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 STANDARDS
EOP-011-3 AND EOP-012-1 AND REQUEST FOR EXPEDITED ACTION

Lauren A. Perotti
Senior Counsel
North American Electric Reliability Corporation
1401 H Street, N.W., Suite 410
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099 – facsimile
lauren.perotti@nerc.net

Counsel for the North American Electric Reliability Corporation

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Pursuant to Section 215(d)(1) of the Federal Power Act ("FPA")[1] and Section 39.5[2] of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations, the North American Electric Reliability Corporation ("NERC")[3] hereby submits for Commission approval two proposed Reliability Standards: proposed Reliability Standard EOP-012-1 (Extreme Cold Weather Preparedness and Operations) and proposed Reliability Standard EOP-011-3 (Emergency Operations).[4]

The proposed Reliability Standards represent a significant advancement in NERC's longstanding efforts to reduce the risks posed by extreme cold weather to the reliability of the Bulk-Power System. Building upon the first round of cold weather Reliability Standards approved by the Commission in 2021,[5] the proposed Reliability Standards create a more comprehensive

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1 16 U.S.C. § 824o.

2 18 C.F.R. § 39.5 (2022).

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

4 Unless otherwise indicated, all capitalized terms used in this petition shall have the meaning set forth in the *Glossary of Terms used in NERC Reliability Standards* ("NERC Glossary"), https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

5 *See N. Am. Elec. Reliability Corporation*, 176 FERC ¶ 61,119 (2021) (approving Reliability Standards EOP-011-2, IRO-010-4, and TOP-003-5).

framework of requirements addressing generator preparedness for cold weather operations. The proposed Reliability Standards also address the use of manual load shed during Emergency conditions, requiring Transmission Operators to take steps to minimize the use of manual load shed that could further exacerbate Emergency conditions and threaten system reliability. In so doing, the proposed Reliability Standards address certain key recommendations from the FERC, NERC, and Regional Entity Staff Report on the causes of the February 2021 cold weather event affecting Texas and the south central United States.[6] As discussed more fully in this petition, work is presently underway to address the remaining recommendations related to Reliability Standards enhancements through NERC's standard development process.

NERC requests that the Commission approve the proposed Cold Weather Reliability Standards and the defined terms Generator Cold Weather Critical Component, Extreme Cold Weather Temperature, and Generator Cold Weather Reliability Event, as shown in **Exhibit A**, as just, reasonable, not unduly discriminatory or preferential, and in the public interest. NERC also requests that the Commission approve: (i) the associated Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") (**Exhibit E**); (ii) the retirement of Reliability Standard EOP-011-2; and (iii) the proposed implementation plan (**Exhibit B**).

In light of the demonstrated risks to reliability posed by the failure to prepare properly for cold weather, NERC respectfully requests that the Commission consider approving the proposed Reliability Standards, associated elements, and the implementation plan on an expedited timeframe.

[6] FERC, NERC, Regional Entity Staff Report: *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 [hereinafter Joint Inquiry Report]. This cold weather reliability event will be referred to throughout this petition as the "February 2021 Event."

As required by Section 39.5(a)[7] of the Commission's regulations, this petition presents the technical basis and purpose of the proposed Reliability Standards, a demonstration that the proposed Reliability Standards meet the criteria identified by the Commission in Order No. 672[8] (**Exhibit D**), and a summary of the standard development history (**Exhibit F**). The NERC Board of Trustees adopted the proposed Reliability Standards on October 26, 2022.

This petition is organized as follows: Section I provides a summary of the proposed Reliability Standards and the February 2021 Event that led to their development. Section II of the petition provides the individuals to whom notices and communications related to the filing should be provided. Section III provides relevant background regarding the regulatory structure governing the Reliability Standards approval process. Section IV provides relevant background regarding the need for enhanced Reliability Standards to address cold weather preparedness and operations. This section includes information regarding the first set of cold weather Reliability Standards approved by the Commission in 2021 to address the recommendations of Commission and NERC staff following the January 17, 2018 cold weather event. This section also explains how the Joint Inquiry Report examining the causes of the February 2021 Event identified opportunities for additional Reliability Standards enhancements. Section V provides a brief summary of the development process for the proposed Reliability Standards. Section VI of the petition provides an overview and justification for the proposed Reliability Standards and defined terms. Section VII of the petition provides a summary of the proposed implementation plan, and Section VIII provides a

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7 18 C.F.R. § 39.5(a).

8 The Commission specified in Order No. 672 certain general factors it would consider when assessing whether a particular Reliability Standard is just and reasonable. *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 P 262, 321-37 ("Order No. 672"), *order on reh'g*, Order No. 672-A, 114 FERC ¶ 61,328 (2006).

summary of next steps NERC plans to take regarding cold weather reliability risks. Section IX summarizes why NERC requests expedited action in this proceeding.

I. SUMMARY

Over the last decade, several notable events have demonstrated the substantial impacts that extreme cold weather conditions can have on the reliability of the Bulk-Power System. Extreme cold weather was a major factor in Bulk-Power System reliability events in 2011,[9] 2014,[10] and 2018.[11] The most recent extreme cold weather reliability event, in February 2021, proved to be exceptionally severe. The conditions experienced during the February 2021 Event resulted in emergencies in three Reliability Coordinator footprints in the south central United States and required the use of firm load shed to maintain system reliability. In the Electric Reliability Council of Texas ("ERCOT") Interconnection, system conditions deteriorated significantly due to the exceptionally high number of generator outages combined with exceptionally high customer demand. System operators in ERCOT and other neighboring areas ordered what ultimately became the largest controlled firm load shed event in United States history to avoid a complete blackout. The resulting power outages, combined with the historically cold temperatures gripping the region, resulted in significant human and economic impacts. Many people lost their lives.

The February 2021 Event, like those cold weather reliability events before it, had two main causes, both triggered by cold weather. First, generating units, unprepared for cold weather, failed

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[9] *See* FERC and NERC Staff, *Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011: Causes and Recommendations* (Aug. 2011), https://www.ferc.gov/sites/default/files/2020-04/08-16-11-report.pdf.

[10] *See* NERC, *Polar Vortex Review* (Sep. 2014), https://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf (reviewing generator outages during the January 2014 polar vortex weather event).

[11] *See* FERC and NERC Staff, 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-NERCReport_20190718.pdf

in large numbers. Second, declines in natural gas production led to supply issues, which were exacerbated by the grid's increasing reliance on natural gas fired generation. NERC has highlighted in its reliability assessments the rapid transformation of the grid, including the increasing reliance on variable generation and "just in time" natural gas deliveries, and how that transformation has produced a generation resource mix that is more sensitive to extreme temperature conditions than the fleet of prior years. This trend has underscored the need for Reliability Standards to address the potential implications for reliability.

In 2021, NERC took an important first step to assure the reliability of the Bulk-Power System in future winter seasons through the development of the first cold weather Reliability Standards, Reliability Standards EOP-011-2 (Emergency Preparedness and Operations), IRO-010-4 (Reliability Coordinator Data Specification and Collection), and TOP-003-5 (Operational Reliability Data). These Reliability Standards were approved by the Commission in August 2021 and will become effective April 1, 2023. These Reliability Standards will advance the reliability of the Bulk-Power System by both improving generator readiness for cold weather conditions and enhancing awareness of factors that could limit generating unit availability by the entities responsible for the reliable operation of the grid.

While Reliability Standards EOP-011-2, IRO-010-4, and TOP-003-5 represent a significant advancement for cold weather reliability, the Joint Inquiry Report provided ten recommendations for further standards enhancements based on detailed analysis of the factors causing or contributing to the February 2021 Event. NERC developed proposed Reliability Standards EOP-012-1 and EOP-011-3 to address several of these Joint Inquiry Report recommendations, and work is currently underway to address the remaining recommendations.

As discussed more fully in this petition, proposed Reliability Standards EOP-012-1 and EOP-011-3 build upon NERC's prior work and would further advance reliability through improved operations and generator cold weather preparedness requirements. Proposed Reliability Standard EOP-012-1 is a new Reliability Standard that builds on the cold weather preparedness plan and training requirements currently found in Reliability Standard EOP-011-2 to form a more comprehensive framework for advancing the reliability of the BPS through improved generator cold weather preparedness. The proposed Reliability Standard includes requirements for freeze protection measures for both new and existing generation, the development of enhanced cold weather preparedness plans and annual training on those plans, and the development and implementation of Corrective Action Plans to address freezing issues. Proposed Reliability Standard EOP-011-3 builds upon the improvements reflected in Reliability Standard EOP-011-2 to improve how Transmission Operators account for the overlap of manual load shed and automatic load shed in their emergency Operating Plans. The proposed Reliability Standards would complement the improved generator cold weather operating parameter information sharing requirements approved by the Commission in Reliability Standards TOP-003-5 and IRO-010-4. Through these new and revised requirements, the proposed Reliability Standards would further strengthen the reliability of the Bulk-Power System during cold weather conditions.

NERC, however, recognizes that further work remains to be done. Work is presently underway to address the remaining standards-related recommendations from the Joint Inquiry Report by winter 2023-2024, in accordance with the timelines of the Joint Inquiry Report. As the standard drafting team addresses these recommendations, it may propose further enhancements to the proposed Reliability Standards to improve clarity or further advance reliability. Additionally, NERC will continue to support entities in the intervening winter seasons before the proposed

Reliability Standards become fully enforceable. NERC has several options in its reliability toolkit to support improved cold weather operations and preparedness, and it is fully committed to using them during the implementation period for the proposed Reliability Standards. NERC also recognizes the need to monitor closely the implementation of the proposed Reliability Standards to ensure they are providing the intended benefits for reliability.

While work remains to be done, the proposed Reliability Standards represent an important and timely step forward in NERC's efforts to assure the reliability of the Bulk-Power System in cold weather and would provide new protections not currently found in any Reliability Standard. NERC respectfully requests that the Commission approve the proposed Reliability Standards 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:

Lauren A. Perotti
Senior Counsel
North American Electric Reliability Corporation
1401 H Street NW
Suite 410
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099 – facsimile
lauren.perotti@nerc.net

Howard Gugel
Vice President and Director of Engineering and Standards
North American Electric Reliability Corporation
3353 Peachtree Road, N.E.
Suite 600, North Tower
Atlanta, GA 30326
(404) 446-2560
(404) 446-2595 – facsimile
howard.gugel@nerc.net

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

[12] 16 U.S.C. § 824o.

("BPS"), and with the duties of certifying an ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1)[13] of the FPA states that all users, owners, and operators of the BPS in the United States will be subject to Commission-approved Reliability Standards. Section 215(d)(5)[14] of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard. Section 39.5(a)[15] of the Commission's regulations requires the ERO to file with the Commission for its approval each new 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 should be made effective.

The Commission is vested with the regulatory responsibility to approve Reliability Standards that protect the reliability of the BPS and to ensure that Reliability Standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest. Pursuant to Section 215(d)(2) of the FPA[16] and Section 39.5(c)[17] 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.

B. NERC Reliability Standards Development Procedure

The proposed Reliability Standards were developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process. NERC

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13 *Id.* § 824o(b)(1).

14 *Id.* § 824o(d)(5).

15 18 C.F.R. § 39.5(a).

16 16 U.S.C. § 824o(d)(2).

17 18 C.F.R. § 39.5(c)(1).

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 order certifying NERC as the Commission's ERO, the Commission found that NERC's rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards,[19] and thus satisfy several of the Commission's criteria for approving Reliability Standards.[20] The development process is open to any person or entity with a legitimate interest in the reliability of the BPS. NERC considers the comments of all stakeholders. Stakeholders must approve, and the NERC Board of Trustees must adopt, a new or revised Reliability Standard before NERC submits the Reliability Standard to the Commission for approval.

IV. THE NEED FOR ENHANCED RELIAIBLITY STANDARDS TO ADDRESS COLD WEATHER PREPAREDNESS AND OPERATIONS

As NERC has highlighted in its reliability assessments, the generation resource mix that powers the North American grid is transforming at a rapid pace. Over time, the resource mix has shifted to be increasingly reliant on variable energy resources, such as wind and solar, and "just in time" natural gas deliveries, resulting in a generation fleet that is more sensitive to extreme temperature conditions than the fleet of prior years.[21] Several notable events over the last decade have demonstrated the substantial impacts that extreme cold weather conditions can have on the

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18 The NERC Rules of Procedure, including Appendix 3A, NERC Standard Processes Manual, are available at http://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx.

19 *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 at P 250 (2006).

20 Order No. 672*, supra* note 8, at PP 268, 270.

21 In response to these developments, NERC began introducing fuel risks into its seasonal assessments and developed more probabilistic analysis of reliability. NERC's Winter Reliability Assessment depicts regions in North America where, under peak demand scenarios, there is heightened reliability risk due to potential extreme weather or fuel supply disruptions. *See, e.g.*, NERC, 2021-2022 Winter Reliability Assessment (Nov. 2021), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2021.pdf.

reliability of the Bulk-Power System. Extreme cold weather was a major factor in BPS reliability events in 2011,[22] 2014,[23] and 2018.[24] Extreme cold weather was also major factor in the February 2021 Event affecting Texas and the south central United States.

Addressing the risks to reliability posed by cold weather has long been a focus area for NERC and the Regional Entities. In its assessments, NERC has highlighted areas where there is potential reliability risk due to extreme weather conditions. Following the 2011 event, NERC published a Reliability Guideline, *Generating Unit Winter Weather Readiness* to aid entities in preparing for cold weather.[25] After the 2011 event and the 2014 polar vortex event, NERC and the Regional Entities also prepared numerous other materials, including training webinars, lessons learned, and other cold weather guidance, to help entities prepare for the winter season. The January 17, 2018 cold weather event affecting the south central United States, however, demonstrated the need for NERC to develop mandatory Reliability Standards as an integral part of a broader framework for addressing the risks to reliability posed by cold weather. The February 2021 Event affecting Texas and the south central United States further underscored the need for comprehensive Reliability Standards to address cold weather preparedness and operations.

