analyses help a transmission planner to determine if the results of the base case are sensitive to changes in the inputs. The use of sensitivity analyses is particularly necessary when studying extreme heat and cold events because some of the assumptions made when developing a base case may change if temperatures change – for example, during extreme cold events, load may increase as temperatures decrease, while a decrease in temperature may result in a decrease in generation. We… direct NERC to define during the Reliability Standard development process a baseline set of sensitivities for the new or modified Reliability Standard. While we do not require the inclusion of any specific sensitivity in this final rule, NERC should consider including conditions that vary with temperature such as load, generation, and system transfers." **P125**. "We do not agree ... that responsible entities alone should determine the sensitivity cases that must be considered in the responsible entity's study. … We…believe that responsible entities should be free to study additional sensitivities relevant to their planning areas…cooperation will be necessary between responsible entities conducting extreme heat and extreme cold weather studies and other registered entities within their	This directive is addressed in proposed TPL-008-1 in Requirement R3, which requires all PCs within the same zone to coordinate to implement a process for developing benchmark planning cases and sensitivity cases. Sensitivity cases are used to demonstrate the impact of changes to the basic assumptions used in the benchmark planning cases. Per Requirement R3 Part 3.4, PCs must include provisions in the case development process to identify changes to generation, real and reactive forecasted Load, and/or transfers to develop sensitivity cases. The identification of changes for sensitivity cases within the coordinated process of Requirement R3 addresses the directive that precludes responsible entities from determining sensitivities alone. However, nothing prevents responsible entities from conducting additional sensitivity studies they find relevant to their planning areas.

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extreme weather study footprints to ensure the selection of appropriate sensitivities."	
P134. "[W]e directs NERC to require in the new or modified Reliability Standard the use of planning methods that ensure adequate consideration of the broad characteristics of extreme heat and cold weather conditions. We further direct NERC to determine during the standard development process whether probabilistic elements can be incorporated into the new or modified Reliability Standard and implemented presently by responsible entities. If NERC identifies probabilistic elements which responsible entities can feasibly implement and that would improve upon existing planning practices, we expect the inclusion of those methods in the proposed Reliability Standard." **P138.** "[W]e direct NERC to identify during the standard development process any probabilistic planning methods that would improve upon existing planning practices, but that NERC deems infeasible to include in the proposed Reliability Standard at this time. If any such methods are identified, NERC shall describe in its petition for approval of the proposed Reliability Standard the barriers preventing the implementation of those probabilistic elements. We intend to use this information to determine whether and what next steps may be warranted to facilitate the use of probabilistic methods in transmission system planning practices."	The drafting team discussed probabilistic elements and determined while probabilistic analysis would be a good step forward, it would be better suited for the future as the methodology, process, and tools mature. Probabilistic assessment of generation and transmission facilities for the benchmark planning cases was discussed during the process of drafting the TPL-008-1 standard. However, based on the actual extreme heat and extreme cold events that have occurred, outages for generation and transmission facilities were unique for each of these events. Thus, it was challenging to draw correlation for the outages that occurred for different extreme heat and cold events for different regions and different timeframes. In addition, the data, available from these events, was limited to perform an adequate probabilistic assessment. Due to these reasons, the drafting team has decided not to pursue any probabilistic assessment for the current TPL-008-1 standard. This, however, does not preclude future development of probabilistic assessment when having additional data, as well as mature methodology, process and tools that can provide meaningful probabilistic assessment for generation and transmission outages under extreme temperature conditions.
P152. "[W]e direct NERC to require in the new or modified Reliability Standard the development of extreme weather corrective action plans for specified instances when performance standards are not met. In addition, as explained below, we direct NERC to develop certain processes to facilitate interaction and coordination with applicable regulatory authorities or governing bodies responsible for retail electric service as appropriate in implementing a corrective action plan."	The directive is addressed in the proposed TPL-008-1 Requirement R9. When the benchmark planning case study results indicate the System is unable to meet performance requirements for P0 and P1 Contingencies, Corrective Action Plans (CAPs) must be developed. Additionally, in accordance with Requirement R9 Part 9.1, responsible entities shall make their CAP available to, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.

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P155: "[T]he Commission is not directing any specific result or content of the corrective action plan."	
P157. "[W]e direct NERC to require in the new or modified Reliability Standard the development of corrective action plans that include mitigation for specified instances where performance requirements for extreme heat and cold events are not met—i.e., when certain studies conducted under the Standard show that an extreme heat or cold event would result in cascading outages, uncontrolled separation, or instability." **P158**: "[W]e give NERC in this final rule the flexibility to specify the circumstances that require the development of a corrective action plan."	The directive is addressed in the proposed TPL-008-1 Requirement R9. When the benchmark planning case study results indicate the system is unable to meet performance requirements for P0 and P1 Contingencies, Corrective Action Plans must be developed.
P165. "[w]e direct NERC to require in the new or modified Reliability Standard that responsible entities share their corrective action plans with, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues."	The directive is addressed in the proposed TPL-008-1 Requirement R9. Requirement R9.1 requires the responsible entities to make their CAP available and solicit feedback from applicable regulatory authorities or governing bodies responsible for retail electric service issues.
P167. "Further, because an important goal of transmission planning is to avoid load shed, any responsible entity that includes non-consequential load loss in its corrective action plan should also identify and share with applicable regulatory authorities or governing bodies responsible for retail electric service alternative corrective actions that would, if approved and implemented, avoid the use of load shedding."	This directive is addressed in proposed TPL-008-1 Requirement R9. As stipulated in Requirement R9 Part 9.2, when Non-Consequential Load Loss is utilized as an element of a CAP for a Table 1 P1 Contingency, the responsible entity must document the alternative(s) considered, and notify the applicable regulatory authorities or governing bodies responsible for retail electric service issues.
P188. "[W]e direct NERC to submit a new or modified Reliability Standard within 18 months of the date of publication of this final rule in the Federal Register. Further, we direct NERC to propose an implementation timeline for the new or modified Reliability Standard, with implementation beginning no later than 12 months after the effective date of a Commission order approving the proposed Reliability Standard."	The directive is addressed with the publication of TPL-008-1 and will be filed with the regulatory government no later than December 23, 2024, within 18 months of the date Order No. 896 was published in the *Federal Register*. The implementation plan addresses Requirement R1 becoming effective 12 months from the effective date of the Commission order approving the

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	TPL-008-1. In addition, phased-in approaches have been provided for other Requirements needing additional time. See the TPL-008-1 Implementation Plan.
P193. "[W]e direct NERC to establish an implementation timeline for the proposed Reliability Standard. In complying with this directive, NERC will have discretion to develop a phased-in implementation timeline for the different requirements of the proposed Reliability Standard (i.e., developing benchmark cases, conducting studies, developing corrective action plans). However, this phased-in implementation must begin within 12 months of the effective date of a Commission order approving the proposed Reliability Standard and must include a clear deadline for implementation of all requirements."	The implementation plan addresses Requirement R1 becoming effective 12 months from the effective date of the Commission order approving the TPL-008-1. In addition, phased-in approaches have been provided for other Requirements needing additional time. See the TPL-008-1 Implementation Plan.

DRAFT ERO Enterprise Process for TPL-008-1 Benchmark Weather Event Development and Maintenance

Standards Development and Engineering Process Document
October 2024

Background

This Electric Reliability Organization (ERO) Enterprise Process for TPL-008-1[1] Benchmark Weather Event Development and Maintenance addresses how ERO Enterprise staff will develop and maintain a library of benchmark weather events (herein as the Weather Event Library) to be used by Planning Coordinators and Transmission Planners for TPL-008-1 studies. Per Requirement R3 of TPL-008-1 and consistent with directives outlined in FERC Order No. 896[2], Planning Coordinators and Transmission Planners will have benchmark temperature events available via the Weather Event Library to select from when developing their benchmark planning cases.

Purpose

The purpose of this process document is to formalize a repeatable approach to develop and maintain the Weather Event Library. While both the TPL-008-1 study requirements and this process are in the initial stages of development, it is essential that industry is informed of this process and how it will be designed and implemented following the completion of NERC Project 2023-07. This process document outlines an initial set of process objectives and approach but is not considered to be complete at this time. This document will be revised as needed throughout the development of NERC Project 2023-07.

Document Maintenance

NERC will maintain this document to assure it is consistent with acceptable practices and publicly available. This document will be reviewed as it is implemented. Updates will be made by NERC Standards Development and Engineering, as needed, to reflect lessons learned as the process matures. Any substantive changes to this process, supplemental/attached criteria, or other guidance to be used by NERC in developing additional benchmark events, archiving/removing benchmark events, or other modifications to the Weather Event Library, will be reviewed in consultation with NERC Legal, NERC Compliance Assurance, Zoneal Entity staff, and FERC. Approved substantive revisions to this document will be detailed in the Appendix, broadly communicated to industry, and included as part of informational filings to FERC.

[1] *Link pending final approval of TPL-008-1*
[2] FERC Docket No. RM22-10-000; Order No. 896; https://www.ferc.gov/media/e-1-rm22-10-000; June 15, 2023

Definitions

Refer to the NERC Glossary of Terms[3] for the below capitalized terms used in this process.

- Affected Zoneal Entity (ARE)
- Compliance Enforcement Authority (CEA)
- Coordinated Oversight
- Extreme Temperature Assessment (ETA)
- Lead Zoneal Entity (LRE)
- Multi-Zone Registered Entity (MRRE)

Process Overview

The following is a five-year iterative process coinciding with Planning Coordinator and Transmission Planner implementation of TPL-008-1. As TPL-008-1 and associated benchmark event(s) will be submitted to FERC in December 2024, the first iteration of this process will cover five years (2025—2029).

- December 2024
  - Weather Event Library developed and ready to go live for industry.
  - Benchmark Events, for the first five-years required per the TPL-008-1 Reliability Standard, completed and uploaded to the Weather Event Library.
- Year One (2025):
  - ERO to provide Weather Event Library training.
  - ERO to engage with industry subject matter experts (SMEs), Planning Coordinators, research labs, and trade organizations, and NERC technical committees on additional and updated criteria for developing benchmark events.
- Year Two (2026):
  - ERO to initiate review of benchmark event criteria, identify any changes needed, and incorporate feedback from year one.
  - ERO to deliver a webinar on updated criteria for developing benchmark events.
- Year Three (2027):
  - ERO to develop new benchmark events[4] based on updated criteria in year two.
  - ERO to update the Weather Event Library with updated benchmark events.
- Year Four (2028):
  - ERO to draft informational filing with FERC.

[3] NERC Glossary of Terms: Glossary_of_Terms.pdf (nerc.com)
[4] Note: This is for the second iteration of benchmark events being developed.

  - ERO will engage with industry subject matter experts (SMEs), Planning Coordinators, research labs, and trade organizations, and NERC technical committees on additional information needed.

- Year Five (2029):
  - ERO to File informational filing with FERC.
  - ERO to conduct review of this process and make necessary revisions based on lessons-learned and feedback (e.g., CMEP feedback loops, FERC, SMEs)
  - ERO to provide training on benchmark event process and changes to the Weather Event Library.

Year 1
- Deliver Weather Event Library Training
- Develop training and guidance for planning case development

Year 2
- Review and modify benchmark event criteria
- Informational session on updated criteria

Year 3
- Update library with new/removed benchmark events

Year4
- ERO to draft Informational filing to FERC for any change to criteria and modifications to Weather Events Library

Year 5
- Informational filing to FERC for any change to criteria and modifications to Weather Events Library
- Review process and revise based on lessons learned and other feedback loops
- Update Weather Event Library training

Criteria in Attachment B

Scoping

While the development of the extreme weather event library was intended to be comprehensive, it was not exhaustive. Instead, this initial assessment is a part of a multi-year effort by NERC and industry to develop a robust, North American weather dataset and detailed process for extreme weather events. In the interim, this library of extreme heat and cold events has notable considerations:

- Only extreme heat and cold temperature events were evaluated. The analysis did not assess other weather events such as hydrologic droughts, wind and solar droughts, wildfires, hurricanes, or other extreme weather events that could jeopardize grid reliability.
- Only historical meteorological data was considered. The analysis did not incorporate climate projections or future weather patterns.
- The analysis identified extreme events over a 43-year historical record and did not give higher priority to recent events
- The study is limited in identifying extreme events, not validating or explaining meteorological drivers of that event
- The analysis relied on historical reanalysis and *modeled* weather data rather than historical observed data for the United States (A smaller observed dataset was used for Canada).

Data Sources

A Pacific Northwest National Laboratory (PNNL) weather dataset[5] used in this study consists of 43 years (1980-2022) of historical hourly meteorology and roughly 80 years (2020-2099) of projected hourly meteorology. Hourly observations were dynamically downscaled from historical reanalysis of ERA5 data into higher temporal and spatial resolutions using the Weather Research and Forecasting Model (WRF). The model resolution consisted of 12km^2 areas that were spatially-averaged by county and then population-weighted to 54 Balancing Authorities (BAs) in the conterminous United States. The variables included in the final BA weather data are listed in Table 1. While additional parameters like humidity, solar irradiance, and wind speed are available in the dataset, the identification of extreme weather events in this study was solely determined by the temperature value.

Table 1: Weather Variables in PNNL Dataset

Variable	Name	Description	Units
Time	Time_UTC	Hour in Coordinated Universal Time	-
Temperature	T2	2-m temperature	K
Specific Humidity	Q2	2-m water vapor mixing ratio	kg kg^{-1}
Shortwave Radiation	SWDOWN	Downwelling shortwave radiative flux at the surface	W m^{-2}
Longwave Radiation	GLW	Downwelling longwave radiative flux at the surface	W m^{-2}
Wind Speed	WSPD	10-m wind speed (derived from U10 and V10)	m s^{-1}

[5] Burleyson, C., Thurber, T., & Vernon, C. (2023). Projections of Hourly Meteorology by Balancing Authority Based on the IM3/HyperFACETS Thermodynamic Global Warming (TGW) Simulations (v1.0.0) [Data set]. MSD-LIVE Data Repository. https://doi.org/10.57931/1960530

The PNNL dataset and contributing model were chosen for this study due to the consistency, breadth and granularity of the weather data. The availability of weather data at the BA-level coincides with topology standards in power-system coordination in North America. Temperature observation methods can differ zoneally, so a standardized weather model, such as one in the PNNL dataset, offers unparallelled data consistency across large geographical areas.

Topology

The zone topology is a function of balancing authority jurisdiction and general knowledge of zoneal weather patterns. The goal of the topology was to split the North American System into several distinct zones that have similar electric power system properties (i.e. balancing authority and interconnections) and similar weather or climatological patterns. Balancing authorities with large areas of jurisdiction, exclusively ISOs and RTOs, are assigned their own weather zone. In geographical areas comprised of multiple balancing authorities, generalized weather zones are created to best represent zoneal weather patterns.

Table 2: Balancing Authority to Weather Zone Mappings

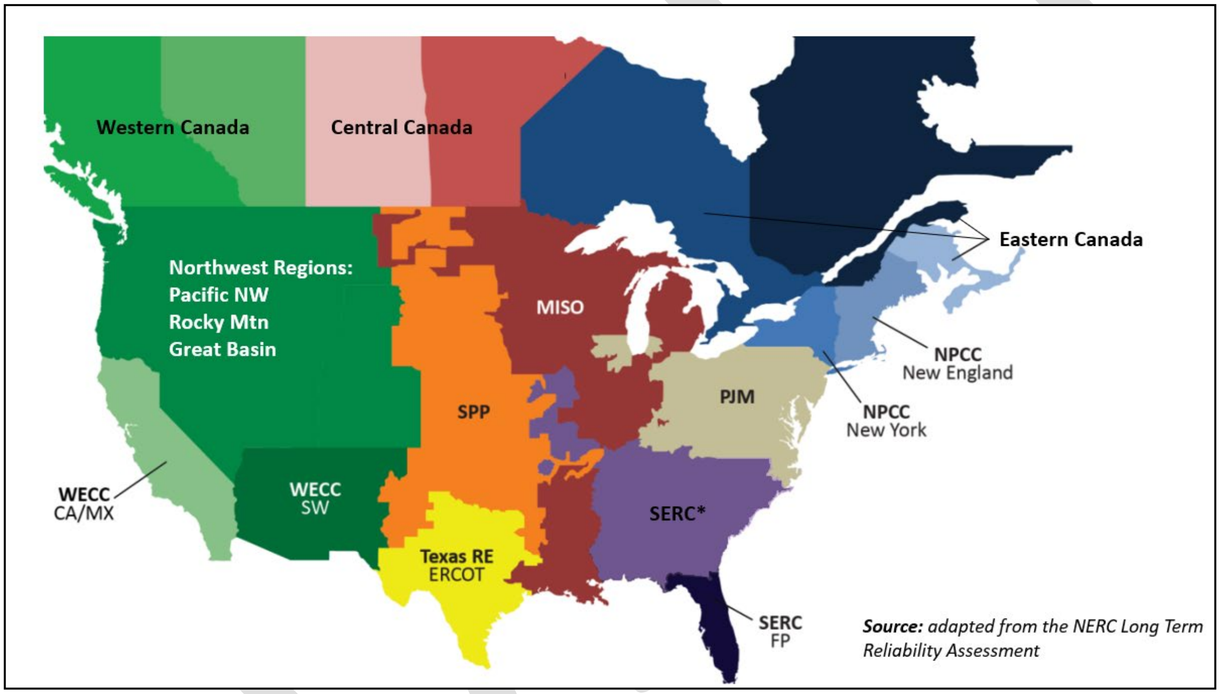
Zone	Balancing Authorities
Midwest	MISO
New England	ISONE
Central US	SPP
Texas	ERCOT
New York	NYISO
Central Atlantic	PJM
California	5 balancing authorities
Pacific Northwest	10 balancing authorities
Rocky Mountain	3 balancing authorities
Great Basin	4 balancing authorities
Southwest	6 balancing authorities
Southeast	7 balancing authorities
Florida	9 balancing authorities

In addition to the 13 weather zones representing the United States, three weather zones were developed to represent Eastern, Central, and Western Canada. The PNNL weather dataset does not contain data for Canada, so this study compiled observed weather data from weather stations in the lower Canadian Provinces. The sixteen weather zones best represent the area of study and complement the granularity of available data. A graphical representation of the final weather zones is shown in Figure 1.

Table 3: Canadian Weather Stations to Weather Zone Mappings

Weather Zones	Province	Weather Stations
Eastern Canada	Ontario	1 weather station
	Quebec	3 weather stations
	New Brunswick	1 weather station
	Nova Scotia	1 weather station
Central Canada	Saskatchewan	2 weather stations
	Manitoba	1 weather station
Western Canada	British Columbia	2 weather stations
	Alberta	2 weather stations

Figure 1: North American Weather Zones for Extreme Weather Events



Event Selection Process

Extreme weather events are defined in this study as extremely hot or cold multi-day events spanning across multiple weather zones. The process to select these extreme events used temperature as the sole defining variable, with emphasis placed on date ranges where multiple weather zones were experiencing historically hot or cold temperatures.

Aggregating balancing authority data to geographical weather zones

Following the topology detailed above, the hourly temperature observations from either the PNNL weather dataset or Canadian weather stations are assigned to weather zones. For each balancing area in the United States, the PNNL data is aggregated from a county-level basis up to the balancing authority based on the population in each county. The balancing authority temperature aggregation was therefore provided in the PNNL dataset.

Additional aggregations were required to develop an average minimum, average, and maximum temperature for zones with multiple balancing authorities in the Northwest, Southwest, and Southeast. In these weather zones, the hourly temperature of each balancing authority was weighted by the 2022 peak load value reported in the EIA Form-861 database. For the Canadian zones, weather station temperature observations were assigned to the nearest population center and weighted by 2021 Census population.

Calculating Three-Day Rolling Average Min/Max Temperatures

Rather than isolating single hours of extreme weather, the rolling 3-day average of minimum and maximum daily temperatures are chosen to represent prolonged periods of extreme weather. The three-day averaging period is centered on every day in the data set (January 1, 1980, to December 31, 2022) and identifies the average minimum and maximum temperature from the day before, day of, and day after. The output of this process develops a dataset of multi-day minimum and maximum temperatures to filter out individual days of extreme heat or cold under the assumption that the power system is more challenged by sustained periods of extreme heat or cold due to cumulative effects on increasing demand and generator outages.

Selecting and Ranking Extreme Weather Events by Severity

Once 3-day average temperatures were calculated for every day, the forty coldest minimum values and forty warmest maximum values were isolated and ranked for each zone, with rank 1 illustrating the most extreme event. To avoid overlap of events within the same period, any ranked weather events within one week of another would be removed in favor of the most extreme event. For example, if a zone's seventh- and tenth-most extreme event occur within a 7-day period, only the day with the seventh-most extreme event would remain in the event database. As a result, some zones may have a discontinuous ranked list given the removal of "duplicate" events.

A similar one-week overlap method was developed to group contemporaneous extreme weather events amongst weather zones. First, all event dates were expanded to have a one-week "overlap period" centered on each date. Then, beginning with the earliest event date, all events that share at least one day of their overlap periods with the selected event date's overlap period will be grouped together. The final event date range will take the earliest and latest dates of all grouped event overlap periods.

The design of the distinct event date ranges encourages multiple weather zones to share extreme weather events over the course of a one- to two-week event period. To graphically represent the shared extreme events, all event ranges are listed with the affected zones' ranks in west-to-east order. A final shortlist of extreme weather events was developed across all zones. This list included the top one and two most extreme events, done separately for heat and cold periods. Any event that included at least three zones experience a top five event simultaneous was also included. For example, if PJM, NYISO, and ISONE all experienced a top five extreme event, but it was not a top one or two event for any zone in isolation, the event was included in the final shortlist.

Results

The result tables show the filtered list of event date ranges with the event ranks for each affected zone; a lower rank represents a more extreme event and is shaded darker.

Cold Events

The cold events shown in Table 4 demonstrate more concentrated events among nearby zones, with the most extreme temperature event occurring December 20th to December 29th, 1983. The event uniquely spanned across the conterminous United States and yielded top ten coldest 3-day average minimum temperatures in 10 different weather zones.

Under these results, the following cold events are recommended for the NERC library:

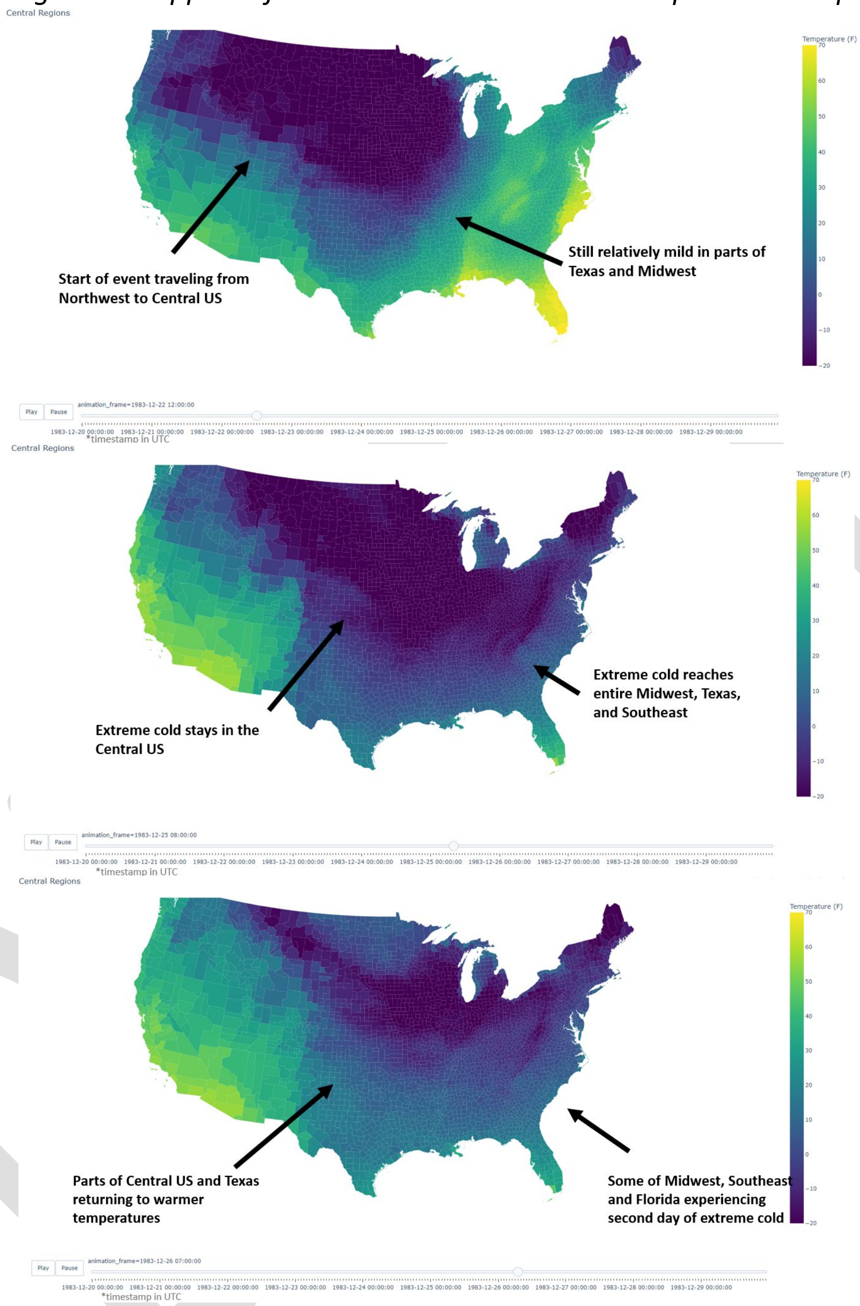
- 12/17/1990 – 1/2/1991 for the Western U.S. and Canada
  - 12/21 for Pacific NW
  - 12/22 for Rocky Mountain, Great Basin, California
  - 12/23 for Southwest
  - 12/29 for Western Canada
- 12/19/1989 – 12/27/1989 for Central and Southeast U.S. and Canada
  - 12/23 for Central Canada
  - 12/24 for Central US
  - 12/25 for Texas, Midwest, Southeast
  - 12/26 for Florida
- 1/13/1994 – 1/29/1994 for the Northeast U.S. and Canada
  - 1/16 for New England, Eastern Canada
  - 1/20 for Central Atlantic, New York

Table 4: Shortlist of Cold Events

Start Date	End Date	Western Canada	Pacific NW	Rocky Mountain	Great Basin	California	Southwest	Texas	Central Canada	Central US	Midwest	Southeast	Florida	Central Atlantic	New York	New England	Eastern Canada
1/1/1981	1/7/1981														10	1	1
1/9/1981	1/16/1981											12	4	10	2	12	11
1/15/1982	1/21/1982													9	7	6	2
12/20/1983	12/29/1983	9	3	4				3	6	2	4	2	3	3			
1/16/1984	1/24/1984			7						13	3	15		2	3		16
1/17/1985	1/25/1985							11		10	10	1	1	4			
1/29/1985	2/7/1985		15	2	3	12	6	9		7	9						
1/29/1989	2/9/1989	1	2	3	2	2			16	12							
12/19/1989	12/27/1989							1		1	5	3	2	5			15
12/17/1990	1/2/1991	8	1	1	1	1	1			16							
1/13/1994	1/29/1994										2	7		1	1	3	4
1/28/1996	2/8/1996	15	10	9				5	1	3	1	5		7	18		
1/23/1997	1/29/1997	2							7								
1/11/2004	1/18/2004														9	2	6
1/30/2011	2/12/2011			5			2	4		11	13						
1/10/2013	1/17/2013				4	5	3										
2/10/2021	2/19/2021			12				2	2	4	15						

It is important to note that these weather events do not affect all zones simultaneously, but instead move across the continent in predictable patterns. This has important implications for power system operations and reliability as load and generator availability may be affected in different zones in different times. An example of this is from the 1983 event shown geographically in Figure 2. In this example, the worst case does not occur at the same time in each zone and ideally multiple time periods should be assessed by the planning coordinators.

Figure 2: Snippets of Animated Weather Event Temperature Map



Heat Events

The heat events shown in Table 5 are more numerous and disparate from one another. In other words, while extreme cold events tend to affect large geographies simultaneously, heat events can be more localized. The unconcentrated nature of heat events makes selecting the most extreme event more ambiguous.

Under these results, the following heat events are recommended for the NERC library:

- 7/13/2006 – 7/26/2006 for the Western U.S. and Canada
  - 7/16 for Rocky Mountain, Great Basin
  - 7/22 for Western Canada, Pacific NW
  - 7/23 for California, Southwest
- 6/21/2012 – 7/9/2012 for Central and Southeast U.S. and Canada
  - 6/26 for Texas
  - 6/28 for Central Canada, Central US
  - 6/30 for Southeast, Florida
  - 7/5 for Midwest
- 7/16/2021 – 7/25/2021 for the Northeast U.S. and Canada
  - 7/21 for Central Atlantic, Eastern Canada
  - 7/22 for New York, New England

Table 5: Shortlist of Heat Events

Start Date	End Date	Western Canada	Pacific NW	Rocky Mountain	Great Basin	California	Southwest	Texas	Central Canada	Central US	Midwest	Southeast	Florida	Central Atlantic	New York	New England	Eastern Canada
6/24/1980	7/2/1980						13	2									
8/23/1984	8/29/1984								2								
7/3/1988	7/11/1988										13			13			1
8/11/1988	8/19/1988										1			4	7	17	
6/23/1990	6/29/1990						2										
7/16/1991	7/24/1991													16	9	1	8
7/25/1995	7/31/1995			10			1	10									
6/15/1998	6/21/1998												1				
6/28/1998	7/4/1998												2				
7/9/1998	7/22/1998			2	3			14									
7/2/1999	7/8/1999													2	1	6	
9/1/2000	9/7/2000							1									
8/5/2001	8/11/2001													8	3	5	2
6/23/2002	7/6/2002	4		7										18	13	2	3
7/8/2002	7/16/2002	5			1												
7/8/2005	7/26/2005			1	8		8			13							16
7/13/2006	7/26/2006	2	6	5		3				3	9						
8/13/2007	8/19/2007											2					
7/16/2011	7/25/2011									9	14			6	2	3	4
7/30/2011	8/6/2011							5		2		4					
6/21/2012	7/9/2012			3				9		5	2	1		1			
7/29/2012	8/5/2012									1	8						
8/6/2018	8/14/2018	3	18						1								
9/3/2020	9/9/2020					1											
6/25/2021	7/2/2021	1	1												16	21	
7/8/2021	7/14/2021				2												
8/10/2021	8/18/2021	8	2						5								

Recommendations

The results of this study should inform planning coordinators of potential dates of when to study power system conditions under extreme weather scenarios. While the final selection of event date ranges aligns with historical records of extreme weather, a few recommendations and considerations should be made before proceeding with this study's results.

- Planning coordinators should assess the entire list of distinct events shown and determine which events were the most extreme for their jurisdiction along with neighboring areas
- Modelled temperature data provides widespread consistency of weather data across many years and many zones. Observed temperature data can recognizably vary from modelled values due to the variety of observation methods at individual weather stations. The temperatures derived from the PNNL dataset for the extreme weather event selection can be provided, but actual temperature values used in planning scenarios may need to be derived from observed weather records for local consistency.

- While temperature is a strong indicator of extreme weather events, it is not the only indicator available in historical weather data sets. The inclusion of other weather variables such as humidity and wind speed could further quantify the severity of extreme weather events.
- Care should be taken when developing wind, solar, and generator outage assumptions in the planning cases, using meteorological information to dispatch.
- Exceptions need to be accounted for – including HVDC and switchable units.

Attachment B: Criteria used to develop the benchmark events

Criteria

Criteria for benchmark events to be drafted.

TPL-008-1 ERO Enterprise Benchmark Weather Event Development and Maintenance Process Document Version History			
Version	**Date**	**Owner**	**Change tracking**
1	TBD	Standards Staff	Initial Version

TPL-008-1 Benchmark Temperature Events

November 2024

The below provides extreme heat and extreme cold benchmark temperature event data per the zones identified in Attachment 1 of the TPL-008-1 Standard. Should entities not agree with the data provided below, you are welcome to coordinate with all Planning Coordinators within your zone to developing one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event per Requirement R2.

Benchmark Events			
Zone	**Daily Data**	**Top 40 Hottest/Coldest 3-Day Average**	**Hourly Data Selected Events**
Eastern Interconnection			
Canada Central	Daily	Top 40	*N/A*
Florida	Daily	Top 40	Hourly
ISO-NE	Daily	Top 40	Hourly
Maritimes	Daily	Top 40	*N/A*
MISO North	Daily	Top 40	Hourly
MISO South	Daily	Top 40	Hourly
NYISO	Daily	Top 40	Hourly
Ontario	Daily	Top 40	*N/A*
PJM	Daily	Top 40	Hourly
SERC	Daily	Top 40	Hourly
SPP North	Daily	Top 40	Hourly
SPP South	Daily	Top 40	Hourly
Western Interconnection			
California/Mexico	Daily	Top 40	Hourly
Great Basin	Daily	Top 40	Hourly
Rocky Mtn	Daily	Top 40	Hourly
Pacific NW	Daily	Top 40	Hourly

WECC Southwest	Daily	Top 40	Hourly
Canada West	Daily	Top 40	*N/A*
ERCOT Interconnection			
ERCOT	Daily	Top 40	Hourly
Quebec Interconnection			
Quebec	Daily	Top 40	*N/A*

NERC TPL-008 Data Library Documentation

Daily Data

Daily temperature statistics by Weather Zone.

- **Region:** The weather region associated with the data
- **Date:** Date in mm/dd/yyyy format
- **Daily_Min_Temp:** Minimum hourly temperature recorded on the associated date (F)
- **Daily_Avg_Temp:** Average hourly temperature recorded on the associated date (F)
- **Daily_Max_Temp:** Minimum hourly temperature recorded on the associated date (F)
- **3_Day_Rolling_Avg_Max_Temp:** Three-day rolling average of daily maximum temperature (F)
- **3_Day_Rolling_Avg_Min_Temp:** Three-day rolling average of daily minimum temperature (F)

Top 40 Events

Top 40 hottest and coldest days in each weather zone, measured by 3-day rolling average temperatures

- **Region:** The weather region associated with the data
- **Event_Type:** Heat Event or Cold Event
- **Year:** Year of associated event
- **Month:** Month of associated event
- **Date:** Date of associated event in mm/dd/yyyy format
- **Daily_Min_Temp:** Minimum hourly temperature recorded on the associated date (F)
- **Daily_Avg_Temp:** Average hourly temperature recorded on the associated date (F)
- **Daily_Max_Temp:** Minimum hourly temperature recorded on the associated date (F)
- **3_Day_Rolling_Avg_Max_Temp:** Three-day rolling average of daily maximum temperature (F)
- **3_Day_Rolling_Avg_Min_Temp:** Three-day rolling average of daily minimum temperature (F)
- **Event_Temp:** Temperature used to benchmark weather event (3_Day_Rolling_Avg_Max_Temp for Heat Events, 3_Day_Rolling_Avg_Min_Temp for Cold Events)

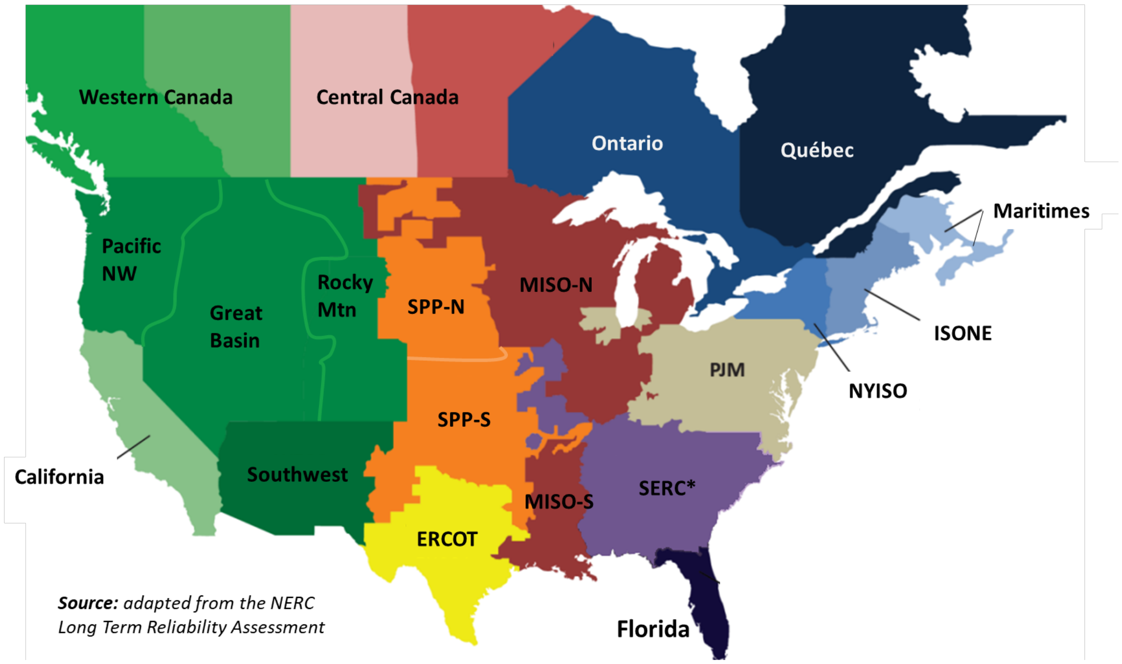
Hourly Data (Filtered)

Hourly weather data from PNNL Dataset with modifications. Values are weighted if the region was represented by multiple BAs. Values are filtered to only include Top 40 event days. Temperature converted from Kelvin to Fahrenheit.

- **Region:** The weather region associated with the data
- **Time_UTC:** Datetime of hourly data in UTC timezone
- **Temperature_F:** Hourly temperature measured at 2-m (F)
- **Q2:** Specific humidity measured as 2-m water vapor mixing ratio (kg/kg)
- **SWDOWN:** Shortwave radiation measured as downwelling shortwave radiative flux at the surface (W/m^2)
- **SLW:** Longwave radiation measured as radiative flux at the surface (W/m^2)
- **WSPD:** Wind speed measured as 10-m wind speed (m/s)

For original data, including hourly data by county and balancing authority, please refer to:
Burleyson, C., Thurber, T., & Vernon, C. (2023). Projections of Hourly Meteorology by Balancing Authority Based on the IM3/HyperFACETS Thermodynamic Global Warming (TGW) Simulations (v1.0.0) [Data set]. MSD-LIVE Data Repository. https://doi.org/10.57931/1960530

Weather Zones



NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2023-07 Transmission Planning Performance Requirements for Extreme Weather

Formal Comment Period Open through November 21, 2024

Now Available

A 15-day formal comment period for draft four of **TPL-008-1 – Transmission System Planning Performance Requirements for Extreme Temperature Events** is open through **8 p.m. Eastern, Thursday, November 21, 2024**.

The Standards Committee approved waivers to the Standards Process Manual at their December 2023 meeting. These waivers were sought by NERC Standards for reduced formal comment and ballot periods to assist the drafting teams in expediting the standards development process due to firm timeline expectations set by FERC Order 896.

The standard drafting team's considerations of the responses received from the previous comment period are reflected in this draft of the standard.

Reminder Regarding Corporate RBB Memberships

Under the NERC Rules of Procedure, each entity and its affiliates is collectively permitted one voting membership per Registered Ballot Body Segment. Each entity that undergoes a change in corporate structure (such as a merger or acquisition) that results in the entity or affiliated entities having more than the one permitted representative in a particular Segment must withdraw the duplicate membership(s) prior to joining new ballot pools or voting on anything as part of an existing ballot pool. Contact ballotadmin@nerc.net to assist with the removal of any duplicate registrations.

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. An unofficial Word version of the comment form is posted on the project page.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

Additional ballots for the standard and implementation plan, as well as a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **November 12-21, 2024**.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Jordan Mallory (via email) or at 404-479-7358. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify "Project 2023-07 Transmission Planning Performance Requirements for Extreme Weather observer list" in the Description Box.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comment Report

Project Name:	2023-07 Transmission Planning Performance Requirements for Extreme Weather | Draft 4
Comment Period Start Date:	11/7/2024
Comment Period End Date:	11/21/2024
Associated Ballots:	2023-07 Transmission Planning Performance Requirements for Extreme Weather Implementation Plan AB 4 OT 2023-07 Transmission Planning Performance Requirements for Extreme Weather TPL-008-1 AB 4 ST

There were 50 sets of responses, including comments from approximately 140 different people from approximately 89 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. The Drafting Team (DT) updated Requirement R2 based on comments received. Do you agree? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

2. The DT updated Requirement R9 based on comments received. Do you agree? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

3. The DT updated Attachment 1 based on comments received. Do you agree? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

4. The DT believes proposed modifications in TPL-008-1 provide entities with flexibility to meet the reliability objectives in a cost-effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost-effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

5. Provide any additional comments for the drafting team to consider, including the provided technical rationale document, if desired.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
BC Hydro and Power Authority	Adrian Andreoiu	1	WECC	BC Hydro	Hootan Jarollahi	BC Hydro and Power Authority	3	WECC
					Helen Hamilton Harding	BC Hydro and Power Authority	5	WECC
					Adrian Andreoiu	BC Hydro and Power Authority	1	WECC
MRO	Anna Martinson	1,2,3,4,5,6	MRO	MRO Group	Shonda McCain	Omaha Public Power District (OPPD)	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jamison Cawley	Nebraska Public Power District	1,3,5	MRO
					Jay Sethi	Manitoba Hydro (MH)	1,3,5,6	MRO
					Husam Al-Hadidi	Manitoba Hydro (System Preformance)	1,3,5,6	MRO
					Kimberly Bentley	Western Area Power Adminstration	1,6	MRO
					Jaimin Patal	Saskatchewan Power Coporation (SPC)	1	MRO
					George Brown	Pattern Operators LP	5	MRO
					Larry Heckert	Alliant Energy (ALTE)	4	MRO
					Terry Harbour	MidAmerican Energy Company (MEC)	1,3	MRO
					Dane Rogers	Oklahoma Gas and Electric (OG&E)	1,3,5,6	MRO

					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Ayotte	ITC Holdings	1	MRO
					Andrew Coffelt	Board of Public Utilities-Kansas (BPU)	1,3,5,6	MRO
					Peter Brown	Invenergy	5,6	MRO
					Angela Wheat	Southwestern Power Administration	1	MRO
					Joshua Phillips	Southwest Power Pool	2	MRO
					Patrick Tuttle	Oklahoma Municipal Power Authority	4,5	MRO
Exelon	Daniel Gacek	1		Exelon	Daniel Gacek	Exelon	1	RF
					Kinte Whitehead	Exelon	3	RF
Independent Electricity System Operator	Helen Lainis	2		IRC SRC	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Charles Yeung	SPP	2	SERC
					Elizabeth Davis	PJM	2	RF
Eversource Energy	Joshua London	1		Eversource	Joshua London	Eversource Energy	1	NPCC
					Vicki O'Leary	Eversource Energy	3	NPCC
Public Utility District No. 1 of Chelan County	Joyce Gundry	3		CHPD	Rebecca Zahler	Public Utility District No. 1 of Chelan County	5	WECC
					Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC
					Diane Landry	Public Utility District No. 1	1	WECC

						of Chelan County		
					Tamarra Hardie	Public Utility District No. 1 of Chelan County	6	WECC
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	RF
Black Hills Corporation	Rachel Schuldt	6		Black Hills Corporation - All Segments	Travis Grablander	Black Hills Corporation	1	WECC
					Josh Combs	Black Hills Corporation	3	WECC
					Rachel Schuldt	Black Hills Corporation	6	WECC
					Carly Miller	Black Hills Corporation	5	WECC
					Sheila Suurmeier	Black Hills Corporation	5	WECC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC

					Randy Buswell	Vermont Electric Power Company	1	NPCC
					James Grant	NYISO	2	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					David Burke	Orange and Rockland	3	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
					Sean Cavote	PSEG	4	NPCC
					Jason Chandler	Con Edison	5	NPCC
					Tracy MacNicoll	Utility Services	5	NPCC
					Shivaz Chopra	New York Power Authority	6	NPCC
					Vijay Puran	New York State Department of Public Service	6	NPCC
					David Kiguel	Independent	7	NPCC
					Joel Charlebois	AESI	7	NPCC
					Joshua London	Eversource Energy	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC
					Joel Charlebois	AESI	7	NPCC
					John Hastings	National Grid	1	NPCC

					Erin Wilson	NB Power	1	NPCC
					James Grant	NYISO	2	NPCC
					Michael Couchesne	ISO-NE	2	NPCC
					Kurtis Chong	IESO	2	NPCC
					Michele Pagano	Con Edison	4	NPCC
					Bendong Sun	Bruce Power	4	NPCC
					Carvers Powers	Utility Services	5	NPCC
					Wes Yeomans	NYSRC	7	NPCC
Shannon Mickens	Shannon Mickens		MRO,SPP RE,WECC	SPP RTO	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Mia Wilson	Southwest Power Pool Inc.	2	MRO
					Eddie Watson	Southwest Power Pool Inc.	2	MRO
					Erin Cullum	Southwest Power Pool Inc.	2	MRO
					Jonathan Hayes	Southwest Power Pool Inc.	2	MRO
					Jeff McDiarmid	Southwest Power Pool Inc.	2	MRO
					Scott Jordan	Southwest Power Pool Inc	2	MRO
					Mason Favazza	Southwest Power Pool Inc	2	MRO
					Zach Sabey	Southwest Power Pool Inc	2	MRO
					Josh Phillips	Southwest Power Pool Inc.	2	MRO
Tim Kelley	Tim Kelley		WECC	SMUD and BANC	Nicole Looney	Sacramento Municipal Utility District	3	WECC

					Charles Norton	Sacramento Municipal Utility District	6	WECC
					Wei Shao	Sacramento Municipal Utility District	1	WECC
					Foung Mua	Sacramento Municipal Utility District	4	WECC
					Nicole Goi	Sacramento Municipal Utility District	5	WECC
					Kevin Smith	Balancing Authority of Northern California	1	WECC

1. The Drafting Team (DT) updated Requirement R2 based on comments received. Do you agree? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro

Answer	No
Document Name	

Comment

BC Hydro appreciates the drafting team's efforts and opportunity to comment, and offers the following comments.

(1) The ERO is not subject to TPL-008-1 regulatory compliance. Entities are relying on the ERO's infrastructure and commitment to maintain the benchmark temperature event library. As drafted, a PC can be in a potential noncompliance if they choose to use a benchmark event from the ERO-maintained library, and the event is not meeting the specifications per Parts 2.1 and 2.2.

BC Hydro is requesting that the drafting team in conjunction with the ERO document the controls that will be in place to maintain the library. These controls should include the location of the library and quality checks to ensure the events in the library meet R2 Parts 2.1 and 2.2.

BC Hydro recommends revising the language of R2 Parts 2.1 and 2.2 to apply if a PC develops their own benchmark events, and not apply to the ERO benchmark events library.

(2) A Planning Coordinator may be in a potential noncompliance if another PC is not participating in the required coordination and assessment activities, which may be the case as different jurisdictions (such as Canada and US, or even between BC and Alberta within Canada) have different standard adoption timelines.

BC Hydro suggests that the Implementation Plan include provisions that allow for compliance enforcement only when TPL-008-1 is effective in all applicable jurisdictions.

Alternatively, the Canada West zone should be split into a BC-only zone. This may help alleviate compliance risks and it will also help creating a more robust ETA given the different geographic areas and weather zones across the Canadian provinces of BC and Alberta.

There could also be scenario where in a multiple PC zone there may one PC that does not participate in the coordination, or there is no agreement on a common event. In such a scenario, all PCs may be found in noncompliance.

BC Hydro recommends that the standard include provisions to allow for conflict resolution.

Likes 0	
Dislikes 0	

Response

Richard Vendetti - NextEra Energy - 5

Answer	No
Document Name	

Comment

NextEra does not agree with the modifications to R2. The SAR references the use of either “a projected frequency (e.g., 1-in-50-year event); or a probability distribution (95th percentile event).” The development of extreme events refers to foot note 9 *“Benchmark events will form the basis for a planner's benchmark planning case— i.e., the base case representing system conditions under the relevant benchmark event—that will be used to study the potential wide-area impacts of anticipated extreme heat and cold weather events.”*

FERC via the SAR requested to develop a base case that is representative of system conditions which could be a 1 in 50 year or a P95 event. Following the proposed language in the standard and the ERO library, the warmest temperature Florida could use for its winter assessment is 32.3 degrees and the lowest being 24.9F. The concern is that the entire state is at freezing temperatures and will generate significant winter loads in Florida much larger than the 20% sensitivity we use for winter, thereby generating transmission projects that will not provide value to our customers. NextEra does not consider this a P95 event, especially if the average 3 rolling day is taking into consideration (also not requested by the SAR). The coldest temperature experienced in Miami over the last 40 years was during the winter of 1989, where temperatures were as low as 30 degrees. The lowest 3 day rolling average was 32.6 degrees (12/23-27F, 12/24-31F, 12/25-30F and 12/27-38F). The standard as written will force NextEra to plan to a greater than P100 winter loads. This is an un-realistic approach, considering most of Florida’s load is located in Southern Florida south of Lake Okeechobee. NextEra recommends the language in R2 to state “Represent the 95th percentile extreme conditions for the climate zone based on the 3-day rolling average of maximum (heat) or minimum (cold) temperature across the zone.”

Likes 0	
Dislikes 0	

Response

Donald Lock - Talen Generation, LLC - 5

Answer	No
Document Name	

Comment

R2.2, "Represent one of the 20 most extreme temperature conditions based on the three-day rolling average of daily maximum (heat) or daily minimum (cold) temperature across the zone," is far too lax. Selecting the 20th most severe event of the past four decades would not constitute much of a challenge.

Likes 0	
Dislikes 0	

Response

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	

Comment

CenterPoint Energy Houston Electric, LLC (CEHE) believes with the current zone designations, there are some zones where temperature differences would be significant due to their very large north/south geographical spans. A concern arises whether the chosen extreme temperature event case is applicable to the overall zone in these cases. It might not be representative of certain parts of the zone. Transmission Planners should be involved in the selection. CEHE recommends the following revision: Each Planning Coordinator**, in conjunction with its Transmission Planner(s)**, shall select which extreme heat and extreme cold weather events to develop benchmark extreme temperature events applicable to their region.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO

Answer	No
Document Name	

Comment

SPP opposes splitting our region into North and South zones. As a contiguously integrated system, our system does not demarcate at state lines boundaries. We recently completed our 2024 Integrated Transmission Plan that resulted in $7.5B in network upgrades to further strengthen this integration.

The standard as written could require SPP to select a high and low temperature extreme in both the northern region and southern region, creating a situation where we are disconnecting the interconnections we built and those planned to in the future. This results in a needless complication to the existing systems and creates an unnecessary burden that does not improve reliability. As proposed in the previous version of the document, we request the Planning Coordinator zone be reestablished into a contiguous system for evaluating these extreme events. The bifurcation is even less appropriate when considering the events proposed in the *ERO Enterprise Process for TPL-008-1 Benchmark Weather Event Development and Maintenance* indicate using an event that overlaps both SPP regions from December 24, 1989. Conversely, the proposed extreme heat case only affected the proposed SPP South Region.