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22 *See* FERC and NERC Staff, *Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011: Causes and Recommendations* (Aug. 2011), https://www.ferc.gov/sites/default/files/2020-04/08-16-11-report.pdf.

23 *See* NERC, *Polar Vortex Review* (Sep. 2014), https://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf (reviewing generator outages during the January 2014 polar vortex weather event).

24 *See* FERC and NERC Staff, *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 [hereinafter January 2018 Event Report].

25 The first version of this Reliability Guideline was developed in 2012. The current version of the Reliability Guideline – Generating Unit Winter Weather Readiness – Current Industry Practices (v.3, 2020) is available on NERC's website at: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_Generating_Unit_Winter_Weather_Readiness_v3_Final.pdf.

A. The Cold Weather Reliability Standards: EOP-011-2, IRO-010-4, and TOP-003-5 Marked an Important First Step in Advancing System Reliability During Cold Weather Conditions.

NERC developed Reliability Standards EOP-011-2, IRO-010-4, and TOP-003-5, approved by the Commission in August 2021,[26] to address the recommendations of the January 2018 Event Report. In that report, FERC and NERC staff concluded that the primary cause of the January 2018 event was a failure to properly prepare or winterize generation facilities for cold temperatures, with natural gas supply issues a major contributing factor.[27] FERC and NERC staff recommended a three-pronged approach, including new or revised Reliability Standards, enhanced outreach to Generator Owners and Generator Operators, and market rules where appropriate, to address reliability needs in cold weather conditions. Specifically, the report recommended addressing the following:

- The need for Generator Owners/Generator Operators to perform winterization activities on generating units to prepare for adverse cold weather, in order to maximize generator output and availability for BES reliability during these conditions. These preparations for cold weather should include Generator Owners/Generator Operators:
    - Implementing freeze protection measures and technologies (e.g., installing adequate wind breaks on generating units where necessary).
    - Performing periodic adequate maintenance and inspection of freeze protection elements (e.g., generating units' heat tracing equipment and thermal insulation).
    - If gas-fueled generating units, clearly informing their Reliability Coordinators and Balancing Authorities whether they have firm transportation capacity for natural gas supply
    - Conducting winter-specific and plant-specific operator awareness training.

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26 *N. Am. Elec. Reliability Corporation*, 176 FERC ¶ 61,119 (2021).

27 January 2018 Event Report at 80, 84.

- The need for Generator Owners/Operators to ensure accuracy of their generating units' ambient temperature design specifications. The accurate ambient temperature design specifications and expected generating unit performance, including for peak winter conditions, should be incorporated into the plans, procedures and training for operating generating units, and shared with Reliability Coordinators and Balancing Authorities.

- The need for Balancing Authorities and Reliability Coordinators to be aware of specific generating units' limitations, such as ambient temperatures beyond which they cannot be expected to perform or lack of firm gas transportation, and take such limitations into account in their operating processes to determine contingency reserves, and in performing operational planning analyses, respectively.[28]

To address these recommendations, Reliability Standard EOP-011-2 contains two new requirements related to generator cold weather preparedness, including a requirement for Generator Owners to implement and maintain cold weather preparedness plans addressing freeze protection measures, annual inspection and maintenance for such measures, and identification of cold weather operating parameters, including fuel considerations and operating temperatures (Requirement R7), and a second requirement to provide training on such plans to generator personnel (Requirement R8). Reliability Standard EOP-011-2 also contains revised requirements to address reliability impacts of cold weather conditions specifically in Transmission Operator and Balancing Authority emergency Operating Plans (Requirements R1 Part 1.2.6 and R2 Part 2.2.9, respectively). Reliability Standards IRO-010-4 and TOP-003-5 add requirements for the inclusion of generator cold weather data and information in Reliability Coordinator, Transmission Operator, and Balancing Authority data specifications, including data and information regarding generator operating limitations in cold weather and the expected operating temperature of the generator.

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[28] January 2018 Event Report at 86-87.

These Reliability Standards mark an important first step in assuring the reliability of the grid in future winter seasons. Reliability Standards EOP-011-2, IRO-010-4, and TOP-003-5 will become mandatory and enforceable on registered entities on April 1, 2023. In the interim, NERC and the Regional Entities have continued to support cold weather preparedness through training and outreach. NERC also issued two Level 2 alerts, the first in August 2021 and the second in September 2022, regarding cold weather preparations for extreme weather events.[29]

B. The February 2021 Event Underscored the Need for Additional Reliability Standards Enhancements to Address Cold Weather Preparedness and Operations.

During the development of the Cold Weather Reliability Standards EOP-011-2, IRO-010-4, and TOP-003-5, another cold weather event struck Texas and the south central United States, threatening BPS reliability and resulting in significant human and economic costs. This event, which took place from February 8-20, 2021, affected three Reliability Coordinator footprints, ERCOT, Midcontinent Independent System Operator ("MISO"), and Southwest Power Pool ("SPP"), with ERCOT being affected most severely. The conditions experienced during the February 2021 Event resulted in emergencies in the ERCOT, MISO, and SPP areas and necessitated the use of firm load shed to maintain system reliability. In ERCOT, the system came dangerously close to a complete blackout, and operators in those three Reliability Coordinator footprints ordered what was ultimately the largest controlled firm load shed event in United States

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29 *See* NERC Alert R-2021-08-18-01 Recommendation to Industry: Cold Weather Preparations for Extreme Weather Events (Aug. 18, 2021) (Level 2 Alert) *and* NERC Alert 2022-09-12-01 Recommendation to Industry: Cold Weather Preparations for Extreme Weather Events – II (Sep. 12, 2022) (Level 2 Alert), available at https://www.nerc.com/pa/rrm/bpsa/Pages/Alerts.aspx.

NERC issues alerts under Section 810 of the NERC Rules of Procedure, Information Exchange and Issuance of NERC Advisories, Recommendations, and Essential Actions. Level 2 alerts convey specific actions that NERC is recommending be considered on a particular topic by certain segments of owners, operators, and users of the Bulk Power system according to each entity's fact and circumstances. Those entities are to evaluate and take appropriate action and report back to NERC by the established deadline.

history to maintain the stability of the system. In Texas, more than 4.5 million people lost power. At least 210 people lost their lives during the event. The economic damages from the February 2021 Event were estimated at over $100 billion.[30]

This tragic and devastating event, the fourth cold weather reliability event in a decade, underscored the need for mandatory cold weather preparedness and operations Reliability Standards, and it prompted the NERC Board of Trustees to take the then-unprecedented step of establishing a deadline for the prompt completion of Reliability Standards EOP-011-2, IRO-010-4, and TOP-003-5. This earlier standards development effort, however, did not have the benefit of a complete analysis and set of recommendations addressing the causes of the February 2021 Event. As such, the standard drafting team had to base its work on addressing the findings and recommendations of the January 2018 Event Report. Later, the Joint Inquiry Report would provide insight into additional Reliability Standards enhancements that could help protect the grid during future extreme cold weather situations. These insights prompted the development of the proposed Reliability Standards discussed in this petition.

1. Overview of the February 2021 Event

As summarized by the Joint Inquiry Report,[31] an arctic cold front descended on large parts of Texas and the south central United States beginning on February 8, bringing with it freezing temperatures. There was a sharp decline of natural gas supply caused by unplanned outages of natural gas wellheads due to freeze-related issues, loss of power, and facility shut-ins to prevent imminent freezing issues.[32] Supply issues contributed to outages and derates of many gas-powered generating units. The area also experienced periods of freezing participation and snow, which

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30 Joint Inquiry Report at 9-10.

31 For a complete summary of the February 2021 Event, *see* Joint Inquiry Report at Section I.A, Synopsis of Event at 10-15.

32 *Id.* at 13.

caused additional outages from wind turbine blade icing. As the cold conditions continued, ERCOT and SPP experienced rising load. Although ERCOT and SPP issued several alerts, no emergency actions were taken in the early days of the February 2021 Event because enough generation was online to meet load.[33]

On February 14, 2021, ERCOT set an all-time winter peak record for system load of 69,871 MW.[34] As increasingly colder temperatures set in, unplanned outages and derates sharply increased. In the early morning hours of February 15, ERCOT issued an Energy Emergency Alert 1 and deployed demand response resources to maintain reliability. Subsequently, the ERCOT Interconnection frequency began to fall below normal levels, and ERCOT began ordering load shed. At one point, ERCOT operators only had nine minutes to prevent approximately 17,000 MW of generating units from tripping due to underfrequency relays, which could have caused a complete blackout of the Interconnection. System frequency remained below the trip level for over four minutes. Over the next several days, ERCOT averaged 34,000 MW of generation outages (based on expected capacity), including generators already on planned or unplanned outages when the Event began. To balance ERCOT's load against these losses, ERCOT continued to order firm load shed for nearly three consecutive days, peaking at 20,000 MW on February 15.[35]

SPP and MISO also experienced generating outages and rising load and experienced energy and transmission emergencies. SPP averaged 20,000 MW of generation unavailable from February 15 to 19, and MISO South averaged 14,500 MW of generation unavailable from February 16 to 18.[36] SPP and MISO were able to make up many of their shortfalls by importing power from

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33 *Id.*

34 *Id.*

35 *Id.* at 14.

36 *Id.*

other Balancing Authorities to the east that were not experiencing the same cold conditions. However, the transfers, combined with widespread generation outages, created local and system wide transmission emergencies on February 15 and 16 which required MISO operators to order a combined 2,000 MW of firm load shed. SPP also experienced system-wide transmission emergencies, but they did not result in firm load shed. SPP ordered firm load shed to address energy emergencies on February 15 and 16 for a total of four hours across two days. At the worst point, following MISO's curtailment of SPP's imports due to MISO's transmission emergency, SPP ordered 2,718 MW of firm load shed. On February 16, MISO ordered firm load shed that lasted for over two hours to address an energy emergency, reaching 700 MW at its worst point.[37]

2. Key Findings and Recommendations

In the summary of the key findings and causes of the February 2021 Event, the Joint Inquiry Report team identified that two causes, both triggered by cold weather, lead to the Event, and that these two causes form a recurring pattern in cold weather events over the previous ten years. The first cause was that generating units unprepared for cold weather failed in large numbers. The second cause was related to supply issues caused by the decline in natural gas production, exacerbated by the increasing reliance on natural gas fired generation.[38]

During the February 2021 Event, 1,045 individual generating units, consisting of multiple generation types,[39] experienced a total of 4,124 outages, derates, or failures to start. Freezing issues (44.2 percent) and fuel issues (31.4 percent) caused the bulk of these outages, derates, and start-

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37 *Id.* at 14-15.

38 *Id.* at 11-12.

39 *Id.* at 16. Of the 1,045 individual generating units experiencing outages, derates, or start-up failures, 604 (58%) were gas generators, 285 (27%) were wind generators, 58 (6%) were coal generators, 22 (2%) were solar generators, 4 (.38%) were nuclear generators, and 72 (7%) were other fuel types.

up failures, with natural gas fuel supply issues causing the majority (87%) of the fuel issues.[40] Of the remaining outages, derates, and start-up failures, 21% were caused by mechanical/electrical issues (with the timing of these issues indicating a relationship with the cold temperatures), 2% were caused by transmission system issues, and 2% were due to other causes.[41]

The Joint Inquiry team identified that, despite prior recommendations that entities take steps to prepare for winter, a significant number of generating units failed to have any winterization plans.[42] The Joint Inquiry team further determined that 81% of the freeze-related generating unit outages occurred at temperatures above the unit's stated ambient design temperature.[43]

In response to these findings, the Joint Inquiry Report contains a number of recommendations for further action in the areas of cold weather preparedness and operations. Recommendation 1, consisting of ten sub-recommendations for Reliability Standards enhancements, invoke NERC's electric reliability authority under Section 215 of the Federal Power Act; other recommendations address matters to be addressed by industry or other regulatory authorities.

Related to generator cold weather preparedness and generator availability, the Joint Inquiry Report contains seven sub-recommendations for Reliability Standards enhancements in Key Recommendation 1, along with recommended timelines by which the standards should be completed and submitted for regulatory approval:

- **Key Recommendation 1a**: To require Generator Owners to identify cold-weather-critical components and systems for each generating unit. Cold-weather-critical components and

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40 *Id.* at 15-16.

41 *Id.* at 15-16.

42 *Id.* at 17.

43 *Id.*

systems are those which are susceptible to freezing or otherwise failing due to cold weather, and which could cause the unit to trip, derate, or fail to start. (Winter 2023-2024);[44]

- **Key Recommendation 1b**: To require Generator Owners to identify and implement freeze protection measures for the cold-weather-critical components and systems (see Key Recommendation 1f., below, for guidance on ambient temperature and weather conditions to be considered). The Generator Owner should consider previous freeze-related issues experienced by the generating unit, and any corrective or mitigation actions taken in response. At an interval of time to be determined by the Balancing Authority, the Generator Owner should analyze whether the list of identified cold-weather-critical components and systems remains accurate, and whether any additional freeze protection measures are necessary. (Winter 2023-2024);[45]

- **Key Recommendation 1c**: To revise EOP-011-2, R7.3.2 to require Generator Owners to account for the effects of precipitation and the accelerated cooling effect of wind when providing temperature data. (Winter 2023-2024);[46]

- **Key Recommendation 1d**: To require Generator Owners that experience outages, failures to start, or derates due to freezing to review the generating unit's outage, failure to start, or derate and develop and implement a corrective action plan (CAP) for the identified equipment, and evaluate whether the CAP applies to similar equipment for its other generating units. Based on the evaluation, the Generator Owner will either revise its cold weather preparedness plan to apply the CAP to the similar equipment, or explain in a declaration (a) why no revisions to the cold weather preparedness plan are appropriate, and (b) that no further corrective actions will be taken. The Standards Drafting Team should specify the specific timing for the CAP to be developed and implemented after the outage, derate or failure to start, but the CAP should be developed as quickly as possible, and be completed by no later than the beginning of the next winter season. (Winter 2022-2023);[47]

- **Key Recommendation 1e**: To revise EOP-011-2, R8, to require Generator Owners and Generator Operators to conduct annual unit-specific cold weather preparedness plan training. (Winter 2022-2023);[48]

- **Key Recommendation 1f**: To require Generator Owners to retrofit existing generating units, and when building new generating units, to design them, to operate to a specified ambient temperature and weather conditions (e.g., wind, freezing precipitation). The specified ambient temperature and weather conditions should be based on available extreme temperature and weather data for the generating unit's location. (Winter 2022-2023);[49] and

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44 *Id.* at 184 (internal citation omitted).

45 *Id.* at 184.

46 *Id.* at 186 (internal citation omitted).

47 *Id.* at 187.

48 *Id.* at 188.

49 *Id.* at 188-189 (internal citation omitted).

- **Key Recommendation 1g**: To provide greater specificity about the relative roles of the Generator Owner, Generator Operator, and Balancing Authority in determining the generating unit capacity that can be relied upon during "local forecasted cold weather" in TOP-003-5:

    - Based on its understanding of the "full reliability risks related to the contracts and other arrangements [Generator Owners/Generator Operators] have made to obtain natural gas commodity and transportation for generating units," each Generator Owner/Generator Operator should be required to provide the Balancing Authority with data on the total percentage of the generating unit's capacity that the Generator Owner/Generator Operator reasonably believes the Balancing Authority can rely upon during the "local forecasted cold weather."
    - Each Balancing Authority should be required to use the data provided by the Generator Owner/Generator Operator, combined with its evaluation, based on experience, to calculate the percentage of total generating capacity that it can rely upon during the "local forecasted cold weather," and share its evaluation with the [Reliability Coordinator].
    - Each Balancing Authority should be required to use its calculation of the percentage of total generating capacity that it can rely upon to "prepare its analysis functions and Real-time monitoring," and to "manag[e] generating resources in its Balancing Authority Area to address . . . fuel supply and inventory concerns" as part of its Capacity and Energy Emergency Operating Plans. (Winter 2023-2024).[50]

Additionally, the Joint Inquiry team identified cold weather operations issues that could have or did contribute to natural gas supply unavailability during the February 2021 Event, including the participation in demand response programs of natural gas infrastructure loads supplying gas for generation[51] and the inclusion of natural gas production and processing facilities in manual load shedding programs.[52] Related to these findings, the Joint Inquiry Report contains two sub-recommendations for Reliability Standards enhancements in Key Recommendation 1, along with recommended timelines as follows:

- **Key Recommendation 1h**: To require Balancing Authorities' operating plans (for contingency reserves and to mitigate capacity and energy emergencies) to prohibit use for demand response of critical natural gas infrastructure loads. (Winter 2023-2024);[53] and

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50 *Id.* at 189-190 (internal citations omitted).

51 *Id.* at 208.

52 *Id.* at 209.

53 *Id.* at 208 (internal citation omitted).

- **Key Recommendation 1i**: To protect critical natural gas infrastructure loads from manual and automatic load shedding (to avoid adversely affecting Bulk Electric System reliability):
    - To require Balancing Authorities' and Transmission Operators' provisions for operator-controlled manual load shedding to include processes for identifying and protecting critical natural gas infrastructure loads in their respective areas;
    - To require Balancing Authorities', Transmission Operators', Planning Coordinators', and Transmission Planners' respective provisions and programs for manual and automatic (e.g., underfrequency load shedding, undervoltage load shedding) load shedding to protect identified critical natural gas infrastructure loads from manual and automatic load shedding by manual and automatic load shed entities within their footprints;
    - To require manual and automatic load shed entities to distribute criteria to natural gas infrastructure entities that they serve and request the natural gas infrastructure entities to identify their critical natural gas infrastructure loads; and
    - To require manual and automatic load shed entities to incorporate the identified critical natural gas infrastructure loads into their plans and procedures for protection against manual and automatic load shedding. (Winter 2023-2024).[54]

Lastly, the Joint Inquiry team observed that changes in how entities implement manual load shed in emergency conditions could help maintain system frequency when operators have the best chance of doing so.[55] Related to this observation, the Joint Inquiry Report contains one sub-recommendation for Reliability Standards enhancements, along with the recommended timeline as follows:

- **Key Recommendation 1j**: In minimizing the overlap of manual and automatic load shed, the load shed procedures of Transmission Operators, Transmission Owners and Distribution Providers should separate circuits that will be used for manual load shed from circuits used for underfrequency load shedding/undervoltage load shedding or serving critical load. Underfrequency load shedding/undervoltage load shedding circuits should only be used for manual load shed as a last resort and should start with the final stage (lowest frequency). (Winter 2022-2023)[56]

As discussed more fully below, proposed Reliability Standards EOP-012-1 and EOP-011-3 represent the conclusion of the first phase of work to address Key Recommendations 1d, 1e, 1f,

54 *Id.* at 208-209.

55 *Id.* at 209.

56 *Id.* at 209.

and 1j, each with a target Winter 2022-2023 completion date, as well as Key Recommendation 1a, with a target Winter 2023-2024 completion date. Work is currently underway to develop Reliability Standards to address the remaining Key Recommendations 1b, 1c, 1g, 1h, and 1i.

V. SUMMARY OF DEVELOPMENT, PROJECT 2021-07 EXTREME COLD WEATHER GRID OPERATIONS, PREPAREDNESS, AND COORDINATION

Recognizing the importance of addressing the recommendations of the FERC/ERO Enterprise Staff Report in a timely manner, the NERC Board of Trustees took action at its November 2021 meeting to direct the development of Reliability Standards be completed within the timelines recommended by the joint inquiry team, as follows:

- New and revised Reliability Standards to be submitted for regulatory approval before Winter 2022/2023: development completed by September 30, 2022, for the Board's consideration in October 2022;
- New and revised Reliability Standards to be submitted for regulatory approval before Winter 2023/2024: development completed by September 30, 2023, for the Board's consideration in October 2023.[57]

NERC initiated Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination to consider Reliability Standards modifications in two phases to address Key Recommendation 1 from the report, consistent with the timelines directed by the NERC Board of Trustees. The Project 2021-07 standard drafting team developed new Reliability Standard EOP-012-1 and developed revisions to the approved, but not yet effective Reliability Standard EOP-011-2.

On May 18, 2022, the Standards Committee approved a waiver under Section 16.0 of the *Standard Processes Manual* to allow shorter than usual periods for comment and ballot for this project. Specifically, the Standards Committee approved shortening the initial formal comment

[57] NERC Board of Trustees November 4, 2021 Meeting Minutes at 9-10, https://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/BOT%20Open%20Meeting%20Minutes%20-%20November%204,%202021.pdf.

and ballot period from 45 days to as little as 30 days, with ballot pools formed in the first 15 days and ballots conducted in the last 10 days, shortening the additional formal comment and ballot period(s) from 45 days to as little as 25 days, with ballot conducted during the last 10 days; and shortening the final ballot from 10 days to as little as 5 days.[58] The proposed Reliability Standards were then posted for two abbreviated formal comment and ballot periods. The first formal comment period and ballot ran from May 19, 2022 through June 21, 2022. The proposed Reliability Standards were posted for a second formal comment period and ballot from August 3, 2022 through September 1, 2022. The proposed Reliability Standards were posted for final ballot from September 23, 2022 through September 30, 2022 and achieved the following approval percentages:

- Proposed Reliability Standard EOP-011-3: 83.64% approval / 95.86% quorum;
- Proposed Reliability Standard EOP-012-1: 79.04% approval / 95.54% quorum; and
- Implementation Plan: 87.89% approval / 95.19% quorum.

The NERC Board of Trustees adopted the proposed Reliability Standards on October 26, 2022. A summary of the development history and the complete record of development is attached to this petition as **Exhibit F**.

VI. JUSTIFICATION FOR APPROVAL

In this petition, NERC submits for Commission approval proposed Reliability Standard EOP-012-1 – Extreme Cold Weather Preparedness and Operations, proposed Reliability Standard EOP-011-3 - Emergency Operations, and three new defined terms for inclusion in the NERC

[58] *See* NERC Standards Committee May 18, 2022 Meeting Minutes at 1-2, https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/SC%20May%20Meeting%20Minutes%20-%20Approved%20June%2015,%202022.pdf.

Glossary. The proposed Reliability Standards build upon NERC's prior work with the cold weather Reliability Standards EOP-011-2, IRO-010-4, and TOP-003-5 and would further advance reliability through improved operations and generator cold weather preparedness requirements. Proposed Reliability Standard EOP-012-1 would establish a continent-wide framework for cold weather preparedness while recognizing differences in climate and conditions across North America. Consistent with Key Recommendations 1a, 1d, 1e, and 1f of the Joint Inquiry Report, proposed Reliability Standard EOP-012-1 contains new and revised requirements that build on the cold weather preparedness plan and training requirements currently found in Reliability Standard EOP-011-2 and advance the reliability of the BPS through improved generator cold weather preparedness. The proposed Reliability Standard includes requirements for freeze protection measures for both new and existing generation, the development of enhanced cold weather preparedness plans and annual training on those plans, and the development and implementation of Corrective Action Plans to address freezing issues. Consistent with Key Recommendation 1j of the Joint Inquiry Report, proposed Reliability Standard EOP-011-3 builds upon the cold weather operations planning improvements reflected in Reliability Standard EOP-011-2 to improve how Transmission Operators account for the overlap of manual load shed and automatic load shed in their emergency Operating Plans. The new and revised requirements in the proposed Reliability Standards are discussed in detail below.

As discussed in **Exhibit D**, the proposed Reliability Standards meet the Commission's criteria for approval in Order No. 672 and are just, reasonable, not unduly discriminatory, and in the public interest. NERC respectfully requests that the Commission approve the proposed Reliability Standards and defined terms, to become effective in accordance with the proposed implementation plan discussed in Section VII.

A. New Defined Terms Proposed for Inclusion in the NERC *Glossary*

NERC proposes three new defined terms used in proposed Reliability Standard EOP-012-1 for inclusion in the NERC *Glossary*. These terms are Extreme Cold Weather Temperature, Generator Cold Weather Critical Component, and Generator Cold Weather Reliability Event. The proposed definitions are discussed below.

1. Extreme Cold Weather Temperature

Under proposed Reliability Standard EOP-012-1, each Generator Owner would be required to determine the "Extreme Cold Weather Temperature" for its applicable generating unit(s) (Requirement R3 Part 3.1), and to review and update that calculation every five years (Requirement R4 Part 4.1). The term "Extreme Cold Weather Temperature" refers to "the temperature equal to the lowest .2 percentile of the hourly temperatures measured in December, January, and February from 1/1/2000 through the date the temperature is calculated." This temperature is specific to the location of the generating unit, and it provides clarity to the Generator Owner in understanding their obligations under the standard, including identifying and implementing the freeze protection measures that would be required to provide operations capability at that temperature (Requirements R1 and R2) and understanding which generator freezing events would require Corrective Action Plans to address identified issues (Requirement R6).

In developing this definition, the standard drafting team considered various methods, and it determined to use a statistical approach to determine the design temperature when implementing generation facility freeze protection measures, consistent with typical engineering practice. The standard drafting team determined to use only winter temperature values in the historical analysis, and to define winter as the months December, January, and February as that is consistent with the United States National Ocean and Atmospheric Administration definition of meteorological winter.[59] The standard drafting team selected January 1, 2000 as the start date for the historical analysis because the U.S. National Weather Service project known as the Modernization and Associated Restructuring completed in 2000, providing expanded data availability.[60]

Based on analysis of multiple sites, the standard drafting team determined that, by using the lowest 0.2 percentile, there would be sufficient data points to ensure that a single hour at a temperature that may not be accurate or may be a statistical anomaly would not result in an overly conservative design. The standard drafting team reviewed actual temperature data from multiple sites and reviewed various potential percentiles for consideration prior to the selection of the 0.2 percentile. The standard drafting team selected the 0.2 percentile of winter month temperatures since January 1, 2000 to identify a temperature which has been rarely surpassed, but which would allow some margin for a Generator Owner to have previously demonstrated successful operation. The proposed definition of Extreme Cold Weather Temperature thus represents a high, but reasonable, benchmark for the first set of mandatory Reliability Standard requirements to address generator freeze protection measures.

In developing this definition and the related requirements for freeze protection measures, the standard drafting team considered certain findings from the Joint Inquiry Report, including that

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59 U.S. National Oceanic and Atmospheric Administration, *Meteorological versus Astronomical Seasons*, https://www.ncei.noaa.gov/news/meteorological-versus-astronomical-seasons (last visited Oct. 4, 2022).

60 For more information on the benefits provided by this initiative, *see* National Academy of Sciences, National Research Council, *The National Weather Service Modernization and Associated Restructuring: a Retrospective Assessment* (2011), https://nap.nationalacademies.org/resource/13216/NWS-Modernization-Report-Brief-Final.pdf.

This report stated:

> Overall, Modernization and Associated Restructuring successfully improved the weather enterprise, leading to a greater integration of science into weather service activities, and improved outreach and coordination with state and local government, emergency management, and communities. By the 1980s the National Weather Service was nearly obsolete, and, therefore, the $4.5 billion investment on modernization was both needed and generally well-spent.

a significant number of the generating units that went offline during the February 2021 Event did so soon after the temperatures dropped on February 14-15, and that most (81%) of generating units experiencing freezing outages during the Event were within their intended ambient operating temperatures when they went offline.[61] The standard drafting team also considered the broad effective range of most freeze protection measures.

The standard drafting team initially considered using the lowest recorded hourly ambient temperature for the location in the last 50 years (i.e. 1970s) as the benchmark for required performance;[62] however, after further analysis, the standard drafting team determined that the statistical approach to setting the Extreme Cold Weather Temperature for a site was more reasonable. During the standard development process, multiple commenters suggested that using a 50-year historical low temperature for the standard would be arbitrary, overly conservative, and not provide reliability benefits commensurate with the cost or burden of implementation.[63] Commenters further indicated that obtaining hourly weather data for the earlier time ranges would be challenging.[64] Based on these comments, the standard drafting team identified a further issue with its initial approach: the difficulty of demonstrating the ability to operate a unit at a 50-year historical low temperature without undertaking a full engineering analysis. Under Reliability Standard EOP-011-2 Requirement R7 (moved to proposed Reliability Standard EOP-012-1 Requirement R3), the Generator Owner must identify a generating unit minimum temperature in its cold weather preparedness plan. This temperature could be developed from design temperature data, historical operating temperature, or an engineering analysis. Generator Owners may not have

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61 Joint Inquiry Report at 17, 126.