If required to use two zones, we would like to see clarification in the language that indicates regions are allowed to utilize the same scenario provided it meets the requirements in 2.1 and 2.2.

Likes 0	
Dislikes 0	

Response

Gary Trezza - Long Island Power Authority - 1 - NPCC

Answer	Yes
Document Name	

Comment

We have some comments / observations regarding Req #2 that we would like to share with the SDT:

- In Req #2 language, the word ‘select’ has been replaced by ‘identify’. However, we observe that the word ‘select’ is still utilized in the Measure #2 language, the Req #3 language and in the Technical Rationale document. This inconsistency could cause some confusion about the actual intent.

For example, the word ‘identify’ might better imply the coordination that is allowed by Req #2.

The Technical Rationale should be updated to highlight and clarify the significance of this wording change.

- Req #2 states that the benchmark temperature events shall be obtained from the benchmark library maintained by the ERO or developed by the Planning Coordinators. Is this implying that some of the benchmark events may not be available on the library after they are developed by the PCs? If so, is there any expectation (or should there be any) that these benchmark events be somewhat communicated/shared to other PCs for awareness if they are developed and not on the benchmark library?

Likes 0	
Dislikes 0	

Response

Daniela Atanasovski - APS - Arizona Public Service Co. - 1

Answer	Yes
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	Yes
Document Name	

Comment

FirstEnergy has no concerns with the update to Requirement R2.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Texas RE recommends revising Measure M2 from "…to select one common extreme heat benchmark temperature event" to "to identify one common extreme heat benchmark temperature event. This makes the language consist with the revision made to Requirement R2.	
Likes 0	
Dislikes 0	
Response	

Sharon Darwin - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Southern Company supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
ITC supports the proposed changes made to Requirement R2.	
Likes 0	
Dislikes 0	
Response	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes

Document Name	
Comment	
EEI supports the changes made to Requirement R2, which empowers the Planning Coordinator to develop the benchmark temperature events rather then solely depending on the benchmark temperature events contained in the benchmark library.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
PNM & TNMP supports EEI's comments and supports R2.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	Yes
Document Name	
Comment	
Exelon agrees with the updated proposed TPL-008 Reliability Standard Requirement R2. Additionally, are there any plans to add guidance regarding "most extreme temperature conditions" in section 2.2? Can a planning coordinator come up with its own criteria/metric considering that they are likely a broad range of temperatures throughout the weather zone(s) for each temperature events?	
Likes 0	
Dislikes 0	
Response	
Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop	
Answer	Yes

Document Name	
Comment	
Ameren agrees with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	

See EEI Comments

Likes 0	
Dislikes 0	

Response

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples

Answer	Yes
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) on question 1

Likes 0	
Dislikes 0	

Response

Helen Lainis - Independent Electricity System Operator - 2, Group Name IRC SRC

Answer	Yes
Document Name	

Comment

The ISO/RTO Council Standards Review Committee (IRC SRC) generally agrees with the revisions to Requirement R2, and recommends the following additional revisions to further clarify the Requirement:

- Revise the second-to-last sentence at the end of R2 as follows to reference PCs first and the ERO benchmark library second to avoid a possible inference that the PC is required to develop its own benchmark library:

“The benchmark temperature events shall be developed by the Planning Coordinators or obtained from the benchmark library maintained by the ERO.”

- Revise the last sentence at the end of R2 to read as follows to better reflect the fact that the Planning Coordinator (rather than the benchmark temperature event) is ultimately the entity making the considerations described in Parts 2.1 and 2.2: “**The Planning Coordinator’s selection of** each benchmark temperature event shall:”

- Revise Part 2.2 as follows to clarify that the temperature conditions referenced in Part 2.2 are required to fall within the time period referenced in Part 2.1: “Represent one of the 20 most extreme temperature conditions **within the period identified in Part 2.1** based on the three-day rolling average…”

Likes 0	

Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) for this question and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
AEPC has signed on to ACES comments. Please review ACES comments.	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - Greg Sorenson	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Broc Bruton - Broc Bruton On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Broc Bruton	
Answer	
Document Name	
Comment	
Abstain	
Likes 0	
Dislikes 0	
Response	

2. The DT updated Requirement R9 based on comments received. Do you agree? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO

Answer	No
Document Name	

Comment

The current language in R9.4 says revisions to Corrective Action Plans are limited to the subsequent Extreme Temperature Assessments, yet the underlying system may have change identified through system upgrades. These Corrective Action Plans should be more flexible in the event a system upgrade is completed or a separate assessment demonstrates the underlying performance issue has been mitigated. The inclusion of “or other planning assessments” in 9.4 appeared amicable during the drafting team discussion, and we request this be adopted as proposed in the following revision:

9.4. Be permitted to have revisions to the Corrective Action Plan in subsequent Extreme Temperature Assessments **or other planning assessments**, provided that the planned Bulk Electric System shall continue to meet the performance requirements of Table 1.

Likes 0	
Dislikes 0	

Response

Mark Flanary - Midwest Reliability Organization - 10

Answer	No
Document Name	

Comment

MRO is not confortable with two parts of R9.3, both of which limit signicantly the region's ability to meaningfully enforce the requirement:

1. The terms “regulatory authorities” and “governing bodies” are not specific

2. There are no timning requirements prescribed for the responsible entity concerning when the responsible entity must make its Corrective Action Plan available to, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.

Likes 0	
Dislikes 0	

Response

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2

Answer	No
Document Name	
Comment	

ERCOT joins the comments submitted by the IRC SRC for this question and adopts them as its own.

Likes 0	
Dislikes 0	
Response	

Helen Lainis - Independent Electricity System Operator - 2, Group Name IRC SRC

Answer	No
Document Name	
Comment	

The current language in R9.4 says revisions to Corrective Action Plans are limited to subsequent Extreme Temperature Assessments. However, the underlying system may change between assessments because of system upgrades. These Corrective Action Plans should be more flexible in the event a system upgrade is completed or a separate assessment demonstrates the underlying performance issue has been mitigated. The inclusion of "or other planning assessments" in 9.4 appeared to be acceptable during the drafting team discussion, and we request this be adopted as proposed in the following revision:

a. 9.4. Be permitted to have revisions to the Corrective Action Plan in subsequent Extreme Temperature Assessments **or other planning assessments**, provided that the planned Bulk Electric System shall continue to meet the performance requirements of Table 1.

Likes 0	
Dislikes 0	
Response	

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	
Comment	

The current draft is not clear what the timeframe is for providing the CAP in R9.1. In addition, there is no timeframe when to notify the applicable regulatory authorities or governing bodies in R9.2. CEHE strongly disagrees with the following statement in R9.3: "Make its Corrective Action Plan available to, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues." CEHE recommends that "applicable regulatory authorities or governing bodies" be defined. CEHE also recommends that TPs should be providing CAP information only to their PC.

Likes 0	

Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	
NextEra does not agree with the language of R9.3 regarding the solicitation of feedback, as this is in line and satisfied through R11 of the standard.	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	
During the recent revisions, a proposal was made with support to clarify 9.4 that revisions to a Corrective Action Plan should be allowed if other planning assessments resolve the concern. As such this should be captured in requirement 9.4 such as the following: 9.4. Be permitted to have revisions to the Corrective Action Plan in subsequent Extreme Temperature Assessments **or other planning assessments**, provided that the planned Bulk Electric System shall continue to meet the performance requirements of Table 1.	
Likes 1	Scott Brame, N/A, Brame Scott
Dislikes 0	
Response	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	No
Document Name	
Comment	
• The purpose and required response actions related to the sharing of CAPs and solicitation of feedback is not clear. • Documentation of alternatives is an additional administrative burden and provides little benefit to reliability. It is also unclear if there is some type of expectation these alternatives are reviewed or potentially challenged as invalid.	

- The role of the TO and/or GO in implementing or otherwise responding to CAPs that may require additions or modifications to their systems/facilities is not captured in these requirements.
- There appears to be a significant amount of outside review required but no clear actions the responsible entity is required to take, particularly if there is a dispute. What is the purpose of the review and the expected response? This potentially produces an undue burden on the PC/TP and adds subjectivity in requiring a review with no documented guidelines for conducting the review.
- GTC recommends the restructuring of requirement 9 such that documentation of alternatives along with the sharing and soliciting feedback back is only necessary when utilizing Non-Consequential Load Loss as an interim solution.

Likes 0	
Dislikes 0	

Response

Joshua London - Eversource Energy - 1, Group Name Eversource

Answer	No
Document Name	

Comment

Eversource has concerns regarding compliance with Requirement R9.3. Because this standard is focused on "Extreme Temperature Events", the company can foresee issues with regulatory agencies not wanting the company to invest significant funds into these issues. What would occur if Eversource supplied a CAP to the appropriate governing body and they state they do not agree the work is necessary? Would creating the CAP still meet the intent of the requirement although it may not be allowed to be implemented? Eversource recommends the DT consider adding language in case such a scenario arises.

Likes 0	
Dislikes 0	

Response

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

We recommend that further clarification be given to how "applicable" regulatory authorities or governing bodies are determined.

Likes 0	
Dislikes 0	

Response

Broc Bruton - Broc Bruton On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Broc Bruton

Answer	No
Document Name	
Comment	

Oncor strongly disagrees with the following statement in R9.3: “Make its Corrective Action Plan available to, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.” We propose that “applicable regulatory authorities or governing bodies” be defined and limited. For example, a TP should only need to provide their PC with CAP information.

Likes 0	
Dislikes 0	
Response	

Carver Powers - Utility Services, Inc. - 4

Answer	Yes
Document Name	
Comment	

1) Based on other projects that include developing and implementing CAPs, USV does not agree with the proposed modifications and would feel more confident if there were guidelines and more structured timelines set for the CAPs. Perhaps not in the standard itself, but guidance on timelines could be explained in the technical rationale and include timelines for implementing CAPs and when entities can utilize backup action plans such as Non-Consequential Load Loss.

2) The newly proposed modifications to R9 compared to the proposed modifications from the previous draft do not change the obligations for responsible entities. The new requirement 9.3 is administrative in nature and does not appear to provide any increase in reliability, if anything it would delay the implementation of the CAP. USV understands the directives in FERC order 896 and the need for R9. However, we disagree that any significant improvements have been made to previously proposed R9 modifications.

Likes 0	
Dislikes 0	
Response	

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples

Answer	Yes
Document Name	
Comment	

Evergy supports and incorporates by reference the comments of the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 2

Likes 0	
Dislikes 0	

Response

Selene Willis - Edison International - Southern California Edison Company - 5

Answer	Yes
Document Name	

Comment

See EEI Comments

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	Yes
Document Name	

Comment

None.

Likes 0	
Dislikes 0	

Response

Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop

Answer	Yes
Document Name	

Comment

Ameren agrees with EEI's comments.

Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	Yes
Document Name	
Comment	
Exelon agrees with the updated proposed TPL-008 Reliability Standard Requirements R9.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
PNM & TNMP agrees with R9.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the changes made to Requirement R9 and offers no additional changes.	
Likes 0	
Dislikes 0	

Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
ITC supports the proposed changes made to Requirement R9.	
Likes 0	
Dislikes 0	
Response	
Sharon Darwin - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Southern Company supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy has no concerns with the update to Requirement R9.	
Likes 0	
Dislikes 0	
Response	

Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - Greg Sorenson	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gary Trezza - Long Island Power Authority - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3,	

6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	

Comment	
Texas RE continues to recommend including a timeframe for which the CAPs need to be developed and implemented once the benchmark planning case study results indicate the System is unable to meet performance requirements. Requirement R2 states: “Be permitted to utilize Non-Consequential Load Loss as an interim solution, which normally is not permitted for category P0 in Table 1, in for situations that are beyond the control of the Planning Coordinator or Transmission Planner that prevent the implementation of a Corrective Action Plan in *the required timeframe*…” Texas RE reads the proposed standard language as allowing the entity to determine the “required timeframe.” While the revised language provides for a coordination process with regulatory authorities, it does not appear these entities could reject a Corrective Action Plan if the required timeframe was unduly extended. Texas RE therefore continues to recommend placing more explicit requirements around CAP development and implementation to prevent unilaterally lengthy CAPs and ensure their timely and effective implementation.	
Likes 0	
Dislikes 0	
Response	

3. The DT updated Attachment 1 based on comments received. Do you agree? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford

Answer	No
Document Name	

Comment

The SDT made vast improvements to Attachment 1 by splitting MISO and SPP zones into MISO North, MISO South, SPP North, and SPP South. The SDT attempted to move the disjointed sections of SERC Central to the appropriate MISO or SPP zones. However, the SDT needs to include geographical boundaries to clarify which SERC Central PCs should belong to MISO North, MISO South, SPP North, and SPP South. For example:

- Zone - “MISO South”
- Planning Coordinator(s) – “Planning Coordinator(s) in MISO and *SERC* that serve portions of Montana, North Dakota, South Dakota, Minnesota, Iowa, Wisconsin, Michigan, Indiana, Illinois, Missouri, or Kentucky”

Likes 0	
Dislikes 0	

Response

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro

Answer	No
Document Name	

Comment

B.C. has a wide geographic area, applying one common extreme temperature is not ideal. The Canada West cold benchmark event temperatures are closer to our BC Hydro south region coldest days temperature. However, as winter peaking utilities, most of BC Hydro’s temperature sensitive load (mostly distribution load) are located in the Lower Mainland and Vancouver Island.

BC Hydro recommends that the Canada West zone be split into BC and Alberta based on weather and geographical differences that are more conducive to a robust ETA.

Likes 0	
Dislikes 0	

Response

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No

Document Name	
Comment	

Please view response to Question 1.

Likes 0	
Dislikes 0	
Response	

Helen Lainis - Independent Electricity System Operator - 2, Group Name IRC SRC

Answer	No
Document Name	
Comment	

It is not clear to the IRC SRC whether the current draft addresses temperature variances from east to west of the current zones, not just north to south. For example, entities with a wide east to west territory may have vastly different climates that may need to be split into additional zones.

During the last comment review, the drafting team discussion indicated that a Planning Coordinator with more than one zone may utilize the same weather event. Ideally the drafting team would revert to the contiguous planning coordinator zones. Either way, this understanding, that two zones within a single PC may use the same event, should be documented within the standard to ensure there is no ambiguity should an entity carry out such approach. The IRC SRC would like to see clarification in the language that indicates regions are allowed to utilize the same scenario provided it meets the requirements in 2.1 and 2.2.

ERCOT, IESO, and PJM abstain from IRC SRC response and comments to Q3.

Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO

Answer	No
Document Name	
Comment	

SPP's PC footprint should not be split into northern and southern zones (see question #1).

Likes 0	
Dislikes 0	

Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy has no concerns with the update to Attachment 1.	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
In the attachment 1, remove “WECC” from “WECC Southwest” to match up with the Zones Map.	
Likes 0	
Dislikes 0	
Response	

Sharon Darwin - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Southern Company supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
ITC supports the proposed changes made to Attachment 1 zones.	
Likes 0	
Dislikes 0	
Response	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the changes made to Attachment 1.	
Likes 0	
Dislikes 0	
Response	

Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes

Document Name	
Comment	
PNM & TNMP agrees with the changes to Attachment 1.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	Yes
Document Name	
Comment	
Exelon agrees with the updates made to the table and map in Attachment 1.	
Likes 0	
Dislikes 0	
Response	
Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - Greg Sorenson	
Answer	Yes
Document Name	
Comment	
There may be only limited value is running dynamic analysis on a Long-Term planning case (i.e. 10 yr out case). And these cases are difficult to build and are often not N-1 secure (meaning not all single contingencies will result in a valid load flow solution). Given this, and the multiple future assumptions, the dynamic portion of the studies may not provide tangible value."	
Likes 0	
Dislikes 0	
Response	
Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop	
Answer	Yes
Document Name	

Comment	
Ameren agrees with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	

See EEI Comments

Likes 0	
Dislikes 0	

Response

Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD

Answer	Yes
Document Name	Draft 4 Attachment 1 Example.pdf

Comment

The Attachment 1 graphic would greatly benefit from including state boundaries. Please see attached example.

Draft 4 Attachment 1 Example.pdf

Likes 0	
Dislikes 0	

Response

Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gary Trezza - Long Island Power Authority - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Broc Bruton - Broc Bruton On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Broc Bruton	
Answer	
Document Name	
Comment	
Abstain	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	

Answer	
Document Name	

Comment

Texas RE continues to be concerned that multiple contingencies may not be used to assess the system in extreme temperature events. In Requirement R7, Table 1 only shows single contingencies and double circuit contingencies for assessing steady state and stability performances. Based on the contingencies listed in Table 1, the reasoning for R7 is not clear. Are the responsible entities expected to select single contingencies and double circuit contingencies and use those contingencies to assess the system? During extreme temperature events, multiple overlapping contingencies are expected and frequently occur. Given this fact, the proposed standard should correspondingly require Registered entities to study overlapping contingencies to identify system deficiencies and prepare the mitigation plans.

Likes 0	
Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	
Document Name	

Comment

During the last comment review, the drafting team discussion indicated that a Planning Coordinator with more than one zone may utilize the same weather event. This understanding should be documented within the standard to ensure there is no ambiguity should an entity conduct such an approach. The MRO-NSRF would like to see clarification in the language that indicates regions are allowed to utilize the same scenario provided it meets the requirements in 2.1 and 2.2.

Likes 1	Scott Brame, N/A, Brame Scott
Dislikes 0	

Response

4. The DT believes proposed modifications in TPL-008-1 provide entities with flexibility to meet the reliability objectives in a cost-effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost-effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle

Answer	No
Document Name	

Comment

Sensitivity to generation, load and transfers are already studied as part of TPL-001-5.1 yearly for near and long-term scenarios (year 10/year 12). The sensitivity additional studies proposed for R8.2 are unlikely to yield any new information and will be duplicative work for Transmission Planners.

The Extreme Temperature Assessment is already a very extreme sensitivity study itself that should already capture modified load, generation, transmission, and transfers befitting this analysis per R3, so it is not needed nor appropriate to study sensitivities for sensitivity cases. Further sensitivity cases to adjust such power flow variables would be a nice idea, but it does not appear cost effective to mandate developing and evaluating “sensitivity” cases in addition to the already sensitive nature if the extreme weather assessment.

If sensitivity cases are deemed necessary, it would be more cost-effective to waive the obligation to study and analyze stability for those sensitivities.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO

Answer	No
Document Name	

Comment

The changes to the zoning and mapping create an administrative burden with little benefit to the reliability based upon the current language. This requires coordination with ourselves and the proposed event library recommends the same across our entire footprint. This would not be cost effective to create multiple models and sensitivities which would not leverage the transmission system built to support reliability.

Likes 0	
Dislikes 0	

Response

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No

Document Name	
Comment	
CEHE believes the new draft TPL-008-1 still imposes a cost and time burden to PCs/TPs without substantial benefits to reliability of BPS. To support this standard CEHE would like to learn more information on any economic analysis that was performed.	
Likes 0	
Dislikes 0	
Response	

Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
See our comments for Question 1.	
Likes 0	
Dislikes 0	
Response	

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
• ITC believes it is not cost effective to build sensitivity models and analyze the required events yet not require any Corrective Action Plans. If these cases have value and justification to be created and analyzed, then the problems generated within them are also justified to need mitigation to assure reliability. • Corrective Action plans utilizing only Non Consequential Load Loss do not provide value regarding reliability objectives. Reliability should aim to maintain service to serve firm load and for single contingencies when it may be critical to end users/load under extreme temperature conditions. Entities would need to proactively start shedding load for changes in generation, real and reactive forecasted Load, or transfers; load shed is not a solution to the problems identified on how to deliver reliable service to load.	
Likes 0	
Dislikes 0	
Response	

Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford

Answer	No
Document Name	
Comment	

The attempt for flexibility is appreciated but this standard still falls short of something that is clear and allows the PC/TP to appropriately plan to meet reliability goals during extreme temperature events. The inclusion of outside entity reviews of CAPs offers the reviewer flexibility as there are no bounds provided to them. The PC/TP, however, is potentially impacted by subjective reviews that have no framework with which the PC/TP can effectively respond.

Likes 0	
Dislikes 0	
Response	

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1

Answer	No
Document Name	
Comment	

New Standard requiring extensive coordination with adjacent PCs/TPs within the defined “zones”. New Standards impose a cost and time burden to PCs/TPs without necessarily providing substantial benefits to the reliability of the BPS.

Likes 0	
Dislikes 0	
Response	

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3

Answer	No
Document Name	
Comment	

This should be part of TPL-001 and not a separate TPL Standard.

Likes 0	
Dislikes 0	
Response	

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	No
Document Name	
Comment	

At this time, we are unable to fully agree that this standard provides the necessary flexibility to meet the reliability objectives in a cost-effective manner. We would be interested in more information on any economic analysis that was performed.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	Yes
Document Name	

Comment

FirstEnergy has no concerns with the cost-effectiveness of this draft.

Likes 0	
Dislikes 0	

Response

Daniela Atanasovski - APS - Arizona Public Service Co. - 1

Answer	Yes
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sharon Darwin - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Gary Trezza - Long Island Power Authority - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response	
Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	
Document Name	
Comment	
NV Energy does not have a comment regarding the cost-effectiveness.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
Duke Energy's focus is on system reliability and will not respond to the cost effectiveness question.	
Likes 0	
Dislikes 0	
Response	
Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop	

Answer	
Document Name	
Comment	
Ameren prefers not to comment on the cost effectiveness of the project.	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	
Document Name	
Comment	
Black Hills Corporation will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Broc Bruton - Broc Bruton On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Broc Bruton	
Answer	
Document Name	
Comment	
Abstain	
Likes 0	
Dislikes 0	
Response	

5. Provide any additional comments for the drafting team to consider, including the provided technical rationale document, if desired.

Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	
Document Name	
Comment	
HQ supports these revisions.	
Likes 0	
Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	
Document Name	
Comment	
Requirement R10 should explicitly clarify that a Corrective Action Plan is not required for P7 Contingencies, as stated in the previous draft 2, Table 2.1, page 11. R6 VRF is 'High', but it should be set as 'Medium' to match TPL-008 R5.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	
AEP offers the following additional comments regarding potential overlapping or duplicative obligations. R3 and R4 appear duplicative in that they both involve the formation of study cases. R3 states “Implement a process for developing benchmark planning cases” while R4 states “Use the coordination process… to develop the following… planning benchmark cases.” R1’s “shall complete its responsibilities such that the … assessment is completed…” appears duplicative with R8’s “shall complete steady-state and stability analysis… ”. AEP	

recommends removing the last sentence from R1 regarding completing the Extreme Temperature Assessment at least once every five calendar years and appending it to R8.

Regarding R5, the TP and PC should already possess steady state voltage criteria to satisfy TPL-001 R5. As a result, AEP recommends removing R5 to avoid compliance risk associated with duplicative obligations. If the drafting team chooses to retain R5, the phrase “shall have criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations” might benefit from something more actionable than “shall have.” AEP recommends the drafting team consider “shall devise” or “shall develop.”

R6’s identification of instability, uncontrolled separation, and cascading per criteria or methodology is already required in TPL-001 R6, which once again appears duplicative and would unnecessarily increase compliance risk. AEP recommends it be removed.

Likes 0	
Dislikes 0	

Response

Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD

Answer	
Document Name	

Comment

The below comment was provided previously for R2.

NERC's consultant uses BA load weighting (based on notes and conversations provided in the 9/10 TPL-008 presentation). As a result, this weighting practice does not appear to directly meet this proposed R2.2 language regarding the most extreme events for a region. The temperature may not actually be representative of “across the zone” because of this weighting. Of reliability considerations, load is certainly part of the need, but potential impacts to generation and the connecting transmission, which may be in other regions, are also important pieces to the delivery of resource to load. Removal or modification of this R2 ‘most extreme’ language is recommended; or exempting the NERC library from needing to follow these criteria. Alternately, the SDT may modify to allow weighting to be used in method.

Because the NERC Extreme Weather Event library is only updated every 3 years in the current plan, it is possible that an event in the library would contain events that would not meet these R2 criteria for event “freshness”. The SDT may wish to consider modifying the language regarding time, or an additional clause, to permit events currently in the NERC Extreme Weather Event library to not be subject to the selection criteria currently in R2, or that entities may use the other criteria to evaluate and select other events.

The below comment was provided previously for R3-R4.

In FERC Order 896, paragraph 39, there is a Commission Determination as follows:

“We also direct NERC to include in the Reliability Standard the framework and criteria that responsible entities shall use to develop from the relevant benchmark event planning cases to represent potential weather-related contingencies (e.g., concurrent/correlated generation and transmission outages, derates) and expected future conditions of the system such as changes in load, transfers, and generation resource mix, and impacts on generators sensitive to extreme heat or cold, due to the weather conditions indicated in the benchmark events. Developing such a framework would provide a common design basis for responsible entities to follow when creating benchmark planning cases. This would not only help establish a clear set of expectations for responsible entities to follow when developing benchmark planning events, but also facilitate auditing and enforcement of the Standard.”

In review of Order 896, we find the term “contingencies” is used two different ways. Paragraph 39 describes things that are in the base or N-0 state – for example, a cold weather event occurs, and certain wind generators can no longer operate – this as a base contingency. Similarly, in paragraph 88, there is an additional Commission Determination as follows, in further support of these baseline “contingency” outages:

“Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to require under the new or revised Reliability Standard the study of concurrent/correlated generator and transmission outages due to extreme heat and cold events in benchmark events as described in more detail below.”

Then later, in Paragraph 92 (still under the Commission Determination), FERC further clarifies:

“Regarding the comments of NYISO and EPRI on the difference between extreme events and contingencies covered under Reliability Standard TPL-001-5.1, we clarify that all contingencies included in benchmark planning cases under the new or modified Reliability Standard will represent initial conditions for extreme weather event planning and analysis. These contingencies (i.e., correlated/concurrent, temperature sensitive outages, and derates) shall be identified based on similar contingencies that occurred in recent extreme weather events or expected to occur in future forecasted events.”

From these, it is clear that Order 896 is expecting “contingencies” of weather-based equipment outages to be part of the base or N-0 system state. The more traditional “contingencies” are then addressed on top of this condition, as presented in Order 896, Section G, starting at Paragraph 95.

The specific request from this comment is for the SDT to clarify how it expects such base “contingencies” to be included in the model. There does not appear to be language currently in the standard in support of this, and it is clear from Order 896 that it is expected both the base model outage “contingencies” and then subsequent contingency events to test system performance.

The SDT responded to this in its version 3 comment response:

“The SDT drafted Requirement R4 to require the responsible entity to use data consistent with Reliability Standard MOD-032, supplemented by other sources as needed, for developing benchmark planning cases that represent System conditions based on selected benchmark temperature events. This aligns with directives in FERC Order No. 896, paragraph 30, emphasizing the requirement of developing both benchmark planning cases and sensitivity study cases. Requirement R4 is consistent with Reliability Standard TPL-001-5.1 in cross-referencing Reliability Standard MOD-032, which establishes consistent modeling data requirements and reporting procedures for the development of planning horizon cases necessary to support analysis of the reliability of the interconnected System. It is also consistent with Reliability Standard TPL-001-5.1 in acknowledging that data from other sources may be required to supplement the data collected through Reliability Standard MOD-032 procedures.”

The original comment was not related at all to MOD-032 data. FERC is expecting NERC to develop a standard to build extreme weather cases, and as part of those cases, FERC is requiring that in the base N-0 condition also include “weather-related contingencies (e.g., concurrent/correlated generation and transmission outages, derates)”. The current draft of TPL-008 does not mention outages, de-rates, or generator availability due to extreme weather in its R3 or R4 language. R3.2 simply includes “Forecasted seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers within the zone.” And R3.3 similar “Assumed seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers in areas outside the zone, as needed.”, but language for “weather-related contingencies (e.g., concurrent/correlated generation and transmission outages, derates)” from Order 896 is absent from the standard in its current form. This language should be added, likely to R3.2 and R3.3 because it conveys powerful root concept of unexpected equipment outages and limitations in the base state due to extreme weather. If it is the SDT’s intention that entities will review Order 896 and conclude that such concurrent outages are to be covered by a ‘supplemented by other sources as needed’ clause, this is not the case. The standard needs to include language for entities to consider how such extreme weather related concurrent/correlated outages are to be included in the base case.

The below comment was provided previously for R9.

In Order 896, FERC’s Commission determination in paragraph 157 reads:

“As stated above, we adopt and modify the NOPR proposal and direct NERC to require in the new or modified Reliability Standard the development of corrective action plans that include mitigation for specified instances where performance requirements for extreme heat and cold events are not met—i.e., when certain studies conducted under the Standard show that an extreme heat or cold event would result in cascading outages, uncontrolled separation, or instability.”

FERC's directive is when the outcome of studies would result in cascading outages, uncontrolled separation, or instability, a corrective action plan is required. However, in TPL-008, the SDT has gone further. The current state of draft TPL-001-8 R9 states:

"Each responsible entity, as identified in Requirement R1, shall develop a Corrective Action Plan(s) when the analysis of a benchmark planning case, in accordance with Requirement R8 Part 8.1, indicates its portion of the Bulk Electric System is unable to meet performance requirements for category P0 or P1 in Table 1. For each Corrective Action Plan, the responsible entity shall:"

The difference here is Order 896 is only requiring corrective action plans for cascading outages, uncontrolled separation, or instability. the SDT is proposing to require corrective action plans for not meeting performance criteria, which also includes normal voltage limits or normal line ratings, even though these exceedances may not result in cascading outages, uncontrolled separation, or instability. The request is for the SDT to align its R9 language with Order 896 paragraph 157 language. These other limits are needed to assess for cascading outages, uncontrolled separation, or instability, but the requirement to develop a corrective action plan for such exceedances is beyond Order 896's request for this proposed standard.

Likes 0	
Dislikes 0	

Response

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

BPA understands the complexities of drafting technically sound standards and appreciates the SDT's efforts through the multiple postings of this project.

Likes 0	
Dislikes 0	

Response

Broc Bruton - Broc Bruton On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Broc Bruton

Answer	
Document Name	

Comment

No Comment

Likes 0	
Dislikes 0	

Response

Kevin Conway - Western Power Pool - 4	
Answer	
Document Name	
Comment	

The Western Power Pool would like to thank the Drafting Team for working hard to find consensus. We understand the challenges the Drafting Team faces in meeting the expectations of a number of different organzations across North America.

Likes 0	
Dislikes 0	
Response	

Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	
Document Name	
Comment	

Requirement 3 –

Eversource recommends reinserting "Transmission Planner" or the phrase used in R4 "Each responsible entity, as identified in Requirement R1" as part of the coordination in R3. The DT stated in its Consideration of Comments that "Coordination is at the PC level and not at the TP level." Eversource agrees this to be true for developing the Temperature Events but disagrees in regards to implementing a process for developing planning cases. If the TPs are going to be expected to have a role in completing the Extreme Temperature Assessment as stated in Requirement 1, they should participate in implementing a process for the development of cases.

Each Planning Coordinator shall coordinate with all Planning Coordinators **and Transmission Planners** within each of its zone(s)…; or

Each Planning Coordinator shall coordinate with all Planning Coordinators and **with each responsible entity, as identified in Requirement R1,** within each of its zone(s)…;

Likes 0	
Dislikes 0	
Response	

Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	
Document Name	
Comment	

None	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
FirstEnergy has no additional comments.	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
NA	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE continues to underscore that the Standard Requirements, as currently stated, do not appear to require assessing the impact of concurrent failures of the Bulk Power System generation **and** transmission equipment that are typically experienced during extreme heat or cold weather conditions. FERC Order No. 896 states: "…the impact of concurrent failures of Bulk-Power System generation and transmission equipment and the	

potential for cascading outages that may be caused by extreme heat and cold weather events should be studied". The Considerations of the Order document says "Per Requirement R4, the data necessary to build the benchmark planning cases must be provided via MOD-032 and supplemented by other sources as needed. Any concurrent/correlated generator and transmission outages due to extreme heat and cold events in benchmark temperature events should be reflected in the model data and thus represented in the initial conditions of the benchmark planning cases."

Based on the current Requirements R3 and R4 language, the cases could be built with high loads and high generation dispatch for the extreme weather without including concurrent outages. Therefore, a requirement in R3 or R4 that specifically says to include "concurrent" generator and transmission outages in the initial conditions of the benchmark planning cases needs to be added in accordance with the FERC Order. Also, the rationale for those concurrent outages selected for the initial conditions shall be available as supporting information. Texas RE noticed that the Technical Rationale does mention concurrent outages and recommends incorporating this language directly into the requirement language itself through the note described below.

Texas RE suggests either requiring the basic assumptions described in R3 to include, at minimum, the severe contingencies or outages experienced within each Transmission Planner's respective area during the most extreme conditions to be modeled in the benchmarking cases. Texas RE recommends the following language for Requirement R3:

3.5 The most severe continencies experienced in each Transmission Planner's respective area during a historical most extreme conditions shall be documented and modeled in the benchmark planning case(s).

Likes 0	
Dislikes 0	

Response

Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford

Answer	
Document Name	

Comment

Comments: GTC has provided the below recommendations in previous ballots, however, it appears that the SDT has not considered revising the proposed standard to address, therefore, these concerns/recommendations are still considered valid by GTC.

R4:

• The SDT should consider removing R4.2, since the assessment already covers multiple extreme weather scenarios. There is questionable reliability benefit in running additional sensitivities that do not rise to the level of requiring (or eliminating) corrective actions.

R5:

• The recently adopted NERC Glossary term, System Voltage Limits, should be referenced in this requirement instead of the outdated wording "System steady state voltage limits". "…shall have criteria for acceptable System Voltage Limits …"

• Since this requirement appears to refer to steady-state voltage, the post contingency voltage deviation portion of the existing requirement should be removed. The resultant steady-state voltage level being outside of acceptable high and low limits is the point of concern. For example, if a low voltage criterion is 0.92 p.u., then voltages below this limit would violate this particular criterion regardless of whether the beginning voltage was 0.95 p.u., 0.98 p.u., or any other voltage level.

R6:

• The inclusion of “within an Interconnection” is not appropriate as the PC or TP should not be required to assess outside of its applicable area. Note the inclusion of more appropriate language referring to the PC’s or TP’s planning area (its portion of the Bulk Electric System) in this draft so it is not clear why some requirements refer to an Interconnection while others, more correctly, refer to the area of actual responsibility for the PC or TP.

• The following bullet contains a wording addition to clarify the applicability of this requirement to System-wide impacts. This is also consistent with wording in other Reliability Standards when referencing these types of impacts.

• “Each responsible entity, as identified in Requirement R1, shall define and document the criteria or methodology used in the Extreme Temperature Assessment analysis to identify instability, uncontrolled separation, or Cascading of the Bulk Electric System.”

R8:

• It is unclear if the responsible entity must identify continencies for each event type shown within each category, or only those event types that are expected to produce more severe System impacts on its portion of the Bulk Electric System

Likes 0	
Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	
Document Name	2023-07_Unofficial_Comment_Form Draft_4_110724_MRO.docx

Comment

Requirement R3 indicates forecasting Load, generation, and Transmission. There are significant barriers to modeling Load and generation based upon temperatures, notably forecasting out into the long-term planning timeframes. With that said, the MRO NSRF recommends that the NERC and drafting team develop implementation guidance and/or a reliability guideline to ensure Planning Coordinators can meet the requirements in the R3 section.

Several terms in the TPL-008-1 ERO Benchmark Weather Event Development and Maintenance Process DRAFT indicated defined terms are located in the glossary of terms, yet these terms are not defined in the glossary of terms. The term Zoneal is used rather than the term Zonal. There are also acronyms that do not represent the words spelled, for example it lists Affected Zonal Entity as ARE rather than the more representative term AZE.

Definitions Refer to the NERC Glossary of Terms3 for the below capitalized terms used in this process.

• Affected Zoneal Entity (ARE)

• Compliance Enforcement Authority (CEA)

• Coordinated Oversight

• Extreme Temperature Assessment (ETA)

• Lead Zoneal Entity (LRE)

• Multi-Zone Registered Entity (MRRE)

Likes 1	Scott Brame, N/A, Brame Scott
Dislikes 0	

Response

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro

Answer	
Document Name	

Comment

1. Requirement R1 as drafted includes two separate requirements, i.e. to (1) identify responsibilities amongst applicable PCs and TPs, and (2) complete an Extreme Temperature Assessment every five years.

BC Hydro suggests that these are separate objectives and recommends that this Requirement be split to reflect these accordingly for enforceability (e.g. incident severity level), and cause-based incident monitoring.

2. BC Hydro's understanding is that in order to determine the Contingencies that have a more severe impact per R7, the ETA needs to account for all contingencies within the identified zone(s), and not just those within its portion of the BES. Please confirm or provide additional clarity as appropriate.

3. Requirement R4 and the associated VSL Levels reference "the coordination process developed in Requirement R3". R3 requires a benchmark planning cases development process, it does not require a coordination process.

BC Hydro recommends Recommend revising R4 and the associated VSL Levels for clarity and consistency.

BC Hydro also recommends that the language of R3 be revised to read "to implement a documented process" rather than "to implement a process".

4. The VSL Table for Requirement R1 indicates a Severe Level if an entity "failed to identify individual and joint responsibilities". There are no other Severity Levels associated with responsibilities identification, which is conducive to an interpretation that failing to identify even one of the R2 through R11 associated responsibility would be classified as a Severe VSL. BC Hydro suggests that failing to identify one or less than the full set of responsibility should carry less Severity Levels, and recommends that this be reflected in the lower Severity Levels as well.

5. The High and Severe VSL Levels for Requirement R8 are based on an entity's failing to evaluate the results of the sensitivity (High VSL) and benchmarking cases (Severe VSL). R8 and its associated M8 do not explicitly require that an evaluation be also retained as evidence of compliance, in addition to the results documentation.

BC Hydro recommends that the R8, M8 and corresponding VSL Levels be revised for consistency.

Likes 0	
Dislikes 0	

Response

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	
Document Name	

Comment

- ITC believes that the Yes for NCLL for P0 Sensitivity Cases should be changed to No. If it is deemed important to analyze a sensitivity case, the system should be able to serve firm load both for system normal and for single contingencies. With the requirements left as proposed, entities would need to proactively start shedding load for changes in generation, real and reactive forecasted Load, or transfers. System Operators will be forced to rely on preventative load shed during long term construction outages when experiencing extreme weather as it is highly likely that these will not be able to be cancelled.
- ITC believes that the Yes allowing for NCLL for P1 Base and Sensitivity Cases should be changed to No. ITC believes that a reliable system should be able to serve firm load for system normal and for single contingencies. Utilities typically schedule long term construction outages during winter (off-peak) and then experience extreme temperature scenarios. System Operators will need to rely on preventative load shed during these long term construction outages, that could not be cancelled if entities include NCLL as part of their corrective action plan.
- **ITC suggests that Footnote 6 (Page 12) include a clarification that Non Consequential Load Loss shall not be the only element in a Corrective Action Plan. See below:**
    - Benchmark planning cases require the development of a Corrective Action Plan when the responsible entity's portion of the BES is unable to meet the performance requirements for categories P0 or P1. Additionally, in benchmark planning cases, Non-Consequential Load Loss is not permitted for category P0 and **Non Consequential Load Loss shall not be the only element of a Corrective Action Plan unless approved by applicable regulatory authorities or governing bodies responsible for retail electric service issues.** *See Requirement R9 for the relevant requirements.*
- Specify if temperature is F or C on benchmark table of events. Clarify and specify timing on standard on when they will review the benchmark events.
- In DRAFT ERO Enterprise Process for TPL-008-1 Benchmark Weather Event Development and Maintenance Standards Development and Engineering Process Document October 2024, ITC suggests moving footnote 4 page 2 into the Process Overview and clarify if these actions will happen every cycle, or just the first iteration.

Likes 0	
Dislikes 0	

Response

Casey Perry - PNM Resources - 1,3 - WECC,Texas RE

Answer	
Document Name	

Comment

No additional comments.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1, Group Name Exelon

Answer	

Document Name	
Comment	

Below are a few additional comments or questions for the drafting team to consider:

1. Clarify what “long-term transmission planning horizon” is in Requirement 3.1, which is the target time horizon for this standard. Currently NERC definition indicates year 6-10 or beyond. From our understanding, our PC intends to align with LTRTP.

2. Based on our interpretation, a benchmark temperature event doesn’t have to be a historical event. Is that correct?

Likes 0	
Dislikes 0	
Response	

Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - Greg Sorenson

Answer	
Document Name	
Comment	

RF appreciates the efforts of the Standards Drafting Team to apply comments recieved.

Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC

Answer	
Document Name	
Comment	

NPCC RSC agrees with the changes proposed by the standard drafting team.

Likes 0	
Dislikes 0	
Response	

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 5	
Likes 0	
Dislikes 0	
Response	

Helen Lainis - Independent Electricity System Operator - 2, Group Name IRC SRC	
Answer	
Document Name	
Comment	
The IRC SRC is concerned that Requirement R3 unnecessarily and inadvertently limits the ability of entities to properly develop their benchmark planning cases. Specifically, the IRC SRC is concerned that R3 could be understood to mean that entities are limited to making the adjustments specifically described in R3 and are prevented from making adjustments necessary to ensure that the generation necessary to serve load is available so that the case can solve. As the drafting team recognizes in the Technical Rationale, adjusting the case to ensure that it contains enough generation to serve the modeled load is essential to ensure that the standard does not stray into the realm of resource adequacy issues and fully complies with paragraph 94 of FERC Order No. 896, which states that resource adequacy is not in scope for this project. While the IRC SRC appreciates this recognition, the Technical Rationale is not a binding document, and future revisions to the standard may introduce additional ambiguity regarding what types of adjustments are permissible under Requirement R3.	

To clarify the standard and better position it for future revisions, the IRC SRC recommends that the drafting team revise Part 3.2 by replacing the period at the end of Part 3.2 with the following: ", provided that the responsible entity may adjust the total modeled generation or Load in each case as necessary to allow the total modeled generation to serve the total modeled System Load."

The IRC SRC also recommends that Requirement R4 be revised as needed to align with any revisions made to Requirement R3.

In addition, the IRC SRC requests that the ERO develop a Reliability Guideline for this proposed standard, and in particular, for Requirement R3 showing how a Planning Coordinator would adjust the benchmark planning case to ensure that it contains enough generation necessary to serve load.

Likes 0	
Dislikes 0	

Response

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2

Answer	
Document Name	

Comment

ERCOT joins the comments submitted by the IRC SRC for this question and adopts them as its own.

Likes 0	
Dislikes 0	

Response

Gregory Campoli - New York Independent System Operator - 2

Answer	
Document Name	

Comment

The NYISO would like to confirm that is it acceptable to use additional (beyond those directed in Requirement 2) weather metrics to identify the benchmark temperature events. For example, summer extreme conditions could include a temperature-humidity index which integrates temperature and humidity and is shown to be a more robust predictor of peak loads than temperature alone. Likewise, winter extreme conditions could include a wind component (i.e., a wind-chill index). In either case, the associated temperature value could easily be extracted, as necessary, for any follow-on analysis (e.g., line ratings) requiring temperature specifically.

The NYISO would like to confirm that is it acceptable to use additional (beyond those directed in Requirement 2) averaging mechanisms which have been demonstrated to be robust predicators of extreme peak loads. For example, the NYISO currently employs a three-day weighted average temperature index for summer conditions and a three-day weighted average of a temperature-wind index variable for winter conditions.

The NYISO would like to confirm that is it acceptable to leverage their own knowledge and expertise in constructing the specific extreme heat and cold temperature events to be studied, within reasonable constraints, such as the 40-year historic period.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO

Answer	
Document Name	

Comment

Another concern for SPP is applicable to the model not being able to solve which includes the sensitivity (stability cases for P0 condition). It is unclear on the expectation of the drafting team in reference to the PC not being able to solve the models for the various categories of the ETA. Also, there are concerns around gathering and aligning the appropriate temperature data independently.

Requirement R3 indicates forecasting Load, generation, and Transmission. There are significant barriers to modeling Load and generation based upon temperatures, notably forecasting out into the long-term planning timeframes. With that said, SPP recommends that the NERC and drafting team develop implementation guidance and/or a reliability guideline to ensure Planning Coordinators are able to meet the requirements in the R3 section.

Likes 0	
Dislikes 0	

Response

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1

Answer	
Document Name	

Comment

Thank you for the opportunity to comment.

Likes 0	
Dislikes 0	

Response

Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle

Answer	
Document Name	

Comment

The DT should highly consider or leave it to Planning Coordinator’s discretion when it comes to sensitivities: PC’s should be given the opportunity/flexibility in determining whether sensitivities are needed or as to how much study is needed regarding sensitivities.

Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	
Document Name	
Comment	
OPG supports NPCC Regional Standards Committee’s comments.	
Likes 0	
Dislikes 0	
Response	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	
Document Name	
Comment	
While ATC has voted in support of approving project 2023-07; we are also in support of the comments provided by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments

Project Name:	2023-07 Transmission Planning Performance Requirements for Extreme Weather | Draft 4
Comment Period Start Date:	11/7/2024
Comment Period End Date:	11/21/2024
Associated Ballot(s):	2023-07 Transmission Planning Performance Requirements for Extreme Weather Implementation Plan AB 4 OT 2023-07 Transmission Planning Performance Requirements for Extreme Weather TPL-008-1 AB 4 ST

There were 50 sets of responses, including comments from approximately 140 different people from approximately 89 companies representing 10 of the Industry Segments as shown in the table on the following pages.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, contact Director, Standards Development Jamie Calderon (via email) or at (404) 446-9647.

Questions

1. The Drafting Team (DT) updated Requirement R2 based on comments received. Do you agree? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

2. The DT updated Requirement R9 based on comments received. Do you agree? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

3. The DT updated Attachment 1 based on comments received. Do you agree? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

4. The DT believes proposed modifications in TPL-008-1 provide entities with flexibility to meet the reliability objectives in a cost-effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost-effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

5. Provide any additional comments for the drafting team to consider, including the provided technical rationale document, if desired.

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
BC Hydro and Power Authority	Adrian Andreoiu	1	WECC	BC Hydro	Hootan Jarollahi	BC Hydro and Power Authority	3	WECC
					Helen Hamilton Harding	BC Hydro and Power Authority	5	WECC
					Adrian Andreoiu	BC Hydro and Power Authority	1	WECC
MRO	Anna Martinson	1,2,3,4,5,6	MRO	MRO Group	Shonda McCain	Omaha Public Power District (OPPD)	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jamison Cawley	Nebraska Public Power District	1,3,5	MRO
					Jay Sethi	Manitoba Hydro (MH)	1,3,5,6	MRO
					Husam Al-Hadidi	Manitoba Hydro (System Performance)	1,3,5,6	MRO
					Kimberly Bentley	Western Area Power Administration	1,6	MRO

					Jaimin Patal	Saskatchewan Power Corporation (SPC)	1	MRO
					George Brown	Pattern Operators LP	5	MRO
					Larry Heckert	Alliant Energy (ALTE)	4	MRO
					Terry Harbour	MidAmerican Energy Company (MEC)	1,3	MRO
					Dane Rogers	Oklahoma Gas and Electric (OG&E)	1,3,5,6	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Ayotte	ITC Holdings	1	MRO
					Andrew Coffelt	Board of Public Utilities-Kansas (BPU)	1,3,5,6	MRO
					Peter Brown	Invenergy	5,6	MRO
					Angela Wheat	Southwestern Power Administration	1	MRO

					Joshua Phillips	Southwest Power Pool	2	MRO
					Patrick Tuttle	Oklahoma Municipal Power Authority	4,5	MRO
Exelon	Daniel Gacek	1		Exelon	Daniel Gacek	Exelon	1	RF
					Kinte Whitehead	Exelon	3	RF
Independent Electricity System Operator	Helen Lainis	2		IRC SRC	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Charles Yeung	SPP	2	SERC
					Elizabeth Davis	PJM	2	RF
Eversource Energy	Joshua London	1		Eversource	Joshua London	Eversource Energy	1	NPCC
					Vicki O'Leary	Eversource Energy	3	NPCC
Public Utility District No. 1 of Chelan County	Joyce Gundry	3		CHPD	Rebecca Zahler	Public Utility District No. 1 of Chelan County	5	WECC
					Joyce Gundry	Public Utility District No. 1	3	WECC

						of Chelan County		
					Diane Landry	Public Utility District No. 1 of Chelan County	1	WECC
					Tamarra Hardie	Public Utility District No. 1 of Chelan County	6	WECC
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	RF
Black Hills Corporation	Rachel Schuldt	6		Black Hills Corporation - All Segments	Travis Grablander	Black Hills Corporation	1	WECC
					Josh Combs	Black Hills Corporation	3	WECC

					Rachel Schuldt	Black Hills Corporation	6	WECC
					Carly Miller	Black Hills Corporation	5	WECC
					Sheila Suurmeier	Black Hills Corporation	5	WECC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
					Randy Buswell	Vermont Electric Power Company	1	NPCC
					James Grant	NYISO	2	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC

					David Burke	Orange and Rockland	3	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
					Sean Cavote	PSEG	4	NPCC
					Jason Chandler	Con Edison	5	NPCC
					Tracy MacNicoll	Utility Services	5	NPCC
					Shivaz Chopra	New York Power Authority	6	NPCC
					Vijay Puran	New York State Department of Public Service	6	NPCC
					David Kiguel	Independent	7	NPCC

					Joel Charlebois	AESI	7	NPCC
					Joshua London	Eversource Energy	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC
					Joel Charlebois	AESI	7	NPCC
					John Hastings	National Grid	1	NPCC
					Erin Wilson	NB Power	1	NPCC
					James Grant	NYISO	2	NPCC
					Michael Couchesne	ISO-NE	2	NPCC
					Kurtis Chong	IESO	2	NPCC
					Michele Pagano	Con Edison	4	NPCC
					Bendong Sun	Bruce Power	4	NPCC
					Carvers Powers	Utility Services	5	NPCC
					Wes Yeomans	NYSRC	7	NPCC
Shannon Mickens	Shannon Mickens		MRO,SPP RE,WECC	SPP RTO	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Mia Wilson	Southwest Power Pool Inc.	2	MRO
					Eddie Watson	Southwest Power Pool Inc.	2	MRO

					Erin Cullum	Southwest Power Pool Inc.	2	MRO
					Jonathan Hayes	Southwest Power Pool Inc.	2	MRO
					Jeff McDiarmid	Southwest Power Pool Inc.	2	MRO
					Scott Jordan	Southwest Power Pool Inc	2	MRO
					Mason Favazza	Southwest Power Pool Inc	2	MRO
					Zach Sabey	Southwest Power Pool Inc	2	MRO
					Josh Phillips	Southwest Power Pool Inc.	2	MRO
Tim Kelley	Tim Kelley		WECC	SMUD and BANC	Nicole Looney	Sacramento Municipal Utility District	3	WECC
					Charles Norton	Sacramento Municipal Utility District	6	WECC
					Wei Shao	Sacramento Municipal Utility District	1	WECC

					Foung Mua	Sacramento Municipal Utility District	4	WECC
					Nicole Goi	Sacramento Municipal Utility District	5	WECC
					Kevin Smith	Balancing Authority of Northern California	1	WECC

1. The Drafting Team (DT) updated Requirement R2 based on comments received. Do you agree? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	No
Document Name	
Comment	

BC Hydro appreciates the drafting team's efforts and opportunity to comment, and offers the following comments.