62 See Draft 1 of proposed EOP-012-1 (Exhibit F Record of Development item 12).

63 *See, e.g.*, Comments on Draft 1 Postings (Exhibit F Record of Development item 27) (comments of Minnesota Power, Ogelthorpe Power Corporation, Vistra Energy, NEI, FMPA, among others).

64 *See, e.g.*, Comments on Draft 1 Postings (Exhibit F Record of Development item 27) (comments of CMS Energy).

design data or historical operating data available to support the ability to operate at the 50-year low temperature, thus requiring them to perform an engineering analysis on each of their existing sites. The standard drafting team considered that many of the generating units that would be subject to such a requirement have in fact demonstrated reliable performance during recent extreme cold weather events.

The standard drafting team considered these comments and reviewed other approaches for standards development.[65] It determined that a statistical approach using modern weather data would advance reliability while avoiding being overly burdensome for those responsible for compliance. This approach is reflected in the proposed definition of Extreme Cold Weather Temperature. The standard drafting team provided additional considerations for calculating the Extreme Cold Weather Temperature from available data in the supporting Technical Reference Document, included in Exhibit F (Record of Development at item 62) to this petition.

2. Generator Cold Weather Critical Component

Under proposed Reliability Standard EOP-012-1, each Generator Owner would be required to document its Generator Cold Weather Critical Components in its cold weather preparedness plans and, for new units, implement freeze protection measures that assume a concurrent 20 mph wind speed on those components to assure reliability of the generating unit in expected cold weather conditions. Generator Cold Weather Critical Components are defined as follows:

> **Generator Cold Weather Critical Component** - Any generating unit component or associated fixed fuel supply component, that is under the Generator Owner's control, and is susceptible to freezing issues, the occurrence of which would likely lead to a Generator Cold Weather Reliability Event.

[65] For example, the standard drafting team considered information presented at the Commission's April 2022 Technical Conference regarding Improving Winter Readiness of Generating Units (*see* Speaker Materials of Mark Dittus, Black & Veatch (describing an approach based on average temperatures)), as well as the approaches used in other standards relying on weather data, such as the ASHRAE standards for building systems.

The standard drafting team determined that best method to address where freeze protection measures should be implemented (*see* Key Recommendation 1b) was a defined term to specify a subset of components that may be susceptible to freezing and which are critical to the operation of the generating unit, and for which the Generator Owner would be able to take protective measures. The phrase "fixed fuel supply component" refers to non-mobile equipment that supports the reliable delivery of fuel to the generating unit that is controlled by the Generator Owner. It would include gaseous, liquid, or solid fuel handling components that are installed as fixed parts of the fuel delivery system that are under the Generator Owner's control. It would not include mobile equipment such as trains, bulldozers, or other equipment that are not fixed in one location, nor would it include components that are not "under the Generator's Owner's control."[66]

This term is consistent with the Joint Inquiry Report Key Recommendation 1a, which defines "cold-weather critical components and systems" as "those which are susceptible to freezing or otherwise failing due to cold weather, and which could cause the unit to trip, derate, or fail to start." Trips, derates, and failures to start are addressed in the definition of Generator Cold Weather Reliability Event discussed below.

3. Generator Cold Weather Reliability Event

Under proposed Reliability Standard EOP-012-1, a Generator Owner that experiences a Generator Cold Weather Reliability Event would be required to develop a Corrective Action Plan to address the identified issues that lead to the event. The term Generator Cold Weather Reliability Event is defined as follows:

> **Generator Cold Weather Reliability Event** - One of the following events for which the apparent cause(s) is due to freezing of equipment within the Generator Owner's control and the dry bulb temperature at the time of the event was at or above the Extreme Cold Weather Temperature:

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66 *See* Exhibit C-2, Technical Rationale for EOP-012-1, at 3.

(1) a forced derate of more than 10% of the total capacity of the unit and exceeding 20 MWs for longer than four hours in duration;

(2) a start-up failure where the unit fails to synchronize within a specified start-up time; or

(3) a Forced Outage.

This definition is discussed in detail the context of Requirement R6 in Section VI.B.6, below.

B. Proposed Reliability Standard EOP-012-1 – Extreme Cold Weather Preparedness and Operations

The purpose of proposed Reliability Standard EOP-012-1 is "to address the effects of operating in extreme cold weather by ensuring each Generator Owner has developed and implemented plan(s) to mitigate the reliability impacts of extreme cold weather on its generating units." The proposed Reliability Standard is applicable to Generator Owners that own Facilities that are expected to operate during freezing conditions, defined as conditions at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius), as well as Generator Operators providing the cold weather preparedness plan training required under the standard.

The proposed Reliability Standard has seven requirements, five of which are new and two of which have been moved from Reliability Standard EOP-011-2 and revised. Three new proposed *Glossary* terms are used in the Reliability Standard. With requirements addressing freeze protection measures, the development and periodic review of cold weather preparedness plans and annual training, and the implementation of Corrective Action Plans developed to address identified issues in cold weather preparedness, proposed Reliability Standard EOP-012-1 would advance the reliability of the BPS by helping improve generator reliability in cold weather. The applicability and individual requirements are discussed more fully below.

1. Applicability

Proposed Reliability Standard EOP-012-1 would be applicable to the Generator Owner and Generator Operator functional entities owning or operating the Facilities described in the standard. The Facilities section contains inclusions and exemptions, carefully tailored to place the responsibility for cold weather preparedness on those generating units that are being depended on to operate in cold weather and on which the reliability of the system depends, while avoiding undue burden on those generating units that are not expected to operate in cold weather, as shown below:

4.2. Facilities:

4.2.1 For purposes of this standard, the term "generating unit" subject to these requirements refers to the following Bulk Electric System (BES) resources:

4.2.1.1 A Bulk Electric System generating unit that commits or is obligated to serve a Balancing Authority load pursuant to a tariff obligation, state requirement as defined by the relevant electric regulatory authority, or other contractual arrangement, rule, or regulation, for a continuous run of four hours or more at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius); or

4.2.1.2 A Blackstart Resource

4.2.2 Exemptions:

4.2.2.1 Any Bulk Electric System generating unit included under Section 4.2.1 above that has a calculated Extreme Cold Weather Temperature exceeding 32 degrees Fahrenheit (zero degrees Celsius) under Requirement R3 Part 3.1 and as part of the required five year review in Requirement R4 Part 4.1 is exempt from further requirements in this standard.

4.2.2.2 A Bulk Electric System generating unit that is not committed or obligated to operate at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius) for any continuous run of more than four hours, but is called upon to operate for more than four hours in order to assist in the mitigation of BES Emergencies, Capacity Emergencies, or Energy Emergencies during periods at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius).

The Facilities section first defines "generating unit" as a Bulk Electric System (BES) resource. The Applicability section further defines which BES resources are intended to be subject to the requirements of the standard, and which BES resources are exempt from all or most requirements. These exemptions are narrowly tailored and consistent with the Joint Inquiry Report Key Recommendation 1f, which recognized that an exemption from requirements for winterizing new and existing generating units would be appropriate for those units that commit solely for summer peaking purposes.[67] Such units may not be able to secure fuel in the winter and therefore commit to serve only during non-winter months.

Under proposed Reliability Standard EOP-012-1, owners and operators of BES resources that commit or are obligated to serve Balancing Authority load for a continuous run of four hours or more at or below freezing temperatures would be required to comply with the standard. The standard drafting team recognized that this commitment or obligation may look different depending on the market or area in which the generating unit is located. BES resources may be committed or obligated to run in freezing conditions under tariff obligations, state requirements defined by regulatory authorities, or other contractual arrangements, rules, or regulations applicable to their area. The standard drafting team determined that a four-hour operations timeframe was appropriate in consideration of those generating units that typically do not commit to run during freezing conditions, but are nevertheless running when conditions drop below freezing for a short period of time.

Proposed Reliability Standard EOP-012-1 would also apply to owners and operators of Blackstart Resources, which play an important role in system reliability and restoration. Blackstart Resources are defined in the *Glossary* as:

> A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the

[67] Joint Inquiry Report, supra note 6, at 189.

> Transmission Operator's restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan.

As noted above, the Facilities section exempts certain BES resources from all or most of the requirements of proposed Reliability Standard EOP-012-1. These exemptions are narrow and intended to avoid undue burden on those entities that do not experience freezing conditions at their locations as well as those entities that generally do not run their generating units during freezing conditions, but may be called upon to do so to mitigate an Emergency.

Under the first exemption, Applicability Section 4.2.2.1, if a Generator Owner determines that its otherwise applicable generating unit does not experience freezing temperatures at its location, through calculating the Extreme Cold Weather Temperature under Requirement R3 Part 3.1 and as part of the required five year review under Requirement R4 Part 4.1, the generating unit would be exempt from further requirements under the standard. The definition of Extreme Cold Weather Temperature, discussed previously in this petition, is intended to set a high bar for this determination: "the temperature equal to the lowest 0.2 percentile of the hourly temperatures measured in December, January, and February from 1/1/2000 through the date the temperature is calculated." This exemption reflects the standard drafting team's determination that requiring owners of generating units to implement freeze protection measures at locations that do not experience freezing conditions would not likely provide a reliability benefit commensurate with the burden of compliance. To be clear, this partial exemption would only apply when the initial calculation shows an Extreme Cold Weather Temperature for the location that is above freezing, and this continues to be true upon each five-year review. If a subsequent review determines that the Extreme Cold Weather Temperature for the location has dropped below freezing, the Generator Owner (and the Generator Operator, if providing cold weather preparedness plan training) must then comply with the other requirements of the standard for which their generating unit was previously exempt. However, this partial exemption would not apply when a Generator Owner has initially determined that the Extreme Cold Weather Temperature for its applicable generating unit is below freezing, but later determines through the required five-year review that the new Extreme Cold Weather Temperature is above freezing.

Under the second exemption, Applicability Section 4.2.2.2, the standard clarifies that BES resources that do not commit or are obligated to serve Balancing Authority Load in freezing temperatures for any continuous run exceeding four hours, but are called upon to run during extreme cold weather emergency contingencies, would be exempt under the standard. The standard drafting team determined that, in the interest of avoiding unintended consequences which could have detrimental impacts on reliability, these resources should be able to respond to the Balancing Authority's commitment requests to help mitigate Emergency conditions without triggering the requirements of the standard.

2. Requirements R1 and R2

Proposed Reliability Standard EOP-012-1 Requirements R1 and R2 are new requirements that address the Generator Owner's obligation to implement freeze protection measures on each of its applicable units to provide capability to operate at the Extreme Cold Weather Temperature for the unit's location. These requirements were developed to respond to Joint Inquiry Report Key Recommendation 1f regarding the design and modification of freeze protection measures that would allow the generating unit to operate in the cold weather conditions it can reasonably be expected to experience in its area.

Requirement R1 would apply to new generation units, or those that enter commercial operation after the effective date of the requirement under an approved implementation plan.[68] Requirement R1 states as follows:

> **R1.** For each generating unit(s) with a commercial operation date subsequent to [Effective Date of this requirement], the Generator Owner shall:
>
> - Implement freeze protection measures that provide capability to operate for a period of not less than twelve (12) continuous hours at the Extreme Cold Weather Temperature for the unit(s), assuming a concurrent twenty (20) mph wind speed on any exposed Generator Cold Weather Critical Components; or
> - Explain in a declaration any technical, commercial, or operational constraints, as defined by the Generator Owner, that preclude the ability to implement appropriate freeze protection measures to provide capability of operating for twelve (12) hours at the documented Extreme Cold Weather Temperature.

In the Joint Inquiry Report, the Joint Inquiry team identified that not only did many generating units fail to perform at the lowest ambient temperature for the nearest city, but many failed to perform at their own ambient design temperatures.[69] The Joint Inquiry team reported that 81 percent of the freeze-related generating unit outages during the February 2021 Event occurred at temperatures above the unit's stated ambient design temperature, representing about 63,000 MW of nameplate capacity.[70] Key Recommendation 1f therefore recommended, in part, that Generator Owners be required to design new units to operate to a specified ambient temperature and weather conditions based on available extreme temperature and weather data for the unit's location.[71]

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[68] Upon approval of the proposed Reliability Standard and the associated implementation plan, NERC would replace the bracketed language in Requirements R1 and R2 ([Effective Date of this requirement]) with the actual date. It is the intent of the standard drafting team that this date remain fixed across future versions of the EOP-012 standard, to distinguish between requirements applicable to generation that exists at the time the first version of the standard becomes effective, and requirements applicable to generation that enters commercial operation after the first version of the standard becomes effective, unless a future standard drafting team determines an alternative approach is appropriate.

[69] Joint Inquiry Report at 189.

[70] *Id.* at 17.

[71] *Id.* at 188-89.

Proposed Reliability Standard EOP-012-1 Requirement R1 addresses this part of Key Recommendation 1f by requiring Generator Owners to design their new generating units with freeze protection measures that provide capability to operate for a period of not less than twelve (12) continuous hours at the Extreme Cold Weather Temperature for the unit(s), assuming a concurrent twenty (20) mph wind speed on any exposed Generator Cold Weather Critical Components, or else explain in a declaration the constraints prohibiting the Generator Owner from implementing these measures.

The standard drafting team determined that a design specification of freeze protection measures providing 12 hours of continuous operation at the Extreme Cold Weather Temperature was appropriate, because it is the typical length of the nighttime in winter and the maximum amount of time that generating units would experience the Extreme Cold Weather Temperature. The standard drafting chose to require that Generator Owners assume a concurrent 20 mph speed on their exposed Cold Weather Critical Components after an evaluation of data using the wind chill formula developed by the U.S. National Weather Service.[72]

The standard drafting team recognized that technical, commercial, or operational constraints may exist that prevent a new generating unit from implementing freeze protection measures that provide capability to operate for 12 continuous hours at its calculated Extreme Cold Weather Temperature. In such cases, the Generator Owner would be required to explain in a declaration these constraint(s) and how it precludes the ability to implement freeze protection measures providing the required capability.