(1) The ERO is not subject to TPL-008-1 regulatory compliance. Entities are relying on the ERO's infrastructure and commitment to maintain the benchmark temperature event library. As drafted, a PC can be in potential noncompliance if they choose to use a benchmark event from the ERO-maintained library, and the event is not meeting the specifications per Parts 2.1 and 2.2.

BC Hydro is requesting that the drafting team in conjunction with the ERO document the controls that will be in place to maintain the library. These controls should include the location of the library and quality checks to ensure the events in the library meet R2 Parts 2.1 and 2.2.

BC Hydro recommends revising the language of R2 Parts 2.1 and 2.2 to apply if a PC develops their own benchmark events, and not apply to the ERO benchmark events library.

(2) A Planning Coordinator may be in a potential noncompliance if another PC is not participating in the required coordination and assessment activities, which may be the case as different jurisdictions (such as Canada and US, or even between BC and Alberta within Canada) have different standard adoption timelines.

BC Hydro suggests that the Implementation Plan include provisions that allow for compliance enforcement only when TPL-008-1 is effective in all applicable jurisdictions.

Alternatively, the Canada West zone should be split into a BC-only zone. This may help alleviate compliance risks and it will also help creating a more robust ETA given the different geographic areas and weather zones across the Canadian provinces of BC and Alberta.

There could also be a scenario where in a multiple PC zone there may be one PC that does not participate in the coordination, or there is no agreement on a common event. In such a scenario, all PCs may be found in noncompliance. BC Hydro recommends that the standard include provisions to allow for conflict resolution.	
Likes 0	
Dislikes 0	

Response

Thank you for your comments.

1. Flexibility has been provided for entities who wish to develop, in coordination with other Planning Coordinators within its zone, its own benchmark events. Additionally, the ERO has developed a process to follow to provide updated data every five years and is committed to providing this for entities. The data developed by the ERO followed the criteria in Parts 2.1 and 2.2 and an entity would pull the information provided in the library to show compliance for the 40 worst and 20 extreme.

   A link has been added to the ERO Benchmark Event Library under the Associated Documents section for the location of the library.

   The team feels benchmark events are clear in the standard and can be completed by the ERO or the PC. Language from the standard states: "when completing the Extreme Temperature Assessment. The benchmark temperature events shall be obtained from the benchmark library maintained by the ERO or developed by the Planning Coordinators."

2. If an entity runs into the issue of other Planning Coordinators not willing to coordinate, it can reach out to its respective Regional Entity for assistance. In addition, for compliance purposes, an entity can show that they attempted to coordinate with other Planning Coordinators within its zone. Essentially, the entity has done all it can and will be able to show that evidence that it attempted to coordinate and come to consensus.

   The implementation plan has standard language and, if entities have issues coordinating with other Planning Coordinators, it can complete the steps listed above.

   The team does not agree with further splitting out zones as multiple iterations have been completed and the focus of FERC Order 896 is coordination between wide areas. The team feels all zones are in a good place for version one of TPL-008.

Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	

NextEra does not agree with the modifications to R2. The SAR references the use of either "a projected frequency (e.g., 1-in-50-year event); or a probability distribution (95th percentile event)." The development of extreme events refers to foot note 9 *"Benchmark events will form the basis for a planner's benchmark planning case— i.e., the base case representing system conditions under the relevant benchmark event—that will be used to study the potential wide-area impacts of anticipated extreme heat and cold weather events."*

FERC via the SAR requested to develop a base case that is representative of system conditions which could be a 1 in 50 year or a P95 event. Following the proposed language in the standard and the ERO library, the warmest temperature Florida could use for its winter assessment is 32.3 degrees and the lowest being 24.9F. The concern is that the entire state is at freezing temperatures and will generate significant winter loads in Florida much larger than the 20% sensitivity we use for winter, thereby generating transmission projects that will not provide value to our customers. NextEra does not consider this a P95 event, especially if the average 3 rolling day is taking into consideration (also not requested by the SAR). The coldest temperature experienced in Miami over the last 40 years was during the winter of 1989, where temperatures were as low as 30 degrees. The lowest 3 day rolling average was 32.6 degrees (12/23-27F, 12/24-31F, 12/25-30F and 12/27-38F). The standard as written will force NextEra to plan to a greater than P100 winter loads. This is an un-realistic approach, considering most of Florida's load is located in Southern Florida south of Lake Okeechobee. NextEra recommends the language in R2 to state "Represent the 95th percentile extreme conditions for the climate zone based on the 3-day rolling average of maximum (heat) or minimum (cold) temperature across the zone."

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The benchmark events are based on 95% of major prior extreme heat and cold weather events over the past 40 years. If the events provided in the ERO benchmark event library do not work for your zone, you are welcome to work with other Planning Coordinators within your zone to develop one common extreme heat and one common extreme cold temperature benchmark event following the expectations laid out in Requirements R2.

Donald Lock - Talen Generation, LLC - 5

Answer	No
Document Name	
Comment	
R2.2, "Represent one of the 20 most extreme temperature conditions based on the three-day rolling average of daily maximum (heat) or daily minimum (cold) temperature across the zone," is far too lax. Selecting the 20th most severe event of the past four decades would not constitute much of a challenge.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. When considering extreme events over a 3-day rolling average over 40-years does not provide a ton of data to work from. While yes, extreme events have become more common in recent years, it is important for an entity to be able to evaluate events that happened over 40-years as some of the events may not be extreme compared to other events. It is important to collect 20 extreme events to review and consider which event to study for further studies. This provides enough data for entities to review and select their worst events for that zone to work from.	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC (CEHE) believes with the current zone designations, there are some zones where temperature differences would be significant due to their very large north/south geographical spans. A concern arises whether the chosen extreme temperature event case is applicable to the overall zone in these cases. It might not be representative of certain parts of the zone. Transmission Planners should be involved in the selection. CEHE recommends the following revision: Each Planning Coordinator**, in conjunction with its Transmission Planner(s)**, shall select which extreme heat and extreme cold weather events to develop benchmark extreme temperature events applicable to their region.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comments. Requirement R1 requires Planning Coordinators and Transmission Planners to identify individual or joint responsibilities throughout TPL-008-1. It is the teams understanding that Planning Coordinators have the wide area view regarding zones and the Transmission Planners may not be privy to that specific information, but there is nothing that precludes Transmission Planners from being involved in conversations for certain parts that are up to Planning Coordinators. The importance of TPL-008-1 and FERC Order 896 is that entities are talking and preparing for extreme temperature events to keep the grid reliable and running so customers maintain power during these extreme events. FERC Order focus is wide area.	
Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO	
Answer	No
Document Name	
Comment	
SPP opposes splitting our region into North and South zones. As a contiguously integrated system, our system does not demarcate at state lines boundaries. We recently completed our 2024 Integrated Transmission Plan that resulted in $7.5B in network upgrades to further strengthen this integration. The standard as written could require SPP to select a high and low temperature extreme in both the northern region and southern region, creating a situation where we are disconnecting the interconnections we built and those planned to in the future. This results in a needless complication to the existing systems and creates an unnecessary burden that does not improve reliability. As proposed in the previous version of the document, we request the Planning Coordinator zone be reestablished into a contiguous system for evaluating these extreme events. The bifurcation is even less appropriate when considering the events proposed in the *ERO Enterprise Process for TPL-008-1 Benchmark Weather Event Development and Maintenance* indicate using an event that overlaps both SPP regions from December 24, 1989. Conversely, the proposed extreme heat case only affected the proposed SPP South Region. If required to use two zones, we would like to see clarification in the language that indicates regions are allowed to utilize the same scenario provided it meets the requirements in 2.1 and 2.2.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Please see updated language added to Attachment 1. There is nothing that prevents zones from combining if they find it necessary. Zones identified are the bare minimum and the DT believes are required to meet the wide area needs of the FERC Order 896. This does not prevent zones from merging.	
Gary Trezza - Long Island Power Authority - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
We have some comments / observations regarding Req #2 that we would like to share with the SDT: - In Req #2 language, the word 'select' has been replaced by 'identify'. However, we observe that the word 'select' is still utilized in the Measure #2 language, the Req #3 language and in the Technical Rationale document. This inconsistency could cause some confusion about the actual intent. For example, the word 'identify' might better imply the coordination that is allowed by Req #2. The Technical Rationale should be updated to highlight and clarify the significance of this wording change. - Req #2 states that the benchmark temperature events shall be obtained from the benchmark library maintained by the ERO or developed by the Planning Coordinators. Is this implying that some of the benchmark events may not be available on the library after they are developed by the PCs? If so, is there any expectation (or should there be any) that these benchmark events be somewhat communicated/shared to other PCs for awareness if they are developed and not on the benchmark library?	
Likes 0	

Dislikes 0	
Response	

Thank you for your comments.

M2. Please see the updated Measure.

TR: R2 language has been updated and the TR does not need to be updated.

R2. All events will be provided by the ERO within the library and all events are posted for entities to prepare for TPL-008-1 first set of five years required. The flexibility was added to TPL-008-1 to allow entities who wished to develop their own events that opportunity. All required events will be provided by the ERO in the ERO library by the following the process developed and posted for entities to see. Also, please see updated TR.

Daniela Atanasovski - APS - Arizona Public Service Co. - 1

Answer	Yes
Document Name	
Comment	

None

Likes 0	
Dislikes 0	
Response	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	Yes
Document Name	
Comment	

FirstEnergy has no concerns with the update to Requirement R2.	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Texas RE recommends revising Measure M2 from "…to select one common extreme heat benchmark temperature event" to "to identify one common extreme heat benchmark temperature event. This makes the language consist with the revision made to Requirement R2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see updated measure.	
Sharon Darwin - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Southern Company supports EEI's comments.	
Likes 0	

Dislikes 0	
Response	
Please see the DTs response to EEI.	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
ITC supports the proposed changes made to Requirement R2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the changes made to Requirement R2, which empowers the Planning Coordinator to develop the benchmark temperature events rather than solely depending on the benchmark temperature events contained in the benchmark library.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
PNM & TNMP supports EEI's comments and supports R2.	
Likes 0	
Dislikes 0	
Response	
Please see DT's response to EEI.	
Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	Yes
Document Name	
Comment	
Exelon agrees with the updated proposed TPL-008 Reliability Standard Requirement R2. Additionally, are there any plans to add guidance regarding "most extreme temperature conditions" in section 2.2? Can a planning coordinator come up with its own criteria/metric considering that they are likely a broad range of temperatures throughout the weather zone(s) for each temperature events?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The Requirement R2 Part 2.2 is general in which the PCs can discuss within their study zone to determine what would be appropriate to meet one of the 20 most extreme temperature conditions that are based on the three-day rolling average of the maximum or minimum temperatures. An example could be the highest three-day rolling average of the maximum temperatures, or	

the lowest three-day rolling average. The PC can document their process based on its documented process criteria for selecting an event if you do not select an event from the ERO library.	
Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop	
Answer	Yes
Document Name	
Comment	
Ameren agrees with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to EEI.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	Yes

Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Please see DT's response to EEI.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Please see DT's response to EEI.	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	Yes
Document Name	
Comment	

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) on question 1	
Likes 0	
Dislikes 0	
Response	
Please see DT's response to EEI.	
Helen Lainis - Independent Electricity System Operator - 2, Group Name IRC SRC	
Answer	Yes
Document Name	
Comment	
The ISO/RTO Council Standards Review Committee (IRC SRC) generally agrees with the revisions to Requirement R2, and recommends the following additional revisions to further clarify the Requirement: - Revise the second-to-last sentence at the end of R2 as follows to reference PCs first and the ERO benchmark library second to avoid a possible inference that the PC is required to develop its own benchmark library: "The benchmark temperature events shall be developed by the Planning Coordinators or obtained from the benchmark library maintained by the ERO." - Revise the last sentence at the end of R2 to read as follows to better reflect the fact that the Planning Coordinator (rather than the benchmark temperature event) is ultimately the entity making the considerations described in Parts 2.1 and 2.2: "**The Planning Coordinator's selection of** each benchmark temperature event shall:" - Revise Part 2.2 as follows to clarify that the temperature conditions referenced in Part 2.2 are required to fall within the time period referenced in Part 2.1: "Represent one of the 20 most extreme temperature conditions **within the period identified in Part 2.1** based on the three-day rolling average…"	
Likes 0	
Dislikes 0	

Response	
Thank you for your comments. The DT does agree with swapping the order as it does not see a difference. It is clear that you can obtain the info from the ERO library or develop your own. The TP may consult with the PC on these decisions. This is also laid out in R1 that PCs and TPs will lay out their joint or individual responsibilities. Please see updated TPL-008-1 Requirement R2 including PCs. You cannot complete Part 2.2 without completing 2.1. Your understanding of this is correct and the team does not feel this additional language is necessary.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) for this question and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to ISO/RTO	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	

AEPC has signed on to ACES comments. Please review ACES comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to ACES.	
Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - Greg Sorenson	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Broc Bruton - Broc Bruton On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Broc Bruton	
Answer	
Document Name	
Comment	
Abstain	
Likes 0	
Dislikes 0	
Response	

2. The DT updated Requirement R9 based on comments received. Do you agree? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.	
Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO	
Answer	No
Document Name	
Comment	
The current language in R9.4 says revisions to Corrective Action Plans are limited to the subsequent Extreme Temperature Assessments, yet the underlying system may have change identified through system upgrades. These Corrective Action Plans should be more flexible in the event a system upgrade is completed or a separate assessment demonstrates the underlying performance issue has been mitigated. The inclusion of "or other planning assessments" in 9.4 appeared amicable during the drafting team discussion, and we request this be adopted as proposed in the following revision: 9.4. Be permitted to have revisions to the Corrective Action Plan in subsequent Extreme Temperature Assessments **or other planning assessments**, provided that the planned Bulk Electric System shall continue to meet the performance requirements of Table 1.	
Likes 0	
Dislikes 0	
Response	
Please see updated Technical Rationale.	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	No
Document Name	

Comment	
MRO is not comfortable with two parts of R9.3, both of which limit significantly the region's ability to meaningfully enforce the requirement: 1. The terms "regulatory authorities" and "governing bodies" are not specific 2. There are no timing requirements prescribed for the responsible entity concerning when the responsible entity must make its Corrective Action Plan available to, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. This requirement is addressing the FERC Order 896 directive in P152 that states "we direct NERC to develop certain processes to facilitate interaction and coordination with applicable regulatory authorities or governing bodies responsible for retail electric service as appropriate in implementing a corrective action plan." Lastly, the TPL-008-1 Standard is aligning with what the FERC Order 896 directs. The DT feels flexibility is an important aspect of the timing requirements. Your Corrective Action Plan should capture your timing component. In addition, other entities have various processes in place throughout the US and the DT feels it is important that flexibility be provided for those that have certain processes already in place for soliciting feedback, etc.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT joins the comments submitted by the IRC SRC for this question and adopts them as its own.	
Likes 0	
Dislikes 0	

Response	
Please see the DT's response to IRC SRC.	
Helen Lainis - Independent Electricity System Operator - 2, Group Name IRC SRC	
Answer	No
Document Name	
Comment	

The current language in R9.4 says revisions to Corrective Action Plans are limited to subsequent Extreme Temperature Assessments. However, the underlying system may change between assessments because of system upgrades. These Corrective Action Plans should be more flexible in the event a system upgrade is completed, or a separate assessment demonstrates the underlying performance issue has been mitigated. The inclusion of "or other planning assessments" in 9.4 appeared to be acceptable during the drafting team discussion, and we request this be adopted as proposed in the following revision:

a. 9.4. Be permitted to have revisions to the Corrective Action Plan in subsequent Extreme Temperature Assessments **or other planning assessments**, provided that the planned Bulk Electric System shall continue to meet the performance requirements of Table 1.

Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Please see the updated TR.	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	

The current draft is not clear what the timeframe is for providing the CAP in R9.1. In addition, there is no timeframe when to notify the applicable regulatory authorities or governing bodies in R9.2. CEHE strongly disagrees with the following statement in R9.3: "Make its Corrective Action Plan available to, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues." CEHE recommends that "applicable regulatory authorities or governing bodies" be defined. CEHE also recommends that TPs should be providing CAP information only to their PC.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. Please see the updated TR.

This requirement is addressing the FERC Order 896 directive in P152 that states "we direct NERC to develop certain processes to facilitate interaction and coordination with applicable regulatory authorities or governing bodies responsible for retail electric service as appropriate in implementing a corrective action plan." Lastly, the TPL-008-1 Standard is aligning with what the FERC Order 896 directs. The DT feels flexibility is an important aspect of the timing requirements. Your Corrective Action Plan should capture your timing component. In addition, other entities have various processes in place throughout the US and the DT feels it is important that flexibility be provided for those that have certain processes already in place for soliciting feedback, etc.

Richard Vendetti - NextEra Energy - 5

Answer	No
Document Name	

Comment

NextEra does not agree with the language of R9.3 regarding the solicitation of feedback, as this is in line and satisfied through R11 of the standard.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. R9 and R11 require different objectives.

R9 addresses FERC Order 896 by requiring feedback from regulatory authorities and governing bodies. This requirement is addressing the FERC Order 896 directive in P152 that states "we direct NERC to develop certain processes to facilitate interaction and coordination with applicable regulatory authorities or governing bodies responsible for retail electric service as appropriate in implementing a corrective action plan." R11 is providing your information to RCs.	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	
During the recent revisions, a proposal was made with support to clarify 9.4 that revisions to a Corrective Action Plan should be allowed if other planning assessments resolve the concern. As such this should be captured in requirement 9.4 such as the following: 9.4. Be permitted to have revisions to the Corrective Action Plan in subsequent Extreme Temperature Assessments **or other planning assessments**, provided that the planned Bulk Electric System shall continue to meet the performance requirements of Table 1.	
Likes 1	Scott Brame, N/A, Brame Scott
Dislikes 0	
Response	
Thank you for your comment. Please see the updated TR.	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	No
Document Name	
Comment	
• The purpose and required response actions related to the sharing of CAPs and solicitation of feedback is not clear. • Documentation of alternatives is an additional administrative burden and provides little benefit to reliability. It is also unclear if there is some type of expectation these alternatives are reviewed or potentially challenged as invalid.	

• The role of the TO and/or GO in implementing or otherwise responding to CAPs that may require additions or modifications to their systems/facilities is not captured in these requirements. • There appears to be a significant amount of outside review required but no clear actions the responsible entity is required to take, particularly if there is a dispute. What is the purpose of the review and the expected response? This potentially produces an undue burden on the PC/TP and adds subjectivity in requiring a review with no documented guidelines for conducting the review. • GTC recommends the restructuring of requirement 9 such that documentation of alternatives along with the sharing and soliciting feedback back is only necessary when utilizing Non-Consequential Load Loss as an interim solution.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. FERC Order No. 896 directs NERC "to develop certain processes to facilitate interaction and coordination with applicable regulatory authorities or governing bodies responsible for retail electric service as appropriate in implementing a corrective action plan" (¶152). In the event that Non-Consequential Load Loss is included in the Corrective Action Plan for a P1 Contingency, the responsible entity shall document alternative(s) considered, make the Corrective Action Plan available to, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues. So long as an entity makes its Corrective Action Plan available to, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues, and determines that it needs to move forward with its CAP, you have successfully completed what is required of R9 Part 9.3. The charge of the SAR does not incorporate TOs and GOs. This is a planning standard. Based on review of the FERC Order, CAPs are for all types stated in TPL-008-1. TPL-008-1 is assisting in ensuring entities are prepared for extreme temperature events and know how to keep the grid reliable and the power on. Please read FERC Order 896. It states in P 153. "We adopt our rationale set forth in the NOPR and conclude that the directive to require the development of corrective action plans is needed for Reliable Operation of the Bulk-Power System. Under the currently effective Reliability Standard TPL-001-5.1, planning coordinators and transmission planners are required to evaluate possible actions to reduce the likelihood or mitigate the consequences of extreme weather events, but are not obligated to develop corrective action plans, even if such events are found to cause cascading outages. Experience over the past decade has demonstrated that the potential severity of extreme heat and cold weather events exacerbates the likelihood to cause system instability, uncontrolled separation, or cascading failures as a result of a sudden disturbance or unanticipated failure of system elements. Thus, we conclude that entities should proactively address known system vulnerabilities by	

developing corrective action plans that include mitigation for specified instances where performance requirements for extreme heat and cold events are not met”.
Joshua London - Eversource Energy - 1, Group Name Eversource

Answer	No
Document Name	

Comment
Eversource has concerns regarding compliance with Requirement R9.3. Because this standard is focused on “Extreme Temperature Events”, the company can foresee issues with regulatory agencies not wanting the company to invest significant funds into these issues. What would occur if Eversource supplied a CAP to the appropriate governing body and they state they do not agree the work is necessary? Would creating the CAP still meet the intent of the requirement although it may not be allowed to be implemented? Eversource recommends the DT consider adding language in case such a scenario arises.

Likes 0	
Dislikes 0	

Response
Thank you for your comments. FERC Order No. 896 directs NERC “to develop certain processes to facilitate interaction and coordination with applicable regulatory authorities or governing bodies responsible for retail electric service as appropriate in implementing a corrective action plan” (¶152). In the event that Non-Consequential Load Loss is included in the Corrective Action Plan for a P1 Contingency, the responsible entity shall document alternative(s) considered, make the Corrective Action Plan available to, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues. So long an entity makes its Corrective Action Plan available to, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues, and determines that it needs to move forward with its CAP, you have successfully completed what is required of R9 Part 9.3. Lastly, if you solicit the feedback and make aware options, such as, load shed opportunities, etc. You are not required to get regulatory approval nor can you force the regulatory authority to respond. You have done what is required of the requirement. In the end permits could be achieved, etc. consistent with requirement.
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	No
Document Name	
Comment	
We recommend that further clarification be given to how “applicable” regulatory authorities or governing bodies are determined.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. This would be the regulatory authorities or governing bodies that may have authority on rate making or permitting transmission upgrade authorities, etc. (state public utility commission. local municipal utilities, etc.)	
Broc Bruton - Broc Bruton On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Broc Bruton	
Answer	No
Document Name	
Comment	
Oncor strongly disagrees with the following statement in R9.3: “Make its Corrective Action Plan available to, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.” We propose that “applicable regulatory authorities or governing bodies” be defined and limited. For example, a TP should only need to provide their PC with CAP information.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. This requirement is addressing the FERC Order 896 directive in P152 that states “we direct NERC to develop certain processes to facilitate interaction and coordination with applicable regulatory authorities or governing bodies responsible for retail electric service as appropriate in implementing a corrective action plan.” Lastly, the TPL-008-1 Standard is aligning with what the FERC Order 896 directs. The DT did its best to align with TPL-001 while meeting the FERC Order 896 directives.	

In addition, the individual or joint responsibilities are determined in R1 by the TP and PC.	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
1) Based on other projects that include developing and implementing CAPs, USV does not agree with the proposed modifications and would feel more confident if there were guidelines and more structured timelines set for the CAPs. Perhaps not in the standard itself, but guidance on timelines could be explained in the technical rationale and include timelines for implementing CAPs and when entities can utilize backup action plans such as Non-Consequential Load Loss. 2) The newly proposed modifications to R9 compared to the proposed modifications from the previous draft do not change the obligations for responsible entities. The new requirement 9.3 is administrative in nature and does not appear to provide any increase in reliability, if anything it would delay the implementation of the CAP. USV understands the directives in FERC order 896 and the need for R9. However, we disagree that any significant improvements have been made to previously proposed R9 modifications.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The DT feels flexibility is an important aspect of the timing requirements. Your Corrective Action Plan should capture your timing component. In addition, other entities have various processes in place throughout the US and the DT feels it is important that flexibility be provided for those that have certain processes already in place for soliciting feedback, etc. Requirement R9 Part 9.3 is addressing the FERC Order 896 directive in P152 that states “we direct NERC to develop certain processes to facilitate interaction and coordination with applicable regulatory authorities or governing bodies responsible for retail electric service as	

appropriate in implementing a corrective action plan." Lastly, the TPL-008-1 Standard is aligning with what the FERC Order 896 directs. The DT did its best to align with TPL-001 while meeting the FERC Order 896 directives.	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	Yes
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 2	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to MRO NSRF.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop	
Answer	Yes
Document Name	
Comment	
Ameren agrees with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to EEI.	
Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	Yes
Document Name	
Comment	

Exelon agrees with the updated proposed TPL-008 Reliability Standard Requirements R9.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
PNM & TNMP agrees with R9.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the changes made to Requirement R9 and offers no additional changes.	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
ITC supports the proposed changes made to Requirement R9.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Sharon Darwin - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Southern Company supports EEI’s comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to EEI.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes

Document Name	
Comment	
FirstEnergy has no concerns with the update to Requirement R9.	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - Greg Sorenson	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gary Trezza - Long Island Power Authority - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE continues to recommend including a timeframe for which the CAPs need to be developed and implemented once the benchmark planning case study results indicate the System is unable to meet performance requirements. Requirement R2 states: "Be permitted to utilize Non-Consequential Load Loss as an interim solution, which normally is not permitted for category P0 in Table 1, in for situations that are beyond the control of the Planning Coordinator or Transmission Planner that prevent the implementation of a Corrective Action Plan in *the required timeframe*…" Texas RE reads the proposed standard language as allowing the entity to determine the "required timeframe." While the revised language provides for a coordination process with regulatory authorities, it does not appear these entities could reject a Corrective Action Plan if the required timeframe was unduly extended. Texas RE therefore continues to	

recommend placing more explicit requirements around CAP development and implementation to prevent unilaterally lengthy CAPs and ensure their timely and effective implementation.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT feels flexibility is an important aspect of the timing requirements. Your Corrective Action Plan should capture your timing component. In addition, other entities have various processes in place throughout the US and the DT feels it is important that flexibility be provided for those that have certain processes already in place for soliciting feedback, etc.	

3. The DT updated Attachment 1 based on comments received. Do you agree? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	No
Document Name	
Comment	
The SDT made vast improvements to Attachment 1 by splitting MISO and SPP zones into MISO North, MISO South, SPP North, and SPP South. The SDT attempted to move the disjointed sections of SERC Central to the appropriate MISO or SPP zones. However, the SDT needs to include geographical boundaries to clarify which SERC Central PCs should belong to MISO North, MISO South, SPP North, and SPP South. For example: • Zone - "MISO South" • Planning Coordinator(s) – "Planning Coordinator(s) in MISO and *SERC* that serve portions of Montana, North Dakota, South Dakota, Minnesota, Iowa, Wisconsin, Michigan, Indiana, Illinois, Missouri, or Kentucky"	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT does not agree that boundaries would be beneficial. Keeping that map as a noncompliance visual aid allows entities to see an approximation and this also assists in the future changes to boundaries. However, the attachment 1 table provides the details needed when determining Planning Coordinator locations within the zones.	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	No
Document Name	
Comment	

B.C. has a wide geographic area, applying one common extreme temperature is not ideal. The Canada West cold benchmark event temperatures are closer to our BC Hydro south region coldest days temperature. However, as winter peaking utilities, most of BC Hydro's temperature sensitive load (mostly distribution load) are located in the Lower Mainland and Vancouver Island.

BC Hydro recommends that the Canada West zone be split into BC and Alberta based on weather and geographical differences that are more conducive to a robust ETA.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The team does not agree with further splitting out zones.

FERC Order 896 explains the importance of coordination among entities, which has been reflected in the TPL-008-1 standard. It is time for Planning Coordinators to discuss and plan for future events to promote reliability on the grid and prevent black outs due to extreme temperature events. As stated before, if entities within a zone have trouble determining common events to work from, additional meetings need to be scheduled among one another to coordinate and talk through the best event to work from or reach out to the respective Regional Entity for assistance. Pull wide area comment from FERC Order.

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	

Comment

Please view response to Question 1.

Likes 0	
Dislikes 0	

Response

Please see the DT's response to Q1.	
Helen Lainis - Independent Electricity System Operator - 2, Group Name IRC SRC	
Answer	No
Document Name	
Comment	
It is not clear to the IRC SRC whether the current draft addresses temperature variances from east to west of the current zones, not just north to south. For example, entities with a wide east to west territory may have vastly different climates that may need to be split into additional zones. During the last comment review, the drafting team discussion indicated that a Planning Coordinator with more than one zone may utilize the same weather event. Ideally the drafting team would revert to the contiguous planning coordinator zones. Either way, this understanding, that two zones within a single PC may use the same event, should be documented within the standard to ensure there is no ambiguity should an entity carry out such approach. The IRC SRC would like to see clarification in the language that indicates regions are allowed to utilize the same scenario provided it meets the requirements in 2.1 and 2.2. ERCOT, IESO, and PJM abstain from IRC SRC response and comments to Q3.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see updated language added to Attachment 1 in TPL-008-1.	
Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO	
Answer	No
Document Name	
Comment	

SPP's PC footprint should not be split into northern and southern zones (see question #1).	
Likes 0	
Dislikes 0	
Response	
Please see DT's response to Q1.	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy has no concerns with the update to Attachment 1.	
Likes 0	
Dislikes 0	

Response	
Thank you.	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
In the attachment 1, remove “WECC” from “WECC Southwest” to match up with the Zones Map.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT does not agree that boundaries would be beneficial. Keeping that map as a noncompliance visual aid allows entities to see an approximation and this also assists in the future changes to boundaries. However, the attachment 1 table provides the details needed when determining Planning Coordinator locations within the zones.	
Sharon Darwin - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Southern Company supports EEI’s comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to EEI.	

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
ITC supports the proposed changes made to Attachment 1 zones.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the changes made to Attachment 1.	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to EEI.	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	

PNM & TNMP agrees with the changes to Attachment 1.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	Yes
Document Name	
Comment	
Exelon agrees with the updates made to the table and map in Attachment 1.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - Greg Sorenson	
Answer	Yes
Document Name	
Comment	
There may be only limited value in running dynamic analysis on a Long-Term planning case (i.e. 10 yr out case). And these cases are difficult to build and are often not N-1 secure (meaning not all single contingencies will result in a valid load flow solution). Given this, and the multiple future assumptions, the dynamic portion of the studies may not provide tangible value.”	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. FERC directive to look at both flows and stability analysis. This is a long term focus too and is no different than transient stability of TPL-001 long term assessment.	
Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop	
Answer	Yes
Document Name	
Comment	
Ameren agrees with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to EEI.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	

Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to EEI.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to EEI.	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	Yes
Document Name	Draft 4 Attachment 1 Example.pdf

Comment	
The Attachment 1 graphic would greatly benefit from including state boundaries. Please see attached example. Draft 4 Attachment 1 Example.pdf	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT does not agree that boundaries would be beneficial. Keeping that map as a noncompliance visual aid allows entities to see an approximation and this also assists in the future changes to boundaries. However, the attachment 1 table provides the details needed when determining Planning Coordinator locations within the zones.	
Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gary Trezza - Long Island Power Authority - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Broc Bruton - Broc Bruton On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Broc Bruton	
Answer	
Document Name	
Comment	
Abstain	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE continues to be concerned that multiple contingencies may not be used to assess the system in extreme temperature events. In Requirement R7, Table 1 only shows single contingencies and double circuit contingencies for assessing steady state and stability performances. Based on the contingencies listed in Table 1, the reasoning for R7 is not clear. Are the responsible entities expected to select single contingencies and double circuit contingencies and use those contingencies to assess the system? During extreme temperature events, multiple overlapping contingencies are expected and frequently occur. Given this fact, the proposed standard should correspondingly require Registered entities to study overlapping contingencies to identify system deficiencies and prepare the mitigation plans.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. Please see the technical rationale document. This is a minimum requirement. Any responsible entity that feels they want to go beyond what is required, is welcome to do so.	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	
Document Name	
Comment	
During the last comment review, the drafting team discussion indicated that a Planning Coordinator with more than one zone may utilize the same weather event. This understanding should be documented within the standard to ensure there is no ambiguity should an entity conduct such an approach. The MRO-NSRF would like to see clarification in the language that indicates regions are allowed to utilize the same scenario provided it meets the requirements in 2.1 and 2.2.	
Likes 1	Scott Brame, N/A, Brame Scott
Dislikes 0	
Response	
Thank you for your comment. Please see the updated language added to attachment 1 in TPL-008-1.	

4. The DT believes proposed modifications in TPL-008-1 provide entities with flexibility to meet the reliability objectives in a cost-effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost-effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle

Answer	No
Document Name	

Comment

Sensitivity to generation, load and transfers are already studied as part of TPL-001-5.1 yearly for near and long-term scenarios (year 10/year 12). The sensitivity additional studies proposed for R8.2 are unlikely to yield any new information and will be duplicative work for Transmission Planners.

The Extreme Temperature Assessment is already a very extreme sensitivity study itself that should already capture modified load, generation, transmission, and transfers befitting this analysis per R3, so it is not needed nor appropriate to study sensitivities for sensitivity cases. Further sensitivity cases to adjust such power flow variables would be a nice idea, but it does not appear cost effective to mandate developing and evaluating “sensitivity” cases in addition to the already sensitive nature if the extreme weather assessment.

If sensitivity cases are deemed necessary, it would be more cost-effective to waive the obligation to study and analyze stability for those sensitivities.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. FERC Order 896 P 2. States: “We take this action to address challenges associated with planning for extreme heat and cold weather events, particularly those that occur during periods when the Bulk-Power System must meet unexpectedly high demand. Extreme heat and cold weather events have occurred with greater frequency in recent years, and are projected to occur with even greater frequency in the future. These events have shown that load shed during extreme temperature

result in unacceptable risk to life and have extreme economic impact. As such, the impact of concurrent failures of Bulk-Power System generation and transmission equipment and the potential for cascading outages that may be caused by extreme heat and cold weather events should be studied and corrective actions should be identified and implemented." Therefore, additional preparation and planning are needed." The DT did its best to draft TPL-008-1 in a cost-effective manner; however, some costs will be required based on the importance of the reliability of the grid.
Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO

Answer	No
Document Name	
Comment	
The changes to the zoning and mapping create an administrative burden with little benefit to the reliability based upon the current language. This requires coordination with ourselves and the proposed event library recommends the same across our entire footprint. This would not be cost effective to create multiple models and sensitivities which would not leverage the transmission system built to support reliability.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. FERC Order 896 P 2. States: "We take this action to address challenges associated with planning for extreme heat and cold weather events, particularly those that occur during periods when the Bulk-Power System must meet unexpectedly high demand. Extreme heat and cold weather events have occurred with greater frequency in recent years, and are projected to occur with even greater frequency in the future. These events have shown that load shed during extreme temperature result in unacceptable risk to life and have extreme economic impact. As such, the impact of concurrent failures of Bulk-Power System generation and transmission equipment and the potential for cascading outages that may be caused by extreme heat and cold weather events should be studied and corrective actions should be identified and implemented." Therefore, additional preparation and planning are needed." The DT did its best to draft TPL-008-1 in a cost-effective manner; however, some costs will be required based on the importance of the reliability of the grid.	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	

Answer	No
Document Name	
Comment	
CEHE believes the new draft TPL-008-1 still imposes a cost and time burden to PCs/TPs without substantial benefits to reliability of BPS. To support this standard CEHE would like to learn more information on any economic analysis that was performed.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. FERC Order 896 P 2. States: "We take this action to address challenges associated with planning for extreme heat and cold weather events, particularly those that occur during periods when the Bulk-Power System must meet unexpectedly high demand. Extreme heat and cold weather events have occurred with greater frequency in recent years, and are projected to occur with even greater frequency in the future. These events have shown that load shed during extreme temperature result in unacceptable risk to life and have extreme economic impact. As such, the impact of concurrent failures of Bulk-Power System generation and transmission equipment and the potential for cascading outages that may be caused by extreme heat and cold weather events should be studied and corrective actions should be identified and implemented." Therefore, additional preparation and planning are needed." The DT did its best to draft TPL-008-1 in a cost-effective manner; however, some costs will be required based on the importance of the reliability of the grid.	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
See our comments for Question 1.	
Likes 0	
Dislikes 0	

Response	
Please see DT's response to Q1.	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	

- ITC believes it is not cost effective to build sensitivity models and analyze the required events yet not require any Corrective Action Plans. If these cases have value and justification to be created and analyzed, then the problems generated within them are also justified to need mitigation to assure reliability.
- Corrective Action plans utilizing only Non Consequential Load Loss do not provide value regarding reliability objectives. Reliability should aim to maintain service to serve firm load and for single contingencies when it may be critical to end users/load under extreme temperature conditions. Entities would need to proactively start shedding load for changes in generation, real and reactive forecasted Load, or transfers; load shed is not a solution to the problems identified on how to deliver reliable service to load.

Likes 0	
Dislikes 0	
Response	

Thank you for your comment. FERC Order 896 P 2. States: "We take this action to address challenges associated with planning for extreme heat and cold weather events, particularly those that occur during periods when the Bulk-Power System must meet unexpectedly high demand. Extreme heat and cold weather events have occurred with greater frequency in recent years, and are projected to occur with even greater frequency in the future. These events have shown that load shed during extreme temperature result in unacceptable risk to life and have extreme economic impact. As such, the impact of concurrent failures of Bulk-Power System generation and transmission equipment and the potential for cascading outages that may be caused by extreme heat and cold weather events should be studied and corrective actions should be identified and implemented." Therefore, additional preparation and planning are needed." The DT did its best to draft TPL-008-1 in a cost-effective manner; however, some costs will be required based on the importance of the reliability of the grid.

Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	No

Document Name	
Comment	
The attempt for flexibility is appreciated but this standard still falls short of something that is clear and allows the PC/TP to appropriately plan to meet reliability goals during extreme temperature events. The inclusion of outside entity reviews of CAPs offers the reviewer flexibility as there are no bounds provided to them. The PC/TP, however, is potentially impacted by subjective reviews that have no framework with which the PC/TP can effectively respond.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. FERC Order 896 P 2. States: "We take this action to address challenges associated with planning for extreme heat and cold weather events, particularly those that occur during periods when the Bulk-Power System must meet unexpectedly high demand. Extreme heat and cold weather events have occurred with greater frequency in recent years, and are projected to occur with even greater frequency in the future. These events have shown that load shed during extreme temperature result in unacceptable risk to life and have extreme economic impact. As such, the impact of concurrent failures of Bulk-Power System generation and transmission equipment and the potential for cascading outages that may be caused by extreme heat and cold weather events should be studied and corrective actions should be identified and implemented." Therefore, additional preparation and planning are needed." The DT did its best to draft TPL-008-1 in a cost-effective manner; however, some costs will be required based on the importance of the reliability of the grid.	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	No
Document Name	
Comment	
New Standard requiring extensive coordination with adjacent PCs/TPs within the defined "zones". New Standards impose a cost and time burden to PCs/TPs without necessarily providing substantial benefits to the reliability of the BPS.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. FERC Order 896 P 2. States: "We take this action to address challenges associated with planning for extreme heat and cold weather events, particularly those that occur during periods when the Bulk-Power System must meet unexpectedly high demand. Extreme heat and cold weather events have occurred with greater frequency in recent years, and are projected to occur with even greater frequency in the future. These events have shown that load shed during extreme temperature result in unacceptable risk to life and have extreme economic impact. As such, the impact of concurrent failures of Bulk-Power System generation and transmission equipment and the potential for cascading outages that may be caused by extreme heat and cold weather events should be studied and corrective actions should be identified and implemented." Therefore, additional preparation and planning are needed." The DT did its best to draft TPL-008-1 in a cost-effective manner; however, some costs will be required based on the importance of the reliability of the grid.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	
This should be part of TPL-001 and not a separate TPL Standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. FERC Order 896 P 2. States: "We take this action to address challenges associated with planning for extreme heat and cold weather events, particularly those that occur during periods when the Bulk-Power System must meet unexpectedly high demand. Extreme heat and cold weather events have occurred with greater frequency in recent years, and are projected to occur with even greater frequency in the future. These events have shown that load shed during extreme temperature result in unacceptable risk to life and have extreme economic impact. As such, the impact of concurrent failures of Bulk-Power System generation and transmission equipment and the potential for cascading outages that may be caused by extreme heat and cold weather events should be studied and corrective actions should be identified and implemented." Therefore, additional preparation and planning	

are needed.” The DT did its best to draft TPL-008-1 in a cost-effective manner; however, some costs will be required based on the importance of the reliability of the grid. The DT felt draft a new standard made the best sense to address the 25+ FERC directives from FERC Order 896 instead of trying to add all that is required to the current TPL-001.	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
At this time, we are unable to fully agree that this standard provides the necessary flexibility to meet the reliability objectives in a cost-effective manner. We would be interested in more information on any economic analysis that was performed.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. FERC Order 896 P 2. States: “We take this action to address challenges associated with planning for extreme heat and cold weather events, particularly those that occur during periods when the Bulk-Power System must meet unexpectedly high demand. Extreme heat and cold weather events have occurred with greater frequency in recent years, and are projected to occur with even greater frequency in the future. These events have shown that load shed during extreme temperature result in unacceptable risk to life and have extreme economic impact. As such, the impact of concurrent failures of Bulk-Power System generation and transmission equipment and the potential for cascading outages that may be caused by extreme heat and cold weather events should be studied and corrective actions should be identified and implemented." Therefore, additional preparation and planning are needed.” The DT did its best to draft TPL-008-1 in a cost-effective manner; however, some costs will be required based on the importance of the reliability of the grid.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	

Comment	
FirstEnergy has no concerns with the cost-effectiveness of this draft.	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Sharon Darwin - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gary Trezza - Long Island Power Authority - 1 - NPCC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	
Document Name	
Comment	
NV Energy does not have a comment regarding the cost-effectiveness.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
Duke Energy’s focus is on system reliability and will not respond to the cost effectiveness question.	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop	
Answer	
Document Name	
Comment	

Ameren prefers not to comment on the cost effectiveness of the project.	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	
Document Name	
Comment	
Black Hills Corporation will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Broc Bruton - Broc Bruton On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Broc Bruton	
Answer	
Document Name	
Comment	
Abstain	
Likes 0	
Dislikes 0	

Response

5. Provide any additional comments for the drafting team to consider, including the provided technical rationale document, if desired.	
Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	
Document Name	
Comment	
HQ supports these revisions.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	
Document Name	
Comment	
Requirement R10 should explicitly clarify that a Corrective Action Plan is not required for P7 Contingencies, as stated in the previous draft 2, Table 2.1, page 11. R6 VRF is 'High', but it should be set as ‘Medium’ to match TPL-008 R5.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. R10. The DT finds R10 to be clear as a Corrective Action Plan is not stated anywhere in R10. This is a possible action that is required. VRF: The DT determined that based on the planning for events such as instability, uncontrolled separation, or Cascading events would consist of a high VRF and therefore, kept the VRF as high. This is consistent with the definition of a high VRF in the justification document provided on the NERC website.	
Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	
AEP offers the following additional comments regarding potential overlapping or duplicative obligations. R3 and R4 appear duplicative in that they both involve the formation of study cases. R3 states “Implement a process for developing benchmark planning cases” while R4 states “Use the coordination process… to develop the following… planning benchmark cases.” R1’s “shall complete its responsibilities such that the … assessment is completed…” appears duplicative with R8’s “shall complete steady-state and stability analysis… ”. AEP recommends removing the last sentence from R1 regarding completing the Extreme Temperature Assessment at least once every five calendar years and appending it to R8. Regarding R5, the TP and PC should already possess steady state voltage criteria to satisfy TPL-001 R5. As a result, AEP recommends removing R5 to avoid compliance risk associated with duplicative obligations. If the drafting team chooses to retain R5, the phrase “shall have criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations” might benefit from something more actionable than “shall have.” AEP recommends the drafting team consider “shall devise” or “shall develop.” R6’s identification of instability, uncontrolled separation, and cascading per criteria or methodology is already required in TPL-001 R6, which once again appears duplicative and would unnecessarily increase compliance risk. AEP recommends it be removed.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comments. The DT does not find R3 and R4 to be duplicative. R3 is to draft out your process and R4 is to use the process developed to establish category P0 as the normal System condition in Table 1. The DT originally had the five year statement further down in the requirement language; however, received multiple comments over the standards development process that the five year understanding needed to be made clear up front in the standard, which is why it has been added to Requirement R1. R5 and R6. These are addressing FERC Order 896 and the focus of TPL-008 is on extreme heat and extreme cold temperature conditions, which may land differently from what is determined under TPL-001. In addition, FERC Order 896 explains that TPL-001 does not address all the concerns causing blackouts.	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	
Document Name	
Comment	
The below comment was provided previously for R2. NERC's consultant uses BA load weighting (based on notes and conversations provided in the 9/10 TPL-008 presentation). As a result, this weighting practice does not appear to directly meet this proposed R2.2 language regarding the most extreme events for a region. The temperature may not actually be representative of “across the zone” because of this weighting. Of reliability considerations, load is certainly part of the need, but potential impacts to generation and the connecting transmission, which may be in other regions, are also important pieces to the delivery of resource to load. Removal or modification of this R2 ‘most extreme’ language is recommended; or exempting the NERC library from needing to follow these criteria. Alternately, the SDT may modify to allow weighting to be used in method. Because the NERC Extreme Weather Event library is only updated every 3 years in the current plan, it is possible that an event in the library would contain events that would not meet these R2 criteria for event “freshness”. The SDT may wish to consider modifying the language regarding time, or an additional clause, to permit events currently in the NERC Extreme Weather Event library to not be subject to the selection criteria currently in R2, or that entities may use the other criteria to evaluate and select other events.	

The below comment was provided previously for R3-R4.

In FERC Order 896, paragraph 39, there is a Commission Determination as follows:

"We also direct NERC to include in the Reliability Standard the framework and criteria that responsible entities shall use to develop from the relevant benchmark event planning cases to represent potential weather-related contingencies (e.g., concurrent/correlated generation and transmission outages, derates) and expected future conditions of the system such as changes in load, transfers, and generation resource mix, and impacts on generators sensitive to extreme heat or cold, due to the weather conditions indicated in the benchmark events. Developing such a framework would provide a common design basis for responsible entities to follow when creating benchmark planning cases. This would not only help establish a clear set of expectations for responsible entities to follow when developing benchmark planning events, but also facilitate auditing and enforcement of the Standard."

In review of Order 896, we find the term "contingencies" is used two different ways. Paragraph 39 describes things that are in the base or N-0 state – for example, a cold weather event occurs, and certain wind generators can no longer operate – this as a base contingency. Similarly, in paragraph 88, there is an additional Commission Determination as follows, in further support of these baseline "contingency" outages:

"Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to require under the new or revised Reliability Standard the study of concurrent/correlated generator and transmission outages due to extreme heat and cold events in benchmark events as described in more detail below."

Then later, in Paragraph 92 (still under the Commission Determination), FERC further clarifies:

"Regarding the comments of NYISO and EPRI on the difference between extreme events and contingencies covered under Reliability Standard TPL-001-5.1, we clarify that all contingencies included in benchmark planning cases under the new or modified Reliability Standard will represent initial conditions for extreme weather event planning and analysis. These contingencies (i.e., correlated/concurrent, temperature sensitive outages, and derates) shall be identified based on similar contingencies that occurred in recent extreme weather events or expected to occur in future forecasted events."

From these, it is clear that Order 896 is expecting "contingencies" of weather-based equipment outages to be part of the base or N-0 system state. The more traditional "contingencies" are then addressed on top of this condition, as presented in Order 896, Section G, starting at Paragraph 95.

The specific request from this comment is for the SDT to clarify how it expects such base "contingencies" to be included in the model. There does not appear to be language currently in the standard in support of this, and it is clear from Order 896 that it is expected both the base model outage "contingencies" and then subsequent contingency events to test system performance.

The SDT responded to this in its version 3 comment response:

"The SDT drafted Requirement R4 to require the responsible entity to use data consistent with Reliability Standard MOD-032, supplemented by other sources as needed, for developing benchmark planning cases that represent System conditions based on selected benchmark temperature events. This aligns with directives in FERC Order No. 896, paragraph 30, emphasizing the requirement of developing both benchmark planning cases and sensitivity study cases. Requirement R4 is consistent with Reliability Standard TPL-001-5.1 in cross-referencing Reliability Standard MOD-032, which establishes consistent modeling data requirements and reporting procedures for the development of planning horizon cases necessary to support analysis of the reliability of the interconnected System. It is also consistent with Reliability Standard TPL-001-5.1 in acknowledging that data from other sources may be required to supplement the data collected through Reliability Standard MOD-032 procedures."

The original comment was not related at all to MOD-032 data. FERC is expecting NERC to develop a standard to build extreme weather cases, and as part of those cases, FERC is requiring that in the base N-0 condition also include "weather-related contingencies (e.g., concurrent/correlated generation and transmission outages, derates)". The current draft of TPL-008 does not mention outages, de-rates, or generator availability due to extreme weather in its R3 or R4 language. R3.2 simply includes "Forecasted seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers within the zone." And R3.3 similar "Assumed seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers in areas outside the zone, as needed.", but language for "weather-related contingencies (e.g., concurrent/correlated generation and transmission outages, derates)" from Order 896 is absent from the standard in its current form. This language should be added, likely to R3.2 and R3.3 because it conveys powerful root concept of unexpected equipment outages and limitations in the base state due to extreme weather. If it is the SDT's intention that entities will review Order 896 and conclude that such concurrent outages are to be covered by a 'supplemented by other sources as needed' clause, this is not the case. The standard needs to include language for entities to consider how such extreme weather related concurrent/correlated outages are to be included in the base case.

The below comment was provided previously for R9.

In Order 896, FERC's Commission determination in paragraph 157 reads:

"As stated above, we adopt and modify the NOPR proposal and direct NERC to require in the new or modified Reliability Standard the development of corrective action plans that include mitigation for specified instances where performance requirements for extreme heat

and cold events are not met—i.e., when certain studies conducted under the Standard show that an extreme heat or cold event would result in cascading outages, uncontrolled separation, or instability."

FERC's directive is when the outcome of studies would result in cascading outages, uncontrolled separation, or instability, a corrective action plan is required. However, in TPL-008, the SDT has gone further. The current state of draft TPL-001-8 R9 states:

"Each responsible entity, as identified in Requirement R1, shall develop a Corrective Action Plan(s) when the analysis of a benchmark planning case, in accordance with Requirement R8 Part 8.1, indicates its portion of the Bulk Electric System is unable to meet performance requirements for category P0 or P1 in Table 1. For each Corrective Action Plan, the responsible entity shall:"

The difference here is Order 896 is only requiring corrective action plans for cascading outages, uncontrolled separation, or instability. the SDT is proposing to require corrective action plans for not meeting performance criteria, which also includes normal voltage limits or normal line ratings, even though these exceedances may not result in cascading outages, uncontrolled separation, or instability. The request is for the SDT to align its R9 language with Order 896 paragraph 157 language. These other limits are needed to assess for cascading outages, uncontrolled separation, or instability, but the requirement to develop a corrective action plan for such exceedances is beyond Order 896's request for this proposed standard.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

Sub-parts of Requirement R2 are how the ERO completed the benchmark temperature events. Should an entity not agree with what has been provided, you are welcome to work with other PCs within your zone to develop your own extreme heat and extreme cold benchmark temperature events. All events in the ERO library will follow suit of Requirement R2. Should something change, it will go through the standards development process and update TPL-008 standard accordingly.

A process has been developed to provide entities with the iterative process on how benchmark events will be updated every five years. The process is a separate document from the TPL-008-1 Standard as some of the specifics are not appropriate nor requirements of the TPL-008-1 Standard. For PCs who wish to work with other PCs to develop their own benchmark events should follow the additional requirement language added to Requirement R2. This provides the boundaries entities must follow should the events provided by the ERO not be adequate for Planning Coordinators to consider.

The DT does not agree that it went beyond the FERC Order.

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
BPA understands the complexities of drafting technically sound standards and appreciates the SDT's efforts through the multiple postings of this project.	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Broc Bruton - Broc Bruton On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Broc Bruton	
Answer	
Document Name	
Comment	
No Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	

Answer	
Document Name	
Comment	
The Western Power Pool would like to thank the Drafting Team for working hard to find consensus. We understand the challenges the Drafting Team faces in meeting the expectations of a number of different organizations across North America.	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	
Document Name	
Comment	
Requirement 3 – Eversource recommends reinserting "Transmission Planner" or the phrase used in R4 "Each responsible entity, as identified in Requirement R1" as part of the coordination in R3. The DT stated in its Consideration of Comments that "Coordination is at the PC level and not at the TP level." Eversource agrees this to be true for developing the Temperature Events but disagrees in regards to implementing a process for developing planning cases. If the TPs are going to be expected to have a role in completing the Extreme Temperature Assessment as stated in Requirement 1, they should participate in implementing a process for the development of cases. Each Planning Coordinator shall coordinate with all Planning Coordinators **and Transmission Planners** within each of its zone(s)…; or Each Planning Coordinator shall coordinate with all Planning Coordinators and **with each responsible entity, as identified in Requirement R1,** within each of its zone(s)…;	
Likes 0	

Dislikes 0	
Response	
Thank you for your comments. Coordination is at the PC level and not the TP level. The PC and TP can coordinate together via Requirement R1 and the TP can provide input. There are mechanisms for the TP to get involved.	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
FirstEnergy has no additional comments.	
Likes 0	
Dislikes 0	
Response	
Thank you.	

Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
NA	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE continues to underscore that the Standard Requirements, as currently stated, do not appear to require assessing the impact of concurrent failures of the Bulk Power System generation **and** transmission equipment that are typically experienced during extreme heat or cold weather conditions. FERC Order No. 896 states: "…the impact of concurrent failures of Bulk-Power System generation and transmission equipment and the potential for cascading outages that may be caused by extreme heat and cold weather events should be studied". The Considerations of the Order document says "Per Requirement R4, the data necessary to build the benchmark planning cases must be provided via MOD-032 and supplemented by other sources as needed. Any concurrent/correlated generator and transmission outages due to extreme heat and cold events in benchmark temperature events should be reflected in the model data and thus represented in the initial conditions of the benchmark planning cases." Based on the current Requirements R3 and R4 language, the cases could be built with high loads and high generation dispatch for the extreme weather without including concurrent outages. Therefore, a requirement in R3 or R4 that specifically says to include	

"concurrent" generator and transmission outages in the initial conditions of the benchmark planning cases needs to be added in accordance with the FERC Order. Also, the rationale for those concurrent outages selected for the initial conditions shall be available as supporting information. Texas RE noticed that the Technical Rationale does mention concurrent outages and recommends incorporating this language directly into the requirement language itself through the note described below. Texas RE suggests either requiring the basic assumptions described in R3 to include, at minimum, the severe contingencies or outages experienced within each Transmission Planner's respective area during the most extreme conditions to be modeled in the benchmarking cases. Texas RE recommends the following language for Requirement R3: 3.5 The most severe continencies experienced in each Transmission Planner's respective area during a historical most extreme conditions shall be documented and modeled in the benchmark planning case(s).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Transmission Planner are not the best qualified entity to provide this information, which is why the standard points to MOD-0032, which is provided by the Generator Owner.	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	
Document Name	
Comment	
Comments: GTC has provided the below recommendations in previous ballots, however, it appears that the SDT has not considered revising the proposed standard to address, therefore, these concerns/recommendations are still considered valid by GTC. R4:	

• The SDT should consider removing R4.2, since the assessment already covers multiple extreme weather scenarios. There is questionable reliability benefit in running additional sensitivities that do not rise to the level of requiring (or eliminating) corrective actions.

R5:

• The recently adopted NERC Glossary term, System Voltage Limits, should be referenced in this requirement instead of the outdated wording “System steady state voltage limits”. “…shall have criteria for acceptable System Voltage Limits …”

• Since this requirement appears to refer to steady-state voltage, the post contingency voltage deviation portion of the existing requirement should be removed. The resultant steady-state voltage level being outside of acceptable high and low limits is the point of concern. For example, if a low voltage criterion is 0.92 p.u., then voltages below this limit would violate this particular criterion regardless of whether the beginning voltage was 0.95 p.u., 0.98 p.u., or any other voltage level.

R6:

• The inclusion of “within an Interconnection” is not appropriate as the PC or TP should not be required to assess outside of its applicable area. Note the inclusion of more appropriate language referring to the PC’s or TP’s planning area (its portion of the Bulk Electric System) in this draft so it is not clear why some requirements refer to an Interconnection while others, more correctly, refer to the area of actual responsibility for the PC or TP.

• The following bullet contains a wording addition to clarify the applicability of this requirement to System-wide impacts. This is also consistent with wording in other Reliability Standards when referencing these types of impacts.

• “Each responsible entity, as identified in Requirement R1, shall define and document the criteria or methodology used in the Extreme Temperature Assessment analysis to identify instability, uncontrolled separation, or Cascading of the Bulk Electric System.”

R8:

• It is unclear if the responsible entity must identify continencies for each event type shown within each category, or only those event types that are expected to produce more severe System impacts on its portion of the Bulk Electric System

Likes 0	
Dislikes 0	

Response	
Thank you for your comments. Requirement R43 is in response to FERC Order 896, which requires sensitivities. System Voltage Limits: The DT determined “System Voltage Limits” focuses on operations and planning information and differs from what is used in the standard. The DT concluded to maintain the proposed language consistent with Reliability Standard TPL-001-5.1. R6. DT felt it was important to clarify in certain areas of the standard where it is within the interconnection focused. zone differences. R8. This is similar to how completed entities complete what is needed in TPL-001, but for TPL-008, which should not be new on how to complete. In addition, see R7.	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	
Document Name	2023-07_Unofficial_Comment_Form Draft_4_110724_MRO.docx
Comment	
Requirement R3 indicates forecasting Load, generation, and Transmission. There are significant barriers to modeling Load and generation based upon temperatures, notably forecasting out into the long-term planning timeframes. With that said, the MRO NSRF recommends that the NERC and drafting team develop implementation guidance and/or a reliability guideline to ensure Planning Coordinators can meet the requirements in the R3 section. Several terms in the TPL-008-1 ERO Benchmark Weather Event Development and Maintenance Process DRAFT indicated defined terms are located in the glossary of terms, yet these terms are not defined in the glossary of terms. The term Zoneal is used rather than the term Zonal. There are also acronyms that do not represent the words spelled, for example it lists Affected Zonal Entity as ARE rather than the more representative term AZE. Definitions Refer to the NERC Glossary of Terms3 for the below capitalized terms used in this process. • Affected Zoneal Entity (ARE)	

• Compliance Enforcement Authority (CEA) • Coordinated Oversight • Extreme Temperature Assessment (ETA) • Lead Zoneal Entity (LRE) • Multi-Zone Registered Entity (MRRE)	
Likes 1	Scott Brame, N/A, Brame Scott
Dislikes 0	
Response	
Thank you for your comments. Please see the updated ERO Benchmark Event Process. Information is collected through MOD-032 and the process should not be different from what is completed to-date. Please see updated benchmark event process document.	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	
Document Name	
Comment	
1. Requirement R1 as drafted includes two separate requirements, i.e. to (1) identify responsibilities amongst applicable PCs and TPs, and (2) complete an Extreme Temperature Assessment every five years. BC Hydro suggests that these are separate objectives and recommends that this Requirement be split to reflect these accordingly for enforceability (e.g. incident severity level), and cause-based incident monitoring.	

2. BC Hydro's understanding is that in order to determine the Contingencies that have a more severe impact per R7, the ETA needs to account for all contingencies within the identified zone(s), and not just those within its portion of the BES. Please confirm or provide additional clarity as appropriate.

3. Requirement R4 and the associated VSL Levels reference "the coordination process developed in Requirement R3". R3 requires a benchmark planning cases development process, it does not require a coordination process.

BC Hydro recommends Recommend revising R4 and the associated VSL Levels for clarity and consistency.

BC Hydro also recommends that the language of R3 be revised to read "to implement a documented process" rather than "to implement a process".

4. The VSL Table for Requirement R1 indicates a Severe Level if an entity "failed to identify individual and joint responsibilities". There are no other Severity Levels associated with responsibilities identification, which is conducive to an interpretation that failing to identify even one of the R2 through R11 associated responsibility would be classified as a Severe VSL. BC Hydro suggests that failing to identify one or less than the full set of responsibility should carry less Severity Levels, and recommends that this be reflected in the lower Severity Levels as well.

5. The High and Severe VSL Levels for Requirement R8 are based on an entity's failing to evaluate the results of the sensitivity (High VSL) and benchmarking cases (Severe VSL). R8 and its associated M8 do not explicitly require that an evaluation be also retained as evidence of compliance, in addition to the results documentation.

BC Hydro recommends that the R8, M8 and corresponding VSL Levels be revised for consistency.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

1. The DT feels it is adequate to let the have entities identify responsibilities and that five years up front. The DT strategically put this into R1 as it applies to all requirements following R1.
2. The contingencies requirement are for your portion of the BES. If an entity wants to run contingencies outside its zone, it is not required based on R7.

3. Please see the updated VSL for Requirement R4.
4. R1 is a binary drafted requirement on responsibilities. (pass/fail requirement). A binary requirement is a “pass or fail” type requirement where any degree of noncompliant performance would result in totally or mostly missing the reliability intent of the requirement.
5. Please see updated VSL for Requirement R8.

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	
Document Name	
Comment	

- ITC believes that the Yes for NCLL for P0 Sensitivity Cases should be changed to No. If it is deemed important to analyze a sensitivity case, the system should be able to serve firm load both for system normal and for single contingencies. With the requirements left as proposed, entities would need to proactively start shedding load for changes in generation, real and reactive forecasted Load, or transfers. System Operators will be forced to rely on preventative load shed during long term construction outages when experiencing extreme weather as it is highly likely that these will not be able to be cancelled.
- ITC believes that the Yes allowing for NCLL for P1 Base and Sensitivity Cases should be changed to No. ITC believes that a reliable system should be able to serve firm load for system normal and for single contingencies. Utilities typically schedule long term construction outages during winter (off-peak) and then experience extreme temperature scenarios. System Operators will need to rely on preventative load shed during these long term construction outages, that could not be cancelled if entities include NCLL as part of their corrective action plan.
- **ITC suggests that Footnote 6 (Page 12) include a clarification that Non Consequential Load Loss shall not be the only element in a Corrective Action Plan. See below:**
  - Benchmark planning cases require the development of a Corrective Action Plan when the responsible entity’s portion of the BES is unable to meet the performance requirements for categories P0 or P1. Additionally, in benchmark planning cases, Non-Consequential Load Loss is not permitted for category P0 and **Non Consequential Load Loss shall not be the only element of a Corrective Action Plan unless approved by applicable regulatory authorities or governing bodies responsible for retail electric service issues.** *See Requirement R9 for the relevant requirements.*
- Specify if temperature is F or C on benchmark table of events. Clarify and specify timing on standard on when they will review the benchmark events.

• In DRAFT ERO Enterprise Process for TPL-008-1 Benchmark Weather Event Development and Maintenance Standards Development and Engineering Process Document October 2024, ITC suggests moving footnote 4 page 2 into the Process Overview and clarify if these actions will happen every cycle, or just the first iteration.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Sensitivity cases (change from yes to no). Load, generation transfer would be more extreme than what is expected from TPL-001, etc. and needs to remain as yes in the table of TPL-008-1. Additional elements are allowed within your CAPs, but the standard has been drafted in consensus with industry regarding this matter. Industry disagrees based on previous comments with requiring more of entities based on feedback. The team feels we are in a good position to date. See updated process document and review the TPL-008-1 Read Me Document. This explains that temperature is F. Link to document: TPL-008_Data_Library_Read_Me.pdf	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	

Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	
Document Name	
Comment	
Below are a few additional comments or questions for the drafting team to consider: 1. Clarify what "long-term transmission planning horizon" is in Requirement 3.1, which is the target time horizon for this standard. Currently NERC definition indicates year 6-10 or beyond. From our understanding, our PC intends to align with LTRTP. 2. Based on our interpretation, a benchmark temperature event doesn't have to be a historical event. Is that correct?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. R3 time horizon is long term planning focuses on 6-10 years. Historical event: benchmark event by definition has to be a historical event. However, if you are able to meet Requirement R2 and complete other events beyond historical events, that would be permitted.	
Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - Greg Sorenson	
Answer	
Document Name	
Comment	

RF appreciates the efforts of the Standards Drafting Team to apply comments received.	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	
Document Name	
Comment	
NPCC RSC agrees with the changes proposed by the standard drafting team.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	

Response	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 5	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to MRO NSRF.	
Helen Lainis - Independent Electricity System Operator - 2, Group Name IRC SRC	
Answer	
Document Name	
Comment	
The IRC SRC is concerned that Requirement R3 unnecessarily and inadvertently limits the ability of entities to properly develop their benchmark planning cases. Specifically, the IRC SRC is concerned that R3 could be understood to mean that entities are limited to making the adjustments specifically described in R3 and are prevented from making adjustments necessary to ensure that the generation necessary to serve load is available so that the case can solve. As the drafting team recognizes in the Technical Rationale, adjusting the case to ensure that it contains enough generation to serve the modeled load is essential to ensure that the standard does not stray into the realm of resource adequacy issues and fully complies with paragraph 94 of FERC Order No. 896, which states that resource adequacy is not in scope for this project. While the IRC SRC appreciates this recognition, the Technical Rationale is not a binding document, and	

future revisions to the standard may introduce additional ambiguity regarding what types of adjustments are permissible under Requirement R3.

To clarify the standard and better position it for future revisions, the IRC SRC recommends that the drafting team revise Part 3.2 by replacing the period at the end of Part 3.2 with the following: ", provided that the responsible entity may adjust the total modeled generation or Load in each case as necessary to allow the total modeled generation to serve the total modeled System Load."

The IRC SRC also recommends that Requirement R4 be revised as needed to align with any revisions made to Requirement R3.

In addition, the IRC SRC requests that the ERO develop a Reliability Guideline for this proposed standard, and in particular, for Requirement R3 showing how a Planning Coordinator would adjust the benchmark planning case to ensure that it contains enough generation necessary to serve load.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

R3. Guidance has been provided in the TR as mentioned in your comments and does not feel additional language is needed within the standard. Therefore, the team does not agree to make the changes requested for Requirement R4.

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2

Answer	
Document Name	

Comment

ERCOT joins the comments submitted by the IRC SRC for this question and adopts them as its own.

Likes 0	
Dislikes 0	

Response

Please see the DT's response to IRC SRC.	
Gregory Campoli - New York Independent System Operator - 2	
Answer	
Document Name	
Comment	
The NYISO would like to confirm that is it acceptable to use additional (beyond those directed in Requirement 2) weather metrics to identify the benchmark temperature events. For example, summer extreme conditions could include a temperature-humidity index which integrates temperature and humidity and is shown to be a more robust predictor of peak loads than temperature alone. Likewise, winter extreme conditions could include a wind component (i.e., a wind-chill index). In either case, the associated temperature value could easily be extracted, as necessary, for any follow-on analysis (e.g., line ratings) requiring temperature specifically. The NYISO would like to confirm that is it acceptable to use additional (beyond those directed in Requirement 2) averaging mechanisms which have been demonstrated to be robust predicators of extreme peak loads. For example, the NYISO currently employs a three-day weighted average temperature index for summer conditions and a three-day weighted average of a temperature-wind index variable for winter conditions. The NYISO would like to confirm that is it acceptable to leverage their own knowledge and expertise in constructing the specific extreme heat and cold temperature events to be studied, within reasonable constraints, such as the 40-year historic period.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. As long as you meet the requirement of R2 and its sub parts, you are welcome to consider other components. PCs can develop their own benchmark events with other PCs within its zone if they do not want to select from the ERO benchmark event library.	

Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO	
Answer	
Document Name	
Comment	
Another concern for SPP is applicable to the model not being able to solve which includes the sensitivity (stability cases for P0 condition). It is unclear on the expectation of the drafting team in reference to the PC not being able to solve the models for the various categories of the ETA. Also, there are concerns around gathering and aligning the appropriate temperature data independently. Requirement R3 indicates forecasting Load, generation, and Transmission. There are significant barriers to modeling Load and generation based upon temperatures, notably forecasting out into the long-term planning timeframes. With that said, SPP recommends that the NERC and drafting team develop implementation guidance and/or a reliability guideline to ensure Planning Coordinators are able to meet the requirements in the R3 section.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The DT feels this request is asking for too prescriptive language within the standard. The goal of a standard is to tell an entity what and sometimes when, but not the how. Flexibility is up to the entities on how to address the standards based on regional differences across the US.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	
Thank you for the opportunity to comment.	
Likes 0	

Dislikes 0	
Response	
Thank you.	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	
Document Name	
Comment	
The DT should highly consider or leave it to Planning Coordinator's discretion when it comes to sensitivities: PC's should be given the opportunity/flexibility in determining whether sensitivities are needed or as to how much study is needed regarding sensitivities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT addresses what is required of FERC Order 896.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	
Document Name	
Comment	
OPG supports NPCC Regional Standards Committee's comments.	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	
Document Name	
Comment	
While ATC has voted in support of approving project 2023-07; we are also in support of the comments provided by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support. Please see the DT's response to MRO NSRF.	

End of Report

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Reminder

Standards Announcement

Project 2023-07 Transmission Planning Performance Requirements for Extreme Weather

Additional Ballots and Non-binding Poll Open through November 21, 2024

Now Available

Additional ballots for draft four of **TPL-008-1 – Transmission System Planning Performance Requirements for Extreme Temperature Events** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels are open through **8 p.m. Eastern, Thursday, November 21, 2024**.

The Standards Committee approved waivers to the Standards Process Manual at their December 2023 meeting. These waivers were sought by NERC Standards for reduced formal comment and ballot periods to assist the drafting teams in expediting the standards development process due to firm timeline expectations set by FERC Order 896.

The standard drafting team's considerations of the responses received from the last comment period are reflected in this draft of the standard.

Reminder Regarding Corporate RBB Memberships

Under the NERC Rules of Procedure, each entity and its affiliates is collectively permitted one voting membership per Registered Ballot Body Segment. Each entity that undergoes a change in corporate structure (such as a merger or acquisition) that results in the entity or affiliated entities having more than the one permitted representative in a particular Segment must withdraw the duplicate membership(s) prior to joining new ballot pools or voting on anything as part of an existing ballot pool. Contact ballotadmin@nerc.net to assist with the removal of any duplicate registrations.

Balloting

Members of the ballot pools associated with this project can log in and submit their votes by accessing the Standards Balloting and Commenting System (SBS) here.

Note: Votes cast in previous ballots, will not carry over to additional ballots. It is the responsibility of the registered voter in the ballot pools to place votes again. To ensure a quorum is reached, if you do not want to vote affirmative or negative, cast an abstention.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*

- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will review all responses received during the comment period and determine the next steps of the project.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Jordan Mallory (via email) or at 404-479-7358. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2023-07 Transmission Planning Performance Requirements for Extreme Weather observer list” in the Description Box.

North American Electric Reliability Corporation
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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2023-07 Transmission Planning Performance Requirements for Extreme Weather

Formal Comment Period Open through November 21, 2024

Now Available

A 15-day formal comment period for draft four of **TPL-008-1 – Transmission System Planning Performance Requirements for Extreme Temperature Events** is open through **8 p.m. Eastern, Thursday, November 21, 2024**.

The Standards Committee approved waivers to the Standards Process Manual at their December 2023 meeting. These waivers were sought by NERC Standards for reduced formal comment and ballot periods to assist the drafting teams in expediting the standards development process due to firm timeline expectations set by FERC Order 896.

The standard drafting team's considerations of the responses received from the previous comment period are reflected in this draft of the standard.

Reminder Regarding Corporate RBB Memberships

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Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. An unofficial Word version of the comment form is posted on the project page.

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- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

Additional ballots for the standard and implementation plan, as well as a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **November 12-21, 2024**.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Jordan Mallory (via email) or at 404-479-7358. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2023-07 Transmission Planning Performance Requirements for Extreme Weather observer list” in the Description Box.

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BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/355)
Ballot Name: 2023-07 Transmission Planning Performance Requirements for Extreme Weather TPL-008-1 AB 4 ST
Voting Start Date: 11/12/2024 12:01:00 AM
Voting End Date: 11/21/2024 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 4
Total # Votes: 261
Total Ballot Pool: 314
Quorum: 83.12
Quorum Established Date: 11/21/2024 3:56:05 PM
Weighted Segment Value: 73.71

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	89	1	44	0.698	19	0.302	0	16	10
Segment: 2	8	0.8	6	0.6	2	0.2	0	0	0
Segment: 3	68	1	37	0.74	13	0.26	0	7	11
Segment: 4	18	1	7	0.636	4	0.364	0	2	5
Segment: 5	76	1	28	0.667	14	0.333	0	14	20
Segment: 6	47	1	24	0.75	8	0.25	0	8	7
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	1	0	0	0	0	0	0	1	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	7	0.7	7	0.7	0	0	0	0	0
Totals:	314	6.5	153	4.791	60	1.709	0	48	53

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		None	N/A
1	American Transmission Company, LLC	Amy Wilke		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Travis Grablander		Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
1	Central Electric Power Cooperative (Missouri)	Michael Bax		None	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Third-Party Comments
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	Third-Party Comments
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Third-Party Comments
1	Dominion - Dominion Virginia Power	Steven Belle		Affirmative	N/A
1	Duke Energy	Katherine Street		Affirmative	N/A
1	Edison International - Southern California Edison Company	Robert Blackney		Affirmative	N/A
1	Entergy	Brian Lindsey		None	N/A
1	Evergy	Kevin Frick	Hayden Maples	Affirmative	N/A
1	Eversource Energy	Joshua London		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	John Martinez		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Negative	Comments Submitted
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
1	Great River Energy	Gordon Pietsch		None	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Lidija Efremova	Affirmative	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Matt Lewis		Abstain	N/A
1	LS Power Transmission, LLC	Jennifer Richardson		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
1	MEAG Power	David Weekley	Rebika Yitna	Abstain	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Nikki Carson-Marquis	Negative	Third-Party Comments
1	Muscatine Power and Water	Andrew Kurriger		Abstain	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	NB Power Corporation	Jeffrey Streifling		Abstain	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
1	New York Power Authority	Daniel Valle		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Negative	Comments Submitted
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
1	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Negative	Comments Submitted
1	Orlando Utilities Commission	Aaron Staley		None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Abstain	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Negative	Comments Submitted
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Abstain	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Laura Somak	Israel Perez	Affirmative	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		None	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Negative	Comments Submitted
1	VELCO -Vermont Electric Power Company, Inc.	Randall Buswell		Abstain	N/A
1	Western Area Power Administration	Ben Hammer		Affirmative	N/A
1	Xcel Energy, Inc.	Eric Barry		None	N/A
2	California ISO	Darcy O'Connell		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
2	Independent Electricity System Operator	Helen Lainis		Affirmative	N/A
2	ISO New England, Inc.	John Pearson	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	Kirsten Rowley		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips	Shannon Mickens	Negative	Comments Submitted
3	AEP	Leshel Hutchings		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr	Danielle Moskop	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		None	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Negative	Comments Submitted
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs	Carly Miller	Affirmative	N/A
3	Bonneville Power Administration	Ron Sporseen		Affirmative	N/A
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Negative	Third-Party Comments
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Lincoln Burton		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Victoria Crider		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Abstain	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Entergy	James Keele		None	N/A
3	Evergy	Marcus Moor	Hayden Maples	Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Negative	Comments Submitted
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		None	N/A
3	Great River Energy	Michael Brytowski		Negative	Third-Party Comments
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
3	JEA	Marilyn Williams		Affirmative	N/A
3	Lakeland Electric	Steven Marshall		None	N/A
3	Lincoln Electric System	Sam Christensen		Abstain	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		None	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
3	MEAG Power	Roger Brand	Rebika Yitna	Abstain	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	Third-Party Comments
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	New York Power Authority	Richard Machado		Affirmative	N/A
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
3	Northern California Power Agency	Michael Whitney		None	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
3	Omaha Public Power District	David Heins		Negative	Third-Party Comments
3	OTP - Otter Tail Power Company	Wendi Olson		None	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Negative	Comments Submitted
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
3	Portland General Electric Co.	Mayra Franco		Abstain	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Negative	Comments Submitted
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Santee Cooper	Vicky Budreau		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Seminole Electric Cooperative, Inc.	Usama Tahir		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Abstain	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
3	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel	Joseph Gatten	None	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Third-Party Comments
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		None	N/A
4	Austin Energy	Tony Hua		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	None	N/A
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		Negative	Third-Party Comments
4	CMS Energy - Consumers Energy Company	Aric Root		None	N/A
4	DTE Energy	Patricia Ireland		Abstain	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Georgia System Operations Corporation	Katrina Lyons		Negative	Third-Party Comments
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Third-Party Comments
4	Northern California Power Agency	Marty Hostler	Mason Jones	None	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	George Pino		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
4	Western Power Pool	Kevin Conway		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		None	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		None	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		None	N/A
5	BC Hydro and Power Authority	Christine Jennings		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
5	Bonneville Power Administration	Milli Chennell		Affirmative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	None	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
5	Constellation	Alison MacKellar		Abstain	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Third-Party Comments
5	Dominion - Dominion Resources, Inc.	Barbara Marion		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Abstain	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		None	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A
5	Great River Energy	Jacalynn Bentz	Joseph Knight	None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Abstain	N/A
5	Grid Strategies LLC	Michael Goggin		None	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	Invenergy LLC	Rhonda Jones		None	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
5	LS Power Development, LLC	C. A. Campbell		None	N/A
5	Manitoba Hydro	Kristy-Lee Young	Helen Zhao	None	N/A
5	Muscatine Power and Water	Chance Back		Abstain	N/A
5	National Grid USA	Robin Berry		Affirmative	N/A
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Erin Wilson		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender	Kevin Schawang	Negative	Third-Party Comments
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	NextEra Energy	Richard Vendetti		Negative	Comments Submitted
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Third-Party Comments
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Third-Party Comments
5	Oglethorpe Power Corporation	Donna Johnson		Negative	Third-Party Comments
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Third-Party Comments
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Dania Colon		Affirmative	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	Third-Party Comments
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Negative	Comments Submitted
5	Pattern Operators LP	George E Brown		Negative	Third-Party Comments
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	PSEG Nuclear LLC	Tim Kucey		None	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Loren Harbachuk		None	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
5	Santee Cooper	Carey Salisbury		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Seminole Electric Cooperative, Inc.	Melanie Wong		None	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Abstain	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		Negative	Comments Submitted
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Abstain	N/A
5	Tennessee Valley Authority	Darren Boehm		Negative	Comments Submitted
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Abstain	N/A
6	AEP	Mathew Miller		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Imane Mrini		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A
6	Black Hills Corporation	Rachel Schuldt		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Negative	Third-Party Comments
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
6	Constellation	Kimberly Turco		Abstain	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	John Sturgeon		Affirmative	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
6	Entergy	Julie Hall		None	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
6	Great River Energy	Brian Meloy		Negative	Third-Party Comments
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Manitoba Hydro	Brandin Stoesz		None	N/A
6	Muscatine Power and Water	Nicholas Burns		Abstain	N/A
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Rebecca Blair		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Third-Party Comments
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Stefanie Burke		None	N/A
6	Powerex Corporation	Raj Hundal		Negative	Third-Party Comments
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		None	N/A
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie		Negative	Comments Submitted
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Santee Cooper	Marty Watson		Abstain	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Matthew O'neal		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	Western Area Power Administration	Jennifer Neville		Affirmative	N/A
6	Xcel Energy, Inc.	Steve Szablya		None	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Affirmative	N/A
10	ReliabilityFirst	Tremayne Brown	Greg Sorenson	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

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BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/355)
Ballot Name: 2023-07 Transmission Planning Performance Requirements for Extreme Weather Implementation Plan AB 4 OT
Voting Start Date: 11/12/2024 12:01:00 AM
Voting End Date: 11/21/2024 8:00:00 PM
Ballot Type: OT
Ballot Activity: AB
Ballot Series: 4
Total # Votes: 261
Total Ballot Pool: 314
Quorum: 83.12
Quorum Established Date: 11/21/2024 3:56:12 PM
Weighted Segment Value: 77.72

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	89	1	48	0.762	15	0.238	0	16	10
Segment: 2	8	0.8	7	0.7	1	0.1	0	0	0
Segment: 3	68	1	39	0.78	11	0.22	0	7	11
Segment: 4	18	1	7	0.636	4	0.364	0	2	5
Segment: 5	76	1	30	0.714	12	0.286	0	14	20
Segment: 6	47	1	25	0.781	7	0.219	0	8	7
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	1	0	0	0	0	0	0	1	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	7	0.6	6	0.6	0	0	0	1	0
Totals:	314	6.4	162	4.974	50	1.426	0	49	53

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		None	N/A
1	American Transmission Company, LLC	Amy Wilke		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Travis Grablander		Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
1	Central Electric Power Cooperative (Missouri)	Michael Bax		None	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Third-Party Comments
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	Third-Party Comments
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Third-Party Comments
1	Dominion - Dominion Virginia Power	Steven Belle		Affirmative	N/A
1	Duke Energy	Katherine Street		Affirmative	N/A
1	Edison International - Southern California Edison Company	Robert Blackney		Affirmative	N/A
1	Entergy	Brian Lindsey		None	N/A
1	Evergy	Kevin Frick	Hayden Maples	Affirmative	N/A
1	Eversource Energy	Joshua London		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	John Martinez		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
1	Great River Energy	Gordon Pietsch		None	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Lidija Efremova	Affirmative	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Matt Lewis		Abstain	N/A
1	LS Power Transmission, LLC	Jennifer Richardson		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
1	MEAG Power	David Weekley	Rebika Yitna	Abstain	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Nikki Carson-Marquis	Negative	Third-Party Comments
1	Muscatine Power and Water	Andrew Kurriger		Abstain	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	NB Power Corporation	Jeffrey Streifling		Abstain	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
1	New York Power Authority	Daniel Valle		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Negative	Comments Submitted
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
1	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Affirmative	N/A
1	Orlando Utilities Commission	Aaron Staley		None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Negative	Comments Submitted
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Abstain	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Abstain	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Laura Somak	Israel Perez	Affirmative	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		None	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Negative	Comments Submitted
1	VELCO -Vermont Electric Power Company, Inc.	Randall Buswell		Abstain	N/A
1	Western Area Power Administration	Ben Hammer		Affirmative	N/A
1	Xcel Energy, Inc.	Eric Barry		None	N/A
2	California ISO	Darcy O'Connell		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A
2	Independent Electricity System Operator	Helen Lainis		Affirmative	N/A
2	ISO New England, Inc.	John Pearson	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	Kirsten Rowley		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips	Shannon Mickens	Negative	Comments Submitted
3	AEP	Leshel Hutchings		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr	Danielle Moskop	Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		None	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Negative	Comments Submitted
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs	Carly Miller	Affirmative	N/A
3	Bonneville Power Administration	Ron Sporseen		Affirmative	N/A
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Negative	Third-Party Comments
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Lincoln Burton		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Victoria Crider		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Abstain	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Entergy	James Keele		None	N/A
3	Evergy	Marcus Moor	Hayden Maples	Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		None	N/A
3	Great River Energy	Michael Brytowski		Negative	Third-Party Comments
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
3	JEA	Marilyn Williams		Affirmative	N/A
3	Lakeland Electric	Steven Marshall		None	N/A
3	Lincoln Electric System	Sam Christensen		Abstain	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		None	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
3	MEAG Power	Roger Brand	Rebika Yitna	Abstain	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	Third-Party Comments
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
3	New York Power Authority	Richard Machado		Affirmative	N/A
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
3	Northern California Power Agency	Michael Whitney		None	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
3	Omaha Public Power District	David Heins		Negative	Third-Party Comments
3	OTP - Otter Tail Power Company	Wendi Olson		None	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Negative	Comments Submitted
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
3	Portland General Electric Co.	Mayra Franco		Abstain	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Santee Cooper	Vicky Budreau		Abstain	N/A
3	Seminole Electric Cooperative, Inc.	Usama Tahir		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Abstain	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
3	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel	Joseph Gatten	None	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Third-Party Comments
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		None	N/A
4	Austin Energy	Tony Hua		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	None	N/A
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		Negative	Third-Party Comments
4	CMS Energy - Consumers Energy Company	Aric Root		None	N/A
4	DTE Energy	Patricia Ireland		Abstain	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Georgia System Operations Corporation	Katrina Lyons		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Third-Party Comments
4	Northern California Power Agency	Marty Hostler	Mason Jones	None	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	George Pino		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
4	Western Power Pool	Kevin Conway		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		None	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		None	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		None	N/A
5	BC Hydro and Power Authority	Christine Jennings		None	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Bonneville Power Administration	Milli Chennell		Affirmative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	None	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
5	Constellation	Alison MacKellar		Abstain	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Third-Party Comments
5	Dominion - Dominion Resources, Inc.	Barbara Marion		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Abstain	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		None	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A
5	Great River Energy	Jacalynn Bentz	Joseph Knight	None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Greybeard Compliance Services, LLC	Mike Gabriel		Abstain	N/A
5	Grid Strategies LLC	Michael Goggin		None	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	Invenergy LLC	Rhonda Jones		None	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
5	LS Power Development, LLC	C. A. Campbell		None	N/A
5	Manitoba Hydro	Kristy-Lee Young	Helen Zhao	None	N/A
5	Muscatine Power and Water	Chance Back		Abstain	N/A
5	National Grid USA	Robin Berry		Affirmative	N/A
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Erin Wilson		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender	Kevin Schawang	Negative	Third-Party Comments
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	NextEra Energy	Richard Vendetti		Negative	Comments Submitted
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Third-Party Comments
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Oglethorpe Power Corporation	Donna Johnson		Negative	Third-Party Comments
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Third-Party Comments
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Dania Colon		Affirmative	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	Third-Party Comments
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Negative	Comments Submitted
5	Pattern Operators LP	George E Brown		Negative	Third-Party Comments
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	PSEG Nuclear LLC	Tim Kucey		None	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Loren Harbachuk		None	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
5	Santee Cooper	Carey Salisbury		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		None	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Abstain	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Abstain	N/A
5	Tennessee Valley Authority	Darren Boehm		Negative	Comments Submitted
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Abstain	N/A
6	AEP	Mathew Miller		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Imane Mrini		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A
6	Black Hills Corporation	Rachel Schuldt		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
6	Constellation	Kimberly Turco		Abstain	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	John Sturgeon		Affirmative	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
6	Entergy	Julie Hall		None	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
6	Great River Energy	Brian Meloy		Negative	Third-Party Comments
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Manitoba Hydro	Brandin Stoesz		None	N/A
6	Muscatine Power and Water	Nicholas Burns		Abstain	N/A
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Rebecca Blair		Negative	Comments Submitted
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Third-Party Comments
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Stefanie Burke		None	N/A
6	Powerex Corporation	Raj Hundal		Negative	Third-Party Comments
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		None	N/A
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Santee Cooper	Marty Watson		Abstain	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Matthew O'neal		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Abstain	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	Western Area Power Administration	Jennifer Neville		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Xcel Energy, Inc.	Steve Szablya		None	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Affirmative	N/A
10	ReliabilityFirst	Tremayne Brown	Greg Sorenson	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A

Showing 1 to 314 of 314 entries

BALLOT RESULTS

Ballot Name: 2023-07 Transmission Planning Performance Requirements for Extreme Weather TPL-008-1 | Non-binding Poll AB 4 NB
Voting Start Date: 11/12/2024 12:01:00 AM
Voting End Date: 11/21/2024 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 4
Total # Votes: 250
Total Ballot Pool: 297
Quorum: 84.18
Quorum Established Date: 11/21/2024 3:28:13 PM
Weighted Segment Value: 73.4

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	86	1	40	0.714	16	0.286	20	10
Segment: 2	7	0.5	3	0.3	2	0.2	2	0
Segment: 3	63	1	33	0.767	10	0.233	12	8
Segment: 4	18	1	7	0.636	4	0.364	2	5
Segment: 5	72	1	28	0.718	11	0.282	15	18
Segment: 6	44	1	22	0.759	7	0.241	9	6
Segment: 7	0	0	0	0	0	0	0	0
Segment: 8	1	0	0	0	0	0	1	0
Segment: 9	0	0	0	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 10	6	0.5	5	0.5	0	0	1	0
Totals:	297	6	138	4.395	50	1.605	62	47

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		None	N/A
1	American Transmission Company, LLC	Amy Wilke		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Travis Grablander		Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
1	Central Electric Power Cooperative (Missouri)	Michael Bax		None	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Comments Submitted
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	Comments Submitted
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Steven Belle		Affirmative	N/A
1	Duke Energy	Katherine Street		Affirmative	N/A
1	Edison International - Southern California Edison Company	Robert Blackney		Affirmative	N/A
1	Entergy	Brian Lindsey		None	N/A
1	Evergy	Kevin Frick	Hayden Maples	Affirmative	N/A
1	Eversource Energy	Joshua London		Negative	Comments Submitted
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	John Martinez		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Negative	Comments Submitted
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Comments Submitted
1	Great River Energy	Gordon Pietsch		None	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Lidija Efremova	Abstain	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Matt Lewis		Abstain	N/A
1	LS Power Transmission, LLC	Jennifer Richardson		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	MEAG Power	David Weekley	Rebika Yitna	Abstain	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Nikki Carson-Marquis	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Muscatine Power and Water	Andrew Kurriger		Abstain	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	NB Power Corporation	Jeffrey Streifling		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Daniel Valle		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Negative	Comments Submitted
1	Orlando Utilities Commission	Aaron Staley		None	N/A
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Negative	Comments Submitted
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		None	N/A
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Abstain	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Negative	Comments Submitted
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Abstain	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Laura Somak	Israel Perez	Affirmative	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		None	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Negative	Comments Submitted
1	VELCO -Vermont Electric Power Company, Inc.	Randall Buswell		Abstain	N/A
1	Western Area Power Administration	Ben Hammer		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
2	Independent Electricity System Operator	Helen Lainis		Abstain	N/A
2	ISO New England, Inc.	John Pearson	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	Kirsten Rowley		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips	Shannon Mickens	Negative	Comments Submitted
3	AEP	Leshel Hutchings		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr	Danielle Moskop	Abstain	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		None	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	BC Hydro and Power Authority	Ming Jiang		Negative	Comments Submitted
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs	Carly Miller	Affirmative	N/A
3	Bonneville Power Administration	Ron Sporseen		Affirmative	N/A
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Negative	Comments Submitted
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Lincoln Burton		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Victoria Crider		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Abstain	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Entergy	James Keele		None	N/A
3	Evergy	Marcus Moor	Hayden Maples	Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Negative	Comments Submitted
3	Exelon	Kinte Whitehead		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Negative	Comments Submitted
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
3	JEA	Marilyn Williams		Affirmative	N/A
3	Lakeland Electric	Steven Marshall		None	N/A
3	Lincoln Electric System	Sam Christensen		Abstain	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
3	MEAG Power	Roger Brand	Rebika Yitna	Abstain	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	Richard Machado		Affirmative	N/A
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Abstain	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
3	Northern California Power Agency	Michael Whitney		None	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
3	Omaha Public Power District	David Heins		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Negative	Comments Submitted
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
3	Portland General Electric Co.	Mayra Franco		Abstain	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Abstain	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Negative	Comments Submitted
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Santee Cooper	Vicky Budreau		Abstain	N/A
3	Seminole Electric Cooperative, Inc.	Usama Tahir		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Abstain	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Comments Submitted
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		None	N/A
4	Austin Energy	Tony Hua		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	None	N/A
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		Negative	Comments Submitted
4	CMS Energy - Consumers Energy Company	Aric Root		None	N/A
4	DTE Energy	Patricia Ireland		Abstain	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Georgia System Operations Corporation	Katrina Lyons		Negative	Comments Submitted
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Comments Submitted
4	Northern California Power Agency	Marty Hostler	Mason Jones	None	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	George Pino		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
4	Western Power Pool	Kevin Conway		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		None	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		None	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		None	N/A
5	BC Hydro and Power Authority	Christine Jennings		None	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
5	Bonneville Power Administration	Milli Chennell		Affirmative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	None	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
5	Constellation	Alison MacKellar		Abstain	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Dairyland Power Cooperative	Tommy Drea		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Barbara Marion		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Abstain	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		None	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Abstain	N/A
5	Grid Strategies LLC	Michael Goggin		None	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
5	LS Power Development, LLC	C. A. Campbell		None	N/A
5	Muscatine Power and Water	Chance Back		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	National Grid USA	Robin Berry		Affirmative	N/A
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Erin Wilson		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender	Kevin Schawang	Abstain	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	NextEra Energy	Richard Vendetti		Negative	Comments Submitted
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Comments Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Comments Submitted
5	Oglethorpe Power Corporation	Donna Johnson		Negative	Comments Submitted
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Comments Submitted
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Dania Colon		Affirmative	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	Comments Submitted
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Negative	Comments Submitted
5	Pattern Operators LP	George E Brown		Negative	Comments Submitted
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	PSEG Nuclear LLC	Tim Kucey		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Loren Harbachuk		None	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
5	Santee Cooper	Carey Salisbury		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		None	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Abstain	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Abstain	N/A
5	Tennessee Valley Authority	Darren Boehm		None	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Abstain	N/A
6	AEP	Mathew Miller		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Imane Mrini		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A
6	Black Hills Corporation	Rachel Schuldt		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
6	Constellation	Kimberly Turco		Abstain	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	John Sturgeon		Affirmative	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
6	Entergy	Julie Hall		None	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
6	Great River Energy	Brian Meloy		Negative	Comments Submitted
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Muscatine Power and Water	Nicholas Burns		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Rebecca Blair		Negative	Comments Submitted
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Comments Submitted
6	Omaha Public Power District	Shonda McCain		Negative	Comments Submitted
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Stefanie Burke		None	N/A
6	Powerex Corporation	Raj Hundal		Negative	Comments Submitted
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		None	N/A
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie		Negative	Comments Submitted
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Santee Cooper	Marty Watson		Abstain	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Southern Company - Southern Company Generation and Energy Marketing	Matthew O'neal		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Abstain	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	Western Area Power Administration	Jennifer Neville		Affirmative	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Affirmative	N/A
10	ReliabilityFirst	Tremayne Brown	Greg Sorenson	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A

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Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the final draft of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	July 19, 2023
SAR posted for comment	August 8–September 27, 2023
45-day formal comment period with initial ballot	March 20–May 3, 2024
38-day formal comment period with additional ballot	July 16–August 22, 2024
15-day formal comment period with additional ballot	October 7–21, 2024
15-day formal comment period with additional ballot	November 7–21, 2024

Anticipated Actions	Date
5-day final ballot	December 2–6, 2024
Board adoption	December 10, 2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

Extreme Temperature Assessment – Documented evaluation of future Bulk Electric System performance for extreme heat and extreme cold benchmark temperature events.

A. Introduction

1. **Title:** Transmission System Planning Performance Requirements for Extreme Temperature Events
2. **Number:** TPL-008-1
3. **Purpose:** Establish Transmission system planning performance requirements to develop a Bulk Power System (BPS) that will operate reliably during extreme heat and extreme cold temperature events.
4. **Applicability:**
    - **4.1. Functional Entities:**
        - **4.1.1.** Transmission Planner
        - **4.1.2.** Planning Coordinator
5. **Effective Date:** See Implementation Plan for Project 2023-07.

B. Requirements and Measures

R1. Each Planning Coordinator shall identify, in conjunction with its Transmission Planner(s), each entity's individual and joint responsibilities for completing the Extreme Temperature Assessment, which shall include each of the responsibilities described in Requirements R2 through R11. Each responsible entity shall complete its responsibilities such that the Extreme Temperature Assessment is completed at least once every five calendar years. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M1. Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall provide dated documentation of each entity's individual and joint responsibilities, such as meeting minutes, agreements, copies of procedures, or protocols in effect between entities or between departments of a vertically integrated system, or email correspondence that identifies an agreement has been reached on individual and joint responsibilities for completing the Extreme Temperature Assessment, and that these responsibilities were completed such that the Extreme Temperature Assessment was completed once every five calendar years.

R2. Each Planning Coordinator shall identify the zone(s) to which the Planning Coordinator belongs to under Attachment 1 and shall coordinate with all Planning Coordinators within each of its identified zone(s), to identify one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event for each of its identified zone(s) when completing the Extreme Temperature Assessment. The benchmark temperature events shall be obtained from the benchmark library maintained by the ERO or developed by the Planning Coordinators. Each benchmark temperature event identified by the Planning Coordinators shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. Consider no less than a 40-year period of temperature data ending no more than five years prior to the time the benchmark temperature events are selected; and

2.2. Represent one of the 20 most extreme temperature conditions based on the three-day rolling average of daily maximum (heat) or daily minimum (cold) temperature across the zone.

M2. Each Planning Coordinator shall have evidence in either electronic or hard copy format that it identified the zone(s) to which it belongs to, under Attachment 1, and that it coordinated with all other Planning Coordinators within each of its identified zone(s) to identify one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event meeting the criteria of Requirement R2 for each of their identified zone(s) when completing the Extreme Temperature Assessment.

R3. Each Planning Coordinator shall coordinate with all Planning Coordinators within each of its zone(s) identified in Requirement R2, to implement a process for developing

benchmark planning cases for the Extreme Temperature Assessment that represent the benchmark temperature events selected in Requirement R2 and sensitivity cases to demonstrate the impact of changes to the basic assumptions used in the benchmark planning cases. This process shall include the following: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Selection of System models within the Long-Term Transmission Planning Horizon to form the basis for the benchmark planning cases.

3.2. Forecasted seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers within the zone.

3.3. Assumed seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers in areas outside the zone, as needed.

3.4. Identification of changes to at least one of the following conditions for sensitivity cases: generation, real and reactive forecasted Load, or transfers.

M3. Each Planning Coordinator shall have dated evidence that it implemented a process for coordinating the development of benchmark planning cases and sensitivity cases for the Extreme Temperature Assessment as specified in Requirement R3.

R4. Each responsible entity, as identified in Requirement R1, shall use the process developed in Requirement R3 and data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, to develop the following and establish category P0 as the normal System condition in Table 1: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

4.1. One common extreme heat and one common extreme cold benchmark planning case.

4.2. One common extreme heat and one common extreme cold sensitivity case.

M4. Each responsible entity, as identified in Requirement R1, shall have dated evidence in either electronic or hard copy format that it developed benchmark planning cases and sensitivity cases in accordance with Requirement R4.

R5. Each responsible entity, as identified in Requirement R1, shall have criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations for completing the Extreme Temperature Assessment. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M5. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of the documentation, specifying the criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations for completing the Extreme Temperature Assessment.

R6. Each responsible entity, as identified in Requirement R1, shall define and document the criteria or methodology to be used in the Extreme Temperature Assessment to

identify instability, uncontrolled separation, or Cascading within an Interconnection. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M6. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of documentation, specifying the criteria or methodology to be used in the Extreme Temperature Assessment to identify instability, uncontrolled separation, or Cascading within an Interconnection in accordance with Requirement R6.

R7. Each responsible entity, as identified in Requirement R1, shall identify the Contingencies for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System. The rationale for those Contingencies selected for evaluation shall be available as supporting information. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M7. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of documentation, of the Contingencies for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System along with supporting rationale.

R8. Each responsible entity, as identified in Requirement R1, shall complete steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, and shall document the assumptions and results. Steady state and transient stability analyses shall be performed for the following: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

8.1. Benchmark planning cases developed in accordance with Requirement R4 Part 4.1.

8.2. Sensitivity cases developed in accordance with Requirement R4 Part 4.2.

M8. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of documentation, of the assumptions and results of the steady state and transient stability analyses completed in the Extreme Temperature Assessment.

R9. Each responsible entity, as identified in Requirement R1, shall develop a Corrective Action Plan(s) when the analysis of a benchmark planning case, in accordance with Requirement R8 Part 8.1, indicates its portion of the Bulk Electric System is unable to meet performance requirements for category P0 or P1 in Table 1. For each Corrective Action Plan, the responsible entity shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

9.1. Document alternative(s) considered when Non-Consequential Load Loss is utilized as an element of a Corrective Action Plan for a Table 1 P1 Contingency.

9.2. Be permitted to utilize Non-Consequential Load Loss as an interim solution, which normally is not permitted for category P0 in Table 1 for situations that are

beyond the control of the Planning Coordinator or Transmission Planner that prevent the implementation of a Corrective Action Plan in the required timeframe, provided that the responsible entity documents the situation causing the problem, alternatives evaluated, and takes actions to resolve the situation.

9.3. Make its Corrective Action Plan available to, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.

9.4. Be permitted to have revisions to the Corrective Action Plan in subsequent Extreme Temperature Assessments, provided that the planned Bulk Electric System shall continue to meet the performance requirements of Table 1.

M9. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of documentation, of each Corrective Action Plan developed in accordance with Requirement R9 when the analysis of a benchmark planning case indicates its portion of the Bulk Electric System is unable to meet performance requirements for category P0 or P1 in Table 1. Evidence shall include documentation of correspondence with applicable regulatory authorities or governing bodies responsible for retail electric service issues and any revision history.

R10. Each responsible entity, as identified in Requirement R1, shall evaluate and document possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) if analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection, for the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

10.1. Table 1 P7 Contingencies in benchmark planning cases analyzed in accordance with Requirement R8 Part 8.1.

10.2. Categories P0, P1, and P7 in Table 1 in sensitivity cases analyzed in accordance with Requirement R8 Part 8.2.

M10. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of documentation that it evaluated and documented possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts when the analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection for Table 1 P7 Contingencies in benchmark planning cases or categories P0, P1, or P7 in Table 1 in sensitivity cases.

R11. Each responsible entity, as identified in Requirement R1, shall provide its Extreme Temperature Assessment results within 60 calendar days of a request to any functional entity that has a reliability related need and submits a written request for the information. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M11. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as email notices, documentation of updated web pages, or postal receipts showing recipient, that it provided its Extreme Temperature Assessment to any

functional entity who has a reliability need within 60 calendar days of a written request.