Key Recommendation 1f of the Joint Inquiry Report also recommended that Generator Owners be required to "retrofit" existing units. The standard drafting team understood the

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[72] *See* additional discussion in Exhibit C-2, Technical Rationale for EOP-012-1, at 5-6.

recommendation for existing units to call for the implementation of new or modified existing freeze protection measures, and drafted proposed Requirement R2 accordingly. Proposed Requirement R2 would apply to existing generating units, or those in commercial operation prior to the effective date of the requirement under an approved implementation plan, and states as follows:

> **R2**. For each generating unit(s) in commercial operation prior to [Effective Date of this requirement],the Generator Owner shall ensure its generating unit(s) add new or modify existing freeze protection measures as needed to provide the capability to operate for a period of not less than one (1) hour at the unit(s) Extreme Cold Weather Temperature. Generating unit(s)that are not capable of operating for one (1) hour at its Extreme Cold Weather Temperature shall develop a Corrective Action Plan (CAP) for the identified issues, including identification of any needed modifications to the cold weather preparedness plan required under Requirement R3.

Requirement R2 would require each Generator Owner to add new or modify existing freeze protection measures to provide capability to operate for at least one hour at the Extreme Cold Weather Temperature. The standard drafting team determined that a shorter operations capability of one hour was appropriate for existing units in recognition of the difficulty of performing the same level of design analysis on existing generation as on new generation, the high threshold of the Extreme Cold Weather Temperature, and the expected availability of historical data to support sustained operations at that Extreme Cold Weather Temperature. In selecting the duration of one hour, the standard drafting team also considered the peaking units that would only stay online for a short time in extreme cold weather conditions. Where the generating unit is not capable of operating at the Extreme Cold Weather Temperature for at least one hour, the Generator Owner shall develop a Corrective Action Plan for the identified issues. Implementation of Corrective Action Plans is addressed in Requirement R7, discussed below.

Together, proposed Requirements R1 and R2 address Key Recommendation 1f of the Joint Inquiry Report. These proposed requirements would advance reliability during future cold weather seasons by ensuring that Generator Owners proactively take steps to design and operate their units to maintain their reliability during the extreme cold weather conditions they are reasonably likely to face in their area. Proposed Requirement R6, discussed below, would require Generator Owners that experience certain freezing events at or above the Extreme Cold Weather Temperature to develop Corrective Action Plans to address the identified issues.

3. Requirement R3

Proposed Reliability Standard EOP-012-1 Requirement R3 is an existing requirement that is currently contained in Reliability Standard EOP-011-2 as Requirement R7. As part of the revisions proposed in this petition, NERC proposes to remove this requirement in proposed Reliability Standard EOP-011-3 so it can be included in a consolidated generator preparedness standard.

Certain changes are proposed from the approved requirement to address the Joint Inquiry Report recommendations, as shown below:

> **R3.** Each Generator Owner shall implement and maintain one or more cold weather preparedness plan(s) for its generating units. The cold weather preparedness plan(s) shall include the following, at a minimum:
>
> **3.1** The Extreme Cold Weather Temperature for their unit(s) including the calculation date and source of temperature data;
>
> **3.2** Documentation identifying the Generator Cold Weather Critical Components;
>
> **3.3** ~~Generating unit(s) freeze protection measures based on geographical location and plant configuration~~ Documentation of freeze protection measures implemented on Generator Cold Weather Critical Components which may include measures used to reduce the cooling effects of wind determined necessary by the Generator Owner to protect against heat loss, and where applicable, the effects of freezing precipitation (e.g., sleet, snow, ice, and freezing rain);
>
> **3.4** Annual inspection and maintenance of generating unit(s) freeze protection measures; and
>
> **3.5** Generating unit(s) cold weather data, to include:

3.5.1 Generating unit(s) operating limitations in cold weather to include:

3.5.1.1 ~~c~~Capability and availability;

3.5.1.2 ~~f~~Fuel supply and inventory concerns;

3.5.1.3 ~~f~~Fuel switching capabilities; and

3.5.1.4 ~~e~~Environmental constraints.

3.5.2 Generating unit(s) minimum:

- ~~d~~Design temperature;
- ~~h~~Historical operating temperature; or
- ~~c~~Current cold weather performance temperature determined by an engineering analysis.

The proposed modifications identified above reflect revisions to the required cold weather preparedness plan to implement other requirements in the proposed standard necessary to address the Key Recommendations slated for completion in phase 1 of standards development. The proposed modifications also address Key Recommendation 1a, originally slated for completion under phase 2, and lay the groundwork for addressing the remaining Key Recommendations slated for completion under phase 2.

New Requirement R3 Part 3.1 would require the Generator Owner to identify the Extreme Cold Weather Temperature for its unit(s), including the calculation date and source of temperature data. This information supports performance under proposed Requirements R1, R2, and R5 and must be periodically re-evaluated under proposed Requirement R4. New Requirement R3 Part 3.2 would require the Generator Owner to identify the Generator Cold Weather Critical Components at its unit, in support of documenting the freeze protection measures implemented on those components in revised Requirement R3 Part 3.3 and for purposes of implementing freeze protection measures to provide the required performance capability under Requirement R1. Different factors for consideration for freeze protection measures are identified (cooling effects of wind, effects of freezing participation). These new provisions address Joint Inquiry Report

Recommendation 1a, regarding Generator Owner identification of cold-weather critical components and systems for each unit, and lays the foundation for addressing Joint Inquiry Report Recommendation 1b in phase 2, regarding implementing freeze protection measures for those components and systems, with consideration to temperature and other ambient conditions.[73]

Requirements R3 Part 3.4 and 3.5 are substantively unchanged from the approved Reliability Standard EOP-011-2.

4. Requirement R4

Proposed Reliability Standard EOP-012-1 Requirement R4 is a new requirement that would require the Generator Owner to periodically review its previous Extreme Cold Weather Temperature calculation and related information as follows:

> **R4.** Once every five calendar years, each Generator Owner shall for each generating unit:
>
> **4.1** Calculate the Extreme Cold Weather Temperature, and update the cold weather preparedness plan if this temperature is now lower than the previous lowest calculation;
>
> **4.2** Review its documented generating unit(s) minimum temperature contained within its cold weather preparedness plan(s), pursuant to Part 3.5.2; and
>
> **4.3** Review whether its generating units have the freeze protection measures required to operate at the Extreme Cold Weather Temperature pursuant to R1 or R2 as applicable, and if not develop a CAP for the identified issues, including identification of any needed modifications to the cold weather preparedness plan required under Requirement R3.

Proposed Requirement R4 reflects the need to periodically review temperature data for new lower temperatures that may require the Generator Owner to add or modify freeze protection measures to continue to provide for reliable operation of their unit(s), and it supports the ongoing consideration of new technologies when protecting against extreme cold weather. As such,

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[73] *See* Joint Inquiry Report at 184.

proposed Requirement R4 is responsive in part to the Joint Inquiry Report Key Recommendation 1b, slated for completion in phase 2, that Generator Owners periodically reassess whether any additional freeze protection measures are necessary for their units. The standard drafting team determined that a five year periodicity for this review for all entities was appropriate and reasonable based on the actions required in the standard and the general nature of temperature data. To the extent necessary, Generator Owners must develop a Corrective Action Plan for the identified issues, including any needed modifications to its cold weather preparedness plan. Implementation of Corrective Action Plans is addressed in Requirement R7, discussed below.

5. Requirement R5

Proposed Reliability Standard EOP-012-1 Requirement R5 is an existing requirement that is currently contained in Reliability Standard EOP-011-2 as Requirement R8. As part of the revisions proposed in this petition, NERC proposes to remove this requirement in proposed Reliability Standard EOP-011-3 so it can be included in a consolidated generator preparedness standard.

Consistent with Joint Inquiry Report Key Recommendation 1e,[74] the requirement is revised to provide that training shall be provided on an "annual basis," as shown below:

> **R5.** Each Generator Owner in conjunction with its Generator Operator shall identify the entity responsible for providing the generating unit-specific training, and that identified entity shall provide ~~the~~ annual training to its maintenance or operations personnel responsible for implementing the cold weather preparedness plan(s) developed pursuant to Requirement ~~R7~~ R3.

Project 2019-06 Cold Weather established the requirement that the Generator Owner, in conjunction with its Generator Operator, would provide generating unit-specific training for its personnel responsible for implementing cold weather preparedness plan(s) for its generating units.

[74] Joint Inquiry Report at 188.

The Joint Inquiry Report explained that annual training was not a universal practice in the event area and recommended that this requirement be revised to require the generating unit-specific training be provided on an "annual" basis.[75] Proposed Requirement R5 addresses this recommendation.

6. Requirement R6

Proposed Reliability Standard EOP-012-1 Requirement R6 is a new requirement that would require each Generator Owner experiencing an outage, failure to start, or derate due to freezing develop a Corrective Action Plan to address the identified causes. Proposed Requirement R6 provides as follows:

> **R6.** Each Generator Owner that owns a generating unit that experiences a Generator Cold Weather Reliability Event shall develop a CAP, within 150 days or by July 1, whichever is earlier, that contains at a minimum:
>
> **6.1** A summary of the identified cause(s) for the Generator Cold Weather Reliability Event, where applicable, and any relevant associated data;
>
> **6.2** A review of applicability to similar equipment at other generating units owned by the Generator Owner;
>
> **6.3** An identification of any temporary operating limitations or impacts to the cold weather preparedness plan, that would apply until execution of the corrective action(s) identified in the CAP.

Proposed Requirement R6 addresses Key Recommendation 1d of the Joint Inquiry Report, which recommended that a Generator Owner experiencing an outage, failure to start, or derate due to freezing develop a Corrective Action Plan for the identified equipment and evaluate whether the Corrective Action Plan should apply to similar equipment for other units.[76] The Joint Inquiry Report also recommended that the Corrective Action Plans be developed as quickly as possible. Proposed Requirement R6 addresses these aspects of Recommendation 1d by requiring each

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75 *Id*.

76 *Id.* at 187-88.

Generator Owner experiencing a "Generator Cold Weather Reliability Event" to develop a comprehensive Corrective Action Plan to address the identified issues. The standard drafting team developed the definition of "Generator Cold Weather Reliability Event" to establish which types of events must be addressed through the development of a Corrective Action Plan under this requirement.

A "Generator Cold Weather Reliability Event" refers to "one of the following events for which the apparent cause(s) is due to freezing of equipment within the Generator Owner's control and the dry bulb temperature at the time of the event was at or above the Extreme Cold Weather Temperature: (1) a forced derate of more than 10% of the total capacity of the unit and exceeding 20 MWs for longer than four hours in duration; (2) a start-up failure where the unit fails to synchronize within a specified start-up time; or (3) a Forced Outage." Freezing events that are included in this definition are those that occur at temperatures at or above the Extreme Cold Weather Temperature for the site. Using the Extreme Cold Weather Temperature for the site as the threshold provides a consistent basis for which Corrective Action Plans would be required for all generators and generation types, regardless of any effort that Generator Owners previously applied to winterizing their units. Regarding the types of events, the standard drafting team determined that it was appropriate to include all Forced Outages[77] within the scope of this requirement, regardless of duration, as well as start-up failures where the unit fails to synchronize within the specified start-up time. To limit the administrative burden for minimally impactful events, the standard drafting team determined to exclude from the scope of this requirement short-

[77] The NERC *Glossary* defines "Forced Outage" as "1. The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons. 2. The condition in which the equipment is unavailable due to unanticipated failure."

lived derates (specified at 4 hours or less) and derates of small capacity impact (specified as less than 20 MW by the drafting team, consistent with the NERC definition of Bulk Electric System).

Proposed Requirement R6 would require the Generator Owner to develop its Corrective Action Plan within 150 days or by July 1. In selecting these timeframe options, the standard drafting team considered the Joint Inquiry Report recommendation that Corrective Action Plans be developed as quickly as possible. The proposed requirement would require prompt development, as recommended by the Joint Inquiry Report, but would also allow Generator Owners sufficient time to review multiple events holistically following a winter season and, if appropriate, develop a single Corrective Action Plan for components with common mode failures. Implementation of Corrective Action Plans is addressed in proposed Requirement R7, discussed below.

7. Requirement R7

Proposed Reliability Standard EOP-012-1 Requirement R7 is a new requirement regarding the implementation of Corrective Action Plans. The proposed requirement provides as follows:

> **R7.** Each Generator Owner shall:
>
> **7.1** Implement each CAP developed pursuant to Requirements R2, R4, or R6, or explain in a declaration why corrective actions are not being implemented due to any technical, commercial, or operational constraints as defined by the Generator Owner.
>
> **7.2** Update each CAP if actions or timetables change, until completed.

The NERC *Glossary* defines a "Corrective Action Plan" as a "list of actions and an associated timetable for implementation to remedy a specific problem." Proposed Requirement R7 would require Generator Owners to implement any Corrective Action Plans developed under Requirements R2, R4, or R6, or else explain why corrective actions are not being implemented, and to update the Corrective Action Plan as actions and timetables change. The standard drafting team determined to not establish a firm deadline for the completion of any specific actions to allow

Generator Owners the flexibility to choose more effective corrective measures that may take longer to implement over less-effective measures that may be more quickly implemented, and because timelines and milestones for completion are considered part of the Corrective Action Plan as it is defined by NERC. The standard drafting team also recognized that, in some instances, there may be technical, commercial, or operational constraints that prevent the Generator Owner from implementing one or more corrective actions to address an identified issue regarding a Cold Weather Critical Component. For example, the absence of commercially viable technical solutions may be one such constraint. Another example may be the winterization of a component that reduces the reliability of the generating unit in warm weather conditions. The standard drafting team determined that it was important to recognize these constraints in the proposed standard to avoid potential unintended consequences that could themselves have negative impacts on reliability; specifically, the premature retirement of generating units that are unable to implement corrective actions due to these constraints or the withdrawal of those units from the winter markets. Nevertheless, proposed Reliability Standard EOP-012-1 Requirements R2 and R6 would still require the Generator Owner to perform the necessary analysis to develop the Corrective Action Plan, including understanding the extent of the condition in their generating fleet. Further, proposed Requirement R4 would require periodic analysis of weather patterns and freeze protection measures, including any reviews and updates of any Corrective Action Plans. As technologies advance and the regulatory framework evolves,[78] corrective actions that may not be feasible to implement at the time of initial study may later prove feasible, or new corrective actions to address an identified issue may become available.

[78] *See, e.g.,* Joint Inquiry Report Recommendation 2, which recommends that Generator Owners be compensated for the costs of retrofitting units to operate in cold weather conditions through markets or cost recovery approved by state public utility commissions. Joint Inquiry Report at 191-192.

As discussed in Section VIII below, the standard drafting team will further consider implementation of corrective measures as part of its work addressing Joint Inquiry Report Recommendation 1g, which recommends providing greater specificity about the relative roles of the Generator Owner, Generator Operator, and Balancing Authority in determining the generating unit capacity that can be relied upon during "local forecasted cold weather."[79]

C. Proposed Reliability Standard EOP-011-3

1. History of the EOP-011 Reliability Standard

The currently effective Reliability Standard EOP-011-1 – Emergency Operations, was approved by the Commission in 2015.[80] The standard was initially developed to consolidate requirements from three then-effective EOP Reliability Standards into a single standard that clarified the critical requirements for Emergency Operations while ensuring strong communication and coordination across the functional entities. The stated purpose of the standard is "To address the effects of operating Emergencies by ensuring each Transmission Operator and Balancing Authority has developed Operating Plan(s) to mitigate operating Emergencies, and that those plans are coordinated within a Reliability Coordinator Area."

NERC developed Reliability Standard EOP-011-2 to address in part Recommendation 1 of the January 2018 Event Report. This standard, which the Commission approved in 2021,[81] revised the currently effective Reliability Standard EOP-011-1 by adding two new requirements, Requirement R7 and Requirement R8, related to generator cold weather preparedness and training, and revising two requirement parts, Requirement R1.2.6 and 2.2.9, related to the consideration of

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79 *See* Joint Inquiry Report at 189-90.

80 *Revisions to Emergency Operations Reliability Standards; Revisions to Undervoltage Load Shedding Reliability Standards; Revisions to the Definition of "Remedial Action Scheme" and Related Reliability Standards*, Order No. 818, 153 FERC ¶ 61,228 (2015).

81 *N. Am. Elec. Reliability Corporation*, 176 FERC ¶ 61,119 (2021).

the reliability impacts of cold weather conditions in Transmission Operator and Balancing Authority emergency Operating Plan(s). Reliability Standard EOP-011-2 also revised the standard title, purpose, and applicability consistent with the inclusion of Requirements R7 and R8.

2. Revisions in Proposed Reliability Standard EOP-011-3

Proposed Reliability Standard EOP-011-3 revises the approved Reliability Standard EOP-011-2 by removing Requirement R7 and Requirement R8, which, as discussed above, are now in proposed Reliability Standard EOP-012-1 as Requirement R3 and Requirement R5, respectively. With these EOP-011-2 requirements now consolidated into a single generator preparedness standard, the title, purpose, and applicability of EOP-011-1 are restored in proposed EOP-011-3. More substantively, proposed Reliability Standard EOP-011-3 revises Requirement R1 and R2 to address provisions for manual load shed for reliability.

Proposed Reliability Standard EOP-011-3 Requirement R1 revises Reliability Standard EOP-011-2 Requirement R1 as follows:

> **R1.** Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable:
>
> **1.1.** Roles and responsibilities for activating the Operating Plan(s);
>
> **1.2.** Processes to prepare for and mitigate Emergencies including:
>
> **1.2.1.** Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency;
>
> **1.2.2.** Cancellation or recall of Transmission and generation outages;
>
> **1.2.3.** Transmission system reconfiguration;
>
> **1.2.4.** Redispatch of generation request;
>
> **1.2.5.** <u>Operator-controlled manual Load shedding during an Emergency that accounts for each of the following:</u>
>
> **1.2.5.1.** ~~**1.2.5.**~~ Provisions for ~~operator-controlled~~ manual Load shedding ~~that minimizes the overlap with~~

~~automatic Load shedding and are~~ capable of being implemented in a timeframe adequate for mitigating the Emergency; ~~and~~

1.2.5.2. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that serve designated critical loads;

1.2.5.3. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for underfrequency load shed (UFLS) or undervoltage load shed (UVLS); and

1.2.5.4. Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions.

1.2.6. Provisions to determine reliability impacts of:

1.2.6.1. cold weather conditions; and

1.2.6.2. extreme weather conditions.

Corresponding revisions are reflected in proposed Reliability Standard EOP-011-3 Requirement R2 Part 2.2.8 as follows:

R2. Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable:

2.1. Roles and responsibilities for activating the Operating Plan(s);

2.2. Processes to prepare for and mitigate Emergencies including:

2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;

2.2.2. Requesting an Energy Emergency Alert, per Attachment 1;

2.2.3. Managing generating resources in its Balancing Authority Area to address:

2.2.3.1. capability and availability;

2.2.3.2. fuel supply and inventory concerns;

2.2.3.3. fuel switching capabilities; and

2.2.3.4. environmental constraints.

2.2.4. Public appeals for voluntary Load reductions;

2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions;

2.2.6. Reduction of internal utility energy use;

2.2.7. Use of Interruptible Load, curtailable Load and demand response;

2.2.8. Provisions for Transmission Operators to implement operator-controlled manual Load ~~shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency~~ shed in accordance with Requirement R1 Part 1.2.5; and

2.2.9. Provisions to determine reliability impacts of:

2.2.9.1. cold weather conditions; and

2.2.9.2. extreme weather conditions.

The proposed revisions to EOP-011 Requirements R1 and R2 address Key Recommendation 1j of the Joint Inquiry Report, which recommended:

> In minimizing the overlap of manual and automatic load shed, the load shed procedures of Transmission Operators, Transmission Owners and Distribution Providers should separate circuits that will be used for manual load shed from circuits used for underfrequency load shedding/undervoltage load shedding or serving critical load. Underfrequency load shedding/undervoltage load shedding circuits should only be used for manual load shed as a last resort and should start with the final stage (lowest frequency).

Reliability Standard EOP-011-2 Requirement R1 Part 1.2.5 states that the Transmission Operator's Operating Plan shall include provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding. Proposed Reliability Standard EOP-011-3 contains additional provisions (Requirement R1 Parts 1.2.5.2 through 1.2.5.4) and clarifies what the Transmission Operator must include in their Operating Plan to mitigate operating Emergencies.

Under proposed Requirement R1 Part 1.2.5.2, Transmission Operators would be required to include provisions for minimizing the overlap of manual Load shed circuits and circuits that serve critical loads, recognizing that it is necessary to prioritize certain critical loads which may be essential to the integrity of the electric system (*see* Joint Inquiry Report Key Recommendation 1i)[82]. The standard drafting team elected to retain the existing phrase "minimize the overlap," instead of moving to language that specifically requires the separation of circuits, in recognition of the fact that it is not always practical or warranted to separate completely circuits used for each of these purposes. The standard drafting team determined that Transmission Operators should have flexibility to determine the methods through which overlap is to be minimized, as each system is unique and will have various constraints that must be balanced in addressing these requirements. Criticality designations should be considered in the context of the situation, including the characteristics of the Load shed event (e.g., depth, duration, and season).

Under proposed Requirement R1 Parts 1.2.5.3 and 1.2.5.4, Transmission Operators would be required to include provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS, and to limit the use of UFLS or UVLS for manual load shed to system conditions where it may be required to maintain reliability. In certain situations, it may be necessary and appropriate to utilize UFLS or UVLS circuits for manual Load shed. These situations may be driven by Load shed magnitudes, local constraints, or other factors. Transmission Operator Operating Plans should identify system conditions that would allow for the utilization of UFLS or UVLS for manual Load shed and how it will be implemented, with consideration to the potential reliability impacts. Where UFLS or UVLS circuits are used to meet Load shed obligations, the Joint Inquiry Report recommends starting with the lowest frequency block.

Proposed EOP-012-1 Requirement R2 Part 2.2.8 is revised to refer to Requirement R1 Part

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82 Joint Inquiry Report at 208-209. Reliability Standards to address this Key Recommendation will be further considered as part of phase 2 work.

1.2.5 to clarify that the Transmission Operator addresses operator-controlled manual Load shed requirements in its Operating Plan.

VII. EFFECTIVE DATE OF THE PROPOSED RELIABILITY STANDARDS

NERC respectfully requests that the Commission approve the implementation plan attached to this petition as **Exhibit B**. The proposed implementation plan provides a step-wise approach which would have the proposed Reliability Standards become effective on the first day of the first calendar quarter that is eighteen (18) months after applicable regulatory approval. Reliability Standard EOP-011-2, which is scheduled to come into effect on April 1, 2023, would be retired immediately prior to the effective date of the revised Reliability Standards. Generator Owners would have additional 42 months from the effective date of proposed Reliability Standard EOP-012-1 to come into compliance with the new freeze protection measures requirements in Requirements R1 and R2, and 60 months from the effective date to perform their first five-year update of the Extreme Cold Weather Temperature.

Under the proposed implementation plan, many of the protections provided by the proposed Reliability Standards would be in place beginning 18 months following regulatory approval, followed by a later compliance date for certain proposed requirements that involve more thorough analysis of the cold weather capability and operability of existing and planned units and require time to implement freeze protection measures. These protections would build upon the cold weather operations and preparedness requirements in approved Reliability Standards EOP-011-2, IRO-010-4, and TOP-003-5 that will become effective on April 1, 2023, as demonstrated below:

- **April 1, 2023**:
  - Generator Owners to develop cold weather preparedness plan addressing generating unit freeze protection measures, annual inspection and

maintenance of freeze protection measures, and generating unit cold weather data and operating limitations (EOP-011-2 Requirement R7);

  - Generator Owners or Generator Operators to provide unit-specific training on the cold weather preparedness plan (EOP-011-2 Requirement R8);
  - Reliability Coordinator, Transmission Operator, and Balancing Authorities to include generator cold weather data and information in data specifications, including data and information regarding generator operating limitations in cold weather and the expected operating temperature of the generator (IRO-010-4 Requirement R1 part 1.3, TOP-003-5 Requirements R1 part 1.3, R2 part 2.3); and
  - Transmission Operator, Balancing Authority to include provisions addressing reliability impacts of cold weather conditions in emergency Operating Plans (EOP-011-2 Requirement R1 part 1.2.6, Requirement R2 part 2.2.9).

- **Regulatory Approval of Proposed EOP-012-1 and EOP-011-3 + 18 months (“Effective Date”)**:
  - Generator Owners to update cold weather preparedness plans to include the Extreme Cold Weather Temperature for the unit(s), the Generator Cold Weather Critical Components, and documentation of the freeze protection measures for those components that now considers the cooling effects of wind and freezing participation (proposed EOP-012-1 Requirement R3);
  - Generator Owners required to develop Corrective Action Plans within 150 days, or by July 1, to address Generator Cold Weather Reliability Events, and to begin implementing them according to the timeline specified in the plan or else declare constraints preventing implementation (proposed EOP-012-1 Requirements R6, R7);
  - Generator Owners and Generator Operators required to provide unit-specific cold weather preparedness plan training on an <u>annual</u> basis (proposed EOP-012-1 Requirement R5); and
  - Transmission Operators required to include enhanced provisions in their Operating Plans for minimizing the overlap between automatic load shed and manual load shed (proposed EOP-011-3 Requirement R1 Part 1.2.5).

- **Effective Date + 42 months (60 months following regulatory approval):**
  - Generator Owners to implement freeze protection measures on new and existing generation to provide capability to operate for the specified durations at the Extreme Cold Weather Temperature (proposed EOP-012-1 Requirements R1 and R2).

- **Effective Date + 60 months (78 months following regulatory approval):**
  - Generator Owners to complete the first re-evaluation of the Extreme Cold Weather Temperature for their units and update cold weather preparedness

> plans and unit freeze protection measures, including developing any Corrective Action Plans, as needed (proposed EOP-012-1 Requirement R4).

This implementation timeline balances the urgency in the need to implement the standards against the time allowed for those who must comply to develop necessary procedures and other relevant capabilities.[83] It reflects consideration that Generator Owners would need a reasonable period of time to calculate the Extreme Cold Weather Temperature for each of their generating unit(s), identify Generator Cold Weather Critical Components, and perform the necessary engineering study and analysis to identify and implement freeze protection measures that would provide the required performance capability or else explain why such measures are precluded by technical, commercial, or operational constraints under proposed Reliability Standard EOP-012-1. The implementation plan provides additional time for entities to address proposed EOP-012-1 Requirements R1 and R2 regarding the implementation of freeze protection measures on new and existing generation, in recognition of the significant engineering, design, analysis, and implementation efforts required to support such work across all applicable units in a Generator Owner's fleet, as well as resource constraints that may make an earlier implementation especially challenging.[84] This implementation timeline also reflects consideration that Transmission Operators would need time to develop and include in their Operating Plans provisions to address the load shed considerations discussed above in proposed Reliability Standard EOP-011-3.

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

84 During the standard development process, the standard drafting team considered comments suggesting that many sites will have to perform a detailed analysis of all Cold Weather Critical Components to determine current winter capability design, followed by an analysis of freeze protection measures to provide the required capability, and only then can consider implementation of those measures. For existing generating units, this analysis may take several years to complete and may require extensive contractor support. *See, e.g.*, Comments on Draft 1 Postings (Exhibit F Record of Development item 27) (comments of Duke Energy).