C. Compliance

1. **Compliance Monitoring Process**

   1.1. **Compliance Enforcement Authority:** "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

   1.2. **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.

   - Each responsible entity shall retain evidence of compliance with each requirement in this standard for five calendar years or one complete Extreme Temperature Assessment cycle, whichever is longer.

   1.3. **Compliance Monitoring and Enforcement Program:** "Compliance Monitoring Enforcement Program" or "CMEP" means, depending on the context (1) the NERC Compliance Monitoring and Enforcement Program (Appendix 4C to the NERC Rules of Procedure) or the Commission-approved program of a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that is responsible for performing compliance monitoring and enforcement activities with respect to Registered Entities' compliance with Reliability Standards.

Table 1 – Steady State & Stability Performance Events
Steady State & Stability: a. Instability, uncontrolled separation, or Cascading within an Interconnection, defined in accordance with Requirement R6, shall not occur. b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0. c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event. d. Simulate Normal Clearing unless otherwise specified. e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings. **Steady State Only:** f. Applicable Facility Ratings shall not be exceeded. g. System steady state voltages and post-Contingency voltage deviations shall meet the criteria identified in Requirement R5.

<table>
<tr><th colspan="8">Table 1 – Steady State & Stability Performance Events</th></tr>
<tr><th rowspan="2">Category</th><th rowspan="2">Initial Condition</th><th rowspan="2">Event[1]</th><th rowspan="2">Fault Type[3]</th><th rowspan="2">Contingency BES Level</th><th rowspan="2">Interruption of Firm Transmission Service Allowed</th><th colspan="2">Non-Consequential Load Loss Allowed</th></tr>
<tr><th>Benchmark Planning Cases</th><th>Sensitivity Cases</th></tr>
<tr><td>P0
No Contingency</td><td>Normal System</td><td>None</td><td>N/A</td><td>N/A</td><td>Yes</td><td>No[6]</td><td>Yes</td></tr>
<tr><td rowspan="2">P1
Single Contingency</td><td rowspan="2">Normal System</td><td>Loss of one of the following:
1. Generator
2. Transmission Circuit
3. Transformer[2]
4. Shunt Device[4]</td><td>3Ø</td><td rowspan="2">≥ 200 kV</td><td rowspan="2">Yes</td><td rowspan="2">Yes[6]</td><td rowspan="2">Yes</td></tr>
<tr><td>5. Single Pole of a DC line</td><td>SLG</td></tr>
<tr><td>P7
Multiple Contingency
(Common Structure)</td><td>Normal System</td><td>The loss of:
1. Any two adjacent (vertically or horizontally) circuits on common structure[5]
2. Loss of a bipolar DC line</td><td>SLG</td><td>≥ 200 kV</td><td>Yes</td><td>Yes</td><td>Yes</td></tr>
</table>

Table 1 – Steady State & Stability Performance Events
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the BES level of the event. For P7 events, the BES level of the event is the highest System voltage level of the element(s) removed for the analyzed event. 2. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers. 3. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria. 4. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground. 5. Excludes circuits that share a common structure for 1 mile or less. 6. Benchmark planning cases require the development of a Corrective Action Plan when the responsible entity's portion of the BES is unable to meet the performance requirements for categories P0 or P1. Additionally, in benchmark planning cases, Non-Consequential Load Loss is not permitted for category P0 except where permitted as an interim solution in a Corrective Action Plan in accordance with Requirement R9 Part 9.2.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed less than or equal to six months late.	The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed more than six months but less than or equal to 12 months late.	The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed more than 12 months but less than or equal to 18 months late.	The Planning Coordinator, in conjunction with its Transmission Planner(s), failed to identify individual and joint responsibilities for completing the Extreme Temperature Assessment. OR The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed more than 18 months late.
R2.	N/A	N/A	The Planning Coordinator coordinated with all Planning Coordinators within each identified zone to identify one common extreme heat and one common extreme cold benchmark temperature event for completing the Extreme Temperature Assessment, but one of the identified events	The Planning Coordinator coordinated with all Planning Coordinators within each identified zone to identify one common extreme heat and one common extreme cold benchmark temperature event for completing the Extreme Temperature Assessment, but both of the identified events

			failed to meet all the criteria of Requirement R2.	failed to meet all of the criteria of Requirement R2. OR The Planning Coordinator failed to coordinate with all Planning Coordinators within each identified zone to identify one common extreme heat and one common extreme cold benchmark temperature event for completing the Extreme Temperature Assessment.
R3.	N/A	N/A	N/A	The Planning Coordinator did not coordinate with all Planning Coordinators within each of its identified zone(s) to implement a process for developing benchmark planning cases. OR The Planning Coordinator coordinated with all Planning Coordinators within each of its identified zone(s) to implement a process for developing benchmark planning cases, but the process did not include all of the required elements.

R4.	N/A	N/A	N/A	The responsible entity, as identified in Requirement R1, did not use the process developed in Requirement R3 to develop benchmark planning cases or sensitivity cases. OR The responsible entity, as identified in Requirement R1, used the process developed in Requirement R3 to develop benchmark planning cases and sensitivity cases, but did not use data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, for one or more of the required cases. OR The responsible entity, as identified in Requirement R1, used the process developed in Requirement R3 and data consistent with that provided in accordance with the MOD-032 standard, supplemented as needed, but failed to develop one or more of the required planning or sensitivity cases.

R5.	N/A	N/A	N/A	The responsible entity, as identified in Requirement R1, did not have criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations for completing the Extreme Temperature Assessment.
R6.	N/A	N/A	N/A	The responsible entity, as identified in Requirement R1, failed to define or document the criteria or methodology to be used in the Extreme Temperature Assessment to identify instability, uncontrolled separation, or Cascading within an Interconnection.
R7.	N/A	N/A	The responsible entity, as identified in Requirement R1, identified Contingencies for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System, but did not include the rationale for those Contingencies selected for evaluation as supporting information.	The responsible entity, as identified in Requirement R1, did not identify Contingencies for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System.

R8.	The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to document the assumptions for one or more sensitivity cases in accordance with Requirement R8.	The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to document the assumptions for one or more benchmark planning cases in accordance with Requirement R8.	The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to document results for one or more of the sensitivity cases in accordance with Requirement R8.	The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to document results for one or more of the benchmark planning cases in accordance with Requirement R8. OR The responsible entity, as identified in Requirement R1, failed to complete steady state or transient stability analyses and document results in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, in accordance with Requirement R8.
R9.	N/A	N/A	The responsible entity, as identified in Requirement R1, developed a Corrective Action Plan in accordance with Requirement R9, but failed to make its Corrective Action Plan available to, or solicit feedback from, applicable	The responsible entity, as identified in Requirement R1, failed to develop a Corrective Action Plan when the benchmark planning case study results indicate the System is unable to meet performance requirements for

			regulatory authorities or governing bodies responsible for retail electric service issues.	the Table 1 P0 or P1 Contingencies. OR The responsible entity, as identified in Requirement R1, developed a Corrective Action Plan, but it was missing one or more of the elements of Requirement R9 Part 9.1, 9.3 and 9.4 (as applicable).
R10.	N/A	N/A	The responsible entity, as identified in Requirement R1, evaluated and documented possible actions to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection where required under Requirement R10 Part 10.1, but failed to evaluate and document possible actions where required under Requirement R10 Part 10.2.	The responsible entity, as identified in Requirement R1, evaluated and documented possible actions to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection where required under Requirement R10 Part 10.2, but failed to evaluate and document possible actions where required under Requirement R10 Part 10.1. OR The responsible entity, as identified in Requirement R1, failed to evaluate and document possible actions to

				reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection where required under Requirement R10 Parts 10.1 and 10.2.
R11.	The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 60 days but less than or equal to 80 days following the request.	The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 80 days but less than or equal to 100 days following the request.	The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 100 days but less than or equal to 120 days following the request.	The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 120 days following the request. OR The responsible entity, as identified in Requirement R1, did not provide its Extreme Temperature Assessment results to functional entities having a reliability related need who submitted a written request for the information.

D. Regional Variances

None.

E. Associated Documents

- Implementation Plan for Project 2023-07
- Technical Rationale Document
- Consideration of Issues and Directives for FERC Order 896.
- ERO Benchmark Event Library
- TPL-008 Data Library Read Me

Version History

Version	Date	Action	Change Tracking
1	TBD	Addressing FERC Order 896	New Standard

Attachment 1: Extreme Temperature Assessment Zones

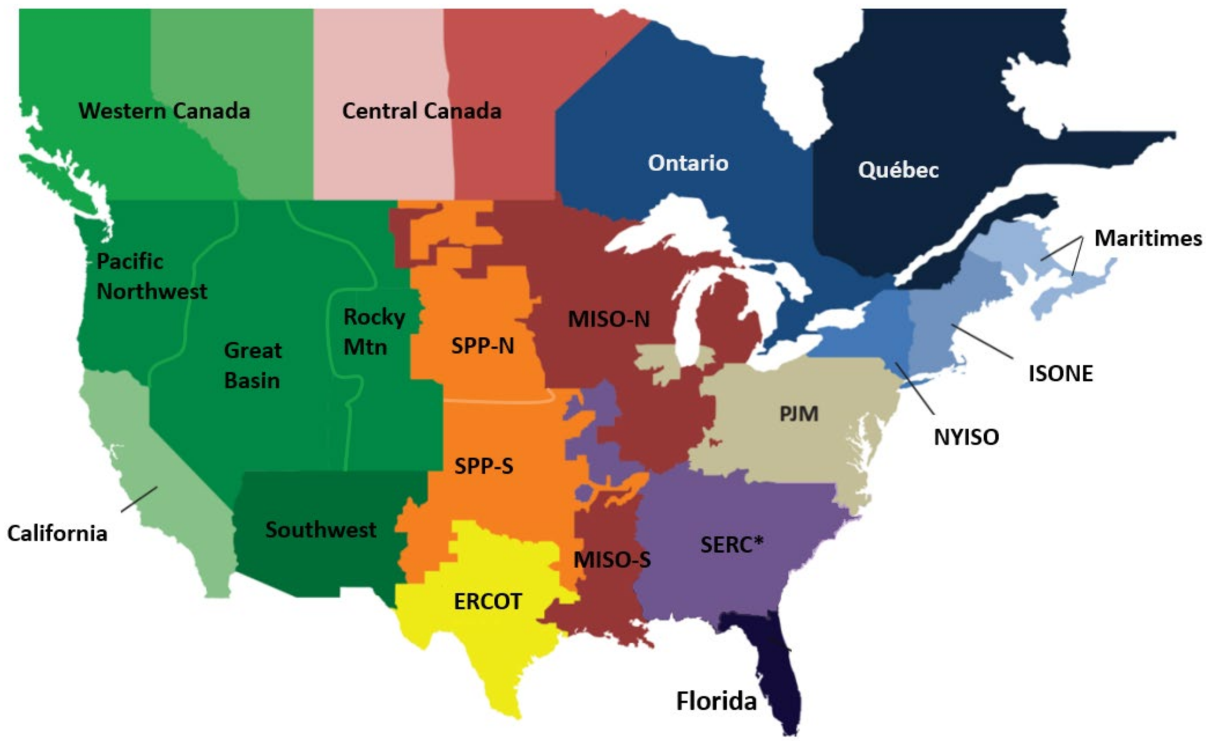
The table below lists the zones to be used in the Extreme Temperature Assessment and identifies the Planning Coordinators that belong to each zone. In accordance with Requirement R2, each Planning Coordinator is required to identify the zone(s) to which it belongs. Planning Coordinators, in different zones within a broader planning region, may use the same benchmark temperature events for their respective benchmark planning cases, provided the benchmark temperature events meet the criteria of Requirement R2 for each zone.

Zone	Planning Coordinators
Eastern Interconnection	
MISO North	Planning Coordinator(s) in MISO that serve portions of MISO in Montana, North Dakota, South Dakota, Minnesota, Iowa, Wisconsin, Michigan, Indiana, Illinois, Missouri, and Kentucky
MISO South	Planning Coordinator(s) in MISO that serve portions of Arkansas, Mississippi, Louisiana, and Texas
SPP North	Planning Coordinator(s) in portions of SPP that serve Iowa, Montana, Nebraska, North Dakota, and South Dakota.
SPP South	Planning Coordinator(s) in portions of SPP that serve Arkansas, Kansas, Louisiana, Missouri, New Mexico, Oklahoma, and Texas.
PJM	Planning Coordinator(s) that serves PJM
New England	Planning Coordinator(s) in NPCC that serve the six New England States
New York	Planning Coordinator(s) in NPCC that serve New York
SERC	Planning Coordinator(s) in SERC, excluding those that serve Florida and those in MISO, SPP, and PJM
Florida	Planning Coordinator(s) in SERC that serve Florida
Central Canada	Planning Coordinator(s) that serve Saskatchewan and Manitoba region of MRO
Ontario	Planning Coordinator(s) in NPCC that serve Ontario
Maritimes	Planning Coordinator(s) in NPCC that primarily serve New Brunswick, Nova Scotia, Prince Edward Island, and Northern Maine
Western Interconnection	
Southwest	Planning Coordinator(s) in the Southwest region of WECC, including El Paso in West Texas
Pacific Northwest	Planning Coordinator(s) in the Pacific Northwest region of WECC

Zone	Planning Coordinators
Great Basin	Planning Coordinator(s) in the Great Basin region of WECC
Rocky Mountain	Planning Coordinator(s) in the Rocky Mountain region of WECC
California/Mexico	Planning Coordinator(s) in the California/Mexico region of WECC
Western Canada	Planning Coordinator(s) that primarily serve British Columbia and Alberta region of WECC
ERCOT Interconnection	
ERCOT	Planning Coordinator(s) in Texas that are part of the ERCOT Interconnection
Quebec Interconnection	
Quebec	Planning Coordinator(s) that serve Quebec in the NPCC Region.

The map below depicts an approximation of the zones to be used in the Extreme Temperature Assessment and is provided as a visual aid; to the extent that there is a conflict between the map and the table, the table controls. This map is not to be used for compliance purposes.

TPL-008-1 Weather Zones Map



Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the fourth draft of the proposed standard posted for a 15-day formal comment period with additional ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	July 19, 2023
SAR posted for comment	August 8–September 27, 2023
45-day formal comment period with initial ballot	March 20–May 3, 2024
38-day formal comment period with additional ballot	July 16–August 22, 2024
15-day formal comment period with additional ballot	October 7–21, 2024

Anticipated Actions	Date
15-day formal comment period with additional ballot	November 7–21, 2024
5-day final ballot	December 2–6, 2024
Board adoption	December 10, 2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

Extreme Temperature Assessment – Documented evaluation of future Bulk Electric System performance for extreme heat and extreme cold benchmark temperature events.

A. Introduction

1. **Title:** Transmission System Planning Performance Requirements for Extreme Temperature Events

2. **Number:** TPL-008-1

3. **Purpose:** Establish Transmission system planning performance requirements to develop a Bulk Power System (BPS) that will operate reliably during extreme heat and extreme cold temperature events.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Transmission Planner

   4.1.2. Planning Coordinator

5. **Effective Date:** See Implementation Plan for Project 2023-07.

B. Requirements and Measures

R1. Each Planning Coordinator shall identify, in conjunction with its Transmission Planner(s), each entity's individual and joint responsibilities for completing the Extreme Temperature Assessment, which shall include each of the responsibilities described in Requirements R2 through R11. Each responsible entity shall complete its responsibilities such that the Extreme Temperature Assessment is completed at least once every five calendar years. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M1. Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall provide dated documentation of each entity's individual and joint responsibilities, such as meeting minutes, agreements, copies of procedures, or protocols in effect between entities or between departments of a vertically integrated system, or email correspondence that identifies an agreement has been reached on individual and joint responsibilities for completing the Extreme Temperature Assessment, and that these responsibilities were completed such that the Extreme Temperature Assessment was completed once every five calendar years.

R2. Each Planning Coordinator shall identify the zone(s) to which the Planning Coordinator belongs to under Attachment 1 and shall coordinate with all Planning Coordinators within each of its identified zone(s), to identify one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event for each of its identified zone(s) when completing the Extreme Temperature Assessment. The benchmark temperature events shall be obtained from the benchmark library maintained by the ERO or developed by the Planning Coordinators. Each benchmark temperature event identified by the Planning Coordinators shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. Consider no less than a 40-year period of temperature data ending no more than five years prior to the time the benchmark temperature events are selected; and

2.2. Represent one of the 20 most extreme temperature conditions based on the three-day rolling average of daily maximum (heat) or daily minimum (cold) temperature across the zone.

M2. Each Planning Coordinator shall have evidence in either electronic or hard copy format that it identified the zone(s) to which it belongs to, under Attachment 1, and that it coordinated with all other Planning Coordinators within each of its identified zone(s) to ~~select~~ identify one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event meeting the criteria of Requirement R2 for each of their identified zone(s) when completing the Extreme Temperature Assessment.

R3. Each Planning Coordinator shall coordinate with all Planning Coordinators within each of its zone(s) identified in Requirement R2, to implement a process for developing

benchmark planning cases for the Extreme Temperature Assessment that represent the benchmark temperature events selected in Requirement R2 and sensitivity cases to demonstrate the impact of changes to the basic assumptions used in the benchmark planning cases. This process shall include the following: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Selection of System models within the Long-Term Transmission Planning Horizon to form the basis for the benchmark planning cases.

3.2. Forecasted seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers within the zone.

3.3. Assumed seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers in areas outside the zone, as needed.

3.4. Identification of changes to at least one of the following conditions for sensitivity cases: generation, real and reactive forecasted Load, or transfers.

M3. Each Planning Coordinator shall have dated evidence that it implemented a process for coordinating the development of benchmark planning cases and sensitivity cases for the Extreme Temperature Assessment as specified in Requirement R3.

R4. Each responsible entity, as identified in Requirement R1, shall use the ~~coordination~~ process developed in Requirement R3 and data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, to develop the following and establish category P0 as the normal System condition in Table 1: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

4.1. One common extreme heat and one common extreme cold benchmark planning case.

4.2. One common extreme heat and one common extreme cold sensitivity case.

M4. Each responsible entity, as identified in Requirement R1, shall have dated evidence in either electronic or hard copy format that it developed benchmark planning cases and sensitivity cases in accordance with Requirement R4.

R5. Each responsible entity, as identified in Requirement R1, shall have criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations for completing the Extreme Temperature Assessment. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M5. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of the documentation, specifying the criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations for completing the Extreme Temperature Assessment.

R6. Each responsible entity, as identified in Requirement R1, shall define and document the criteria or methodology to be used in the Extreme Temperature Assessment to

identify instability, uncontrolled separation, or Cascading within an Interconnection. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M6. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of documentation, specifying the criteria or methodology to be used in the Extreme Temperature Assessment to identify instability, uncontrolled separation, or Cascading within an Interconnection in accordance with Requirement R6.

R7. Each responsible entity, as identified in Requirement R1, shall identify the Contingencies for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System. The rationale for those Contingencies selected for evaluation shall be available as supporting information. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M7. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of documentation, of the Contingencies for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System along with supporting rationale.

R8. Each responsible entity, as identified in Requirement R1, shall complete steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, and shall document the assumptions and results. Steady state and transient stability analyses shall be performed for the following: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

8.1. Benchmark planning cases developed in accordance with Requirement R4 Part 4.1.

8.2. Sensitivity cases developed in accordance with Requirement R4 Part 4.2.

M8. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of documentation, of the assumptions and results of the steady state and transient stability analyses completed in the Extreme Temperature Assessment.

R9. Each responsible entity, as identified in Requirement R1, shall develop a Corrective Action Plan(s) when the analysis of a benchmark planning case, in accordance with Requirement R8 Part 8.1, indicates its portion of the Bulk Electric System is unable to meet performance requirements for category P0 or P1 in Table 1. For each Corrective Action Plan, the responsible entity shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

9.1. Document alternative(s) considered when Non-Consequential Load Loss is utilized as an element of a Corrective Action Plan for a Table 1 P1 Contingency.

9.2. Be permitted to utilize Non-Consequential Load Loss as an interim solution, which normally is not permitted for category P0 in Table 1 for situations that are

beyond the control of the Planning Coordinator or Transmission Planner that prevent the implementation of a Corrective Action Plan in the required timeframe, provided that the responsible entity documents the situation causing the problem, alternatives evaluated, and takes actions to resolve the situation.

9.3. Make its Corrective Action Plan available to, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.

9.4. Be permitted to have revisions to the Corrective Action Plan in subsequent Extreme Temperature Assessments, provided that the planned Bulk Electric System shall continue to meet the performance requirements of Table 1.

M9. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of documentation, of each Corrective Action Plan developed in accordance with Requirement R9 when the analysis of a benchmark planning case indicates its portion of the Bulk Electric System is unable to meet performance requirements for category P0 or P1 in Table 1. Evidence shall include documentation of correspondence with applicable regulatory authorities or governing bodies responsible for retail electric service issues and any revision history.

R10. Each responsible entity, as identified in Requirement R1, shall evaluate and document possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) if analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection, for the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

10.1. Table 1 P7 Contingencies in benchmark planning cases analyzed in accordance with Requirement R8 Part 8.1.

10.2. Categories P0, P1, and P7 in Table 1 in sensitivity cases analyzed in accordance with Requirement R8 Part 8.2.

M10. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of documentation that it evaluated and documented possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts when the analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection for Table 1 P7 Contingencies in benchmark planning cases or categories P0, P1, or P7 in Table 1 in sensitivity cases.

R11. Each responsible entity, as identified in Requirement R1, shall provide its Extreme Temperature Assessment results within 60 calendar days of a request to any functional entity that has a reliability related need and submits a written request for the information. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M11. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as email notices, documentation of updated web pages, or postal receipts showing recipient, that it provided its Extreme Temperature Assessment to any

functional entity who has a reliability need within 60 calendar days of a written request.

C. Compliance

1. **Compliance Monitoring Process**

   1.1. **Compliance Enforcement Authority:** "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

   1.2. **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.

   - Each responsible entity shall retain evidence of compliance with each requirement in this standard for five calendar years or one complete Extreme Temperature Assessment cycle, whichever is longer.

   1.3. **Compliance Monitoring and Enforcement Program:** "Compliance Monitoring Enforcement Program" or "CMEP" means, depending on the context (1) the NERC Compliance Monitoring and Enforcement Program (Appendix 4C to the NERC Rules of Procedure) or the Commission-approved program of a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that is responsible for performing compliance monitoring and enforcement activities with respect to Registered Entities' compliance with Reliability Standards.

Table 1 – Steady State & Stability Performance Events
Steady State & Stability: a. Instability, uncontrolled separation, or Cascading within an Interconnection, defined in accordance with Requirement R6, shall not occur. b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0. c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event. d. Simulate Normal Clearing unless otherwise specified. e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings. **Steady State Only:** f. Applicable Facility Ratings shall not be exceeded. g. System steady state voltages and post-Contingency voltage deviations shall meet the criteria identified in Requirement R5.

Table 1 – Steady State & Stability Performance Events							
Category	Initial Condition	Event[1]	Fault Type[3]	Contingency BES Level	Interruption of Firm Transmission Service Allowed	Non-Consequential Load Loss Allowed	
						Benchmark Planning Cases	Sensitivity Cases
P0 No Contingency	Normal System	None	N/A	N/A	Yes	No[6]	Yes
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[2] 4. Shunt Device[4]	3Ø	≥ 200 kV	Yes	Yes[6]	Yes
		5. Single Pole of a DC line	SLG				
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure[5] 2. Loss of a bipolar DC line	SLG	≥ 200 kV	Yes	Yes	Yes

Table 1 – Steady State & Stability Performance Events
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the BES level of the event. For P7 events, the BES level of the event is the highest System voltage level of the element(s) removed for the analyzed event. 2. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers. 3. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria. 4. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground. 5. Excludes circuits that share a common structure for 1 mile or less. 6. Benchmark planning cases require the development of a Corrective Action Plan when the responsible entity’s portion of the BES is unable to meet the performance requirements for categories P0 or P1. Additionally, in benchmark planning cases, Non-Consequential Load Loss is not permitted for category P0 except where permitted as an interim solution in a Corrective Action Plan in accordance with Requirement R9 Part 9.2.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed less than or equal to six months late.	The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed more than six months but less than or equal to 12 months late.	The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed more than 12 months but less than or equal to 18 months late.	The Planning Coordinator, in conjunction with its Transmission Planner(s), failed to identify individual and joint responsibilities for completing the Extreme Temperature Assessment. OR The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed more than 18 months late.
R2.	N/A	N/A	The Planning Coordinator coordinated with all Planning Coordinators within each identified zone to identify one common extreme heat and one common extreme cold benchmark temperature event for completing the Extreme Temperature Assessment, but one of the identified events	The Planning Coordinator coordinated with all Planning Coordinators within each identified zone to identify one common extreme heat and one common extreme cold benchmark temperature event for completing the Extreme Temperature Assessment, but both of the identified events

			failed to meet all the criteria of Requirement R2.	failed to meet all of the criteria of Requirement R2. OR The Planning Coordinator failed to coordinate with all Planning Coordinators within each identified zone to identify one common extreme heat and one common extreme cold benchmark temperature event for completing the Extreme Temperature Assessment.
R3.	N/A	N/A	N/A	The Planning Coordinator did not coordinate with all Planning Coordinators within each of its identified zone(s) to implement a process for developing benchmark planning cases. OR The Planning Coordinator coordinated with all Planning Coordinators within each of its identified zone(s) to implement a process for developing benchmark planning cases, but the process did not include all of the required elements.

R4.	N/A	N/A	N/A	The responsible entity, as identified in Requirement R1, did not use the ~~coordination~~ process developed in Requirement R3 to develop benchmark planning cases or sensitivity cases. OR The responsible entity, as identified in Requirement R1, used the ~~coordination~~ process developed in Requirement R3 to develop benchmark planning cases and sensitivity cases, but did not use data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, for one or more of the required cases. OR The responsible entity, as identified in Requirement R1, used the ~~coordination~~ process developed in Requirement R3 and data consistent with that provided in accordance with the MOD-032 standard, supplemented as needed, but failed to develop one or more

				of the required planning or sensitivity cases.
R5.	N/A	N/A	N/A	The responsible entity, as identified in Requirement R1, did not have criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations for completing the Extreme Temperature Assessment.
R6.	N/A	N/A	N/A	The responsible entity, as identified in Requirement R1, failed to define or document the criteria or methodology to be used in the Extreme Temperature Assessment to identify instability, uncontrolled separation, or Cascading within an Interconnection.
R7.	N/A	N/A	The responsible entity, as identified in Requirement R1, identified Contingencies for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System, but did not include the rationale for those Contingencies selected for	The responsible entity, as identified in Requirement R1, did not identify Contingencies for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System.

			evaluation as supporting information.	
R8.	The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to document the assumptions for one or more sensitivity cases in accordance with Requirement R8.	The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to document the assumptions for one or more benchmark planning cases in accordance with Requirement R8.	The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to ~~evaluate and~~ document results for one or more of the sensitivity cases in accordance with Requirement R8.	The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to ~~evaluate and~~ document results for one or more of the benchmark planning cases in accordance with Requirement R8. OR The responsible entity, as identified in Requirement R1, failed to complete steady state or transient stability analyses and document results in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, in accordance with Requirement R8.
R9.	N/A	N/A	The responsible entity, as identified in Requirement R1, developed a Corrective Action Plan in accordance with Requirement R9, but failed to	The responsible entity, as identified in Requirement R1, failed to develop a Corrective Action Plan when the benchmark planning case

			make its Corrective Action Plan available to, or solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.	study results indicate the System is unable to meet performance requirements for the Table 1 P0 or P1 Contingencies. OR The responsible entity, as identified in Requirement R1, developed a Corrective Action Plan, but it was missing one or more of the elements of Requirement R9 Part 9.1, 9.3 and 9.4 (as applicable).
R10.	N/A	N/A	The responsible entity, as identified in Requirement R1, evaluated and documented possible actions to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection where required under Requirement R10 Part 10.1, but failed to evaluate and document possible actions where required under Requirement R10 Part 10.2.	The responsible entity, as identified in Requirement R1, evaluated and documented possible actions to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection where required under Requirement R10 Part 10.2, but failed to evaluate and document possible actions where required under Requirement R10 Part 10.1. OR

				The responsible entity, as identified in Requirement R1, failed to evaluate and document possible actions to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection where required under Requirement R10 Parts 10.1 and 10.2.
R11.	The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 60 days but less than or equal to 80 days following the request.	The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 80 days but less than or equal to 100 days following the request.	The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 100 days but less than or equal to 120 days following the request.	The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 120 days following the request. OR The responsible entity, as identified in Requirement R1, did not provide its Extreme Temperature Assessment results to functional entities having a reliability related

				need who submitted a written request for the information.

D. Regional Variances

None.

E. Associated Documents

- Implementation Plan for Project 2023-07
- Technical Rationale Document
- Consideration of Issues and Directives for FERC Order 896.
- ERO Benchmark Event Library
- TPL-008 Data Library Read Me

Version History

Version	Date	Action	Change Tracking
1	TBD	Addressing FERC Order 896	New Standard

Attachment 1: Extreme Temperature Assessment Zones

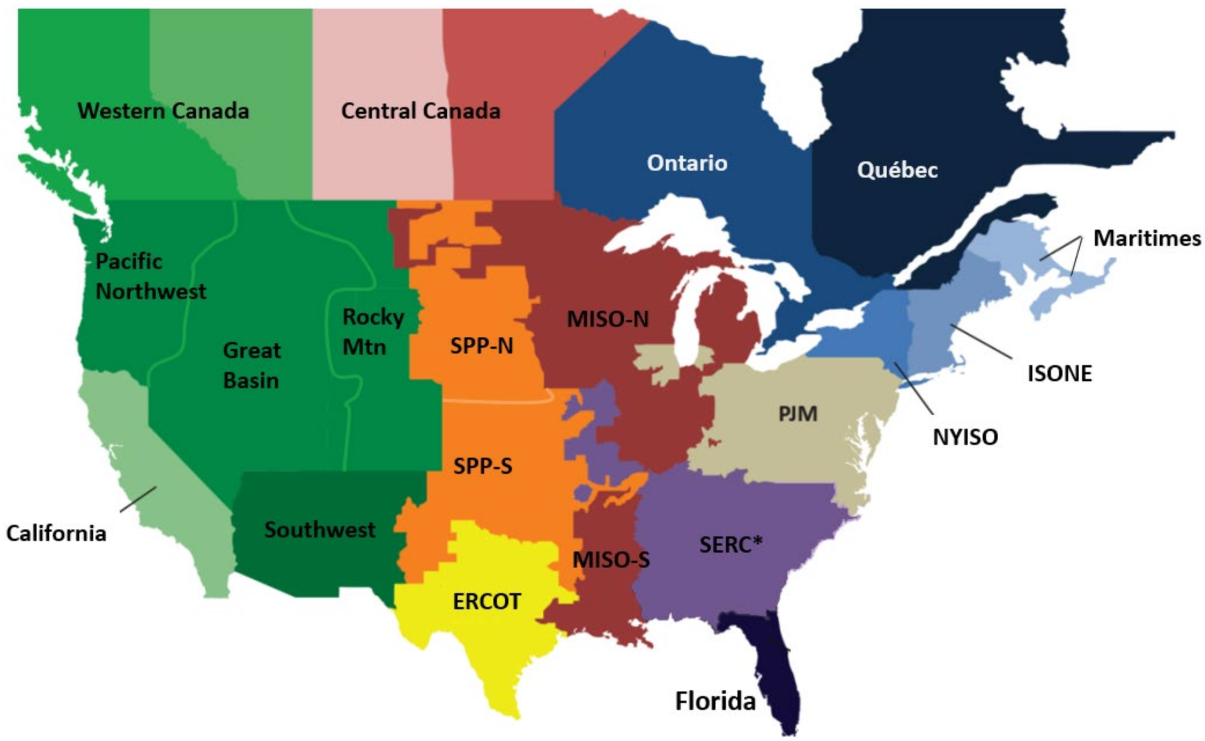
The table below lists the zones to be used in the Extreme Temperature Assessment and identifies the Planning Coordinators that belong to each zone. In accordance with Requirement R2, each Planning Coordinator is required to identify the zone(s) to which it belongs. Planning Coordinators in different zones within a broader planning region may use the same benchmark temperature events for their respective benchmark planning cases, provided the benchmark temperature events meet the criteria of Requirement R2 for each zone.

Zone	Planning Coordinators
Eastern Interconnection	
MISO North	Planning Coordinator(s) in MISO that serve portions of MISO in Montana, North Dakota, South Dakota, Minnesota, Iowa, Wisconsin, Michigan, Indiana, Illinois, Missouri, and Kentucky
MISO South	Planning Coordinator(s) in MISO that serve portions of Arkansas, Mississippi, Louisiana, and Texas
SPP North	Planning Coordinator(s) in portions of SPP that serve Iowa, Montana, Nebraska, North Dakota, and South Dakota.
SPP South	Planning Coordinator(s) in portions of SPP that serve Arkansas, Kansas, Louisiana, Missouri, New Mexico, Oklahoma, and Texas.
PJM	Planning Coordinator(s) that serves PJM
New England	Planning Coordinator(s) in NPCC that serve the six New England States
New York	Planning Coordinator(s) in NPCC that serve New York
SERC	Planning Coordinator(s) in SERC, excluding those that serve Florida and those in MISO, SPP, and PJM
Florida	Planning Coordinator(s) in SERC that serve Florida
Central Canada	Planning Coordinator(s) that serve Saskatchewan and Manitoba region of MRO
Ontario	Planning Coordinator(s) in NPCC that serve Ontario
Maritimes	Planning Coordinator(s) in NPCC that primarily serve New Brunswick, Nova Scotia, Prince Edward Island, and Northern Maine
Western Interconnection	
~~WECC~~ Southwest	Planning Coordinator(s) in the Southwest region of WECC, including El Paso in West Texas
Pacific Northwest	Planning Coordinator(s) in the Pacific Northwest region of WECC

Zone	Planning Coordinators
Great Basin	Planning Coordinator(s) in the Great Basin region of WECC
Rocky Mountain	Planning Coordinator(s) in the Rocky Mountain region of WECC
California/Mexico	Planning Coordinator(s) in the California/Mexico region of WECC
Western Canada	Planning Coordinator(s) that primarily serve British Columbia and Alberta region of WECC
ERCOT Interconnection	
ERCOT	Planning Coordinator(s) in Texas that are part of the ERCOT Interconnection
Quebec Interconnection	
Quebec	Planning Coordinator(s) that serve Quebec in the NPCC Region.

The map below depicts an approximation of the zones to be used in the Extreme Temperature Assessment and is provided as a visual aid; to the extent that there is a conflict between the map and the table, the table controls. This map is not to be used for compliance purposes.

TPL-008-1 Weather Zones Map



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NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan

Project 2023-07 Transmission System Planning Performance Requirements for Extreme Weather
Reliability Standard TPL-008-1

Applicable Standard

- TPL-008-1 – Transmission System Planning Performance Requirements for Extreme Temperature Events

Requested Retirement

- Not applicable

Prerequisite Standard

- Not applicable

Applicable Entities

- Planning Coordinators
- Transmission Planners

New Term in the NERC Glossary of Terms

This section includes all newly defined, revised, or retired terms used or eliminated in the NERC Reliability Standard. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

- **Extreme Temperature Assessment** – Documented evaluation of future Bulk Electric System performance for extreme heat and extreme cold benchmark temperature events.

Background

On June 15, 2023, the U.S. Federal Energy Regulatory Commission ("FERC") issued Order No. 896, a final rule directing NERC to develop a new or modified Reliability Standard to address the lack of a long-term planning requirement(s) for extreme heat and cold weather events.[1] Specifically, FERC directed NERC to develop modifications to Reliability Standard TPL-001-5.1 or develop a new Reliability Standard that requires the following: (1) development of benchmark planning cases based on major prior extreme heat and cold weather events and/or meteorological projections; (2) planning for extreme heat and cold weather

[1] *Transmission System Planning Requirements for Extreme* Weather, Order No. 896, 183 FERC ¶ 61,191 (2023).

events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios including the expected resource mix's availability during extreme heat and cold weather conditions, and including the wide-area impacts of extreme heat and cold weather; and (3) development of Corrective Action Plans that mitigate any instances where performance requirements for extreme heat and cold weather events are not met. FERC further directed NERC to ensure that the proposed new or modified Reliability Standard becomes mandatory and enforceable beginning no later than 12 months from the effective date of FERC approval.

General Considerations

Proposed Reliability Standard TPL-008-1 would require the performance of an Extreme Temperature Assessment at least once every five calendar years (Requirement R1). This implementation plan provides a staggered approach for the performance of the first Extreme Temperature Assessment, with phased-in compliance dates beginning 12 months from the effective date of regulatory approval consistent with Order No. 896. For subsequent Extreme Temperature Assessments, entities may establish timeframes appropriate to their facts and circumstances for carrying out their responsibilities under the standard, provided that the Extreme Temperature Assessment is completed no later than five calendar years following the previous Extreme Temperature Assessment.

Effective Date

The effective date for the proposed Reliability Standard is provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of the proposed Reliability Standard (e.g., an entire Requirement or a portion thereof), the additional time for compliance with that section is specified below. These phased-in compliance dates represent the dates that entities must begin to comply with that particular section of the Reliability Standard, even where the Reliability Standard goes into effect at an earlier date.

TPL-008-1 and Definition

Where approval by an applicable governmental authority is required, the standard and definition of Extreme Temperature Assessment shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard and definition of Extreme Temperature Assessment is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Phased-In Compliance Dates

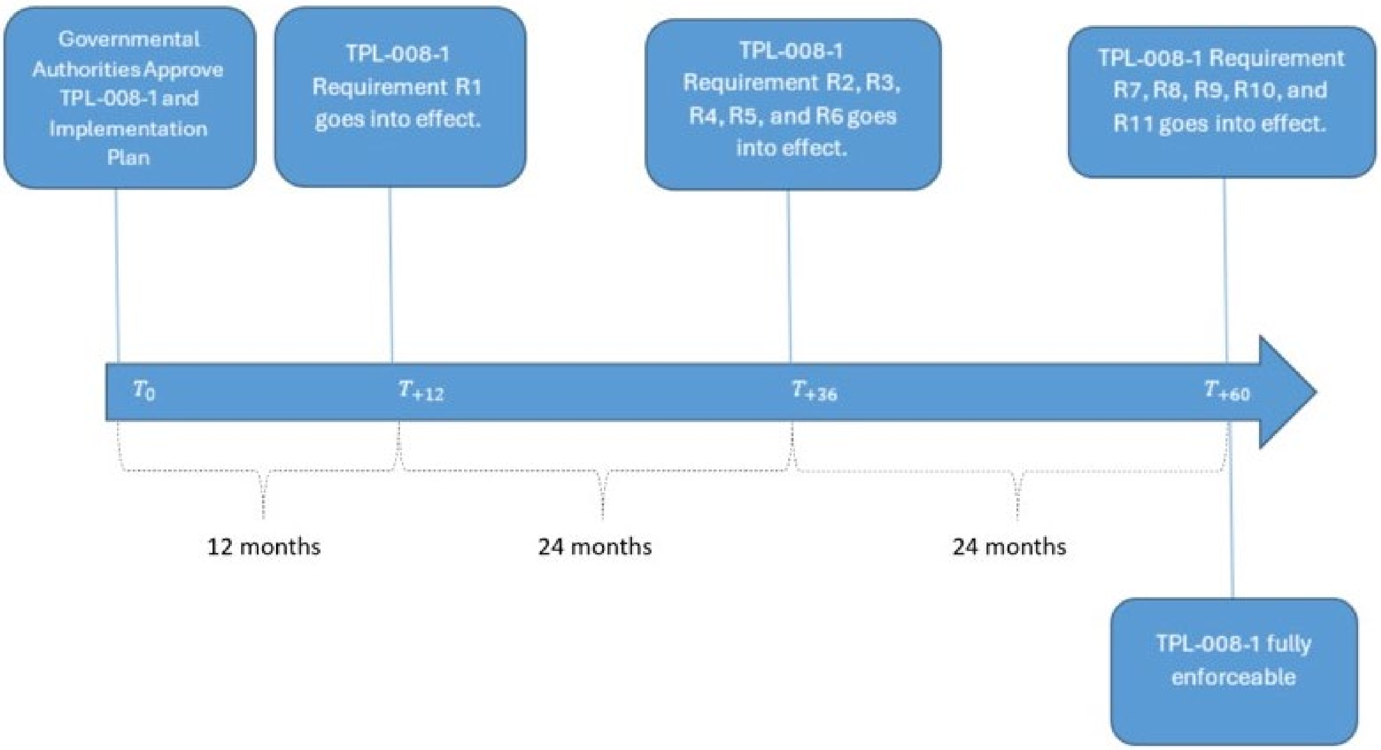
Compliance Date for TPL-008-1 Requirement R1

Entities shall be required to comply with Requirement R1, pertaining to the identification of individual and joint responsibilities for completing the Extreme Temperature Assessment, upon the effective date of Reliability Standard TPL-008-1.

Compliance Date for TPL-008-1 Requirements R2, R3, R4, R5, R6
Entities shall not be required to comply with Requirements R2, R3, R4, R5, and R6 until twenty-four (24) months after the effective date of Reliability Standard TPL-008-1.

Compliance Date for TPL-008-1 Requirements R7, R8, R9, R10, R11
Entities shall not be required to comply with Requirements R7, R8, R9, R10, and R11 until forty-eight (48) months after the effective date of Reliability Standard TPL-008-1.

Figure 1: Implementation Plan, Demonstrating Effective Date and Phased-in Compliance Dates from the effective date of the governmental authority's order approving this standard



Initial Performance of Periodic Requirements

Entities shall complete the Extreme Temperature Assessment no later than forty-eight (48) months after the effective date of Reliability Standard TPL-008-1. Subsequent Extreme Temperature Assessments shall be completed by no later than five calendar years following the completion of the previous Extreme Temperature Assessment.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Technical Rationale and Justification for TPL-008-1

Project 2023-07 Transmission Planning Performance Requirements for Extreme Weather

December 2024

RELIABILITY | RESILIENCE | SECURITY

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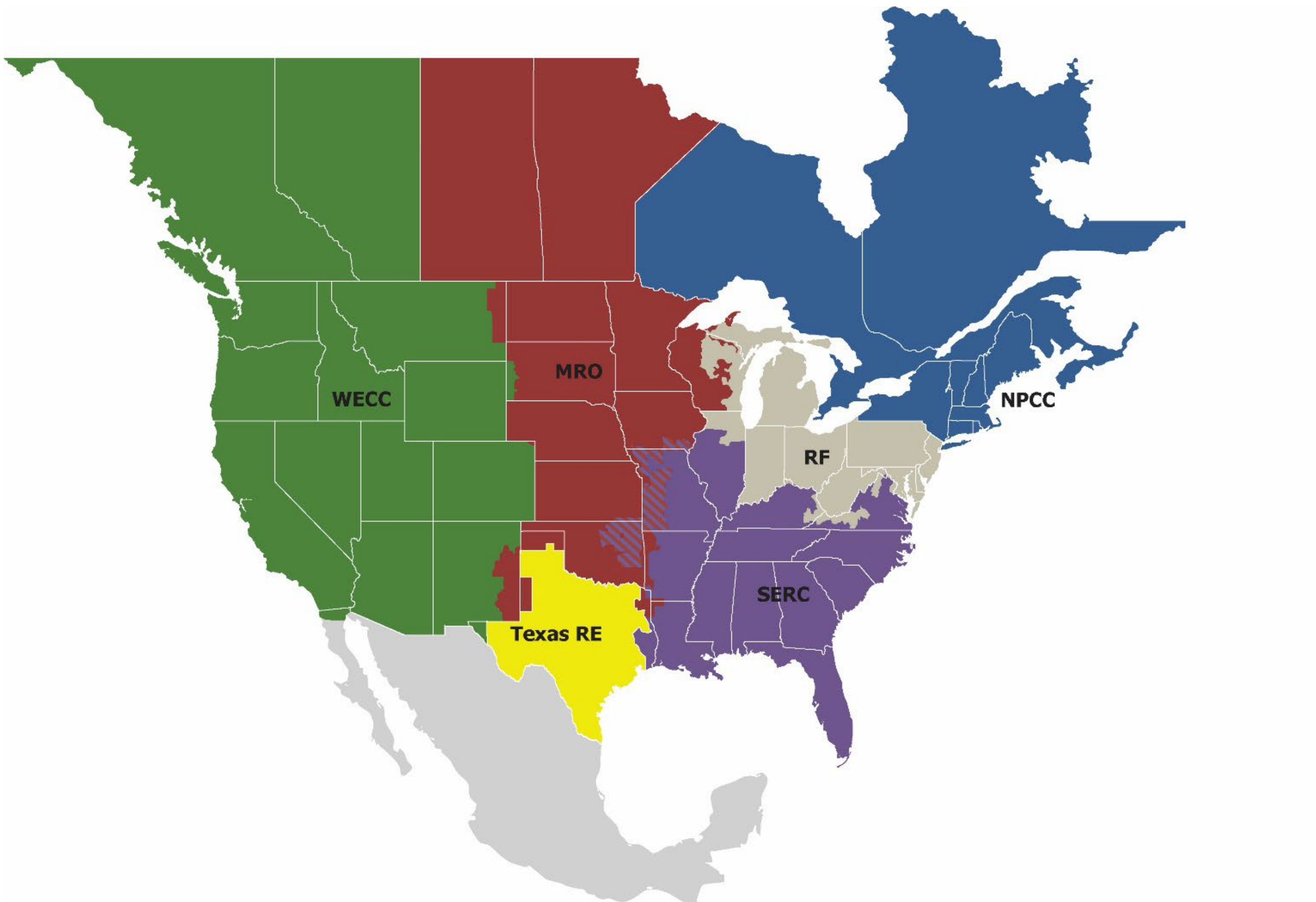
Table of Contents

Preface

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

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

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



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

Introduction

This document explains the technical rationale and justification for the proposed Reliability Standard TPL-008-1. It provides stakeholders and the ERO Enterprise with an understanding of the technology and technical requirements in the Reliability Standard. This Technical Rationale and Justification for TPL-008-1 is not a Reliability Standard and should not be considered mandatory and enforceable.

Background

On June 15, 2023, FERC issued FERC Order No. 896 that acknowledges the "challenges associated with planning for extreme heat and cold weather events, particularly those that occur during periods when the Bulk-Power System must meet unexpectedly high demand. Extreme heat and cold weather events have occurred with greater frequency in recent years and are projected to occur with even greater frequency in the future. These events have shown that load shed during extreme temperatures result in unacceptable risk to life and have extreme economic impact. As such, the impact of concurrent failures of Bulk-Power System (BPS) generation and transmission equipment and the potential for cascading outages that may be caused by extreme heat and cold weather events should be studied and corrective actions should be identified and implemented."[1]

Therefore, the Commission directed in FERC Order No. 896 to develop a new or modified Reliability Standard to address a lack of long-term planning requirement(s) for extreme heat and cold weather events. Specifically, FERC directed NERC to develop modifications to Reliability Standard TPL-001-5.1 or a new Reliability Standard, to require the following: (1) development of benchmark planning cases based on major prior extreme heat and cold weather events and/or meteorological projections; (2) planning for extreme heat and cold weather events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios including the expected resource mix's availability during extreme heat and cold weather conditions, and including the wide-area impacts of extreme heat and cold weather; and (3) development of corrective action plans that mitigate any instances where performance requirements for extreme heat and cold weather events are not met.

[1] N. Am. Elec. Reliability Corp., 183 FERC ¶ 61,191 (2023) (FERC Order), Final Rule. eLibrary | File List (ferc.gov)

Defined Terms

The Drafting Team (DT) defined one term to be added to the NERC Glossary of Terms to make the requirements easier to read and understand.

Extreme Temperature Assessment
Documented evaluation of future Bulk Electric System performance for extreme heat and extreme cold benchmark temperature events.

The definition of Extreme Temperature Assessment was developed by the DT to limit wordiness throughout the requirements.

TPL-008-1 Standard

The FERC Order No. 896 directed NERC to submit a new Reliability Standard or modifications to Reliability Standard TPL-001-5.1 to address the concerns pertaining to transmission system planning for extreme heat and cold weather events that impact the Reliable Operation of the Bulk-Power System.

The SDT determined that a new Reliability Standard was the cleanest way to address FERC's directives versus modifying Reliability Standard TPL-001-5.1. While the TPL-008-1 standard uses similar requirements, this allows industry to have one standard that focuses on extreme heat and extreme cold benchmark temperature events.

The purpose of TPL-008-1 is to "Establish Transmission system planning performance requirements to develop a Bulk Power System (BPS) that will operate reliably during extreme heat and extreme cold temperature events." The directives in FERC Order No. 896 pertain to the reliable operation of the BPS, and the requirements of TPL-008-1 support that by ensuring Planning Coordinators and Transmission Planners are planning their portions of the Bulk Electric System (BES) to meet performance requirements in extreme heat and extreme cold benchmark temperature events.

Requirement R1

Requirement R1 requires each Planning Coordinator (PC) and the Transmission Planner(s) (TP) within the PC's footprint to identify each entity's individual and joint responsibilities when completing the Extreme Temperature Assessment at least once every five calendar years. Due to significant level of data collection and coordination between the Planning Coordinator(s) and Transmission Planner(s) for the potential wide-area extreme heat and extreme cold benchmark events, as well as the need to document the assumptions and study results, the drafting team opined that completing the Extreme Temperature Assessment once every five calendar years is a reasonable timeframe to allow responsible entities to coordinate, prepare, perform, and document the study results. To the extent that responsible entities want to complete more than one set of the Extreme Temperature Assessment for an extreme heat and extreme cold benchmark event, they can do so, but the minimum requirement is once every five calendar years to complete one set of the Extreme Temperature Assessment.

The purpose of this requirement is to have the PC and its TP(s) identify their individual and joint responsibilities for the following activities:

- Identifying the PC's zone(s) and coordinating with all PCs in each of its identified zone(s) to select one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event (Requirement R2),
- Implementing a process for developing benchmark planning cases and sensitivity cases (Requirement R3),
- Developing benchmark planning cases and sensitivity cases (Requirement R4),
- Having acceptable criteria (Requirements R5 and R6),
- Identifying Contingencies for evaluation (Requirement R7),
- Performing steady state and transient stability analyses (Requirement R8),
- Developing Corrective Action Plans when required (Requirement R9),
- Evaluating and documenting possible actions for performance deficiencies that do not require Corrective Action Plans (Requirement R10), and
- Providing study results to any functional entity that has a reliability related need (Requirement R11).

The responsibilities described in Requirements R2 and R3 are explicitly assigned to the PC. The responsibilities described in Requirements R4 through R11 may be completed by either the PC or one or more of its TPs. Requirement R1 requires that an agreement is reached on the individual and joint responsibilities for completing the Extreme Temperature Assessment between the PC and its TPs.