While NERC maintains that its proposed implementation period is reasonable in light of the above considerations, NERC strongly encourages entities to prioritize implementation of the proposed Reliability Standards and to comply with them, in whole or in part, as soon as circumstances allow. For example, entities could design their cold weather preparedness plans under Reliability Standard EOP-011-2 to be compliant with the new requirements of proposed Reliability Standard EOP-012-1, including calculation of Extreme Cold Weather Temperatures for their units, identification of Generator Cold Weather Critical Components, and inclusion of freeze protection measures considering the cooling effects of wind and precipitation. Entities could also begin providing the required cold weather preparedness training on an annual basis, or start examining causes of freezing issues and work to understand the extent of the condition in their fleets. Such voluntary action would provide needed support to the reliability of the Bulk-Power System during those winter weather seasons that elapse before the proposed Reliability Standards become mandatory and enforceable.

VIII. NEXT STEPS

The proposed Reliability Standards addressed in this petition represent the conclusion of the first phase of work under Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination to address Key Recommendations 1d, 1e, 1f, and 1j, each with a target Winter 2022-2023 completion date, and Key Recommendation 1a, with a target Winter 2023-2024 completion date. Work is currently underway to develop Reliability Standards to address the remaining Key Recommendations with a target Winter 2023-2024 completion date. NERC anticipates completing development and filing with the Commission new or revised Reliability Standards addressing these recommendations by November 1, 2023. NERC will keep Commission staff apprised of the standard drafting team's progress during this second phase of standards development.

In addition to addressing the Key Recommendations identified above, the standard drafting team will also be considering certain issues raised during the first phase of standards development. In particular, the standard drafting team will be considering mechanisms for tracking the progress of Generator Owners in implementing freeze protection measures on their applicable units during the implementation period for the proposed Reliability Standards and beyond. The standard drafting team noted the potential reliability benefits of such monitoring and sought comment on proposed mechanisms during the first comment period for the proposed standards.[85] After further discussion, however, the team determined that this issue should be addressed at the same time as Joint Inquiry Report Recommendation 1g regarding providing greater specificity about the relative roles of the Generator Owner, Generator Operator, and Balancing Authority in determining the generating unit capacity that can be relied upon during "local forecasted cold weather."[86] NERC agrees that careful monitoring of the implementation of the proposed Reliability Standards is needed to understand the factors that could lead to reduced generator unavailability during cold weather and to ensure the proposed Reliability Standards are having the intended benefits for reliability. NERC Staff will work closely with the standard drafting team during the second phase of development to identify the appropriate procedural means for such monitoring.

Additionally, while proposed Reliability Standards EOP-012-1 and EOP-011-3 represent a just and reasonable approach for advancing reliability in extreme cold weather conditions through enhanced generator unit preparedness and should be approved on that basis, the standards drafting team may consider whether additional refinements to the proposed Reliability Standards or defined terms discussed herein would be appropriate as they work through the remaining

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[85] *See* Comments on Draft 1 Postings (Exhibit F Record of Development item 27), Question 7 and Summary Response to Comments on Draft 1 Postings (Exhibit F Record of Development item 28) at 11-12.

[86] *See* Joint Inquiry Report at 189-90.

standards-related Key Recommendations of the Joint Inquiry Report, such as to provide enhanced clarity regarding entity obligations or to further advance reliability during cold weather conditions.

As noted previously in this petition, the first round of cold weather Reliability Standards will come into effect on April 1, 2023. NERC and the Regional Entities will support entities as they implement the important protections found in these Reliability Standards. NERC will also continue to use the other resources in its reliability toolkit to support cold weather reliability for the upcoming winter season and beyond. NERC's efforts to date have included industry outreach, NERC alerts, and training webinars. NERC has also used its reliability assessments to highlight areas of particular concern. Efforts such as these would complement the work undertaken by entities during the implementation period for the proposed Reliability Standards.

IX. REQUEST FOR EXPEDITED ACTION

NERC respectfully requests that the Commission approve the proposed Reliability Standards and associated elements in an expedited manner. As noted prior in this petition, the failure to properly prepare or winterize generation facilities for cold temperatures was the primary cause of the February 2021 cold weather event, as it was for the January 2018 cold weather event before that. In recognition of the immense human and economic toll of the February 2021 Event and the need to ensure grid reliability in future winter seasons, the NERC Board of Trustees took the unusual action of directing that development of Reliability Standards be completed in two phases in accordance with the recommended timelines of the Joint Inquiry Report. As with the first cold weather Reliability Standards approved by the Commission in 2021, NERC and its stakeholders recognized the urgency of this issue and successfully met the aggressive development timeline directed by the Board.

As discussed in Section VII, NERC's proposed implementation plan provides for an 18-month implementation timeframe, with subsequent compliance dates for the more resource intensive requirements, which appropriately balances the urgency in the need to implement the standards against the time allowed for those who must comply to develop necessary procedures and other relevant capabilities.[87] An expedited approval of the proposed Reliability Standards would advance the public interest by having the vital cold weather reliability protections these standards would provide in place as soon as is reasonably possible. Further, an expedited approval would provide regulatory certainty to those entities that would seek to implement the proposed standards on their own expedited timeframes, as well as those entities developing new generating unit(s) that will be subject to the performance requirements of proposed Reliability Standard EOP-012-1 Requirement R1. For these reasons, NERC respectfully requests that the Commission consider expedited action on NERC's proposals.

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[87] *See* Order No. 672, *supra* note 8, at P 333.

X. CONCLUSION

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

- Proposed Reliability Standards EOP-011-3 and EOP-012-1, and the associated elements, as shown in **Exhibit A;**
- the retirement of Reliability Standard EOP-011-2; and
- The implementation plan included in **Exhibit B**.

NERC respectfully requests that the Commission consider expedited action in ruling on these proposals.

Respectfully submitted,

/s/ Lauren A. Perotti

Lauren A. Perotti
Senior Counsel
North American Electric Reliability Corporation
1401 H Street, N.W., Suite 410
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099 – facsimile
lauren.perotti@nerc.net

Counsel for the North American Electric Reliability Corporation

October 28, 2022

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Exhibit A

The Proposed Reliability Standards

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Exhibit A-1

Proposed Reliability Standard EOP-011-3
Clean

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

This is the final draft of the proposed standard for a formal 8-day ballot period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR)	11/17/2021
SAR posted for comment	11/22/21 – 12/21/21
30-day formal comment period with ballot	5/19/22 – 6/21/22

Anticipated Actions	Date
8-day final ballot	9/23/22 – 9/30/22
NERC Board of Trustees (Board) adoption	October 2022

A. Introduction

1. **Title:** **Emergency Operations**
2. **Number:** **EOP-011-3**
3. **Purpose:** To address the effects of operating Emergencies by ensuring each Transmission Operator and Balancing Authority has developed plan(s) to mitigate operating Emergencies and that those plans are implemented and coordinated within the Reliability Coordinator Area as specified within the requirements.
4. **Applicability:**
   4.1. Functional Entities:
   4.1.1 Balancing Authority
   4.1.2 Reliability Coordinator
   4.1.3 Transmission Operator
5. **Effective Date:** See Implementation Plan for Project 2021-07.

B. Requirements and Measures

R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

1.1. Roles and responsibilities for activating the Operating Plan(s);

1.2. Processes to prepare for and mitigate Emergencies including:

1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency;

1.2.2. Cancellation or recall of Transmission and generation outages;

1.2.3. Transmission system reconfiguration;

1.2.4. Redispatch of generation request;

1.2.5. Operator-controlled manual Load shedding during an Emergency that accounts for each of the following:

1.2.5.1. Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;

1.2.5.2. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that serve designated critical loads;

1.2.5.3. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for underfrequency load shed (UFLS) or undervoltage load

shed (UVLS); and

1.2.5.4. Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions.

1.2.6. Provisions to determine reliability impacts of:

1.2.6.1. cold weather conditions; and

1.2.6.2. extreme weather conditions.

M1. Each Transmission Operator will have a dated Operating Plan(s) developed in accordance with Requirement R1 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R1.

R2. Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

2.1. Roles and responsibilities for activating the Operating Plan(s);

2.2. Processes to prepare for and mitigate Emergencies including:

2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;

2.2.2. Requesting an Energy Emergency Alert, per Attachment 1;

2.2.3. Managing generating resources in its Balancing Authority Area to address:

2.2.3.1. capability and availability;

2.2.3.2. fuel supply and inventory concerns;

2.2.3.3. fuel switching capabilities; and

2.2.3.4. environmental constraints.

2.2.4. Public appeals for voluntary Load reductions;

2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions;

2.2.6. Reduction of internal utility energy use;

2.2.7. Use of Interruptible Load, curtailable Load and demand response;

2.2.8. Provisions for Transmission Operators to implement operator-controlled

manual Load shed in accordance with Requirement R1 Part 1.2.5; and

2.2.9. Provisions to determine reliability impacts of:

2.2.9.1. cold weather conditions; and

2.2.9.2. extreme weather conditions.

M2. Each Balancing Authority will have a dated Operating Plan(s) developed in accordance with Requirement R2 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R2.

R3. The Reliability Coordinator shall review the Operating Plan(s) to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority regarding any reliability risks that are identified between Operating Plans. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

3.1. Within 30 calendar days of receipt, the Reliability Coordinator shall:

3.1.1. Review each submitted Operating Plan(s) on the basis of compatibility and inter-dependency with other Balancing Authorities' and Transmission Operators' Operating Plans;

3.1.2. Review each submitted Operating Plan(s) for coordination to avoid risk to Wide Area reliability; and

3.1.3. Notify each Balancing Authority and Transmission Operator of the results of its review, specifying any time frame for resubmittal of its Operating Plan(s) if revisions are identified.

M3. The Reliability Coordinator will have documentation, such as dated emails or other correspondences that it reviewed, Transmission Operator and Balancing Authority Operating Plans, within 30 calendar days of submittal in accordance with Requirement R3.

R4. Each Transmission Operator and Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R3 and resubmit its Operating Plan(s) to its Reliability Coordinator within a time period specified by its Reliability Coordinator. *[Violation Risk Factor: High] [Time Horizon: Operation Planning]*

M4. The Transmission Operator and Balancing Authority will have documentation, such as dated emails or other correspondence, with an Operating Plan(s) version history showing that it responded and updated the Operating Plan(s) within the timeframe identified by its Reliability Coordinator in accordance with Requirement R4.

R5. Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and

neighboring Reliability Coordinators. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M5. Each Reliability Coordinator that receives an Emergency notification from a Balancing Authority or Transmission Operator within its Reliability Coordinator Area will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that will be used to determine if the Reliability Coordinator communicated, in accordance with Requirement R5, with other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators.

R6. Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M6. Each Reliability Coordinator, with a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area, will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that it declared an Energy Emergency Alert, as detailed in Attachment 1, in accordance with Requirement R6.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

"Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with the 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 CEA may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

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

- The Transmission Operator shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R1 and R4 and Measures M1 and M4.

- The Balancing Authority shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R2 and R4, and Measures M2 and M4.
- The Reliability Coordinator shall maintain evidence of compliance since the last audit for Requirements R3, R5, and R6 and Measures M3, M5, and M6.

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.

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real-time Operations, Operations Planning, Long-term Planning	High	N/A	The Transmission Operator developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to maintain it.	The Transmission Operator developed an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to have it reviewed by its Reliability Coordinator.	The Transmission Operator failed to develop an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. OR The Transmission Operator developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to implement it.
R2	Real-time Operations, Operations	High	N/A	The Balancing Authority developed a Reliability Coordinator-	The Balancing Authority developed an Operating Plan(s) to mitigate operating	The Balancing Authority failed to develop an

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	Planning, Long-term Planning			reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to maintain it.	Emergencies within its Balancing Authority Area, but failed to have it reviewed by its Reliability Coordinator.	Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area. OR The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to implement it.
R3	Operations Planning	High	N/A	N/A	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission Operator.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					Operator within 30 calendar days.	
R4	Operations Planning	High	N/A	N/A	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator within the timeframe specified by its Reliability Coordinator.	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator.
R5	Real-time Operations	High	N/A	N/A	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority did notify neighboring Reliability Coordinators, Balancing Authorities	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority failed to notify neighboring Reliability Coordinators, Balancing Authorities

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					and Transmission Operators, but failed to notify within 30 minutes from the time of receiving notification.	and Transmission Operators.
R6	Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to declare an Energy Emergency Alert.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	November 13, 2014	Adopted by Board of Trustees	Merged EOP-001-2.1b, EOP-002-3.1 and EOP-003-2.
1	November 19, 2015	FERC approved EOP-011-1. Docket Nos. RM15-7-000, RM15-12-000, and RM15-13-000. Order No. 818	
2	June 11,2021	Adopted by Board of Trustees	Revised under Project 2019-06
2	August 24,2021	FERC approved EOP-011-2. Docket Number RD21-5-000	
2	August 24,2021	Effective Date	4/1/ 2023
3	TBD		Revised under Project 2021-07

Attachment 1-EOP-011-3
Energy Emergency Alerts

Introduction

This Attachment provides the process and descriptions of the levels used by the Reliability Coordinator in which it communicates the condition of a Balancing Authority which is experiencing an Energy Emergency.

A. General Responsibilities

1. **Initiation by Reliability Coordinator.** An Energy Emergency Alert (EEA) may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of an energy deficient Balancing Authority.

2. **Notification**. A Reliability Coordinator who declares an EEA shall notify all Balancing Authorities and Transmission Operators in its Reliability Coordinator Area. The Reliability Coordinator shall also notify all neighboring Reliability Coordinators.

B. EEA Levels

Introduction

To ensure that all Reliability Coordinators clearly understand potential and actual Energy Emergencies in the Interconnection, NERC has established three levels of EEAs. The Reliability Coordinators will use these terms when communicating Energy Emergencies to each other. An EEA is an Emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC Reliability Standards.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. **EEA 1 — All available generation resources in use. Circumstances:**

   - The Balancing Authority is experiencing conditions where all available generation resources are committed to meet firm Load, firm transactions, and reserve commitments, and is concerned about sustaining its required Contingency Reserves.
   - Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. **EEA 2 — Load management procedures in effect. Circumstances:**

   - The Balancing Authority is no longer able to provide its expected energy requirements and is an energy deficient Balancing Authority.
   - An energy deficient Balancing Authority has implemented its Operating Plan(s) to mitigate Emergencies.