Requirement R2

Requirement R2 requires each Planning Coordinator (PC) to identify the zone(s) it will participate in for the components of the Extreme Temperature Assessment that require coordination. PCs in the same zone are required to coordinate to:

- Select one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event (Requirement R2), and
- Implement a process for developing benchmark planning cases and sensitivity cases (Requirement R3).

FERC Order No. 896 directed NERC to require that transmission planning studies under the new or revised Reliability Standard consider the wide-area impacts of extreme heat and cold weather. Considering this directive, the SDT identified the zones depicted in Attachment 1 as reasonable boundaries that balance the need for studies to cover large regions with similar weather patterns with the need for a manageable level of coordination. An earlier proposal to limit coordination to only adjacent PCs was not adequate for meeting FERC's directives. While the zones depicted in Attachment 1 will require some PCs to coordinate with many other PCs, the industry has demonstrated, through various working groups and organizations, that it is capable of cooperating to build models that represent larger areas. The zones depicted in Attachment 1 are either aligned with existing PC boundaries or boundaries of a group of PCs with similar weather patterns.

Requirement R2 describes the need to select extreme benchmark temperature events necessary for the creation of benchmark planning cases. Specifically, extreme hot and cold temperatures experienced during benchmark events are assumed to be outside the ranges used as the basis of planning cases studied under Reliability Standard TPL-001-5.1. Since temperature levels and associated weather conditions affect load levels, generation performance, and transfer levels, the selection of benchmark events is critical to ensuring the Extreme Temperature Assessment appropriately evaluates probable System conditions.

Since any region can experience temperatures that are higher or lower than normal, PCs within the same zone must coordinate to select one common temperature event that includes hotter temperature assumptions and one common temperature event that includes colder temperature assumptions. While it is understood that, for example, one region may typically experience hotter summers and milder winters than another region, both a hotter than average summer and a colder than average winter could result in reliability concerns. Therefore, the requirement is for one common case specific to extreme heat and one common case specific to extreme cold conditions to be studied for the Extreme Temperature Assessment. By selecting the same, common events, PCs ensure that extreme temperatures are studied over the entire zone. The evaluation of a common event taking place over a wide area is foundational to FERC Order No. 896. Furthermore, selecting the same, common events reasonably limits coordination requirements. PCs are required to participate in the selection of events for their zone(s), but have no responsibilities for the selection of events in other zones.

The SDT determined that the extreme heat and extreme cold temperatures selected must have a verified statistical basis based on weather data from credible sources. The SDT has identified several key features that are used to determine when a temperature event will constitute a valid extreme benchmark temperature event for the purposes of completing the Extreme Temperature Assessment. Specifically, extreme benchmark temperature events must:

- Consider no less than 40 years of temperature data,
- Utilize data ending no more than five years prior to the time benchmark temperature events are selected, and
- Represent one of the worst 20 extreme temperature conditions within the zone.

Temperature events are ranked by computing the 3-day rolling average of daily maximum temperatures (for extreme heat) or daily minimum temperatures (for extreme cold). The 3-day rolling average temperatures are calculated for both extreme heat and extreme cold to identify multi-day periods of extreme heat or extreme cold temperature events. The ERO will maintain a library of benchmark events to provide responsible entities access to vetted benchmark temperature events that meet the criteria of Requirement R2. While selection of events from the ERO's provided library assures entities they are selecting valid events, Requirement R2 does not preclude entities from collecting temperature data and identifying benchmark temperature events through their own process. Entities that elect to develop their own benchmark temperature events are responsible for ensuring the input temperature data and selected benchmark temperature events meet the criteria of Requirement R2. Additionally, because Requirement R2 requires PCs within a zone to coordinate in the selection of the benchmark temperature events, the process used to identify these events must be agreeable to those PCs.

The requirement to consider no less than 40 years of temperature data was established based on the observation that many of the worst events identified in various regions of North America occurred in the 1980s and 1990s. For example, preliminary data indicated that the five worst extreme cold temperature events in the PJM region over the last 43 years occurred between 1983 and 1994. Similar results were seen in other regions for both extreme heat and extreme cold temperature events. Thus, the SDT determined that a minimum of 40 years of temperature data should be used to ensure more extreme events weren't excluded by using a shorter duration of temperature data.

Requirement R3

Requirement R3 aligns with directives in FERC Order No. 896, emphasizing the importance of coordinating the development of benchmark planning cases and sensitivity cases amongst PCs within a zone, where the scope of extreme temperature event studies will likely cover large geographical areas exceeding smaller individual planning areas. The SDT considered comments from the industry expressing concerns regarding the necessity to coordinate among all impacted PCs in developing benchmark planning cases and sensitivity cases for various extreme benchmark temperature events. Recognizing that coordination among all impacted PCs may not be necessary to ensure reliability within an individual planning area, the SDT drafted Requirement R3 to require each PC to coordinate with all PCs within a zone to implement a process for the development of benchmark planning cases and sensitivity cases. The SDT believes this change balances the need to ensure the planning cases capture impacts to/from entities affected by the same benchmark temperature event, while recognizing that reliability will be less impacted by system changes far removed from the zone.

PCs within a zone must coordinate to implement a process that results in the development of benchmark planning cases that represent the benchmark temperature events selected in accordance with Requirement R2, and sensitivity cases that demonstrate the impact of changes to the basic assumptions used in the benchmark planning cases. This process requires several components, outlined in the sub-requirements of Requirement R3.

First, Requirement R3 Part 3.1 requires PCs within a zone to identify System models form the basis for developing the benchmark planning cases. These models must represent one of the years in the Long-Term Transmission Planning Horizon. PCs will also need to ensure models include stability modeling data to provide for the performance of stability analysis later in the process. It is reasonably anticipated that PCs will likely utilize a summer peak model as the starting point for the extreme heat benchmark temperature event and a winter peak model as the starting point for the extreme cold benchmark temperature event.

Secondly, Requirement R3 Part 3.2 requires that PCs within a zone provide forecasted data for their area within the zone that represents the benchmark temperature events selected in accordance with Requirement R2. Each PC must provide data for their area within the zone that represents seasonal and temperature adjustments for Load, generation, Transmission, and transfers. The provided data should be used to update the starting point models to reflect the selected benchmark temperature events.

Thirdly, Requirement R3 Part 3.3 allows PCs to agree on assumptions for seasonal and temperature adjustments for Load, generation, Transmission, and transfers in areas *outside* of the zone. As a sub-requirement of Requirement R3, these assumptions must be coordinated among PCs in the zone, as needed. As an example, PCs within the zone may identify the need for imported power during a benchmark event. The PCs may evaluate historical import availability and assume an import from an area outside of the zone is reasonable and should be modeled.

Finally, Requirement R3 Part 3.4 requires PCs to coordinate and identify changes to generation, real and reactive forecasted Load, or transfers that should be reflected in sensitivity cases. Sensitivity cases are intended to demonstrate the impact of changes to the basic assumptions used in the benchmark planning cases, and Requirement R3 Part 3.4 ensures PCs are cooperating to identify changes that sufficiently alter the assumptions reflected in the benchmark planning cases. For example, PCs that identified an import external source to the zone for a benchmark planning case may elect to alter the source of that import in the sensitivity case.

Requirement R4

The SDT drafted Requirement R4 to require the responsible entity to use data consistent with Reliability Standard MOD-032, supplemented by other sources as needed, for developing benchmark planning cases that represent System conditions based on selected benchmark temperature events. This aligns with directives in FERC Order No. 896, paragraph 30, emphasizing the requirement of developing both benchmark planning cases and sensitivity study cases. Requirement R4 is consistent with Reliability Standard TPL-001-5.1 in cross-referencing Reliability Standard MOD-032, which establishes consistent modeling data requirements and reporting procedures for the development of planning horizon cases necessary to support analysis of the reliability of the interconnected System. It is also consistent with Reliability Standard TPL-001-5.1 in acknowledging that data from other sources may be required to supplement the data collected through Reliability Standard MOD-032 procedures.

FERC Order No. 896, paragraph 116, directs NERC "to require in the new or modified Reliability Standard that responsible entities model demand load response in their extreme weather event planning area". This requirement can be met via the use of data consistent with Reliability Standard MO-032, as included in the TPL-008-1 standard's Requirement R4. The modeling of the demand load response can be implemented through the use of MOD-032 in which data needed for study base case development can be requested and obtained for development of the benchmark planning cases and sensitivity cases.

Requirement R4 requires entities to use the coordination process developed in accordance with Requirement R3 to develop the following four cases:

- One common extreme heat benchmark planning case (Requirement R4 Part 4.1),
- One common extreme cold benchmark planning case (Requirement R4 Part 4.1),
- One common extreme heat sensitivity case (Requirement R4 Part 4.2), and
- One common extreme cold sensitivity case (Requirement R4 Part 4.2).

At the completion of the case development process, implemented in accordance with Requirement R3, and executed in Requirement R4, responsible entities will have the four cases listed above. This establishes category P0 as the normal System condition in Table 1 for each case. Requirement R3 does not preclude PCs from implementing a process that develops cases for multiple benchmark temperature events or additional sensitivity cases. Moreover, entities may elect to develop additional cases for their internal use.

As per FERC Order No. 896, paragraph 94, it is clarified that resource adequacy benchmarks are not within the scope of TPL-008-1. The intent of the standard is to evaluate benchmark events where sufficient generation is available to supply load. However, under an extreme heat or extreme cold temperature condition, there may be instances where the benchmark planning cases and/or sensitivity cases may not have sufficient available generation to supply the load. In these scenarios, it may be acceptable for the responsible entity to revise the model to reduce the forecasted Load, or include forecasted generation, to achieve a solution for the benchmark planning cases and/or sensitivity cases and evaluate future Bulk Electric System performance for extreme temperature events. Each responsible entity, as identified in Requirement R1, shall have dated evidence in either electronic or hard copy format that it developed benchmark planning cases and sensitivity cases in accordance with Requirement R4.

Requirement R5

Requirement R5 was drafted to require each responsible entity to set the criteria needed for limits that will be used to evaluate System steady state voltage and post-Contingency voltage deviations for completing the Extreme Temperature Assessment. The establishment of these criteria allows auditors to compare the results of the Extreme Temperature Assessment with the established criteria.

Requirement R6

Requirement R6 was drafted to require the responsible entity to define and document the criteria or methodology used in evaluating the Extreme Temperature Assessment analysis to identify instability, uncontrolled separation, or Cascading within an Interconnection. In developing planning benchmark as well as sensitivity cases for steady-state and transient stability analyses, the Planning Coordinators and Transmission Planners typically use Interconnection-wide starting cases prior to further modifications to reflect the conditions of the benchmark events as well as modifications for sensitivity cases. Analyses that may result in instability, uncontrolled separation, or Cascading typically are confined within an Interconnection where generation and transmission Facilities are interconnected. It is not expected that instability, uncontrolled separation, or Cascading that affect Facilities within an Interconnection would impact other Interconnection(s) as these systems are asynchronous systems (i.e., not connecting synchronously). Adequate and thorough criteria should be built into the Extreme Temperature Assessment to help identify instability, uncontrolled separation, and Cascading conditions. The establishment of these criteria allows auditors to compare the results of the Extreme Temperature Assessment with the established criteria.

Requirement R7

This requirement addresses directives in FERC Order No. 896 to define a set of Contingencies that responsible entities will be required to consider when conducting wide-area studies of extreme heat and cold weather events. FERC's preference to rely on established Contingency definitions, "[w]e believe that it is necessary to establish a set of common contingencies for all responsible entities to analyze. Required contingencies, such as those listed in Table 1 of Reliability Standard TPL-001-5.1 (i.e., category P1 through P7), establish common planning events that set the starting point for transmission system planning assessments," was also considered by the SDT. It is necessary to establish a set of common Contingencies for all responsible entities to analyze. Requiring the study of predefined Contingencies, such as those listed in Table 1, will ensure a level of uniformity across planning regions, considering that extreme heat and cold weather events often exceed the geographic boundaries of most existing planning footprints. Defining the Contingencies in Table 1 consistently with Table 1 of Reliability Standard TPL-001-5.1 meets FERC's preference for commonality.

If feasible, all Contingencies listed in Table 1 should be considered for evaluation by the responsible entity; however, the language affords flexibility in identifying the most appropriate Contingencies. As such, the responsible entity should implement a method and establish sufficient supporting rationale to ensure Contingencies within each category of Table 1, that are expected to produce more severe System impacts within its planning area, are adequately identified. It is noted that since the benchmark planning cases are developed from the extreme temperature benchmark events, they already represent extreme System conditions and thus not all Contingencies from Reliability Standard TPL-001-5.1 Table 1 are included in the TPL-008-1 Table 1 for assessment. The Events included in TPL-008-1 Table 1 represent the more likely Contingencies to occur.

The SDT included categories P0, P1, and P7 in Table 1 of TPL-008-1. The SDT finds it reasonable to exclude P2, P3, P4, P5 and P6 Contingencies from the Extreme Temperature Assessment. Studying categories P0, P1 and P7 is the minimum requirement of TPL-008-1. The standard does not preclude entities from studying additional Contingencies if desired. The following discusses the rationale for excluding P2 through P6 Contingencies for TPL-008-1:

1. Excluding P2 and P4 Contingencies:

   After consideration of comments received from the industry, the SDT removed P2 and P4 Contingencies due to lower probability of occurrence than P1 and P7 Contingencies. TPL-008 now focuses on the single Contingencies (P1) or multiple Contingencies on common structure (P7) that are more likely to be monitored in operational scenarios. P2 Contingencies (e.g. Contingencies caused by internal breaker fault, bus section fault, opening line section without a fault), and P4 Contingencies (e.g., Contingencies caused by stuck breaker), while plausible under extreme temperature conditions, occur in much less frequency when compared to P1 and P7 Contingencies. The standard establishes minimum requirement for Contingencies with higher probability of occurrence. To the extent that the responsible entity determines the need for studying beyond the minimum requirements, the standard does not preclude the entity from doing so.

2. Excluding P3 and P6 Contingencies:

   Part of the decision stems from the complexity of P3 and P6 Contingencies, which involve multiple element outages triggered by multiple Contingencies, with System adjustments allowed between them. Consequently, the occurrence likelihood of P3 and P6 Contingencies could be even lower compared to P1 and P7 Contingencies. Moreover, aligning with the directives set forth in FERC Order 896, which emphasizes the importance of incorporating derated generation, transmission capacity, and the availability of generation and transmission in the development of benchmark planning cases, it becomes imperative for responsible entities to consider potential concurrent or correlated generation and transmission outages and/or derates within relevant benchmark planning cases. This ensures that the benchmark planning case accurately reflects System conditions under extreme temperatures, with generation and transmission derates and/or outages already factored. Therefore, the SDT believes excluding P3 and P6 is justified, as generation and transmission derates and/or outages are already accounted for within the benchmark planning cases.

3. Excluding P5 Contingencies:

   After consideration of comments received from the industry, the SDT removed P5 Contingency (Delayed Fault Clearing due to failure of non-redundant component of a Protection System). This is because while some categories of Contingencies may be assessed in a straightforward approach, category P5 Contingency events often require a significant level of engineering analysis (including protection and/or control analysis). These analyses are sensitive to the System topology and expected dispatch. As the planning benchmark cases are developed for TPL-008-1 that represent System conditions that are different than the typical summer or winter peak conditions, the development of category P5 Contingency events is expected to be a significant burden. Since these events only require evaluations of possible mitigations (and not Corrective Action Plans), violations resulting from these events are unlikely to result in significant transmission System investment. Furthermore, any violations resulting from category P5 events may be mitigated by eliminating and addressing the single point of failure included in the event definition. Thus, the evaluation of possible actions is unlikely to result in further insight beyond the general reliability improvements associated with eliminating single points of failure.

The SDT discussed and decided to keep the P7 Contingency category because common structure Contingencies are often evaluated after categories P0 and P1 as the most common minimum level of transmission reliability assessment. These events have a high likelihood of occurrence due to the following reasons:

- Historical events that include simultaneous forced outage due to tripping of the double-circuit power lines due to electrical storm events;
- Environment-caused factors include pollution buildup, such as dust, that could cause faulted condition that trips both transmission lines on a common tower;
- Avian-caused outages that impact both transmission lines on a common tower;
- Smoke from nearby wildfires can cause simultaneous tripping of both circuits on a common tower;
- Nearby wildfires can impact System Operation as System Operators proactively de-energize both lines on a common tower to avoid further impact to the transmission grid in the event of a simultaneous tripping of both lines that may be carrying high power transfer between areas;
- Weather-related causes such as lightning, flooding, wind, or icing can cause tripping of both transmission lines on a common tower;
- Natural disaster such as winter storm can cause transmission tower to collapse, taking out both lines strung on the same tower;
- Other incidents such as vehicle accident, aircraft accident, vandalism, or animal contact that can adversely impact both transmission lines on the common tower.

Loss of two circuits running in parallel, simultaneously, is likely to have a greater system impact versus loss of two unrelated or geographically separated circuits. Therefore, there is greater potential for reliability concerns, especially during heavy transfers that are likely during periods of extreme weather, due to loss of both circuits of a double-circuit line. Due to the reasons above, Contingencies that involve double-line circuits on a common tower are included in the critical multiple Contingency list in either transmission planning or System Operations reliability assessment.

Some, but not all, items to consider when developing the rationale for selecting Contingencies are:

- Past studies,
- Subject matter expert knowledge of the responsible entity's System (to be supplemented with data or analysis), and
- Historical data from past operating events.

Lastly, regarding the Bulk Electric System (BES) voltage levels for the Contingencies, the SDT reviewed previous major wide-area benchmark events and found that the Facilities that were out of service by these events have voltages that are 200 kV and above. Thus, it is the reason for establishing voltages of 200 kV and above for Contingencies in Table 1 of TPL-008-1. The monitoring of potential impact is still applicable to Facilities with all BES voltage levels. However, with that said, the SDT recognized that many PCs and TPs have Contingencies that include all BES levels. Responsible entities may elect to use the existing Contingencies that they already have and report the criteria violations for the categories in TPL-008-1 Table 1.

Requirement R8

Requirement R8 was drafted to provide clarity on the following:

1. What planning study cases are required?

   The Requirement R8 includes the following number of assessments to complete the Extreme Temperature Assessment and address FERC Order No. 896 directives per paragraph 111 that "direct NERC to require in the proposed new or modified Reliability Standard that responsible entities perform both steady state and transient stability (dynamic) analyses in the extreme heat and cold weather planning studies". In addition, Requirement R8 also addresses FERC Order No. 896 directives per paragraph 124 that "require the use of sensitivity cases to demonstrate the impact of changes to the assumptions used in the benchmark planning case". Requirement R8 also addresses FERC Order No. 896 directives per paragraph 124 that sensitivity cases "should consider including conditions that vary with temperature such as load, generation, and system transfers." Since the benchmark planning case(s) already include System conditions under extreme heat or extreme cold events, the sensitivity analysis is to include changes to at least one of the following conditions: generation, real and reactive forecasted Load, or transfers. Since the minimum requirement includes changes to one of these conditions, the PCs and the TPs can include further sensitivity assessments to change more conditions if they choose to do so.

   The following provides the number of assessments required for the benchmark planning and sensitivity cases to complete the Extreme Temperature Assessment.

Type of Extreme Temperature Assessment	Extreme Cold Temperature Event	Extreme Heat Temperature Event	Total
Benchmark Planning Case Analysis	One extreme cold benchmark planning case assessment	One extreme heat benchmark planning case assessment	Two benchmark planning case assessments
Sensitivity Case Analysis	One sensitivity case with changes to at least one of the following conditions: generation, real and reactive forecasted Load, or transfers	One sensitivity case with changes to at least one of the following conditions: generation, real and reactive forecasted Load, or transfers	Two sensitivity case assessments
Total			A total of four assessments to complete the Extreme Temperature Assessment

2. What are the types of analyses required?

   There are two types of analyses required: steady-state and transient stability. Each type of analysis must be completed for each of the four cases described in the table above. This requirement is to satisfy FERC Order No. 896 directive paragraph 111.

Requirement R9

FERC Order No. 896 identifies a deficiency in the existing Reliability Standard TPL-001-5.1 where "planning coordinators and transmission planners are required to evaluate possible actions to reduce the likelihood or mitigate the consequences of extreme temperature events but are not obligated to develop corrective action plans" (¶139).

Given potential severe consequences of extreme cold and extreme heat events, FERC Order No. 896 raises the bar and "directs NERC to require in the new or modified Reliability Standard the development of extreme weather corrective action plans for specified instances when performance standards are not met" (¶152).

Due to higher likelihood of categories P0 and P1, these categories are held to a higher performance requirement in benchmark planning cases. Corrective Action Plans are required to address performance deficiencies for categories P0 and P1 in benchmark planning cases analyzed in the Extreme Temperature Assessment.

Furthermore, having a Corrective Action Plan requirement for categories P0 and P1 in benchmark planning cases ensures resilience during future extreme cold and extreme heat temperature events, when the transmission System is required to be P1 Contingency-secure (for steady-state and transient stability).

Given that a category P0 represents a continuous System condition without any system disturbances, the SDT determined that load shedding should not be considered as a Corrective Action Plan. However, the SDT has determined that load curtailment may be considered for a P1 Contingency as a Corrective Action Plan where load shed is allowed to prevent system-wide failures and ensuring the continued operation of essential services under a critical P1 Contingency in the extreme heat and cold temperature events. The SDT also emphasizes that alternative solutions, other than firm load curtailment, are evaluated in higher priorities. Non-Consequential Load Loss is permitted as an interim solution in situations that are beyond the control of the Planning Coordinator or Transmission Planner that prevent the implementation of a Corrective Action Plan in the required timeframe; however, the responsible entity must document the situation causing the problem, alternatives evaluated, and take actions to resolve the situation. Future revisions to the Corrective Action Plan are allowed, provided that the planned Bulk Electric System continues to meet the performance requirements of Table 1.

FERC Order No. 896 also directs NERC "to develop certain processes to facilitate interaction and coordination with applicable regulatory authorities or governing bodies responsible for retail electric service as appropriate in implementing a corrective action plan" (¶152). In the event that Non-Consequential Load Loss is included in the Corrective Action Plan for a P1 Contingency, the responsible entity shall document alternative(s) considered, make the Corrective Action Plan available to, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.

Lastly, the standard also permits the responsible entities to revise or update the Corrective Action Plan that was considered and approved in the previous Extreme Temperature Assessment. This allows responsible entities to incorporate approved mitigation measures from other planning assessments, such as annual transmission reliability assessment under TPL-001-5 or subsequent related planning standard, or from other planning assessments for policy-driven or economic needs. The revised or updated Corrective Action Plan associated with TPL-008-1 can be documented as an addendum to the previous Extreme Temperature Assessment's Corrective Action Plan.

Requirement R10

The requirement for responsible entities to evaluate and document possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts when the study results in the benchmark planning cases analyses conclude there could be instability, uncontrolled separation, or Cascading for P7 Contingencies is in response to directives outlined in FERC Order No. 896.

P7 Contingencies involve multiple element outages resulting from a single event, making them relatively less likely to occur, compared to categories P0 and P1, but potentially causing more severe system impacts. Considering both the likelihood of these Contingencies, and the fact that the Extreme Temperature Assessment already addresses low-probability System conditions, the SDT determined that Corrective Action Plans should not be required for P7 Contingencies. However, due to the potential severity resulting from single-Contingency multiple element outages, the SDT believes it is appropriate for responsible entities to at least evaluate and document possible mitigation actions to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses conclude there could be instability, uncontrolled separation, or Cascading. The biggest benefit from the evaluation and documentation of the possible mitigating actions is it allows a responsible entity to see where major reliability concerns exist that may need to be addressed; and, if a sufficiently large number of reliability concerns are identified, it may encourage transmission upgrade mitigation option(s) to be considered and implemented without it being strictly called for in the standard. Not requiring Corrective Action Plans for these Contingencies, but requiring the evaluation, is a compromise from having Corrective Action Plans for all studied Contingencies.

Furthermore, FERC Order No. 896 requires "the use of sensitivity cases to demonstrate the impact of changes to the assumptions used in the benchmark planning case" (¶124). FERC Order No. 896 also states: "NERC should determine whether corrective action plans should be required for single or multiple sensitivity cases, and whether corrective action plans should be developed if a contingency event that is not already included in benchmark planning case would result in cascading outages, uncontrolled separation, or instability" (¶158). The SDT acknowledges that sensitivity analysis is an important component of a robust transmission planning study. A requirement to develop and implement Corrective Action Plans for sensitivity cases may incentivize responsible entities to select fewer or less severe sensitivities. An incentive to select fewer sensitivities is undesirable because sensitivity study results are used to identify constraints and initiate deeper analysis into the variables that impact those constraints. The study results of sensitivity cases are also important to inform the development of Corrective Action Plans in the benchmark planning cases. Therefore, the SDT determined the responsible entity must evaluate and document possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses of sensitivity cases conclude there could be instability, uncontrolled separation, or Cascading for categories P0, P1, and P7. Finally, TPL-008-1 does not preclude the responsible entity from developing Corrective Action Plans for sensitivity cases beyond what is required in the standard.

Requirement R11

The requirement for responsible entities to share Extreme Temperature Assessment results aligns with directives in FERC Order No. 896, emphasizing coordination and sharing of study findings. It ensures collaboration among stakeholders and timely dissemination of critical information to entities with reliability-related needs. This fosters a collective understanding of reliability concerns identified in wide-area studies, thereby enhancing overall grid reliability.

Attachment 1: Extreme Temperature Assessment Zones

The map depicts an approximation of the zones to be used in the Extreme Temperature Assessment and is provided as a visual aid for each Planning Coordinator to identify the zone(s) to which the Planning Coordinator belongs to under Attachment 1. The zone topology is a function of balancing authority jurisdiction and general knowledge of zonal weather patterns, or in some cases, are limited by transmission constraints, or lack of transmission thereof, between zones. The goal of the topology was to split the North American System into several distinct zones that have similar electric power system properties (i.e., balancing authority and interconnections) and similar weather or climatological patterns. Balancing authorities with large areas of jurisdiction, exclusively ISOs and RTOs, are assigned their own weather zone. In geographical areas comprised of multiple balancing authorities, generalized weather zones are created to best represent zonal weather patterns.

The NPCC region of the Eastern Interconnection was divided into New England, New York, Quebec Interconnection, Ontario, and Maritimes. The Planning Coordinators for the NPCC region of the Eastern Interconnection are listed below:

- New England: Planning Coordinators in NPCC that primarily serve the six New England States.
- New York: Planning Coordinators in NPCC that primarily serve New York.
- Quebec: Planning Coordinators that primarily serve Quebec in the NPCC Region.
- Ontario: Planning Coordinators in NPCC that primarily serve Ontario.
- Maritimes: Planning Coordinators in NPCC that primarily serve New Brunswick, Nova Scotia, Prince Edward Island, and the Northern Maine Independent System Administrator (NMISA). The NMISA is responsible for the administration of the northern Maine transmission system and electric power markets in Aroostook and Washington counties, with the load served radially from New Brunswick. It was not included in the New England division since there are no physical transmission ties between NMISA and ISO-NE which is the Planning Coordinator serving the remainder of the six New England States.

Additionally, SERC combined NERC Assessment areas of SERC-East, SERC-Central, and SERC-Southeast into a single zone based on climate similarities. Northwest Regions, WECC-SW, SERC, and SERC-FP were based on balancing authority PNNL data. SPP-N, SPP-S, MISO-N, and MISO-S were aggregated based on county-level PNNL data.

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Violation Risk Factor and Violation Severity Level Justifications

Project 2023-07 Transmission System Planning Performance Requirements for Extreme Weather

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Project 2023-07 Transmission System Planning Performance Requirements for Extreme Weather. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for TPL-008-1, Requirement R1	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to the fact that the Planning Coordinators, in conjunction with its Transmission Planner(s) will determine joint responsibilities for requirements throughout TPL-008-1.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed less than or equal to six months late.	The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed more than six months but less than or equal to 12 months late.	The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed more than 12 months but less than or equal to 18 months late.	The Planning Coordinator, in conjunction with its Transmission Planner(s), failed to identify individual and joint responsibilities for completing the Extreme Temperature Assessment. OR The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed more than 18 months late.

VSL Justifications for TPL-008-1, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL has been assigned as a binary due to the Planning Coordinator and Transmission Planner to determine who completes the responsibilities throughout TPL-008-1. The responsibilities documentation will either be developed or not.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R2	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of high is appropriate due to the fact that selecting a benchmark event to perform an extreme temperature assessment can affect the grid based on planning analysis for future events.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Planning Coordinator coordinated with all Planning Coordinators within each identified zone to identify one common extreme heat and one common extreme cold benchmark temperature event for completing the Extreme Temperature Assessment, but one of the identified events failed to meet all the criteria of Requirement R2.	The Planning Coordinator coordinated with all Planning Coordinators within each identified zone to identify one common extreme heat and one common extreme cold benchmark temperature event for completing the Extreme Temperature Assessment, but both of the identified events failed to meet all of the criteria of Requirement R2. OR The Planning Coordinator failed to coordinate with all Planning Coordinators within each identified zone to identify one common extreme heat and one common extreme cold benchmark temperature event for completing the Extreme Temperature Assessment.

VSL Justifications for TPL-008-1, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	This VSL has been assigned as a binary due to the benchmark event needing to be selected for benchmark planning cases to be completed. You either select a benchmark event or not.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R3	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of medium is appropriate due to the fact that it is important to develop and maintain System models within an entity's planning area for performing Extreme Temperature Assessments. Connecting to MOD-032 to provide important data needed to assist entities with System models is also important for accurate information to be used.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Planning Coordinator did not coordinate with all Planning Coordinators within each of its identified zone(s) to implement a process for developing benchmark planning cases. OR The Planning Coordinator coordinated with all Planning Coordinators within each of its identified zone(s) to implement a process for developing benchmark planning cases, but the process did not include all of the required elements.

VSL Justifications for TPL-008-1, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL has been assigned as a binary due to the responsible entity either develops and maintains the System models within its planning area or it does not develop and maintain the System models within its planning area.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R4	
Proposed VRF	**High**
NERC VRF Discussion	The VRF of High is appropriate because it could directly affect the electrical state or capability of the BPS if coordination is not completed for benchmark planning cases and sensitivity cases for the Extreme Temperature Assessment results.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity, as identified in Requirement R1, did not use the process developed in Requirement R3 to develop benchmark planning cases or sensitivity cases. OR The responsible entity, as identified in Requirement R1, used the process developed in Requirement R3 to develop benchmark planning cases and sensitivity cases, but did not use data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, for one or more of the required cases. OR The responsible entity, as identified in Requirement R1, used the process developed in Requirement R3 and data consistent with that provided in accordance with the MOD-032 standard, supplemented as needed, but failed to develop one or more of the required planning or sensitivity cases.

VSL Justifications for TPL-008-1, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <ins>Guideline 2a</ins>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <ins>Guideline 2b</ins>: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL has been assigned as a binary due to the Planning Coordinator to develop and implement a process for coordinating the development of benchmark planning cases. The benchmark planning cases will either be developed and implemented or not.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R5	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of medium is appropriate due to the importance of having criteria for acceptable System steady state voltage limits of post-Contingency voltage deviations for performing Extreme Temperature Assessments.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity, as identified in Requirement R1, did not have criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations for completing the Extreme Temperature Assessment.

VSL Justifications for TPL-008-1, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL has been assigned as a binary due to the responsible entity either having acceptable criteria for System steady state voltage limits and post-contingency voltage deviations or not.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R6	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate due to the importance of defining and documenting the criteria or methodology for System instability, uncontrolled separation, or Cascading.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity, as identified in Requirement R1, failed to define or document the criteria or methodology to be used in the Extreme Temperature Assessment to identify instability, uncontrolled separation, or Cascading within an Interconnection.

VSL Justifications for TPL-008-1, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R7	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of medium is appropriate for this requirement. Identifying Contingencies for performing Extreme Temperature Assessments for each of the event categories in Table 1 can indirectly impact the BES.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The responsible entity, as identified in Requirement R1, identified Contingencies for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System, but did not include the rationale for those Contingencies selected for evaluation as supporting information.	The responsible entity, as identified in Requirement R1, did not identify Contingencies for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System.

VSL Justifications for TPL-008-1, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R8	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate due to the importance of performing an Extreme Temperature Assessment every 5 years.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to document the assumptions for one or more sensitivity cases in accordance with Requirement R8.	The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to document the assumptions for one or more benchmark planning cases in accordance with Requirement R8.	The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to document results for one or more of the sensitivity cases in accordance with Requirement R8.	The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to document results for one or more of the benchmark planning cases in accordance with Requirement R8. OR The responsible entity, as identified in Requirement R1, failed to complete steady state or transient stability analyses and document results in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, in accordance with Requirement R8.

VSL Justifications for TPL-008-1, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R9	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate for this requirement. Developing a Corrective Action Plan is important to the BES as it assists entities when Systems are unable to meet performance requirements.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R9			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The responsible entity, as identified in Requirement R1, developed a Corrective Action Plan in accordance with Requirement R9, but failed to make its Corrective Action Plan available to, or solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.	The responsible entity, as identified in Requirement R1, failed to develop a Corrective Action Plan when the benchmark planning case study results indicate the System is unable to meet performance requirements for the Table 1 P0 or P1 Contingencies. OR The responsible entity, as identified in Requirement R1, developed a Corrective Action Plan, but it was missing one or more of the elements of Requirement R9 Part 9.1, 9.3 and 9.4 (as applicable).

VSL Justifications for TPL-008-1, Requirement R9	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL has been assigned as a binary due to the responsible entity either having acceptable criteria for System steady state voltage limits and post-contingency voltage deviations or not.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R10	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of lower has been assigned to Requirement R10. Documenting possible actions to reduce the likelihood or mitigate the consequences and adverse impacts are administrative in nature.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R10			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The responsible entity, as identified in Requirement R1, evaluated and documented possible actions to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection where required under Requirement R10 Part 10.1, but failed to evaluate and document possible actions where required under Requirement R10 Part 10.2.	The responsible entity, as identified in Requirement R1, evaluated and documented possible actions to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection where required under Requirement R10 Part 10.2, but failed to evaluate and document possible actions where required under Requirement R10 Part 10.1. OR The responsible entity, as identified in Requirement R1, failed to evaluate and document possible actions to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection where required under Requirement R10 Parts 10.1 and 10.2.

VSL Justifications for TPL-008-1, Requirement R10	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL has been assigned as a binary due to the fact that the responsible entity will have evaluated and documented possible actions to mitigate adverse impacts.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for TPL-008-1, Requirement R11	
Proposed VRF	**Medium**
NERC VRF Discussion	The VRF of Medium is appropriate because it could directly affect the electrical state or capability of the BES if entities are not aware of the results from its Extreme Temperature Assessment results.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement has only a main VRF and no different sub-requirement VRFs.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is in line with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The assigned VRF is consistent with NERC definition of VRFs.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for TPL-008-1, Requirement R11			
Lower	**Moderate**	**High**	**Severe**
The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 60 days but less than or equal to 80 days following the request.	The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 80 days but less than or equal to 100 days following the request.	The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 100 days but less than or equal to 120 days following the request.	The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 120 days following the request. OR The responsible entity, as identified in Requirement R1, did not provide its Extreme Temperature Assessment results to functional entities having a reliability related need who submitted a written request for the information.

VSL Justifications for TPL-008-1, Requirement R11	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of FERC Order 896 Directives

Project 2023-07 Transmission System Planning Performance Requirements for Extreme Weather
December 2024

On June 15, 2023, FERC issued a Final Rule, Order No. 896, directing NERC to develop a new or modified Reliability Standard to address a lack of a long-term planning requirement(s) for extreme heat and cold weather events. Specifically, FERC directed NERC to develop modifications to Reliability Standard TPL-001-5.1 or to develop a new Reliability Standard to require the following: (1) development of benchmark planning cases based on major prior extreme heat and cold weather events and/or meteorological projections; (2) planning for extreme heat and cold weather events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios including the expected resource mix's availability during extreme heat and cold weather conditions, and including the wide-area impacts of extreme heat and cold weather; and (3) development of corrective action plans that mitigate any instances where performance requirements for extreme heat and cold weather events are not met. FERC directed NERC to submit a new or revised standard within 18 months, or by December 2024. The below provides the directives from FERC Order 896 along with the drafting team's consideration of the directives.

FERC Order 896 Directives	
Directive Language	**Consideration of Directives**
P35. "[W]e direct NERC to: (1) develop extreme heat and cold weather benchmark events, and (2) require the development of benchmark planning cases based on identified benchmark events." **P36**: "…As recommended by commenters, NERC should consider the examples of approaches for defining benchmark events identified in the NOPR (e.g., the use of projected frequency or probability distribution). NERC may also consider other approaches that achieve the objectives outlined in this final rule."	The ERO has worked with respective subject matter experts, including climate experts, the six regions, etc., to explore extreme heat and extreme cold benchmark temperature events. NERC, in consultation with climate data subject matter expert consultants on the benchmark events, utilized publicly available modeled data to address the requirements of TPL-008-1 that define extreme heat and extreme cold benchmark temperature events. Specifically, based on the available data, the drafting team determined that extreme benchmark temperature events must: 1) consider no less than forty years of historical temperature data, 2) include recent temperature

FERC Order 896 Directives	
Directive Language	**Consideration of Directives**
	data due to ongoing climate changes, and 3) represent one of the twenty worst extreme temperature conditions over the forty year period, based on a 3-day rolling average of daily maximum (heat) or minimum (cold) temperatures. The ERO will maintain a library of benchmark temperature events that meet these requirements. Responsible entities will be able to review and select benchmark temperature events from this library to assist with the development of benchmark planning cases. However, responsible entities may also identify benchmark temperature events via their own processes, provided that the event meets the criteria of Requirement R2 and is agreed upon by all PCs within the zone. Should the extreme heat and cold weather benchmark events provided not suffice for the entities zone, the Planning Coordinator (PC) in coordination with all PCs within its zone, may develop a common extreme heat and extreme cold weather benchmark event to use for the TPL-008-1 Standard. The drafting team developed requirements within TPL-008-1 to require PCs within zones to select one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event (Requirement R2). After selecting its benchmark events, the responsible entity is required to implement a process for coordinating the development of benchmark planning cases and sensitivity cases among the responsible entities (Requirement R3) and to develop benchmark planning cases and sensitivity cases (Requirement R4).

FERC Order 896 Directives	
Directive Language	**Consideration of Directives**
P37. "Because the impact of most extreme heat and cold events spans beyond the footprints of individual planning entities, it is important that all responsible entities likely to be impacted by the same extreme weather events use consistent benchmark events. Doing so is important to ensuring that neighboring planning regions are assuming similar weather conditions and are able to coordinate their assumptions accordingly. As a result, defining the benchmark event in a manner that provides responsible entities significant discretion to determine the applicable meteorological conditions would not meet the objectives of this final rule."	NERC, in consultation with climate data subject matter expert consultants on benchmark events, developed subregions or "zones" of North America that are likely to experience similar weather conditions. These zones also consider practical concerns with coordination such as the boundaries of Interconnections and Balancing Authority Areas. The drafting team developed Requirement R2 such that PCs within the same zone are required to select one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event. This process balances the opportunity to provide input with the need for common events to be modeled over wide areas.
P38. "[I]n developing extreme heat and cold benchmark events, NERC shall ensure that benchmark events reflect regional differences in climate and weather patterns."	NERC, in consultation with climate data subject matter expert consultants on benchmark events, has utilized publicly available modeled data in the last forty-three years (1980-2022), as well as more than eighty years of projected hourly meteorology data from PNNL to ensure regional differences in climate and weather patterns are reflected in the zones depicted in Attachment 1 of TPL-008-1. A Map has been added to the TPL-008-1 Standard showing the zones split throughout the US and Canada. These are to be considered wide area, and regional differences went into consideration when developing the data based on extreme historical events over the past 40 years.
P39. "We also direct NERC to include in the Reliability Standard the framework and criteria that responsible entities shall use to develop from the relevant benchmark event planning cases to represent potential weather-related contingencies (e.g., concurrent/correlated generation and transmission outages, derates) and expected future conditions of the system such as changes in load, transfers, and generation resource mix, and impacts on generators sensitive to extreme heat or cold, due to the weather conditions indicated in the benchmark events. Developing such a	The directive is addressed in Requirements R3 and R4 of the proposed TPL-008-1 standard. Requirement R3 obligates the PC to implement a process to coordinate the development of the benchmark planning cases and sensitivity cases. This process shall include: 1) the selection of System models within the Long-Term Transmission Planning Horizon to serve as a starting point for the benchmark planning cases, 2) forecasted seasonal and temperature

FERC Order 896 Directives	
Directive Language	**Consideration of Directives**
framework would provide a common design basis for responsible entities to follow when creating benchmark planning cases. This would not only help establish a clear set of expectations for responsible entities to follow when developing benchmark planning events, but also facilitate auditing and enforcement of the Standard.”	dependent adjustments for Load, generation, Transmission, and transfers within the zone to represent the selected benchmark temperature events, 3) assumed seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers outside of the zone as needed, and 4) the identification of changes to at least one of generation, real and reactive forecasted load, or transfers to serve as a sensitivity case. Requirement R4 obligates the responsible entity to develop benchmark planning cases and sensitivity cases for performing the Extreme Temperature Assessment which reflects System conditions from the selected benchmark events. Requirement R4 also references the NERC MOD-032 Reliability Standard that provides PCs and Transmission Planners a mechanism for obtaining the data needed to develop the benchmark planning cases.
P40. “We also direct NERC to ensure the reliability standard contains appropriate mechanisms for ensuring the benchmark event reflects up-to-date meteorological data.”	Requirement R2 Part 2.1 requires that the temperature data collected to identify benchmark temperature events includes 40 years of data “ending no more than 5 years prior to the time the benchmark temperature events are selected”. This requirement ensures that the window of time considered for benchmark temperature events reflects up-to-date data. The up-to five-year gap was included due to potential lags in data sources.
P50. “[W]e…direct NERC to require that transmission planning studies under the new or revised Reliability Standard consider the wide-area impacts of extreme heat and cold weather. We direct NERC to clearly describe the process that an entity must use to define the wide-area boundaries. While commenters provide various views in favor of both a geographical approach and electrical approach to defining wide-area boundaries, we do not adopt any one approach in this final rule…NERC should consider the comments in this proceeding when developing a new or modified reliability standard that considers the broad area impacts of extreme heat and cold weather.”	To understand the complexities of defining wide-area boundaries, the drafting team reviewed the extreme weather events mentioned within FERC Order No. 896, as well as the comments received during the FERC Order proceeding. In addition, NERC consulted with climate data subject matter experts who evaluated publicly available modeled data in the last forty-three years (1980-2022) and more than eighty years of projected hourly meteorology data from PNNL. The drafting team struck a balance between a geographical approach and an electrical approach by dividing North America into zones that are likely to experience similar weather conditions but also consider practical

FERC Order 896 Directives	
Directive Language	**Consideration of Directives**
	concerns with coordination such as the boundaries of Interconnections and Balancing Authority Areas. These zones are depicted in Attachment 1 of TPL-008-1, and PCs will be required to coordinate with all PCs in the zone(s) they belong to.
P58. "[W]e…direct NERC to develop benchmark events for extreme heat and cold weather events through the Reliability Standards development process. We agree … that the development of adequate benchmark events is critical and should be committed to the subject matter experts on the standards drafting team. " **P59.** Further, requiring NERC to develop the new or modified Reliability Standard's benchmark events is consistent with the approach the Commission took in Order No. 779, when the Commission directed NERC to develop benchmark events for geomagnetic disturbance analyses.1 For the same reasons, we also conclude that NERC is best positioned to define mechanisms to periodically update extreme heat and cold weather benchmark events, as discussed above.	The drafting team considered various approaches to developing benchmark temperature events. With assistance from NERC's subject matter expert consultants, the drafting team identified the key components of temperature events that are necessary for the event to constitute an adequate benchmark temperature event. These components were included in Requirement R2. Specifically, based on the available data, the drafting team determined that extreme benchmark temperature events must: 1) consider no less than forty years of historical temperature data, 2) include recent temperature data due to ongoing climate changes, and 3) represent one of the twenty worst extreme temperature conditions over the forty year period based on a 3-day rolling average of daily maximum (heat) or minimum (cold) temperatures. The ERO will maintain a library of benchmark temperature events that meet these requirements. Responsible entities will be able to review and select benchmark temperature events from this library to assist with the development of benchmark planning cases. However, responsible entities may also identify benchmark temperature events via their own processes provided that the event meets the criteria of Requirement R2 and is agreed upon by all PCs within the zone.

FERC Order 896 Directives	
Directive Language	**Consideration of Directives**
	In addition to describing the minimum requirements of a benchmark temperature event, Requirement R2 obligates PCs within the same zone to coordinate in selecting one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event for completing the Extreme Temperature Assessment. This coordination is required to ensure the benchmark temperature event is reflected over a wide-area.
P60. "[W]e…direct NERC to designate the type(s) of entities responsible for developing benchmark planning cases and conducting wide-area studies under the new or modified Reliability Standard…benchmark planning cases should be developed by registered entities such as large planning coordinators, or groups of planning coordinators, with the capability of planning on a regional scope." **P61**: "We believe the designated responsible entities should have certain characteristics, including having a wide-area view of the Bulk-Power System and the ability to conduct long-term planning studies across a wide geographic area. The responsible entities should also have the planning tools, expertise, processes, and procedures to develop benchmark planning cases and analyze extreme weather events in the long-term planning horizon." **P62**: "To comply with this directive, NERC may designate the tasks of developing benchmark planning cases and conducting wide-area studies to an existing functional entity or a group of functional entities (e.g., a group of planning coordinators). NERC may also establish a new functional entity registration to undertake these tasks. In the petition accompanying the proposed Reliability Standard NERC should explain how the applicable registered entity or entities meet the objectives outlined above."	The drafting team discussed that the Transmission Planner (TP) and/or Planning Coordinator (PC) would be the responsible entities to address TPL-008-1 Requirements. Requirement R1 obligates both the TP and PC to identify their individual and joint responsibilities. Requirement R3 obligates each PC to implement a process for coordinating the development of benchmark planning cases and sensitivity cases, using the selected benchmark temperature events identified in Requirement R2. This process must be implemented in coordination with all PCs within the same zone. Requirement R4 obligates each responsible entity, as identified in Requirement R1, to use the coordination process developed in accordance with Requirement R3 and data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, to develop benchmark planning cases and sensitivity cases. The identification of joint and individual responsibilities in Requirement R1 provides a measure of flexibility for PCs and TPs to agree on a distribution of responsibilities. Thus, while PCs are responsible for implementing the case development process in Requirement R3, TPs may be responsible for providing data and completing the case development according to that process.

FERC Order 896 Directives	
Directive Language	**Consideration of Directives**
	The development of benchmark planning cases and sensitivity cases will require cooperation amongst many PCs and TPs. By requiring participation from all entities within a zone, TPL-008-1 ensures that the group of functional entities have a sufficient wide-area view of the Bulk Power System and the planning tools, expertise, processes and procedures necessary for developing benchmark planning cases and sensitivity cases.
P72. "[W]e direct NERC to require functional entities to share with the entities responsible for developing benchmark planning cases and conducting wide-area studies the system information necessary to develop benchmark planning cases and conduct wide-area studies. Further, responsible entities must share the study results with affected transmission operators, transmission owners, generator owners, and other functional entities with a reliability need for the studies."	The directive is addressed in proposed TPL-008-1 in Requirements R3, R4 and R11. Requirement R3 obligates each PC to implement a process for coordinating the development of benchmark planning cases, using the selected benchmark temperature events identified in Requirement R2, among all Planning Coordinators within a zone. Requirement R4 obligates each responsible entity, as identified in Requirement R1, to use the coordination process implemented in accordance with Requirement R3 and data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, to develop benchmark planning cases and sensitivity cases. Requirement R11 obligates each responsible entity, as identified in Requirement R1, to provide its Extreme Temperature Assessment results within 60 calendar days of a request to any functional entity that has a reliability related need and submits a written request for the information.
P73. "Because in this final rule we direct NERC to determine the responsible entities that will be developing benchmark planning cases and conducting wide-area studies, it is possible that the selected responsible entities under the new or modified Reliability Standard will not be able to request and receive needed data pursuant to MOD-032-1, absent modification to that Standard."	The drafting team discussed and determined that data needed to address the Extreme Temperature Assessment would still be appropriate to receive through MOD-032. MOD-032 ensures an adequate means of data collection for transmission planning and requires applicable registered entities to provide steady-state, dynamic, and short circuit modeling data to their Transmission Planner(s) and Planning Coordinator(s). As outlined in Requirement R1 and Attachment 1 of MOD-032, MOD-032 allows various

FERC Order 896 Directives	
Directive Language	**Consideration of Directives**
	data collection such as in-service status and capability associated with demand, generation, and transmission associated with various case types, scenarios, system operating states, or conditions for the long-term planning horizon. MOD-032 also requires applicable registered entities to provide “other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes” for each of the three types of data required. Because the drafting team determined the responsible entities that will be developing benchmark planning cases are limited to Planning Coordinators and Transmission Planners, they will be able to request and receive needed data pursuant to MOD-032. Thus, the drafting team believes that there is no need to update MOD-032.
P76: “[W]e…direct NERC to address the requirement for wide-area coordination through the standards development process, giving due consideration to relevant factors identified by commenters in this proceeding.”	The drafting team reviewed all the extreme weather events mentioned within the FERC Order 896. For this project, the drafting team focused the scope of Requirement R3 to require each PC to implement a process for coordinating the development of benchmark planning cases and sensitivity cases, using the selected benchmark temperature events identified in Requirement R2, among all PCs within a zone.
P77. “[W]e direct NERC to require in the new or modified Reliability Standard that responsible entities share the results of their wide-area studies with other registered entities such as transmission operators, transmission owners, and generator owners that have a reliability related need for the studies.”	This directive is addressed in proposed TPL-008-1 Requirement R11. Requirement R11 obligates each responsible entity to provide the wide-area study results within 60 calendar days of a request to any functional entity that has a reliability related need and has submitted a written request for the information.
P88. “[W]e direct NERC to require under the new or revised Reliability Standard the study of concurrent/correlated generator and transmission outages due to extreme heat and cold events in benchmark events as described in more detail below.” **P92.** “These contingencies (i.e., correlated/concurrent, temperature sensitive outages, and derates) shall be identified based on similar	This directive is addressed in proposed TPL-008-1 through Requirements R3 and R4. Per Requirement R3 Part 3.2, the benchmark planning case development process must include forecasted seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers within the zone. Per Requirement R4, the data necessary to build the benchmark planning cases must be provided via MOD-032, supplemented by other sources as needed. Any concurrent/correlated generator and transmission outages due to extreme heat and cold events in benchmark

FERC Order 896 Directives	
Directive Language	**Consideration of Directives**
contingencies that occurred in recent extreme weather events or expected to occur in future forecasted events.”	temperature events should be reflected in the model data and thus represented in the initial conditions of the benchmark planning cases.
P111. “[W]e direct NERC to require in the proposed new or modified Reliability Standard that responsible entities perform both steady state and transient stability (dynamic) analyses in the extreme heat and cold weather planning studies. In a steady state analysis, the system components are modeled as either in-service or out-of-service and the result is a single point-in-time snapshot of the system in a state of operating equilibrium. A transient stability (dynamic) analysis examines the system from the start to the end of a disturbance to determine if the system regains a state of operating equilibrium. Performing both analyses ensures that the system has been thoroughly assessed for instability, uncontrolled separation, and cascading failures in both the steady state and the transient stability realms.” (internal citations omitted).	This directive is addressed in proposed TPL-008-1 through Requirement R8 and Table 1. Requirement R8 requires the responsible entity to complete both steady state and transient stability analyses and document the assumptions and results. Table 1 obligates each responsible entity to perform both steady state and transient stability analyses and compare the study results against steady state and stability performance requirements.
P112. “[W]e direct NERC to define a set of contingencies that responsible entities will be required to consider when conducting wide-area studies of extreme heat and cold weather events under the new or modified Reliability Standard. We believe that it is necessary to establish a set of common contingencies for all responsible entities to analyze. Required contingencies, such as those listed in Table 1 of Reliability Standard TPL-001-5.1 (i.e., category P1 through P7), establish common planning events that set the starting point for transmission system planning assessments. Requiring the study of predefined contingencies will ensure a level of uniformity across planning regions—a feature that will be necessary in the new or revised Reliability Standard considering that extreme heat and cold weather events often exceed the geographic boundaries of most existing planning footprints.”	This directive is addressed in proposed TPL-008-1 through Requirement R7 and Table 1. Requirement R7 requires the responsible entity to identify Contingencies for completing the Extreme Temperature Assessment. The rationale, for those Contingencies selected for evaluation, shall be available as supporting information. The Contingencies for each category in Table 1 of TPL-008-1 correspond to the well-established Contingencies defined in Reliability Standard TPL-001-5.1. Utilizing these well-established Contingencies will ensure a level of uniformity across planning regions.

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Directive Language	**Consideration of Directives**
P113: "[T]he contingencies required in the new or revised Reliability Standards should reflect the complexities of transmission system planning studies for extreme heat and cold weather events."	
P116. "[W]e direct NERC to require in the new or modified Reliability Standard that responsible entities model demand load response in their extreme weather event planning area. As indicated by several commenters, because demand load response is generally a mitigating action that involves reducing distribution load during periods of stress to stabilize the Bulk-Power System, its effect during an extreme weather event should be modeled." **P 117:** "[I]n addressing this directive, we expect NERC to determine whether responsible entities will need to take additional steps to ensure that the impacts of demand load response are accurately modeled in extreme weather studies, such as by analyzing demand load response as a sensitivity, as is currently the case under Reliability Standard TPL-001-5.1."	TPL-008-1 Requirement R4 meets this directive by requiring each responsible entity to develop benchmark planning cases using data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed. Specifically, Attachment 1 of MOD-032 requires information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes.
P124. "[W]e direct NERC to require the use of sensitivity cases to demonstrate the impact of changes to the assumptions used in the benchmark planning case. Sensitivity analyses help a transmission planner to determine if the results of the base case are sensitive to changes in the inputs. The use of sensitivity analyses is particularly necessary when studying extreme heat and cold events because some of the assumptions made when developing a base case may change if temperatures change – for example, during extreme cold events, load may increase as temperatures decrease, while a decrease in temperature may result in a decrease in generation. We… direct NERC to define during the Reliability Standard development process a baseline set of sensitivities for the new or modified Reliability Standard. While we do not require the inclusion of any specific sensitivity in this final rule, NERC should consider including conditions that vary with temperature such as load, generation, and system transfers."	This directive is addressed in proposed TPL-008-1 in Requirement R3, which requires all PCs within the same zone to coordinate to implement a process for developing benchmark planning cases and sensitivity cases. Sensitivity cases are used to demonstrate the impact of changes to the basic assumptions used in the benchmark planning cases. Per Requirement R3 Part 3.4, PCs must include provisions in the case development process to identify changes to generation, real and reactive forecasted Load, and/or transfers to develop sensitivity cases. The identification of changes for sensitivity cases within the coordinated process of Requirement R3 addresses the directive that precludes responsible entities from determining sensitivities alone. However, nothing prevents responsible entities from conducting additional sensitivity studies they find relevant to their planning areas.

FERC Order 896 Directives	
Directive Language	**Consideration of Directives**
P125. "We do not agree ... that responsible entities alone should determine the sensitivity cases that must be considered in the responsible entity's study. … We…believe that responsible entities should be free to study additional sensitivities relevant to their planning areas…cooperation will be necessary between responsible entities conducting extreme heat and extreme cold weather studies and other registered entities within their extreme weather study footprints to ensure the selection of appropriate sensitivities."	
P134. "[W]e directs NERC to require in the new or modified Reliability Standard the use of planning methods that ensure adequate consideration of the broad characteristics of extreme heat and cold weather conditions. We further direct NERC to determine during the standard development process whether probabilistic elements can be incorporated into the new or modified Reliability Standard and implemented presently by responsible entities. If NERC identifies probabilistic elements which responsible entities can feasibly implement and that would improve upon existing planning practices, we expect the inclusion of those methods in the proposed Reliability Standard." **P138.** "[W]e direct NERC to identify during the standard development process any probabilistic planning methods that would improve upon existing planning practices, but that NERC deems infeasible to include in the proposed Reliability Standard at this time. If any such methods are identified, NERC shall describe in its petition for approval of the proposed Reliability Standard the barriers preventing the implementation of those probabilistic elements. We intend to use this information to determine whether and what next steps may be warranted to facilitate the use of probabilistic methods in transmission system planning practices."	The drafting team discussed probabilistic elements and determined while probabilistic analysis would be a good step forward, it would be better suited for the future as the methodology, process, and tools mature. Probabilistic assessment of generation and transmission facilities for the benchmark planning cases was discussed during the process of drafting the TPL-008-1 standard. However, based on the actual extreme heat and extreme cold events that have occurred, outages for generation and transmission facilities were unique for each of these events. Thus, it was challenging to draw correlation for the outages that occurred for different extreme heat and cold events for different regions and different timeframes. In addition, the data, available from these events, was limited to perform an adequate probabilistic assessment. Due to these reasons, the drafting team has decided not to pursue any probabilistic assessment for the current TPL-008-1 standard. This, however, does not preclude future development of probabilistic assessment when having additional data, as well as mature methodology, process and tools that can provide meaningful probabilistic assessment for generation and transmission outages under extreme temperature conditions.
P152. "[W]e direct NERC to require in the new or modified Reliability Standard the development of extreme weather corrective action plans for	The directive is addressed in the proposed TPL-008-1 Requirement R9.

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Directive Language	**Consideration of Directives**
specified instances when performance standards are not met. In addition, as explained below, we direct NERC to develop certain processes to facilitate interaction and coordination with applicable regulatory authorities or governing bodies responsible for retail electric service as appropriate in implementing a corrective action plan." **P155**: "[T]he Commission is not directing any specific result or content of the corrective action plan."	When the benchmark planning case study results indicate the System is unable to meet performance requirements for P0 and P1 Contingencies, Corrective Action Plans (CAPs) must be developed. Additionally, in accordance with Requirement R9 Part 9.1, responsible entities shall make their CAP available to, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.
P157. "[W]e direct NERC to require in the new or modified Reliability Standard the development of corrective action plans that include mitigation for specified instances where performance requirements for extreme heat and cold events are not met—i.e., when certain studies conducted under the Standard show that an extreme heat or cold event would result in cascading outages, uncontrolled separation, or instability." **P158**: "[W]e give NERC in this final rule the flexibility to specify the circumstances that require the development of a corrective action plan."	The directive is addressed in the proposed TPL-008-1 Requirement R9. When the benchmark planning case study results indicate the system is unable to meet performance requirements for P0 and P1 Contingencies, Corrective Action Plans must be developed.
P165. "[w]e direct NERC to require in the new or modified Reliability Standard that responsible entities share their corrective action plans with, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues."	The directive is addressed in the proposed TPL-008-1 Requirement R9. Requirement R9.1 requires the responsible entities to make their CAP available and solicit feedback from applicable regulatory authorities or governing bodies responsible for retail electric service issues.
P167. "Further, because an important goal of transmission planning is to avoid load shed, any responsible entity that includes non-consequential load loss in its corrective action plan should also identify and share with applicable regulatory authorities or governing bodies responsible for retail electric service alternative corrective actions that would, if approved and implemented, avoid the use of load shedding."	This directive is addressed in proposed TPL-008-1 Requirement R9. As stipulated in Requirement R9 Part 9.2, when Non-Consequential Load Loss is utilized as an element of a CAP for a Table 1 P1 Contingency, the responsible entity must document the alternative(s) considered, and notify the applicable regulatory authorities or governing bodies responsible for retail electric service issues.

FERC Order 896 Directives	
Directive Language	**Consideration of Directives**
P188. "[W]e direct NERC to submit a new or modified Reliability Standard within 18 months of the date of publication of this final rule in the Federal Register. Further, we direct NERC to propose an implementation timeline for the new or modified Reliability Standard, with implementation beginning no later than 12 months after the effective date of a Commission order approving the proposed Reliability Standard."	The directive is addressed with the publication of TPL-008-1 and will be filed with the regulatory government no later than December 23, 2024, within 18 months of the date Order No. 896 was published in the *Federal Register*. The implementation plan addresses Requirement R1 becoming effective 12 months from the effective date of the Commission order approving the TPL-008-1. In addition, phased-in approaches have been provided for other Requirements needing additional time. See the TPL-008-1 Implementation Plan.
P193. "[W]e direct NERC to establish an implementation timeline for the proposed Reliability Standard. In complying with this directive, NERC will have discretion to develop a phased-in implementation timeline for the different requirements of the proposed Reliability Standard (i.e., developing benchmark cases, conducting studies, developing corrective action plans). However, this phased-in implementation must begin within 12 months of the effective date of a Commission order approving the proposed Reliability Standard and must include a clear deadline for implementation of all requirements."	The implementation plan addresses Requirement R1 becoming effective 12 months from the effective date of the Commission order approving the TPL-008-1. In addition, phased-in approaches have been provided for other Requirements needing additional time. See the TPL-008-1 Implementation Plan.

ERO Enterprise Process for TPL-008-1 Benchmark Weather Event Development and Maintenance

Standards Development and Engineering Process Document
December 2024

Background

This Electric Reliability Organization (ERO) Enterprise Process for TPL-008-1[1] Benchmark Weather Event Development and Maintenance addresses how ERO Enterprise staff will develop and maintain a library of benchmark weather events (herein as the Weather Event Library) to be used by Planning Coordinators and Transmission Planners for TPL-008-1 studies. Per Requirement R2 of TPL-008-1 and consistent with directives outlined in FERC Order No. 896[2], Planning Coordinators and Transmission Planners will have benchmark temperature events available, via the Weather Event Library to select from, when developing their benchmark planning cases.

Purpose

The purpose of this process document is to formalize a repeatable approach to develop and maintain the Weather Event Library. While both the TPL-008-1 study requirements and this process are in the initial stages of development, it is essential that industry is informed of this process and how it will be designed and implemented, following the completion of NERC Project 2023-07. This process document outlines an initial set of process objectives and approach, but is not considered to be complete at this time. This document will be revised, as needed, throughout the development of NERC Project 2023-07 and in future updates of the benchmark temperature events.

Document Maintenance

NERC will maintain this document to ensure it is consistent with acceptable and publicly available practices. This document will be reviewed as it is implemented. Updates will be made by NERC Standards Development and Engineering, as needed, to reflect lessons learned as the process matures. Any substantive changes to this process, supplemental/attached criteria, or other guidance to be used by NERC in developing additional benchmark events, archiving/removing benchmark events, or other modifications to the Weather Event Library, will be reviewed in consultation with NERC Legal, NERC Compliance Assurance, Zone Entity staff, and FERC. Approved substantive revisions to this document will be detailed in the Appendix and broadly communicated to industry.

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[1] *Link pending final approval of TPL-008-1*

[2] FERC Docket No. RM22-10-000; Order No. 896; https://www.ferc.gov/media/e-1-rm22-10-000; June 15, 2023

Process Overview

The following is a five-year iterative process coinciding with Planning Coordinator and Transmission Planner implementation of TPL-008-1. As TPL-008-1 and associated benchmark event(s) will be submitted to FERC in December 2024, the first iteration of this process will cover five years.

- December 2024
  - Weather Event Library developed and ready to go live for industry.
  - Benchmark Events, for the first five-years required per the TPL-008-1 Reliability Standard, completed and uploaded to the Weather Event Library.
- Year One:
  - ERO to provide Weather Event Library training.
  - ERO to engage with industry subject matter experts (SMEs), Planning Coordinators, research labs, and trade organizations, and NERC technical committees on additional and updated criteria for developing benchmark events.
- Year Two:
  - ERO to initiate review of benchmark event criteria, identify any changes needed to the minimum TPL-008 Requirement R2 criteria for consideration through the standard development process, identify consideration of additional relevant factors/analysis that may be included in future ERO-developed benchmark events, and incorporate feedback from year one.
  - ERO to deliver a webinar and industry outreach.
- Year Three:
  - ERO to develop new benchmark events[3] based on updated temperature data, with consideration to any additional relevant factors that are identified.
  - ERO to update the Weather Event Library with updated benchmark events.
- Year Four:
  - ERO will engage with industry subject matter experts (SMEs), Planning Coordinators, research labs, and trade organizations, and NERC technical committees on additional future information as needed.
- Year Five:
  - ERO to conduct review of this process and make necessary revisions based on lessons-learned and feedback (e.g., CMEP feedback loops, FERC, SMEs)
  - ERO to provide training on benchmark event process and changes to the TPL-008-1 Benchmark Temperature Events Library[4].

[3] Note: This is for the second iteration of benchmark events being developed.
[4] Link to TPL-008-1 Benchmark Temperature Events Library:
https://www.nerc.com/pa/Stand/Project202307ModtoTPL00151TransSystPlanPerfReqExWe/TPL-008-1_Events.pdf

Year 1
- Deliver Weather Event Library Training
- Develop training and guidance for planning case development

Year 2
- Review and recommend modifications to benchmark event criteria as needed, identify additional relevant factors for ERO-developed benchmarks
- Informational session/industry outreach

Year 3
- Update library with new/removed benchmark events
- Goal is to have process for updating benchmark events on year three of each iteration

Year4
- ERO to conduct review of this process and make necessary revisions based on lessons-learned and feedback (e.g., CMEP feedback loops, FERC, SMEs)

Year 5
- Review process and revise based on lessons learned and other feedback loops
- Update Weather Event Library training

Background for Initial TPL-008 R2 Criteria, Attachment 1 Planning Zones, and the Initial ERO TPL-008-1 Benchmark Temperature

Scoping

While the development of the extreme weather event library was intended to be comprehensive, it was not exhaustive. Instead, this initial assessment is a part of a multi-year effort by NERC and industry to develop a robust, North American weather dataset and detailed process for extreme weather events. In the interim, this library of extreme heat and cold events has notable considerations:

- Only extreme heat and cold temperature events were evaluated. The analysis did not assess other weather events such as hydrologic droughts, wind and solar droughts, wildfires, hurricanes, or other extreme weather events that could jeopardize grid reliability.
- Only historical meteorological data was considered. The analysis did not incorporate climate projections or future weather patterns.

- The analysis identified extreme events over a 43-year historical record and did not give higher priority to recent events
- The study is limited in identifying extreme events, not validating or explaining meteorological drivers of that event
- The analysis relied on historical reanalysis and *modeled* weather data, rather than historical observed data for the United States (A smaller observed dataset was used for Canada).

Data Sources

A Pacific Northwest National Laboratory (PNNL) weather dataset[5], used in this study, consists of 43 years (1980-2022) of historical hourly meteorology and roughly 80 years (2020-2099) of projected hourly meteorology. Hourly observations were dynamically downscaled from historical reanalysis of ERA5 data into higher temporal and spatial resolutions using the Weather Research and Forecasting Model (WRF). The model resolution consisted of 12km^2 areas that were spatially-averaged by county and then population-weighted to 54 Balancing Authorities (BAs) in the conterminous United States. The variables included in the final BA weather data are listed in Table 1. While additional parameters like humidity, solar irradiance, and wind speed are available in the dataset, the identification of extreme weather events in this study was solely determined by the temperature value.

Table 1: Weather Variables in PNNL Dataset

Variable	Name	Description	Units
Time	Time_UTC	Hour in Coordinated Universal Time	-
Temperature	T2	2-m temperature	K
Specific Humidity	Q2	2-m water vapor mixing ratio	kg kg^{-1}
Shortwave Radiation	SWDOWN	Downwelling shortwave radiative flux at the surface	W m^{-2}
Longwave Radiation	GLW	Downwelling longwave radiative flux at the surface	W m^{-2}
Wind Speed	WSPD	10-m wind speed (derived from U10 and V10)	m s^{-1}

The PNNL dataset and contributing model were chosen for this study due to the consistency, breadth and granularity of the weather data. The availability of weather data at the BA-level coincides with topology standards in power-system coordination in North America. Temperature observation methods can differ zonally, so a standardized weather model, such as one in the PNNL dataset, offers unparallelled data consistency across large geographical areas.

Topology

The zone topology is a function of Balancing Authority jurisdiction and general knowledge of zonal weather patterns. The goal of the topology was to split the North American System into several distinct zones that have similar electric power system properties (i.e. balancing authority and interconnections) and similar weather or climatological patterns. In the United States, Balancing Authorities with large areas of

[5] Burleyson, C., Thurber, T., & Vernon, C. (2023). Projections of Hourly Meteorology by Balancing Authority Based on the IM3/HyperFACETS Thermodynamic Global Warming (TGW) Simulations (v1.0.0) [Data set]. MSD-LIVE Data Repository. https://doi.org/10.57931/1960530

jurisdiction, exclusively ISOs and RTOs, are assigned their own weather zone. In geographical areas comprised of multiple balancing authorities, generalized weather zones are created to best represent zonal weather patterns.

Table 2: Balancing Authority to Weather Zone Mappings

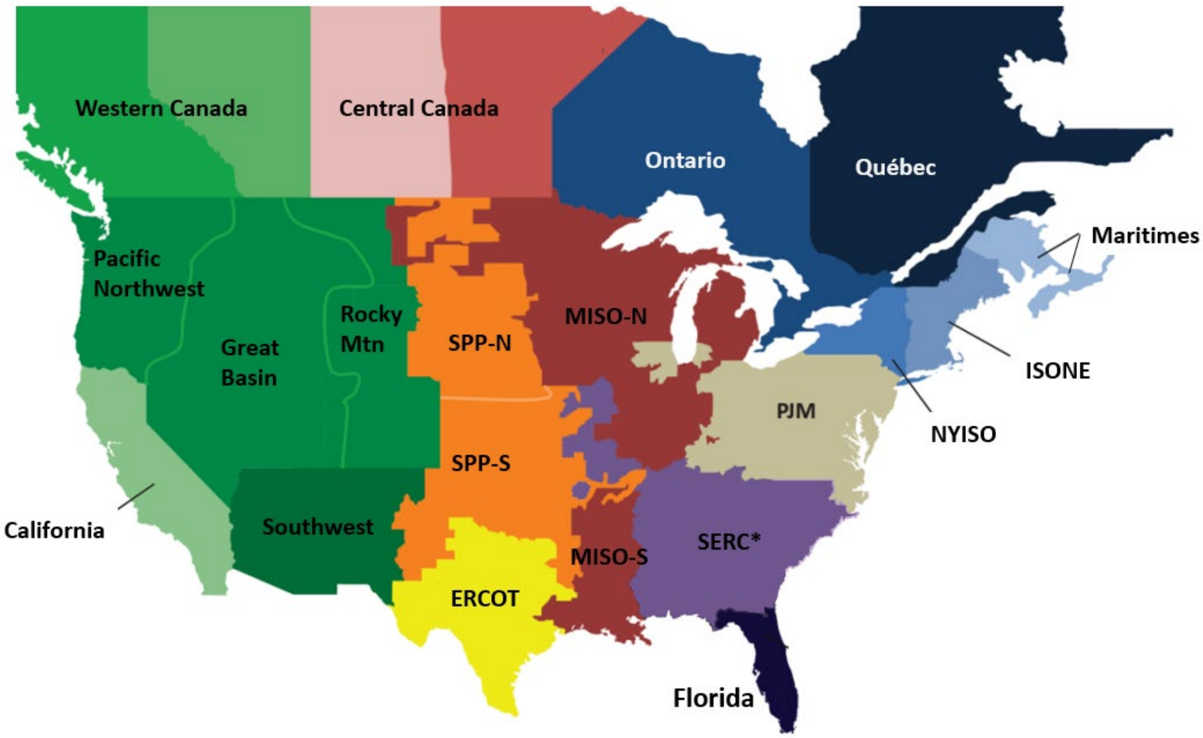
Zone	Balancing Authorities
Midwest North and South	MISO
New England	ISONE
Central US North and South	SPP
Texas	ERCOT
New York	NYISO
Central Atlantic	PJM
California	5 balancing authorities
Pacific Northwest	10 balancing authorities
Rocky Mountain	3 balancing authorities
Great Basin	4 balancing authorities
Southwest	6 balancing authorities
Southeast	7 balancing authorities
Florida	9 balancing authorities

In addition to the 15 weather zones representing the United States, five weather zones were developed to represent Eastern, Central, and Western Canada. The PNNL weather dataset does not contain data for Canada, so this study compiled observed weather data from weather stations in the lower Canadian Provinces. The 20 weather zones best represent the area of study and complement the granularity of available data. A graphical representation of the final weather zones is shown in Figure 1.

Table 3: Canadian Weather Stations to Weather Zone Mappings.

<table>
<tr><th>Weather Zones</th><th>Province</th><th>Weather Stations</th></tr>
<tr><td rowspan="4">Eastern Canada (Ontario, Quebec, and Maritimes)</td><td>Ontario</td><td>1 weather station</td></tr>
<tr><td>Quebec</td><td>3 weather stations</td></tr>
<tr><td>New Brunswick</td><td>1 weather station</td></tr>
<tr><td>Nova Scotia</td><td>1 weather station</td></tr>
<tr><td rowspan="2">Central Canada</td><td>Saskatchewan</td><td>2 weather stations</td></tr>
<tr><td>Manitoba</td><td>1 weather station</td></tr>
<tr><td rowspan="2">Western Canada</td><td>British Columbia</td><td>2 weather stations</td></tr>
<tr><td>Alberta</td><td>2 weather stations</td></tr>
<tr><td></td><td></td><td></td></tr>
</table>

Figure 1: North American Weather Zones for Extreme Weather Events



Event Selection Process

Extreme weather events are defined in this study as extremely hot or cold multi-day events spanning across multiple weather zones. The process to select these extreme events used temperature as the sole defining variable, with emphasis placed on date ranges where multiple weather zones were experiencing historically hot or cold temperatures.

Aggregating balancing authority data to geographical weather zones

Following the topology detailed above, the hourly temperature observations from either the PNNL weather dataset or Canadian weather stations are assigned to weather zones. For each balancing area in the United States, the PNNL data is aggregated from a county-level basis up to the balancing authority based on the population in each county. The balancing authority temperature aggregation was therefore provided in the PNNL dataset.

Additional aggregations were required to develop an average minimum, average, and maximum temperature for zones with multiple balancing authorities in the Northwest, Southwest, and Southeast. In these weather zones, the hourly temperature of each balancing authority was weighted by the 2022 peak load value reported in the EIA Form-861 database. For the Canadian zones, weather station temperature observations were assigned to the nearest population center and weighted by 2021 Census population.

Calculating Three-Day Rolling Average Min/Max Temperatures

Rather than isolating single hours of extreme weather, the rolling 3-day average of minimum and maximum daily temperatures are chosen to represent prolonged periods of extreme weather. The three-day averaging period is centered on every day in the data set (January 1, 1980, to December 31, 2022) and identifies the average minimum and maximum temperature from the day before, day of, and day after. The output of this process develops a dataset of multi-day minimum and maximum temperatures to filter out individual days of extreme heat or cold under the assumption that the power system is more challenged by sustained periods of extreme heat or cold due to cumulative effects on increasing demand and generator outages.

Selecting and Ranking Extreme Weather Events by Severity

Once 3-day average temperatures were calculated for every day, the forty coldest minimum values and forty warmest maximum values were isolated and ranked for each zone, with rank 1 illustrating the most extreme event. To avoid overlap of events within the same period, any ranked weather events within one week of another would be removed in favor of the most extreme event. For example, if a zone's seventh- and tenth-most extreme event occur within a 7-day period, only the day with the seventh-most extreme event would remain in the event database. As a result, some zones may have a discontinuous ranked list given the removal of "duplicate" events.

A similar one-week overlap method was developed to group contemporaneous extreme weather events amongst weather zones. First, all event dates were expanded to have a one-week "overlap period" centered on each date. Then, beginning with the earliest event date, all events that share at least one day of their overlap periods with the selected event date's overlap period, will be grouped together. The final event date range will take the earliest and latest dates of all grouped event overlap periods.

The design of the distinct event date ranges encourages multiple weather zones to share extreme weather events over the course of a one- to two-week event period. To graphically represent the shared extreme events, all event ranges are listed with the affected zones' ranks in west-to-east order. A final shortlist of extreme weather events was developed across all zones. This list included the top one and two most extreme events, done separately for heat and cold periods. Events that included at least three zones experience a top five event simultaneous was also included. For example, if PJM, NYISO, and ISONE all experienced a top five extreme event, but it was not a top one or two event for any zone in isolation, the event was included in the final shortlist.

Results

The result tables show the filtered list of event date ranges with the event ranks for each affected zone; a lower rank represents a more extreme event and is shaded darker.

Cold Events

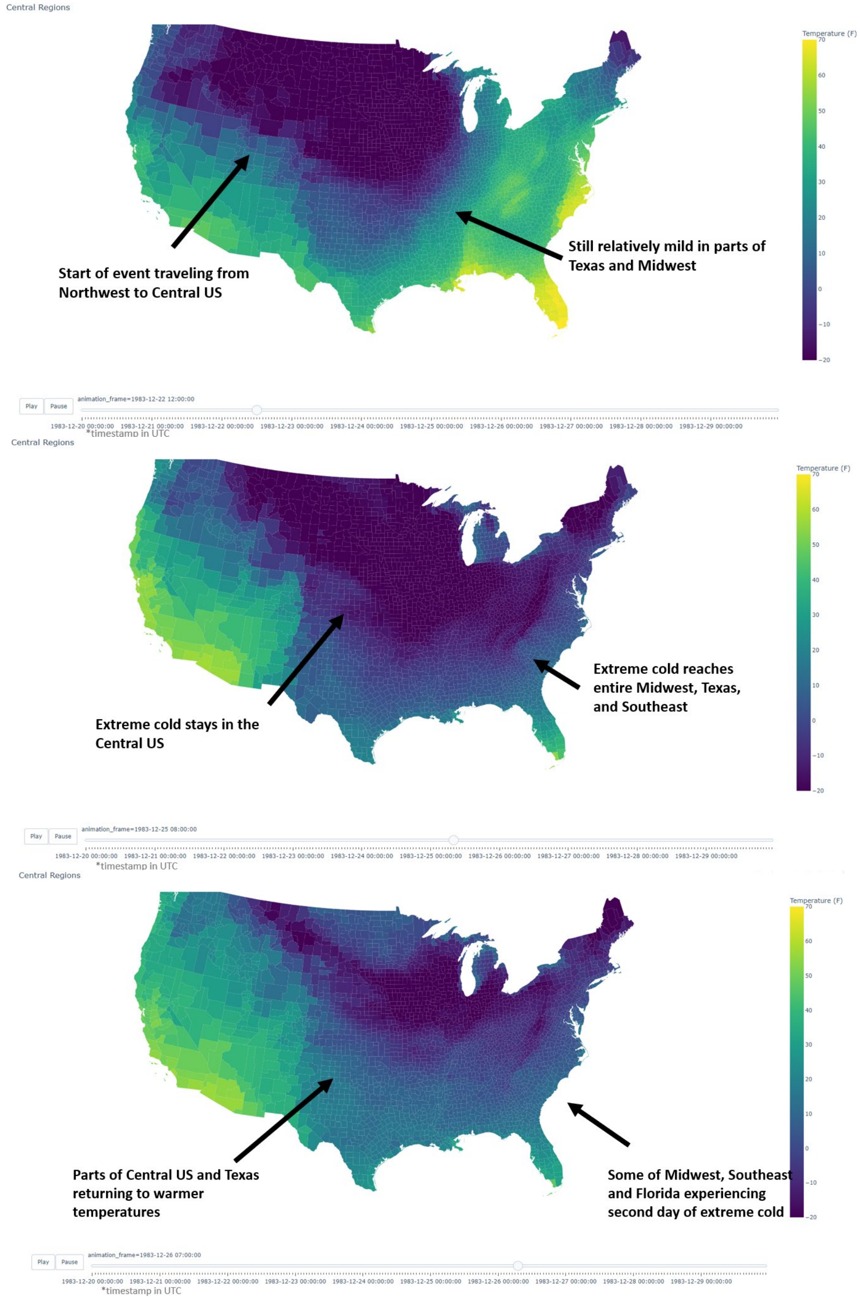
The cold events demonstrate more concentrated events among nearby zones, with the most extreme temperature event occurring December 20th to December 29th, 1983. The event uniquely spanned across the conterminous United States and yielded top ten coldest 3-day average minimum temperatures in 10 different weather zones.

Under these results, the following cold events are recommended for the TPL-008-1 Benchmark Temperature Event Library:

- 12/17/1990 – 1/2/1991 for the Western U.S. and Western part of Canada
  - 12/21 for Pacific NW
  - 12/22 for Rocky Mountain, Great Basin, California
  - 12/23 for Southwest
  - 12/29 for Western Canada
- 12/19/1989 – 12/27/1989 for Central and Southeast U.S. and Central part of Canada
  - 12/23 for Central Canada
  - 12/24 for Central US
  - 12/25 for Texas, ERCOT, Midwest, Southeast
  - 12/26 for Florida
- 1/13/1994 – 1/29/1994 for the Northeast U.S. and Canada
  - 1/16 for New England, Ontario, Quebec and Maritimes
  - 1/20 for Central Atlantic, New York

It is important to note that these weather events do not affect all zones simultaneously, but instead move across the continent in predictable patterns. This has important implications for power system operations and reliability as load and generator availability may be affected in different zones in different times. An example of this is from the 1983 event shown geographically in Figure 2. In this example, the worst case does not occur at the same time in each zone and ideally multiple time periods should be assessed by the planning coordinators.

Figure 2: Snippets of Animated Weather Event Temperature Map



Heat Events

The heat events used are more numerous and disparate from one another. In other words, while extreme cold events tend to affect large geographies simultaneously, heat events can be more localized. The unconcentrated nature of heat events makes selecting the most extreme event more ambiguous.

Under these results, the following heat events are recommended for the NERC TPL-008-1 Benchmark Temperature Event Library:

- 7/13/2006 – 7/26/2006 for the Western U.S. and Western part of Canada
  - 7/16 for Rocky Mountain, Great Basin
  - 7/22 for Western Canada, Pacific NW
  - 7/23 for California, Southwest
- 6/21/2012 – 7/9/2012 for Central and Southeast U.S. and Central part of Canada
  - 6/26 for Texas ERCOT
  - 6/28 for Central Canada, Central US
  - 6/30 for Southeast, Florida
  - 7/5 for Midwest
- 7/16/2021 – 7/25/2021 for the Northeast U.S. and Eastern part of Canada
  - 7/21 for Central Atlantic, Ontario, Quebec and Maritimes
  - 7/22 for New York, New England

Recommendations

The results of this study should inform planning coordinators of potential dates of when to study power system conditions under extreme weather scenarios. While the final selection of event date ranges aligns with historical records of extreme weather, a few recommendations and considerations should be made before proceeding with this study's results.

- Planning coordinators should assess the entire list of distinct events shown and determine which events were the most extreme for their jurisdiction along with neighboring areas.
- Modeled temperature data provides widespread consistency of weather data across many years and many zones. Observed temperature data can recognizably vary from modeled values due to the variety of observation methods at individual weather stations. The temperatures derived from the PNNL dataset for the extreme weather event selection can be provided, but actual temperature values used in planning scenarios may need to be derived from observed weather records for local consistency.
- While temperature is a strong indicator of extreme weather events, it is not the only indicator available in historical weather data sets. The inclusion of other weather variables such as humidity and wind speed could further quantify the severity of extreme weather events.
- Care should be taken when developing wind, solar, and generator de-rates or outage assumptions in the planning cases, using meteorological information to dispatch.
- Exceptions need to be accounted for – including HVDC and switchable units.

TPL-008-1 ERO Enterprise Benchmark Weather Event Development and Maintenance Process Document Version History			
Version	**Date**	**Owner**	**Change tracking**
1	TBD	Standards Staff	Initial Version

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

TPL-008-1 Benchmark Temperature Events

November 2024

The below provides extreme heat and extreme cold benchmark temperature event data per the zones identified in Attachment 1 of the TPL-008-1 Standard. Should entities not agree with the data provided below, you are welcome to coordinate with all Planning Coordinators within your zone to developing one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event per Requirement R2.

Benchmark Events			
Zone	**Daily Data**	**Top 40 Hottest/Coldest 3-Day Average**	**Hourly Data Selected Events**
Eastern Interconnection			
Canada Central	Daily	Top 40	*N/A*
Florida	Daily	Top 40	Hourly
ISO-NE	Daily	Top 40	Hourly
Maritimes	Daily	Top 40	*N/A*
MISO North	Daily	Top 40	Hourly
MISO South	Daily	Top 40	Hourly
NYISO	Daily	Top 40	Hourly
Ontario	Daily	Top 40	*N/A*
PJM	Daily	Top 40	Hourly
SERC	Daily	Top 40	Hourly
SPP North	Daily	Top 40	Hourly
SPP South	Daily	Top 40	Hourly
Western Interconnection			
California/Mexico	Daily	Top 40	Hourly
Great Basin	Daily	Top 40	Hourly
Rocky Mtn	Daily	Top 40	Hourly
Pacific NW	Daily	Top 40	Hourly

WECC Southwest	Daily	Top 40	Hourly
Canada West	Daily	Top 40	*N/A*
ERCOT Interconnection			
ERCOT	Daily	Top 40	Hourly
Quebec Interconnection			
Quebec	Daily	Top 40	*N/A*

NERC TPL-008 Data Library Documentation

Daily Data

Daily temperature statistics by Weather Zone.

- **Region:** The weather region associated with the data
- **Date:** Date in mm/dd/yyyy format
- **Daily_Min_Temp:** Minimum hourly temperature recorded on the associated date (F)
- **Daily_Avg_Temp:** Average hourly temperature recorded on the associated date (F)
- **Daily_Max_Temp:** Minimum hourly temperature recorded on the associated date (F)
- **3_Day_Rolling_Avg_Max_Temp:** Three-day rolling average of daily maximum temperature (F)
- **3_Day_Rolling_Avg_Min_Temp:** Three-day rolling average of daily minimum temperature (F)

Top 40 Events

Top 40 hottest and coldest days in each weather zone, measured by 3-day rolling average temperatures

- **Region:** The weather region associated with the data
- **Event_Type:** Heat Event or Cold Event
- **Year:** Year of associated event
- **Month:** Month of associated event
- **Date:** Date of associated event in mm/dd/yyyy format
- **Daily_Min_Temp:** Minimum hourly temperature recorded on the associated date (F)
- **Daily_Avg_Temp:** Average hourly temperature recorded on the associated date (F)
- **Daily_Max_Temp:** Minimum hourly temperature recorded on the associated date (F)
- **3_Day_Rolling_Avg_Max_Temp:** Three-day rolling average of daily maximum temperature (F)
- **3_Day_Rolling_Avg_Min_Temp:** Three-day rolling average of daily minimum temperature (F)
- **Event_Temp:** Temperature used to benchmark weather event (3_Day_Rolling_Avg_Max_Temp for Heat Events, 3_Day_Rolling_Avg_Min_Temp for Cold Events)

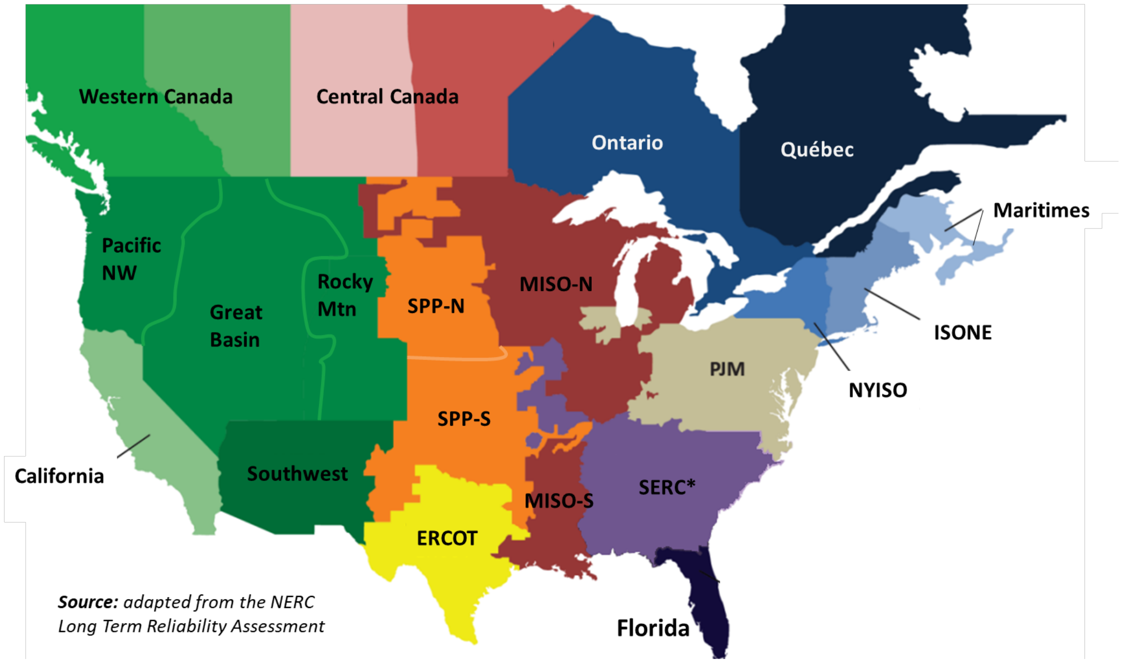
Hourly Data (Filtered)

Hourly weather data from PNNL Dataset with modifications. Values are weighted if the region was represented by multiple BAs. Values are filtered to only include Top 40 event days. Temperature converted from Kelvin to Fahrenheit.

- **Region:** The weather region associated with the data
- **Time_UTC:** Datetime of hourly data in UTC timezone
- **Temperature_F:** Hourly temperature measured at 2-m (F)
- **Q2:** Specific humidity measured as 2-m water vapor mixing ratio (kg/kg)
- **SWDOWN:** Shortwave radiation measured as downwelling shortwave radiative flux at the surface (W/m^2)
- **SLW:** Longwave radiation measured as radiative flux at the surface (W/m^2)
- **WSPD:** Wind speed measured as 10-m wind speed (m/s)

For original data, including hourly data by county and balancing authority, please refer to:
Burleyson, C., Thurber, T., & Vernon, C. (2023). Projections of Hourly Meteorology by Balancing Authority Based on the IM3/HyperFACETS Thermodynamic Global Warming (TGW) Simulations (v1.0.0) [Data set]. MSD-LIVE Data Repository. https://doi.org/10.57931/1960530

Weather Zones



Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the final draft of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	July 19, 2023
SAR posted for comment	August 8–September 27, 2023
45-day formal comment period with initial ballot	March 20–May 3, 2024
38-day formal comment period with additional ballot	July 16–August 22, 2024
15-day formal comment period with additional ballot	October 7–21, 2024
15-day formal comment period with additional ballot	November 7–21, 2024

Anticipated Actions	Date
5-day final ballot	December 2–6, 2024
Board adoption	December 10, 2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

Extreme Temperature Assessment – Documented evaluation of future Bulk Electric System performance for extreme heat and extreme cold benchmark temperature events.

A. Introduction

1. **Title:** Transmission System Planning Performance Requirements for Extreme Temperature Events
2. **Number:** TPL-008-1
3. **Purpose:** Establish Transmission system planning performance requirements to develop a Bulk Power System (BPS) that will operate reliably during extreme heat and extreme cold temperature events.
4. **Applicability:**
    4.1. Functional Entities:
        4.1.1. Transmission Planner
        4.1.2. Planning Coordinator
5. **Effective Date:** See Implementation Plan for Project 2023-07.

B. Requirements and Measures

R1. Each Planning Coordinator shall identify, in conjunction with its Transmission Planner(s), each entity's individual and joint responsibilities for completing the Extreme Temperature Assessment, which shall include each of the responsibilities described in Requirements R2 through R11. Each responsible entity shall complete its responsibilities such that the Extreme Temperature Assessment is completed at least once every five calendar years. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M1. Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall provide dated documentation of each entity's individual and joint responsibilities, such as meeting minutes, agreements, copies of procedures, or protocols in effect between entities or between departments of a vertically integrated system, or email correspondence that identifies an agreement has been reached on individual and joint responsibilities for completing the Extreme Temperature Assessment, and that these responsibilities were completed such that the Extreme Temperature Assessment was completed once every five calendar years.

R2. Each Planning Coordinator shall identify the zone(s) to which the Planning Coordinator belongs to under Attachment 1 and shall coordinate with all Planning Coordinators within each of its identified zone(s), to identify one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event for each of its identified zone(s) when completing the Extreme Temperature Assessment. The benchmark temperature events shall be obtained from the benchmark library maintained by the ERO or developed by the Planning Coordinators. Each benchmark temperature event identified by the Planning Coordinators shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. Consider no less than a 40-year period of temperature data ending no more than five years prior to the time the benchmark temperature events are selected; and

2.2. Represent one of the 20 most extreme temperature conditions based on the three-day rolling average of daily maximum (heat) or daily minimum (cold) temperature across the zone.

M2. Each Planning Coordinator shall have evidence in either electronic or hard copy format that it identified the zone(s) to which it belongs to, under Attachment 1, and that it coordinated with all other Planning Coordinators within each of its identified zone(s) to identify one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event meeting the criteria of Requirement R2 for each of their identified zone(s) when completing the Extreme Temperature Assessment.

R3. Each Planning Coordinator shall coordinate with all Planning Coordinators within each of its zone(s) identified in Requirement R2, to implement a process for developing

benchmark planning cases for the Extreme Temperature Assessment that represent the benchmark temperature events selected in Requirement R2 and sensitivity cases to demonstrate the impact of changes to the basic assumptions used in the benchmark planning cases. This process shall include the following: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Selection of System models within the Long-Term Transmission Planning Horizon to form the basis for the benchmark planning cases.

3.2. Forecasted seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers within the zone.

3.3. Assumed seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers in areas outside the zone, as needed.

3.4. Identification of changes to at least one of the following conditions for sensitivity cases: generation, real and reactive forecasted Load, or transfers.

M3. Each Planning Coordinator shall have dated evidence that it implemented a process for coordinating the development of benchmark planning cases and sensitivity cases for the Extreme Temperature Assessment as specified in Requirement R3.

R4. Each responsible entity, as identified in Requirement R1, shall use the process developed in Requirement R3 and data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, to develop the following and establish category P0 as the normal System condition in Table 1: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

4.1. One common extreme heat and one common extreme cold benchmark planning case.

4.2. One common extreme heat and one common extreme cold sensitivity case.

M4. Each responsible entity, as identified in Requirement R1, shall have dated evidence in either electronic or hard copy format that it developed benchmark planning cases and sensitivity cases in accordance with Requirement R4.

R5. Each responsible entity, as identified in Requirement R1, shall have criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations for completing the Extreme Temperature Assessment. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M5. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of the documentation, specifying the criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations for completing the Extreme Temperature Assessment.

R6. Each responsible entity, as identified in Requirement R1, shall define and document the criteria or methodology to be used in the Extreme Temperature Assessment to

identify instability, uncontrolled separation, or Cascading within an Interconnection. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M6. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of documentation, specifying the criteria or methodology to be used in the Extreme Temperature Assessment to identify instability, uncontrolled separation, or Cascading within an Interconnection in accordance with Requirement R6.

R7. Each responsible entity, as identified in Requirement R1, shall identify the Contingencies for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System. The rationale for those Contingencies selected for evaluation shall be available as supporting information. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M7. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of documentation, of the Contingencies for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System along with supporting rationale.

R8. Each responsible entity, as identified in Requirement R1, shall complete steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, and shall document the assumptions and results. Steady state and transient stability analyses shall be performed for the following: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

8.1. Benchmark planning cases developed in accordance with Requirement R4 Part 4.1.

8.2. Sensitivity cases developed in accordance with Requirement R4 Part 4.2.

M8. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of documentation, of the assumptions and results of the steady state and transient stability analyses completed in the Extreme Temperature Assessment.

R9. Each responsible entity, as identified in Requirement R1, shall develop a Corrective Action Plan(s) when the analysis of a benchmark planning case, in accordance with Requirement R8 Part 8.1, indicates its portion of the Bulk Electric System is unable to meet performance requirements for category P0 or P1 in Table 1. For each Corrective Action Plan, the responsible entity shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

9.1. Document alternative(s) considered when Non-Consequential Load Loss is utilized as an element of a Corrective Action Plan for a Table 1 P1 Contingency.

9.2. Be permitted to utilize Non-Consequential Load Loss as an interim solution, which normally is not permitted for category P0 in Table 1 for situations that are

beyond the control of the Planning Coordinator or Transmission Planner that prevent the implementation of a Corrective Action Plan in the required timeframe, provided that the responsible entity documents the situation causing the problem, alternatives evaluated, and takes actions to resolve the situation.

9.3. Make its Corrective Action Plan available to, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.

9.4. Be permitted to have revisions to the Corrective Action Plan in subsequent Extreme Temperature Assessments, provided that the planned Bulk Electric System shall continue to meet the performance requirements of Table 1.

M9. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of documentation, of each Corrective Action Plan developed in accordance with Requirement R9 when the analysis of a benchmark planning case indicates its portion of the Bulk Electric System is unable to meet performance requirements for category P0 or P1 in Table 1. Evidence shall include documentation of correspondence with applicable regulatory authorities or governing bodies responsible for retail electric service issues and any revision history.

R10. Each responsible entity, as identified in Requirement R1, shall evaluate and document possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) if analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection, for the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

10.1. Table 1 P7 Contingencies in benchmark planning cases analyzed in accordance with Requirement R8 Part 8.1.

10.2. Categories P0, P1, and P7 in Table 1 in sensitivity cases analyzed in accordance with Requirement R8 Part 8.2.

M10. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of documentation that it evaluated and documented possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts when the analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection for Table 1 P7 Contingencies in benchmark planning cases or categories P0, P1, or P7 in Table 1 in sensitivity cases.

R11. Each responsible entity, as identified in Requirement R1, shall provide its Extreme Temperature Assessment results within 60 calendar days of a request to any functional entity that has a reliability related need and submits a written request for the information. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M11. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as email notices, documentation of updated web pages, or postal receipts showing recipient, that it provided its Extreme Temperature Assessment to any

functional entity who has a reliability need within 60 calendar days of a written request.

C. Compliance

1. **Compliance Monitoring Process**

   1.1. **Compliance Enforcement Authority:** "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

   1.2. **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.

   - Each responsible entity shall retain evidence of compliance with each requirement in this standard for five calendar years or one complete Extreme Temperature Assessment cycle, whichever is longer.

   1.3. **Compliance Monitoring and Enforcement Program:** "Compliance Monitoring Enforcement Program" or "CMEP" means, depending on the context (1) the NERC Compliance Monitoring and Enforcement Program (Appendix 4C to the NERC Rules of Procedure) or the Commission-approved program of a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that is responsible for performing compliance monitoring and enforcement activities with respect to Registered Entities' compliance with Reliability Standards.

Table 1 – Steady State & Stability Performance Events
Steady State & Stability: a. Instability, uncontrolled separation, or Cascading within an Interconnection, defined in accordance with Requirement R6, shall not occur. b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0. c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event. d. Simulate Normal Clearing unless otherwise specified. e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings. **Steady State Only:** f. Applicable Facility Ratings shall not be exceeded. g. System steady state voltages and post-Contingency voltage deviations shall meet the criteria identified in Requirement R5.

Table 1 – Steady State & Stability Performance Events							
Category	Initial Condition	Event[1]	Fault Type[3]	Contingency BES Level	Interruption of Firm Transmission Service Allowed	Non-Consequential Load Loss Allowed	
						Benchmark Planning Cases	Sensitivity Cases
P0 No Contingency	Normal System	None	N/A	N/A	Yes	No[6]	Yes
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[2] 4. Shunt Device[4]	3Ø	≥ 200 kV	Yes	Yes[6]	Yes
		5. Single Pole of a DC line	SLG				
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure[5] 2. Loss of a bipolar DC line	SLG	≥ 200 kV	Yes	Yes	Yes

Table 1 – Steady State & Stability Performance Events
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the BES level of the event. For P7 events, the BES level of the event is the highest System voltage level of the element(s) removed for the analyzed event. 2. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers. 3. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria. 4. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground. 5. Excludes circuits that share a common structure for 1 mile or less. 6. Benchmark planning cases require the development of a Corrective Action Plan when the responsible entity’s portion of the BES is unable to meet the performance requirements for categories P0 or P1. Additionally, in benchmark planning cases, Non-Consequential Load Loss is not permitted for category P0 except where permitted as an interim solution in a Corrective Action Plan in accordance with Requirement R9 Part 9.2.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed less than or equal to six months late.	The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed more than six months but less than or equal to 12 months late.	The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed more than 12 months but less than or equal to 18 months late.	The Planning Coordinator, in conjunction with its Transmission Planner(s), failed to identify individual and joint responsibilities for completing the Extreme Temperature Assessment. OR The responsible entity completed its individual and joint responsibilities such that the Extreme Temperature Assessment was completed, but it was completed more than 18 months late.
R2.	N/A	N/A	The Planning Coordinator coordinated with all Planning Coordinators within each identified zone to identify one common extreme heat and one common extreme cold benchmark temperature event for completing the Extreme Temperature Assessment, but one of the identified events	The Planning Coordinator coordinated with all Planning Coordinators within each identified zone to identify one common extreme heat and one common extreme cold benchmark temperature event for completing the Extreme Temperature Assessment, but both of the identified events

			failed to meet all the criteria of Requirement R2.	failed to meet all of the criteria of Requirement R2. OR The Planning Coordinator failed to coordinate with all Planning Coordinators within each identified zone to identify one common extreme heat and one common extreme cold benchmark temperature event for completing the Extreme Temperature Assessment.
R3.	N/A	N/A	N/A	The Planning Coordinator did not coordinate with all Planning Coordinators within each of its identified zone(s) to implement a process for developing benchmark planning cases. OR The Planning Coordinator coordinated with all Planning Coordinators within each of its identified zone(s) to implement a process for developing benchmark planning cases, but the process did not include all of the required elements.

R4.	N/A	N/A	N/A	The responsible entity, as identified in Requirement R1, did not use the process developed in Requirement R3 to develop benchmark planning cases or sensitivity cases. OR The responsible entity, as identified in Requirement R1, used the process developed in Requirement R3 to develop benchmark planning cases and sensitivity cases, but did not use data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, for one or more of the required cases. OR The responsible entity, as identified in Requirement R1, used the process developed in Requirement R3 and data consistent with that provided in accordance with the MOD-032 standard, supplemented as needed, but failed to develop one or more of the required planning or sensitivity cases.

R5.	N/A	N/A	N/A	The responsible entity, as identified in Requirement R1, did not have criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations for completing the Extreme Temperature Assessment.
R6.	N/A	N/A	N/A	The responsible entity, as identified in Requirement R1, failed to define or document the criteria or methodology to be used in the Extreme Temperature Assessment to identify instability, uncontrolled separation, or Cascading within an Interconnection.
R7.	N/A	N/A	The responsible entity, as identified in Requirement R1, identified Contingencies for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System, but did not include the rationale for those Contingencies selected for evaluation as supporting information.	The responsible entity, as identified in Requirement R1, did not identify Contingencies for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System.

R8.	The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to document the assumptions for one or more sensitivity cases in accordance with Requirement R8.	The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to document the assumptions for one or more benchmark planning cases in accordance with Requirement R8.	The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to document results for one or more of the sensitivity cases in accordance with Requirement R8.	The responsible entity, as identified in Requirement R1, completed steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, but failed to document results for one or more of the benchmark planning cases in accordance with Requirement R8. OR The responsible entity, as identified in Requirement R1, failed to complete steady state or transient stability analyses and document results in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, in accordance with Requirement R8.
R9.	N/A	N/A	The responsible entity, as identified in Requirement R1, developed a Corrective Action Plan in accordance with Requirement R9, but failed to make its Corrective Action Plan available to, or solicit feedback from, applicable	The responsible entity, as identified in Requirement R1, failed to develop a Corrective Action Plan when the benchmark planning case study results indicate the System is unable to meet performance requirements for

			regulatory authorities or governing bodies responsible for retail electric service issues.	the Table 1 P0 or P1 Contingencies. OR The responsible entity, as identified in Requirement R1, developed a Corrective Action Plan, but it was missing one or more of the elements of Requirement R9 Part 9.1, 9.3 and 9.4 (as applicable).
R10.	N/A	N/A	The responsible entity, as identified in Requirement R1, evaluated and documented possible actions to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection where required under Requirement R10 Part 10.1, but failed to evaluate and document possible actions where required under Requirement R10 Part 10.2.	The responsible entity, as identified in Requirement R1, evaluated and documented possible actions to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection where required under Requirement R10 Part 10.2, but failed to evaluate and document possible actions where required under Requirement R10 Part 10.1. OR The responsible entity, as identified in Requirement R1, failed to evaluate and document possible actions to

				reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) when analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection where required under Requirement R10 Parts 10.1 and 10.2.
R11.	The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 60 days but less than or equal to 80 days following the request.	The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 80 days but less than or equal to 100 days following the request.	The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 100 days but less than or equal to 120 days following the request.	The responsible entity, as identified in Requirement R1, provided its Extreme Temperature Assessment results to functional entities having a reliability related need who requested the information in writing, but it was more than 120 days following the request. OR The responsible entity, as identified in Requirement R1, did not provide its Extreme Temperature Assessment results to functional entities having a reliability related need who submitted a written request for the information.

D. Regional Variances

None.

E. Associated Documents

- Implementation Plan for Project 2023-07
- Technical Rationale Document
- Consideration of Issues and Directives for FERC Order 896.
- ERO Benchmark Event Library
- TPL-008 Data Library Read Me

Version History

Version	Date	Action	Change Tracking
1	TBD	Addressing FERC Order 896	New Standard

Attachment 1: Extreme Temperature Assessment Zones

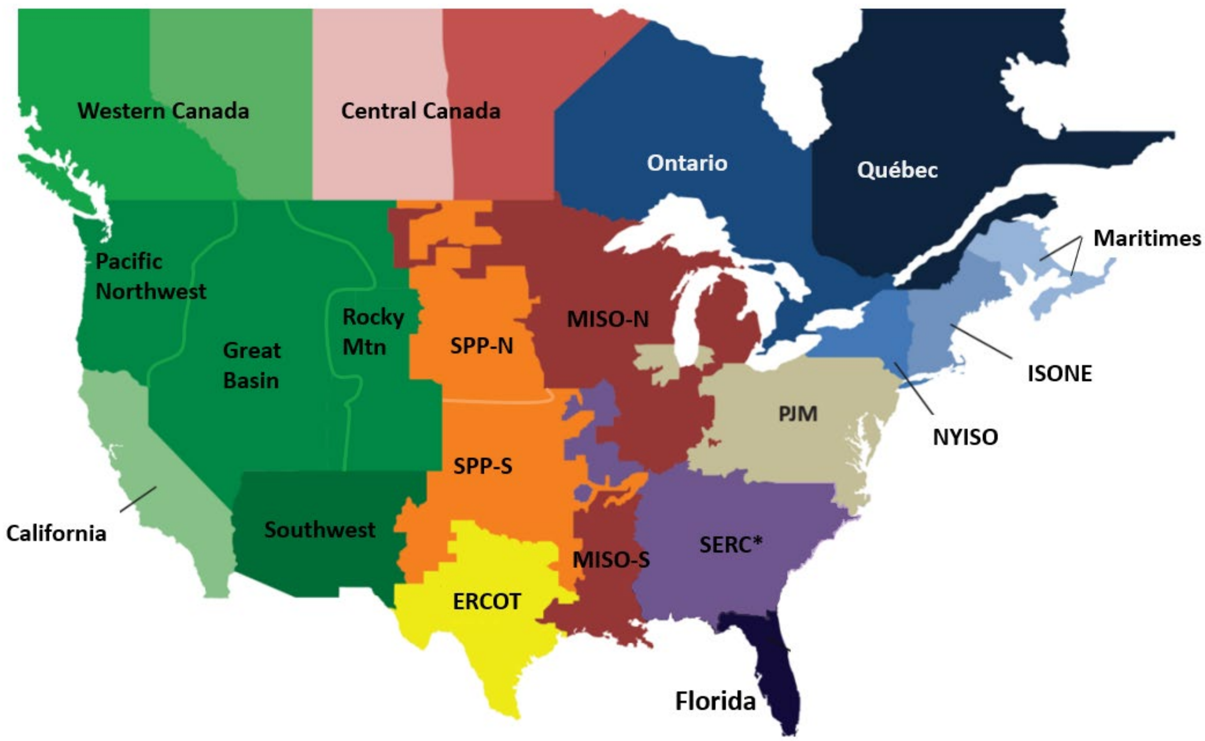
The table below lists the zones to be used in the Extreme Temperature Assessment and identifies the Planning Coordinators that belong to each zone. In accordance with Requirement R2, each Planning Coordinator is required to identify the zone(s) to which it belongs. Planning Coordinators, in different zones within a broader planning region, may use the same benchmark temperature events for their respective benchmark planning cases, provided the benchmark temperature events meet the criteria of Requirement R2 for each zone.

Zone	Planning Coordinators
Eastern Interconnection	
MISO North	Planning Coordinator(s) in MISO that serve portions of MISO in Montana, North Dakota, South Dakota, Minnesota, Iowa, Wisconsin, Michigan, Indiana, Illinois, Missouri, and Kentucky
MISO South	Planning Coordinator(s) in MISO that serve portions of Arkansas, Mississippi, Louisiana, and Texas
SPP North	Planning Coordinator(s) in portions of SPP that serve Iowa, Montana, Nebraska, North Dakota, and South Dakota.
SPP South	Planning Coordinator(s) in portions of SPP that serve Arkansas, Kansas, Louisiana, Missouri, New Mexico, Oklahoma, and Texas.
PJM	Planning Coordinator(s) that serves PJM
New England	Planning Coordinator(s) in NPCC that serve the six New England States
New York	Planning Coordinator(s) in NPCC that serve New York
SERC	Planning Coordinator(s) in SERC, excluding those that serve Florida and those in MISO, SPP, and PJM
Florida	Planning Coordinator(s) in SERC that serve Florida
Central Canada	Planning Coordinator(s) that serve Saskatchewan and Manitoba region of MRO
Ontario	Planning Coordinator(s) in NPCC that serve Ontario
Maritimes	Planning Coordinator(s) in NPCC that primarily serve New Brunswick, Nova Scotia, Prince Edward Island, and Northern Maine
Western Interconnection	
Southwest	Planning Coordinator(s) in the Southwest region of WECC, including El Paso in West Texas
Pacific Northwest	Planning Coordinator(s) in the Pacific Northwest region of WECC

Zone	Planning Coordinators
Great Basin	Planning Coordinator(s) in the Great Basin region of WECC
Rocky Mountain	Planning Coordinator(s) in the Rocky Mountain region of WECC
California/Mexico	Planning Coordinator(s) in the California/Mexico region of WECC
Western Canada	Planning Coordinator(s) that primarily serve British Columbia and Alberta region of WECC
ERCOT Interconnection	
ERCOT	Planning Coordinator(s) in Texas that are part of the ERCOT Interconnection
Quebec Interconnection	
Quebec	Planning Coordinator(s) that serve Quebec in the NPCC Region.

The map below depicts an approximation of the zones to be used in the Extreme Temperature Assessment and is provided as a visual aid; to the extent that there is a conflict between the map and the table, the table controls. This map is not to be used for compliance purposes.

TPL-008-1 Weather Zones Map



NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Reliability Standard Audit Worksheet[1]

TPL-008-1 – Transmission System Planning Performance Requirements for Extreme Temperature Events

This section to be completed by the Compliance Enforcement Authority.

Audit ID:	Audit ID if available; or REG-NCRnnnnn-YYYYMMDD
Registered Entity:	Registered name of entity being audited
NCR Number:	NCRnnnnn
Compliance Enforcement Authority:	Region or NERC performing audit
Compliance Assessment Date(s)[2]:	Month DD, YYYY, to Month DD, YYYY
Compliance Monitoring Method:	[On-site Audit | Off-site Audit | Spot Check]
Names of Auditors:	Supplied by CEA

Applicability of Requirements

	BA	DP	GO	GOP	IA	LSE	PC	PSE	RC	RP	RSG	TO	TOP	TP	TSP
R1							X							X	
R2							X								
R3							X								
R4							X								
R5							X								
R6							X								
R7							X								
R8							X								
R9							X								
R10							X								
R11							X								

[1] NERC developed this Reliability Standard Audit Worksheet (RSAW) language in order to facilitate NERC's and the Regional Entities' assessment of a registered entity's compliance with this Reliability Standard. The NERC RSAW language is written to specific versions of each NERC Reliability Standard. Entities using this RSAW should choose the version of the RSAW applicable to the Reliability Standard being assessed. While the information included in this RSAW provides some of the methodology that NERC has elected to use to assess compliance with the requirements of the Reliability Standard, this document should not be treated as a substitute for the Reliability Standard or viewed as additional Reliability Standard requirements. In all cases, the Regional Entity should rely on the language contained in the Reliability Standard itself, and not on the language contained in this RSAW, to determine compliance with the Reliability Standard. NERC's Reliability Standards can be found on NERC's website. Additionally, NERC Reliability Standards are updated frequently, and this RSAW may not necessarily be updated with the same frequency. Therefore, it is imperative that entities treat this RSAW as a reference document only, and not as a substitute or replacement for the Reliability Standard. It is the responsibility of the registered entity to verify its compliance with the latest approved version of the Reliability Standards, by the applicable governmental authority, relevant to its registration status.

The RSAW may provide a non-exclusive list, for informational purposes only, of examples of the types of evidence a registered entity may produce or may be asked to produce to demonstrate compliance with the Reliability Standard. A registered entity's adherence to the examples contained within this RSAW does not necessarily constitute compliance with the applicable Reliability Standard, and NERC and the Regional Entity using this RSAW reserve the right to request additional evidence from the registered entity that is not included in this RSAW. This RSAW may include excerpts from FERC Orders and other regulatory references which are provided for ease of reference only, and this document does not necessarily include all applicable Order provisions. In the event of a discrepancy between FERC Orders, and the language included in this document, FERC Orders shall prevail.

[2] Compliance Assessment Date(s): The date(s) the actual compliance assessment (on-site audit, off-site spot check, etc.) occurs.

Legend:

Text with blue background:	Fixed text – do not edit
Text entry area with green background:	Entity-supplied information
Text entry area with white background:	Auditor-supplied information

Findings

(This section to be completed by the Compliance Enforcement Authority)

Req.	Finding	Summary and Documentation	Functions Monitored
R1			
R2			
R3			
R4			
R5			
R6			
R7			
R8			
R9			
R10			
R11			

Req.	Areas of Concern

Req.	Recommendations

Req.	Positive Observations

Subject Matter Experts

Identify the Subject Matter Expert(s) responsible for this Reliability Standard.

Registered Entity Response (Required; Insert additional rows if needed):

SME Name	Title	Organization	Requirement(s)

R1 Supporting Evidence and Documentation

R1. Each Planning Coordinator shall identify, in conjunction with its Transmission Planner(s), each entity's individual and joint responsibilities for completing the Extreme Temperature Assessment, which shall include each of the responsibilities described in Requirements R2 through R11. Each responsible entity shall complete its responsibilities such that the Extreme Temperature Assessment is completed at least once every five calendar years. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

M1. Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall provide documentation of each entity's individual and joint responsibilities, such as meeting minutes, agreements, copies of procedures or protocols, in effect between entities or between departments of a vertically integrated system, or email correspondence that identifies an agreement has been reached on individual and joint responsibilities for completing the Extreme Temperature Assessment and that these responsibilities were completed such that the Extreme Temperature Assessment was completed once every five calendar years.

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Documentation of each Entity's individual and joint responsibility for completing the Extreme Temperature Assessment.
Documentation that the Extreme Temperature Assessment and associated responsibilities were completed once every five calendar years.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TPL-008-1, R1

This section to be completed by the Compliance Enforcement Authority

	Verify an Extreme Temperature Assessment was completed once every five calendar years.
	Verify the completion of entity's individual and joint responsibilities for completing the Extreme Temperature Assessment.
	Review processes that identify each entity's individual and joint responsibilities for completing the Extreme Temperature Assessment at least once every five calendar years.
Note to Auditor: Extreme Temperature Assessment - Documented evaluation of future Bulk Electric System performance for extreme heat and extreme cold benchmark temperature events.	

Auditor Notes:

R2 Supporting Evidence and Documentation

R2. Each Planning Coordinator shall identify the zone(s) to which the Planning Coordinator belongs to under Attachment 1 and shall coordinate with all Planning Coordinators within each of its identified zone(s), to identify one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event for each of its identified zone(s) when completing the Extreme Temperature Assessment. The benchmark temperature events shall be obtained from the benchmark library maintained by the ERO or developed by the Planning Coordinators. Each benchmark temperature event identified by the Planning Coordinators shall: [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

2.1. Consider no less than a 40-year period of temperature data ending no more than five years prior to the time the benchmark temperature events are selected; and

2.2. Represent one of the 20 most extreme temperature conditions based on the three-day rolling average of daily maximum (heat) or daily minimum (cold) temperature across the zone.

M2. Each Planning Coordinator shall have evidence in either electronic or hard copy format that it identified the zone(s) to which it belongs to, under Attachment 1, and coordinated with all other Planning Coordinators within each of its identified zone(s) to select one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event meeting the criteria of Requirement R2 for each of their identified zone(s) when completing the Extreme Temperature Assessment.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Documentation of identified zone(s) to which the entity belongs, under Attachment 1.
Documentation of one common extreme heat benchmark temperature event that was selected after coordination with all Planning Coordinators within each of the identified zone(s).
Documentation of one common extreme cold benchmark temperature event t that was selected after coordination with all Planning Coordinators within each of the identified zone(s).
Documentation that each benchmark temperature event considers no less than a 40-year period of temperature data ending no more than five years prior to the time the benchmark temperature events were selected.
Documentation that selected benchmark temperature events represented one of the 20 most extreme temperature conditions based on the three-day rolling average of daily maximum (heat) or daily minimum (cold) temperatures across the zone.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TPL-008-1, R2

This section to be completed by the Compliance Enforcement Authority

	(R2) Verify the entity identified all the zone(s) to which it belongs under Attachment 1.
	(R2) Verify the selection, as coordinated with all Planning Coordinators within the zone, of one common extreme heat benchmark temperature event for each of the entity's identified zone(s) used for completion of the Extreme Temperature Assessment.
	(R2) Verify the selection, as coordinated with all Planning Coordinators within the zone, of one common

	extreme cold benchmark temperature event for each of the entity's identified zone(s) used for completion of the Extreme Temperature Assessment.
	(Part 2.1.) Verify the selected benchmark temperature events considered no less than a 40-year period of temperature data ending no more than five years prior to the time the benchmark temperature events were selected
	(Part 2.2.) Verify the selected benchmark temperature events represented one of the 20 most extreme conditions based on the three-day rolling average of daily maximum (heat) or daily minimum (cold) temperature across the zone.
	(R2) Review processes for the coordination of Planning Coordinators within each of the entity's identified zone(s) to select the common extreme heat and cold benchmark temperature events.
Note to Auditor: The ERO will maintain a library of benchmark events to provide responsible entities access to vetted benchmark temperature events that meet the criteria of Requirement R2. While selection of events from the ERO's provided library assures entities they are selecting valid events, Requirement R2 does not preclude entities from collecting temperature data and identifying benchmark temperature events through their own process. Entities that elect to develop their own benchmark temperature events are responsible for ensuring the input temperature data and selected benchmark temperature events meet the criteria of Requirement R2. Additionally, because Requirement R2 requires PCs within a zone to coordinate in the selection of the benchmark temperature events, the process used to identify these events must be agreeable to those PCs.	

Auditor Notes:

R3 Supporting Evidence and Documentation

R3. Each Planning Coordinator shall coordinate with all Planning Coordinators within each of its zone(s) identified in Requirement R2, to implement a process for developing benchmark planning cases for the Extreme Temperature Assessment that represent the benchmark temperature events selected in Requirement R2 and sensitivity cases to demonstrate the impact of changes to the basic assumptions used in the benchmark planning cases. This process shall include the following: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

3.1. Selection of System models within the Long-Term Transmission Planning Horizon to form the basis for the benchmark planning cases.

3.2. Forecasted seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers within the zone.

3.3. Assumed seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers in areas outside the zone, as needed.

3.4. Identification of changes to at least one of the following conditions for sensitivity cases: generation, real and reactive forecasted Load, or transfers.

M3. Each Planning Coordinator shall have dated evidence that it implemented a process for coordinating the development of benchmark planning cases and sensitivity cases for the Extreme Temperature Assessment as specified in Requirement R3.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Documented and implemented process(es) for coordinating, with applicable Planning Coordinators identified in Requirement R2, the development of benchmark planning cases and sensitivity cases for the Extreme Temperature Assessment. The process(es) must demonstrate the following:
Selection of System models within the Long-Term Transmission Planning Horizon to form the basis for the benchmark planning cases.
Forecasted seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers within the zone.
Assumed seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers in areas outside the zone, as needed.
Identification of changes to at least one of the following conditions for sensitivity cases: generation, real and reactive forecasted Load, or transfers.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TPL-008-1, R3

This section to be completed by the Compliance Enforcement Authority

	(R3) Verify implementation of process(es) for coordinating, with all applicable Planning Coordinators within each of the entity's zone(s) identified in Requirement R2, the development of benchmark planning cases and sensitivity cases for the Extreme Temperature Assessment. Verify this process(es) demonstrate the following:
	(Part 3.1.) Selection of System models within the Long-Term Transmission Planning Horizon to form the basis for the benchmark planning cases.
	(Part 3.2.) Forecasted seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers within the zone.
	(Part 3.3.) Assumed seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers in areas outside the zone, as needed.
	(Part 3.4.) Identification of changes to at least one of the following conditions for sensitivity cases: generation, real and reactive forecasted Load, or transfers.
Note to Auditor:	

Auditor Notes:

R4 Supporting Evidence and Documentation

R4. Each responsible entity, as identified in Requirement R1, shall use the coordination process developed in Requirement R3 and data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, to develop the following and establish category P0 as the normal System condition in Table 1: [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

4.1. One common extreme heat and one common extreme cold benchmark planning case.

4.2. One common extreme heat and one common extreme cold sensitivity case.

M4. Each responsible entity, as identified in Requirement R1, shall have dated evidence in either electronic or hard copy format that it developed benchmark planning cases and sensitivity cases in accordance with Requirement R4.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Evidence of one common extreme heat and one common extreme cold benchmark planning case, showing the coordination process developed in Requirement R3 was used and that data was consistent with that provided in accordance with MOD-032 and that category P0 was established. .
Evidence of one common extreme heat and one common extreme cold sensitivity case, showing the coordination process developed in Requirement R3 was used and that data was consistent with that provided in accordance with MOD-032 . and that category P0 was established.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TPL-008-1, R4

This section to be completed by the Compliance Enforcement Authority

	(R4.) Verify that category P0, as the normal System condition in Table 1, was established.
	(Part 4.1.) Verify that one common extreme heat and one common extreme cold benchmark planning case was developed using the coordination process developed in Requirement R3 and with data consistent with that provided in accordance with the MOD-032 standard.
	(Part 4.2.) Verify that one common extreme heat and one common extreme cold sensitivity case was developed using the coordination process developed in Requirement R3 and with data consistent with

	that provided in accordance with the MOD-032 standard.
Note to Auditor:	

Auditor Notes:

R5 Supporting Evidence and Documentation

R5. Each responsible entity, as identified in Requirement R1, shall have criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations for completing the Extreme Temperature Assessment. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

M5. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of the documentation, specifying the criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations for completing the Extreme Temperature Assessment.

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Documentation specifying the criteria for acceptable System steady state voltage limits for completing the Extreme Temperature Assessment.
Documentation specifying the criteria for acceptable post-Contingency voltage deviations for completing the Extreme Temperature Assessment.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed **(This section to be completed by the Compliance Enforcement Authority)**:

Compliance Assessment Approach Specific to TPL-008-1, R5

This section to be completed by the Compliance Enforcement Authority

	Verify the entity has criteria for acceptable System steady state voltage limits for completing the Extreme Temperature Assessment.
	Verify the entity has criteria for acceptable post-Contingency voltage deviations for completing the Extreme Temperature Assessment.
Note to Auditor: The establishment of these criteria allows auditors to compare the results of the Extreme Temperature Assessment with the established criteria.	

Auditor Notes:

R6 Supporting Evidence and Documentation

R6. Each responsible entity, as identified in Requirement R1, shall define and document the criteria or methodology to be used in the Extreme Temperature Assessment to identify instability, uncontrolled separation, or Cascading within an Interconnection. [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

M6. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of documentation, specifying the criteria or methodology to be used in the Extreme Temperature Assessment to identify instability, uncontrolled separation, or Cascading within an Interconnection in accordance with Requirement R6.

Registered Entity Response **(Required)**:

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]**:**

Provide the following evidence, or other evidence to demonstrate compliance.
Documentation specifying the criteria or methodology used in the Extreme Temperature Assessment to identify instability, uncontrolled separation, or Cascading within an Interconnection.

Registered Entity Evidence **(Required)**:

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TPL-008-1, R6

This section to be completed by the Compliance Enforcement Authority

	Verify the entity has documented criteria or methodology used within the Extreme Temperature Assessment to identify instability, uncontrolled separation, or Cascading within an Interconnection.
Note to Auditor: The establishment of these criteria allows auditors to compare the results of the Extreme Temperature Assessment with the established criteria.	

Auditor Notes:

R7 Supporting Evidence and Documentation

R7. Each responsible entity, as identified in Requirement R1, shall identify the Contingencies for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System. The rationale for those Contingencies selected for evaluation shall be available as supporting information. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

M7. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of documentation, of the Contingencies for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System along with supporting rationale.

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Documentation, including supporting rationale, of the Contingencies for each category in Table 1 that are expected to produce more severe System impacts on your portion of the Bulk Electric System.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TPL-008-1, R7
This section to be completed by the Compliance Enforcement Authority

	Verify that the entity identified Contingencies for each category in Table 1 that are expected to produce more severe System impacts for the entity's portion of the Bulk Electric System.
	Verify the supporting documentation and rationale for those Contingencies selected for evaluation by the entity.
Note to Auditor: If feasible, all Contingencies listed in Table 1 should be considered for evaluation by the responsible entity; however, the language affords flexibility in identifying the most impactful Contingencies. As such, the responsible entity must identify, with supporting rationale, the Contingencies within each category of Table 1 that are expected to produce more severe System impacts within its planning area . It is noted that since the benchmark planning cases are developed from the extreme temperature benchmark events, they already represent extreme System conditions and thus not all Contingencies from Reliability Standard TPL-001-5.1 Table 1 are included in the TPL-008-1 Table 1 for assessment. The Events included in TPL-008- 1 Table 1 represent the more likely Contingencies to occur.	

Auditor Notes:

R8 Supporting Evidence and Documentation

R8. Each responsible entity, as identified in Requirement R1, shall complete steady state and transient stability analyses in the Extreme Temperature Assessment using the Contingencies identified in Requirement R7, and shall document the assumptions and results. Steady state and transient stability analyses shall be performed for the following: [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

8.1. Benchmark planning cases developed in accordance with Requirement R4 Part 4.1.

8.2. Sensitivity cases developed in accordance with Requirement R4 Part 4.2.

M8. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of documentation, of the assumptions and results of the steady state and transient stability analyses completed in the Extreme Temperature Assessment.

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Documentation of assumptions used for the development of steady state and transient stability analyses in the Extreme Temperature Assessment.
Documentation of results of the steady state and transient stability analyses completed in the Extreme Temperature Assessment.
Documentation that the Contingencies identified in Requirement R7 were used to complete the steady state and transient stability analyses in the Extreme Temperature Assessment.
Documentation that steady state and transient stability analyses were performed for benchmark planning cases developed in accordance with Requirement R4 Part 4.1.
Documentation that steady state and transient stability analyses were performed for sensitivity cases developed in accordance with Requirement R4 Part 4.2.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TPL-008-1, R8

This section to be completed by the Compliance Enforcement Authority

	(R8.) Verify the steady state and transient stability analyses were completed in the Extreme Temperature Assessment, using the Contingencies identified in Requirement R7.
	(R8.) Verify the documented assumptions and results of the steady state and transient analyses in the Extreme Temperature Assessment.
	(Part 8.1.) Verify the steady state and transient analyses were performed for the benchmark planning cases developed in accordance with Requirement R4 Part 4.1.
	(Part 8.2.) Verify the steady state and transient analyses were performed for the sensitivity cases developed in accordance with Requirement R4 Part 4.2.
Note to Auditor:	

Auditor Notes:

R9 Supporting Evidence and Documentation

R9. Each responsible entity, as identified in Requirement R1, shall develop a Corrective Action Plan(s) when the analysis of a benchmark planning case, in accordance with Requirement R8 Part 8.1, indicates its portion of the Bulk Electric System is unable to meet performance requirements for category P0 or P1 in Table 1. For each Corrective Action Plan, the responsible entity shall: [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

9.1. Document alternative(s) considered when Non-Consequential Load Loss is utilized as an element of a Corrective Action Plan for a Table 1 P1 Contingency.

9.2. Be permitted to utilize Non-Consequential Load Loss as an interim solution, which normally is not permitted for category P0 in Table 1 for situations that are beyond the control of the Planning Coordinator or Transmission Planner that prevent the implementation of a Corrective Action Plan in the required timeframe, provided that the responsible entity documents the situation causing the problem, alternatives evaluated, and takes actions to resolve the situation.

9.3. Make its Corrective Action Plan available to, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues

9.4. Be permitted to have revisions to the Corrective Action Plan in subsequent Extreme Temperature Assessments, provided that the planned Bulk Electric System shall continue to meet the performance requirements of Table 1.

M9. Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as electronic or hard copies of documentation, of each Corrective Action Plan developed in accordance with Requirement R9 when the analysis of a benchmark planning case indicates its portion of the Bulk Electric System is unable to meet performance requirements for category P0 or P1 in Table 1. Evidence shall include documentation of correspondence with applicable regulatory authorities or governing bodies responsible for retail electric service issues and any revision history.

Registered Entity Response (Required):
Question: Were any Corrective Action Plans developed when the analysis of a benchmark planning case, in accordance with Requirement R8 Part 8.1, indicated a portion of your Bulk Electric System was unable to meet performance requirements for category P0 or P1 in Table 1? If Yes, provide a listing of the Corrective Action Plans, including the start date and if it is still effective.
☐ Yes ☐ No
[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]**:**

Provide the following evidence, or other evidence to demonstrate compliance.
Documentation of each Corrective Action Plan (CAP) developed when the analysis of a benchmark planning case, in accordance with Requirement R8 Part 8.1, indicated a portion of the Bulk Electric System was unable to meet performance requirements for category P0 or P1 in Table 1.
Documentation that each CAP developed in accordance with Requirement R9 addresses Part 9.1 through Part 9.4.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed **(This section to be completed by the Compliance Enforcement Authority)**:

Compliance Assessment Approach Specific to TPL-008-1, R9

This section to be completed by the Compliance Enforcement Authority

	(R9.) Verify a CAP was developed when analysis of a benchmark planning case, in accordance with Requirement R8 Part 8.1, indicated the entity's portion of the Bulk Electric System was unable to meet performance requirements for Category P0 and P1.
	(Part 9.1.) Verify each CAP documents the alternative(s) considered when Non-Consequential Load Loss was utilized for a Table 1 P1 Contingency.
	(Part 9.2.) If Non-Consequential Load Loss was utilized by the entity as an interim solution, verify the situation(s) that was beyond the control of the Planning Coordinator or Transmission Planner.
	(Part 9.2.) If Non-Consequential Load Loss was utilized by the entity as an interim solution, verify the entity documented the situation causing the problem, evaluated alternatives and took action to resolve the situation.
	(Part 9.3.) Verify each CAP was made available to, and solicited feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.
	(Part 9.4.) Verify any revisions to CAP(s) in subsequent Extreme Temperature Assessments and verify that the planned BES meets the performance requirements of Table 1.
Note to Auditor:	

Auditor Notes:

R10 Supporting Evidence and Documentation

R10. Each responsible entity, as identified in Requirement R1, shall evaluate and document possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) if analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection, for the following: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

10.1. Table 1 P7 Contingencies in benchmark planning cases analyzed in accordance with Requirement R8 Part 8.1.

10.2. Categories P0, P1, and P7 in Table 1 in sensitivity cases analyzed in accordance with Requirement R8 Part 8.2.

M10. Each responsible entity, as identified in Requirement R1, shall provide dated evidence such as electronic or hard copies of documentation that it evaluated and documented possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts when the analyses conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection for Table 1 P7 Contingencies in benchmark planning cases or categories P0, P1, or P7 in Table 1 in sensitivity cases.

Registered Entity Response (Required):
Question: Did the analyses of any benchmark planning cases or sensitivity cases as described in Requirement R10. Part 10.1. and Part 10.2. conclude there could be instability, uncontrolled separation, or Cascading within an Interconnection? If Yes, provide a listing of theses analyses.

☐ Yes ☐ No

[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Documented evaluation and possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) if analyses concluded there could be instability, uncontrolled separation, or Cascading within an Interconnection for Table 1 P7 Contingencies in benchmark planning cases analyzed in accordance with Requirement R8 Part 8.1
Documented evaluation and possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) if analyses concluded there could be instability, uncontrolled separation, or Cascading within an Interconnection for Categories P0, P1, and P7 in Table 1 in sensitivity cases analyzed in accordance with Requirement R8 Part 8.2.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TPL-008-1, R10

This section to be completed by the Compliance Enforcement Authority

	(Part 10.1.) Verify the documented evaluation and possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) if analyses concluded there could be instability, uncontrolled separation, or Cascading within an Interconnection for Table 1 P7 Contingencies in benchmark planning cases analyzed in accordance with Requirement R8 Part 8.1
	(Part 10.2.) Verify the documented evaluation and possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) if analyses concluded there could be instability, uncontrolled separation, or Cascading within an Interconnection for Categories P0, P1, and P7 in Table 1 in sensitivity cases analyzed in accordance with Requirement R8 Part 8.2.
Note to Auditor:	

Auditor Notes:

R11 Supporting Evidence and Documentation

R11. Each responsible entity, as identified in Requirement R1, shall provide its Extreme Temperature Assessment results within 60 calendar days of a request to any functional entity that has a reliability related need and submits a written request for the information. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

M11. .Each responsible entity, as identified in Requirement R1, shall provide dated evidence, such as email notices, documentation of updated web pages, or postal receipts showing recipient, that it provided its Extreme Temperature Assessment to any functional entity who has a reliability need within 60 calendar days of a written request.

Registered Entity Response (Required):
Question: Was a written request for the Extreme Temperature Assessment received from any functional entity who had a reliability need? If Yes, provide a listing of the date of request and associated functional entity making the request.
☐ Yes ☐ No
[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Documentation that the Extreme Temperature Assessment was provided within 60 calendar days of a written request to any requesting functional entity who had a reliability need.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to TPL-008-1, R11

This section to be completed by the Compliance Enforcement Authority

	Verify that the Extreme Temperature Assessment results were provided to any written request, as applicable, from any functional entity that has a reliability related need within 60 calendar days.
Note to Auditor:	

Auditor Notes:

Additional Information:

Reliability Standard PDF TO BE ADDED AFTER FERC APPROVAL

The full text of TPL-008-1 may be found on the NERC Web Site (www.nerc.com) under “Program Areas & Departments”, “Reliability Standards.”

In addition to the Reliability Standard, there is an applicable Implementation Plan available on the NERC Web Site.

In addition to the Reliability Standard, there is background information available on the NERC Web Site.

Capitalized terms in the Reliability Standard refer to terms in the NERC Glossary, which may be found on the NERC Web Site.

Sampling Methodology

Sampling is essential for auditing compliance with NERC Reliability Standards since it is not always possible or practical to test 100% of either the equipment, documentation, or both, associated with the full suite of enforceable standards. The Sampling Methodology Guidelines and Criteria (see NERC website), or sample guidelines, provided by the Electric Reliability Organization help to establish a minimum sample set for monitoring and enforcement uses in audits of NERC Reliability Standards.

Regulatory Language

TO BE ADDED AFTER FERC APPROVAL

Revision History for RSAW

Version	Date	Reviewers	Revision Description
1	12/1/2024	NERC Compliance Assurance, Operations and Planning Compliance Task Force	New Document

[i] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

Standards Announcement

Project 2023-07 Transmission Planning Performance Requirements for Extreme Weather

Final Ballots Open through December 6, 2024

Now Available

Final ballots for **TPL-008-1 – Transmission System Planning Performance Requirements for Extreme Temperature Events** and its implementation plan are open through **8 p.m. Eastern, Friday, December 6, 2024.**

The Standards Committee approved waivers to the Standards Process Manual at their December 2023 meeting. These waivers were sought by NERC Standards for reduced formal comment and ballot periods to assist the drafting teams in expediting the standards development process due to firm timeline expectations set by FERC Order 896.

Balloting

In the final ballot, votes are counted by exception. Votes from the previous ballot are automatically carried over in the final ballot. Only members of the applicable ballot pools can cast a vote. Ballot pool members who previously voted have the option to change their vote in the final ballot. Ballot pool members who did not cast a vote during the previous ballot can vote in the final ballot.

Members of the ballot pool(s) associated with this project can log into the Standards Balloting and Commenting System (SBS) and submit votes here.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The voting results will be posted and announced after the ballots close. If approved, the standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Jordan Mallory (via email) or at 404-479-7358.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

BALLOT RESULTS

Ballot Name: 2023-07 Transmission Planning Performance Requirements for Extreme Weather TPL-008-1 FN 5 ST
Voting Start Date: 12/2/2024 11:10:07 AM
Voting End Date: 12/6/2024 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 5
Total # Votes: 264
Total Ballot Pool: 314
Quorum: 84.08
Quorum Established Date: 12/2/2024 12:50:35 PM
Weighted Segment Value: 75.43

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	89	1	46	0.73	17	0.27	0	15	11
Segment: 2	8	0.8	6	0.6	2	0.2	0	0	0
Segment: 3	68	1	39	0.796	10	0.204	0	10	9
Segment: 4	18	1	7	0.636	4	0.364	0	2	5
Segment: 5	76	1	29	0.659	15	0.341	0	14	18
Segment: 6	47	1	25	0.781	7	0.219	0	8	7
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	1	0	0	0	0	0	0	1	0
Segment: 9	0	0	0	0	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	7	0.7	7	0.7	0	0	0	0	0
Totals:	314	6.5	159	4.903	55	1.597	0	50	50

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		None	N/A
1	American Transmission Company, LLC	Amy Wilke		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Trevor Rombough		None	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		None	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	N/A
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	N/A
1	Dominion - Dominion Virginia Power	Steven Belle		Affirmative	N/A
1	Duke Energy	Katherine Street		Affirmative	N/A
1	Edison International - Southern California Edison Company	Robert Blackney		Affirmative	N/A
1	Entergy	Brian Lindsey		None	N/A
1	Evergy	Kevin Frick	Hayden Maples	Affirmative	N/A
1	Eversource Energy	Joshua London		Negative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	John Martinez		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Lidija Efremova	Affirmative	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
1	Long Island Power Authority	Isidoro Behar		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Matt Lewis		Abstain	N/A
1	LS Power Transmission, LLC	Jennifer Richardson		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
1	MEAG Power	David Weekley	Rebika Yitna	Abstain	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Nikki Carson-Marquis	Affirmative	N/A
1	Muscatine Power and Water	Andrew Kurriger		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Abstain	N/A
1	NB Power Corporation	Jeffrey Streifling		Abstain	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	N/A
1	New York Power Authority	Daniel Valle		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Negative	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Negative	N/A
1	Orlando Utilities Commission	Aaron Staley		None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Negative	N/A
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Abstain	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Negative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Abstain	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Laura Somak	Israel Perez	Affirmative	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		None	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	David Plumb		Negative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Negative	N/A
1	VELCO -Vermont Electric Power Company, Inc.	Randall Buswell		Abstain	N/A
1	Western Area Power Administration	Ben Hammer		Affirmative	N/A
1	Xcel Energy, Inc.	Eric Barry		None	N/A
2	California ISO	Darcy O'Connell		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	N/A
2	Independent Electricity System Operator	Helen Lainis		Affirmative	N/A
2	ISO New England, Inc.	John Pearson	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	Kirsten Rowley		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips	Shannon Mickens	Negative	N/A
3	AEP	Leshel Hutchings		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr	Danielle Moskop	Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs	Carly Miller	Affirmative	N/A
3	Bonneville Power Administration	Ron Sporseen		Affirmative	N/A
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Negative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Lincoln Burton		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Victoria Crider		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Abstain	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Entergy	James Keele		None	N/A
3	Evergy	Marcus Moor	Hayden Maples	Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Negative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
3	JEA	Marilyn Williams		Affirmative	N/A
3	Lakeland Electric	Steven Marshall		None	N/A
3	Lincoln Electric System	Sam Christensen		Abstain	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		Abstain	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
3	MEAG Power	Roger Brand	Rebika Yitna	Abstain	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
3	National Grid USA	Brian Shanahan		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	N/A
3	New York Power Authority	Richard Machado		Affirmative	N/A
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Negative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	N/A
3	Northern California Power Agency	Michael Whitney		None	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	OTP - Otter Tail Power Company	Wendi Olson		None	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Negative	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
3	Portland General Electric Co.	Mayra Franco		Abstain	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Negative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Santee Cooper	Vicky Budreau		Abstain	N/A
3	Seminole Electric Cooperative, Inc.	Usama Tahir		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	N/A
3	Tri-State G and T Association, Inc.	Amanda Skubal		Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel	Joseph Gatten	None	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	N/A
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		None	N/A
4	Austin Energy	Tony Hua		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	None	N/A
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		Negative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		None	N/A
4	DTE Energy	Patricia Ireland		Abstain	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Georgia System Operations Corporation	Katrina Lyons		Negative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	N/A
4	Northern California Power Agency	Marty Hostler	Mason Jones	None	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Seminole Electric Cooperative, Inc.	George Pino		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
4	Western Power Pool	Kevin Conway		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		None	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		None	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	BC Hydro and Power Authority	Christine Jennings		Negative	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
5	Bonneville Power Administration	Milli Chennell		Affirmative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	None	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
5	Constellation	Alison MacKellar		Abstain	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	N/A
5	Dominion - Dominion Resources, Inc.	Barbara Marion		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Abstain	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		None	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A
5	Great River Energy	Jacalynn Bentz	Joseph Knight	None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Abstain	N/A
5	Grid Strategies LLC	Michael Goggin		None	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	Invenergy LLC	Rhonda Jones		None	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Los Angeles Department of Water and Power	Robert Kerrigan		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
5	LS Power Development, LLC	C. A. Campbell		None	N/A
5	Manitoba Hydro	Kristy-Lee Young	Helen Zhao	None	N/A
5	Muscatine Power and Water	Chance Back		Abstain	N/A
5	National Grid USA	Robin Berry		Abstain	N/A
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Erin Wilson		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender	Kevin Schawang	Negative	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	NextEra Energy	Richard Vendetti		Negative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Negative	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Dania Colon		Affirmative	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Negative	N/A
5	Pattern Operators LP	George E Brown		Negative	N/A
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	PSEG Nuclear LLC	Tim Kucey		None	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Negative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Loren Harbachuk		None	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
5	Santee Cooper	Carey Salisbury		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		None	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Abstain	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		Negative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Tennessee Valley Authority	Darren Boehm		Negative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Abstain	N/A
6	AEP	Mathew Miller		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Imane Mrini		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A
6	Black Hills Corporation	Rachel Schuldt		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Negative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
6	Constellation	Kimberly Turco		Abstain	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	John Sturgeon		Affirmative	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
6	Entergy	Julie Hall		None	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
6	Great River Energy	Brian Meloy		Negative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Manitoba Hydro	Brandin Stoesz		None	N/A
6	Muscatine Power and Water	Nicholas Burns		Abstain	N/A
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	N/A
6	NiSource - Northern Indiana Public Service Co.	Rebecca Blair		Negative	N/A
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Negative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Stefanie Burke		None	N/A
6	Powerex Corporation	Raj Hundal		Negative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie		Negative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Santee Cooper	Marty Watson		Abstain	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Matthew O'neal		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Abstain	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	Western Area Power Administration	Jennifer Neville		Affirmative	N/A
6	Xcel Energy, Inc.	Steve Szablya		None	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Affirmative	N/A
10	ReliabilityFirst	Tremayne Brown	Greg Sorenson	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

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BALLOT RESULTS

Ballot Name: 2023-07 Transmission Planning Performance Requirements for Extreme Weather Implementation Plan FN 5 OT
Voting Start Date: 12/2/2024 11:11:09 AM
Voting End Date: 12/6/2024 8:00:00 PM
Ballot Type: OT
Ballot Activity: FN
Ballot Series: 5
Total # Votes: 264
Total Ballot Pool: 314
Quorum: 84.08
Quorum Established Date: 12/2/2024 12:50:41 PM
Weighted Segment Value: 79.38

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	89	1	49	0.79	13	0.21	0	16	11
Segment: 2	8	0.8	7	0.7	1	0.1	0	0	0
Segment: 3	68	1	41	0.837	8	0.163	0	10	9
Segment: 4	18	1	7	0.636	4	0.364	0	2	5
Segment: 5	76	1	31	0.705	13	0.295	0	14	18
Segment: 6	47	1	26	0.813	6	0.188	0	8	7
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	1	0	0	0	0	0	0	1	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	7	0.6	6	0.6	0	0	0	1	0
Totals:	314	6.4	167	5.08	45	1.32	0	52	50

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		None	N/A
1	American Transmission Company, LLC	Amy Wilke		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	BC Hydro and Power Authority	Adrian Andreoiu		Negative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Trevor Rombough		None	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		None	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	N/A
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	N/A
1	Dominion - Dominion Virginia Power	Steven Belle		Affirmative	N/A
1	Duke Energy	Katherine Street		Affirmative	N/A
1	Edison International - Southern California Edison Company	Robert Blackney		Affirmative	N/A
1	Entergy	Brian Lindsey		None	N/A
1	Evergy	Kevin Frick	Hayden Maples	Affirmative	N/A
1	Eversource Energy	Joshua London		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	John Martinez		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Lidija Efremova	Affirmative	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
1	Long Island Power Authority	Isidoro Behar		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Matt Lewis		Abstain	N/A
1	LS Power Transmission, LLC	Jennifer Richardson		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
1	MEAG Power	David Weekley	Rebika Yitna	Abstain	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Nikki Carson-Marquis	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Muscatine Power and Water	Andrew Kurriger		Abstain	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Abstain	N/A
1	NB Power Corporation	Jeffrey Streifling		Abstain	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	N/A
1	New York Power Authority	Daniel Valle		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Negative	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Abstain	N/A
1	Orlando Utilities Commission	Aaron Staley		None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Negative	N/A
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Abstain	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Laura Somak	Israel Perez	Affirmative	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		None	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	David Plumb		Negative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Negative	N/A
1	VELCO -Vermont Electric Power Company, Inc.	Randall Buswell		Abstain	N/A
1	Western Area Power Administration	Ben Hammer		Affirmative	N/A
1	Xcel Energy, Inc.	Eric Barry		None	N/A
2	California ISO	Darcy O'Connell		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A
2	Independent Electricity System Operator	Helen Lainis		Affirmative	N/A
2	ISO New England, Inc.	John Pearson	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	Kirsten Rowley		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips	Shannon Mickens	Negative	N/A
3	AEP	Leshel Hutchings		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr	Danielle Moskop	Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	BC Hydro and Power Authority	Ming Jiang		Negative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs	Carly Miller	Affirmative	N/A
3	Bonneville Power Administration	Ron Sporseen		Affirmative	N/A
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Negative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Lincoln Burton		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Victoria Crider		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Abstain	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Entergy	James Keele		None	N/A
3	Evergy	Marcus Moor	Hayden Maples	Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Georgia System Operations Corporation	Scott McGough		None	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
3	JEA	Marilyn Williams		Affirmative	N/A
3	Lakeland Electric	Steven Marshall		None	N/A
3	Lincoln Electric System	Sam Christensen		Abstain	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		Abstain	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
3	MEAG Power	Roger Brand	Rebika Yitna	Abstain	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
3	National Grid USA	Brian Shanahan		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	N/A
3	New York Power Authority	Richard Machado		Affirmative	N/A
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Negative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	N/A
3	Northern California Power Agency	Michael Whitney		None	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Omaha Public Power District	David Heins		Negative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		None	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Negative	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
3	Portland General Electric Co.	Mayra Franco		Abstain	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Santee Cooper	Vicky Budreau		Abstain	N/A
3	Seminole Electric Cooperative, Inc.	Usama Tahir		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Abstain	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	N/A
3	Tri-State G and T Association, Inc.	Amanda Skubal		Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel	Joseph Gatten	None	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	N/A
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		None	N/A
4	Austin Energy	Tony Hua		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	None	N/A
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		Negative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		None	N/A
4	DTE Energy	Patricia Ireland		Abstain	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Georgia System Operations Corporation	Katrina Lyons		Negative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	N/A
4	Northern California Power Agency	Marty Hostler	Mason Jones	None	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	George Pino		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
4	Western Power Pool	Kevin Conway		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		None	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		None	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	BC Hydro and Power Authority	Christine Jennings		Negative	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
5	Bonneville Power Administration	Milli Chennell		Affirmative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	None	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
5	Constellation	Alison MacKellar		Abstain	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	N/A
5	Dominion - Dominion Resources, Inc.	Barbara Marion		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Abstain	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		None	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A
5	Great River Energy	Jacalynn Bentz	Joseph Knight	None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Abstain	N/A
5	Grid Strategies LLC	Michael Goggin		None	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	Invenergy LLC	Rhonda Jones		None	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Los Angeles Department of Water and Power	Robert Kerrigan		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
5	LS Power Development, LLC	C. A. Campbell		None	N/A
5	Manitoba Hydro	Kristy-Lee Young	Helen Zhao	None	N/A
5	Muscatine Power and Water	Chance Back		Abstain	N/A
5	National Grid USA	Robin Berry		Abstain	N/A
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Erin Wilson		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender	Kevin Schawang	Negative	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	NextEra Energy	Richard Vendetti		Negative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Negative	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Dania Colon		Affirmative	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Negative	N/A
5	Pattern Operators LP	George E Brown		Negative	N/A
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	PSEG Nuclear LLC	Tim Kucey		None	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Loren Harbachuk		None	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
5	Santee Cooper	Carey Salisbury		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		None	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Abstain	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Tennessee Valley Authority	Darren Boehm		Negative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Abstain	N/A
6	AEP	Mathew Miller		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Imane Mrini		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A
6	Black Hills Corporation	Rachel Schuldt		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Negative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
6	Constellation	Kimberly Turco		Abstain	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	John Sturgeon		Affirmative	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
6	Entergy	Julie Hall		None	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
6	Great River Energy	Brian Meloy		Negative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Manitoba Hydro	Brandin Stoesz		None	N/A
6	Muscatine Power and Water	Nicholas Burns		Abstain	N/A
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	N/A
6	NiSource - Northern Indiana Public Service Co.	Rebecca Blair		Negative	N/A
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Negative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Stefanie Burke		None	N/A
6	Powerex Corporation	Raj Hundal		Negative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Santee Cooper	Marty Watson		Abstain	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Matthew O'neal		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Abstain	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	Western Area Power Administration	Jennifer Neville		Affirmative	N/A
6	Xcel Energy, Inc.	Steve Szablya		None	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Affirmative	N/A
10	ReliabilityFirst	Tremayne Brown	Greg Sorenson	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A

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Exhibit H

Standard Drafting Team Roster

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RELIABILITY CORPORATION

Drafting Team Roster

Project 2023-07 Transmission System Planning Performance Requirements for Extreme Weather

	Name	Entity	Attendance
Chair	Evan Wilcox	American Electric Power	
Vice Chair	Jared Shaw	Entergy Services	
Members	Josie Daggett	Western Area Power Administration	
	David Duhart	Southwest Power Pool	
	Michael Herman	PJM Interconnection	
	Tracy Judson	Florida Power & Light	
	Sun Wook Kang	ERCOT	
	Andrew Kniska	ISO New England	
	Dmitry Kosterev	Bonneville Power Administration	
	David Le	California ISO	
	Karl Perman	CIP CORPS	
	Meenakshi Saravanan	ISO New England	
	Kurtis Toews	Manitoba Hydro	
	Hayk Zargaryan	Southern California Edison	
PMOS Liaison	Jason Chandler	Con Edison	

	Name	Entity	Attendance
	Donovan Crane	WECC	
NERC Staff	Jordan Mallory – Standards Developer	North American Electric Reliability Corporation	
	Lauren Perotti – Assistant General Counsel	North American Electric Reliability Corporation	