- An energy deficient Balancing Authority is still able to maintain minimum Contingency Reserve requirements.

During EEA 2, Reliability Coordinators and energy deficient Balancing Authorities have the following responsibilities:

2.1 Notifying other Balancing Authorities and market participants. The energy deficient Balancing Authority shall communicate its needs to other Balancing Authorities and market participants. Upon request from the energy deficient Balancing Authority, the respective Reliability Coordinator shall post the declaration of the alert level, along with the name of the energy deficient Balancing Authority on the RCIS website.

2.2 Declaration period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators**.**

2.3 Sharing information on resource availability. Other Reliability Coordinators of Balancing Authorities with available resources shall coordinate, as appropriate, with the Reliability Coordinator that has an energy deficient Balancing Authority.

2.4 Evaluating and mitigating Transmission limitations. The Reliability Coordinator shall review Transmission outages and work with the Transmission Operator(s) to see if it's possible to return to service any Transmission Elements that may relieve the loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).

2.5 Requesting Balancing Authority actions. Before requesting an EEA 3, the energy deficient Balancing Authority must make use of all available resources; this includes, but is not limited to:

2.5.1 All available generation units are on line. All generation capable of being on line in the time frame of the Emergency is on line.

2.5.2 Demand-Side Management. Activate Demand-Side Management within provisions of any applicable agreements.

3. EEA 3 —Firm Load interruption is imminent or in progress. Circumstances:

- The energy deficient Balancing Authority is unable to meet minimum Contingency Reserve requirements.

During EEA 3, Reliability Coordinators and Balancing Authorities have the following responsibilities:

3.1 Continue actions from EEA 2. The Reliability Coordinators and the energy deficient Balancing Authority shall continue to take all actions initiated during EEA 2.

3.2 Declaration Period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities, and Transmission Operators.

3.3 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator shall evaluate the risks of revising SOLs and IROLs for the possibility of delivery of energy to the energy deficient Balancing Authority. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Transmission Operator whose Transmission Owner (TO) equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists, or as allowed by the Transmission Owner whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.3.1 Energy deficient Balancing Authority obligations. The energy deficient Balancing Authority, upon notification from its Reliability Coordinator of the situation, will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding.

3.4 Returning to pre-Emergency conditions. Whenever energy is made available to an energy deficient Balancing Authority such that the Systems can be returned to its pre- Emergency SOLs or IROLs condition, the energy deficient Balancing Authority shall request the Reliability Coordinator to downgrade the alert level.

3.4.1 Notification of other parties. Upon notification from the energy deficient Balancing Authority that an alert has been downgraded, the Reliability Coordinator shall notify the neighboring Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Operators that its Systems can be returned to its normal limits.

Alert 0 - Termination. When the energy deficient Balancing Authority is able to meet its Load and Operating Reserve requirements, it shall request its Reliability Coordinator to terminate the EEA.

3.4.2 Notification. The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the neighboring Balancing Authorities and Transmission Operators.

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Exhibit A-1

Proposed Reliability Standard EOP-011-3
Redline to Last Approved

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

This is the final draft of the proposed standard for a formal 8-day ballot period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR)	11/17/2021
SAR posted for comment	11/22/21 – 12/21/21
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Anticipated Actions	Date
8-day final ballot	9/23/22 – 9/30/22
NERC Board of Trustees (Board) adoption	October 2022

A. Introduction

1. **Title:** **Emergency ~~Preparedness and~~ Operations**

2. **Number:** **EOP-~~011-2~~011-3**

3. **Purpose:** To address the effects of operating ~~emergencies~~Emergencies by ensuring each Transmission Operator~~,~~ and Balancing Authority~~, and Generator Owner~~ has developed plan(s) to mitigate operating Emergencies and that those plans are implemented and coordinated within the Reliability Coordinator Area as specified within the requirements.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Reliability Coordinator

   4.1.3 Transmission Operator

   ~~**3.0.4** Generator Owner~~

   ~~**3.1.5** Generator Operator~~

   ~~**4.2. Facilities**~~

   ~~**4.2.1** For the purpose of this standard, the term "generating unit" means all Bulk Electric System generators.~~

5. **Effective Date:** See Implementation Plan for Project ~~2019-06~~2021-07.

B. Requirements and Measures

R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

1.1. Roles and responsibilities for activating the Operating Plan(s);

1.2. Processes to prepare for and mitigate Emergencies including:

1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency;

1.2.2. Cancellation or recall of Transmission and generation outages;

1.2.3. Transmission system reconfiguration;

1.2.4. Redispatch of generation request;

1.2.5. Operator-controlled manual Load shedding during an Emergency that accounts for each of the following:

1.2.5.1. ~~**1.2.5.**~~ Provisions for ~~operator-controlled~~ manual Load shedding ~~that minimizes the overlap with automatic Load shedding and are~~ capable of being implemented in a timeframe adequate for mitigating the Emergency;~~ and~~

1.2.5.2. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that serve designated critical loads;

1.2.5.3. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for underfrequency load shed (UFLS) or undervoltage load shed (UVLS); and

1.2.5.4. Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions.

1.2.6. Provisions to determine reliability impacts of:

1.2.6.1. cold weather conditions; and

1.2.6.2. extreme weather conditions.

M1. Each Transmission Operator will have a dated Operating Plan(s) developed in accordance with Requirement R1 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R1.

R2. Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

2.1. Roles and responsibilities for activating the Operating Plan(s);

2.2. Processes to prepare for and mitigate Emergencies including:

2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;

2.2.2. Requesting an Energy Emergency Alert, per Attachment 1;

2.2.3. Managing generating resources in its Balancing Authority Area to address:

2.2.3.1. capability and availability;

2.2.3.2. fuel supply and inventory concerns;

2.2.3.3. fuel switching capabilities; and

2.2.3.4. environmental constraints.

2.2.4. Public appeals for voluntary Load reductions;

2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions;

2.2.6. Reduction of internal utility energy use;

2.2.7. Use of Interruptible Load, curtailable Load and demand response;

2.2.8. Provisions for Transmission Operators to implement operator-controlled manual Load ~~shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency~~shed in accordance with Requirement R1 Part 1.2.5; and

2.2.9. Provisions to determine reliability impacts of:

2.2.9.1. cold weather conditions; and

2.2.9.2. extreme weather conditions.

M2. Each Balancing Authority will have a dated Operating Plan(s) developed in accordance with Requirement R2 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R2.

R3. The Reliability Coordinator shall review the Operating Plan(s) to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority regarding any reliability risks that are identified between Operating Plans. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

3.1. Within 30 calendar days of receipt, the Reliability Coordinator shall:

3.1.1. Review each submitted Operating Plan(s) on the basis of compatibility and inter-dependency with other Balancing Authorities' and Transmission Operators' Operating Plans;

3.1.2. Review each submitted Operating Plan(s) for coordination to avoid risk to Wide Area reliability; and

3.1.3. Notify each Balancing Authority and Transmission Operator of the results of its review, specifying any time frame for resubmittal of its Operating Plan(s) if revisions are identified.

M3. The Reliability Coordinator will have documentation, such as dated ~~e-mails~~emails or other correspondences that it reviewed, Transmission Operator and Balancing Authority Operating Plans, within 30 calendar days of submittal in accordance with

Requirement R3.

R4. Each Transmission Operator and Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R3 and resubmit its Operating Plan(s) to its Reliability Coordinator within a time period specified by its Reliability Coordinator. *[Violation Risk Factor: High] [Time Horizon: Operation Planning]*

M4. The Transmission Operator and Balancing Authority will have documentation, such as dated emails or other correspondence, with an Operating Plan(s) version history showing that it responded and updated the Operating Plan(s) within the timeframe identified by its Reliability Coordinator in accordance with Requirement R4.

R5. Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and

neighboring Reliability Coordinators. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M5. Each Reliability Coordinator that receives an Emergency notification from a Balancing Authority or Transmission Operator within its Reliability Coordinator Area will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that will be used to determine if the Reliability Coordinator communicated, in accordance with Requirement R5, with other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators.

R6. Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M6. Each Reliability Coordinator, with a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area, will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that it declared an Energy Emergency Alert, as detailed in Attachment 1, in accordance with Requirement R6.

~~**R7.**~~ ~~Each Generator Owner shall implement and maintain one or more cold weather preparedness plan(s) for its generating units. The cold weather preparedness plan(s) shall include the following, at a minimum: [*Violation Risk Factor: High*] [*Time Horizon: Operations Planning and Real-Time Operations*]~~

~~**7.1.** Generating unit(s) freeze protection measures based on geographical location and plant configuration;~~

~~**7.2.** Annual inspection and maintenance of generating unit(s) freeze protection measures;~~

~~**7.3.** Generating unit(s) cold weather data, to include:~~

~~**7.3.1.** Generating unit(s) operating limitations in cold weather to include:~~

~~**7.3.1.1.** capability and availability;~~

~~**7.3.1.2.** fuel supply and inventory concerns;~~

~~**7.3.1.3.** fuel switching capabilities; and~~

~~**7.3.1.4.** environmental constraints.~~

~~**7.3.2.** Generating unit(s) minimum:~~

~~**7.3.2.1.** design temperature; or~~

~~**7.3.2.2.** historical operating temperature; or~~

~~**7.3.1.3.** current cold weather performance temperature determined by an engineering analysis.~~

~~**M7.** Each Generator Owner will have evidence documenting that its cold weather preparedness plan(s) was implemented and maintained in accordance with Requirement R7.~~

~~**R8.** Each Generator Owner in conjunction with its Generator Operator shall identify the entity responsible for providing the generating unit-specific training, and that identified entity shall provide the training to its maintenance or operations personnel responsible for implementing cold weather preparedness plan(s) developed pursuant to Requirement R7. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]*~~

~~**M8.** Each Generator Operator or Generator Owner will have documented evidence that the applicable personnel completed training of the Generator Owner's cold weather preparedness plan(s). This evidence may include, but is not limited to, documents such as personnel training records, training materials, date of training, agendas or learning objectives, attendance at pre-work briefings, review of work order tasks, tailboards, attendance logs for classroom training, and completion records for computer-based training in fulfillment of Requirement R8.~~

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

"Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with the 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~~CEA may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

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

- The Transmission Operator shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R1 and R4 and Measures M1 and M4.

- The Balancing Authority shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R2 and R4, and Measures M2 and M4.
- The Reliability Coordinator shall maintain evidence of compliance since the last audit for Requirements R3, R5, and R6 and Measures M3, M5, and M6.

1.3. Compliance Monitoring and Enforcement Program:

- ~~The Generator Owner shall retain the cold weather preparedness plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirement R7 and Measure M7.~~

~~**1.3.** The Generator Owner or Generator Operator shall keep data or evidence to show compliance for three years or since its last compliance audit, whichever timeframe is greater, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation, for Requirement R8 and Measure M8.~~ ~~**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.

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real-time Operations, Operations Planning, Long-term Planning	High	N/A	The Transmission Operator developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to maintain it.	The Transmission Operator developed an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to have it reviewed by its Reliability Coordinator.	The Transmission Operator failed to develop an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. OR The Transmission Operator developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission ~~s~~ Operator Area, but failed to implement it.
R2	Real-time Operations, Operations	High	N/A	The Balancing Authority developed a Reliability Coordinator-	The Balancing Authority developed an Operating Plan(s) to mitigate operating	The Balancing Authority failed to develop an

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	Planning, Long-term Planning			reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to maintain it.	Emergencies within its Balancing Authority Area, but failed to have it reviewed by its Reliability Coordinator.	Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area. OR The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to implement it.
R3	Operations Planning	High	N/A	N/A	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission Operator.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					Operator within 30 calendar days.	
R4	Operations Planning	High	N/A	N/A	The Transmission Operator or Balancing Authority failed to update and resubmit ~~tis~~its Operating Plan(s) to its Reliability Coordinator within the timeframe specified by its Reliability Coordinator.	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator.
R5	Real-time Operations	High	N/A	N/A	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority did notify neighboring Reliability Coordinators, Balancing Authorities	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority failed to notify neighboring Reliability Coordinators, Balancing Authorities

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					and Transmission Operators, but failed to notify within 30 minutes from the time of receiving notification.	and Transmission Operators.
R6	Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to declare an Energy Emergency Alert.
~~**R7**~~	~~Operations Planning and Real-time Operations~~	~~High~~	~~The Generator Owner implemented a cold weather preparedness plan(s) but failed to maintain it.~~	~~The Generator Owner's cold weather preparedness plan failed to include one of the applicable requirement Parts within Requirement R7.~~	~~The Generator Owner had and maintained a cold weather preparedness plan(s) but failed to fully implement it.~~ ~~OR~~	~~The Generator Owner does not have a cold weather preparedness plan.~~ ~~OR~~ ~~The Generator Owner has a cold~~

~~R #~~	~~Time Horizon~~	~~VRF~~	~~Violation Severity Levels~~			
			~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
					~~The Generator Owner's cold weather preparedness plan failed to include two of the applicable requirement Parts within Requirement R7.~~	~~weather preparedness plan, but failed to include any of the applicable requirement Parts within Requirement R7.~~
~~R8~~	~~Operations Planning and Real-time Operations~~	~~Medium~~	~~The Generator Owner or Generator Operator failed to provide generating unit-specific training as described in Requirement R8 to the greater of:~~ • ~~one applicable personnel at a single generating unit; or~~ • ~~5% or less of its total applicable personnel.~~	~~The Generator Owner or Generator Operator failed to provide generating unit-specific training as described in Requirement R8 to the greater of:~~ • ~~two applicable personnel at a single generating unit; or~~ • ~~more than 5% or less than or equal to 10% of its total applicable personnel.~~	~~The Generator Owner or Generator Operator failed to provide generating unit-specific training as described in Requirement R8 to the greater of:~~ • ~~three applicable personnel at a single generating unit; or~~ • ~~more than 10% or less than or equal to 15% of its total applicable personnel.~~	~~The Generator Owner or Generator Operator failed to provide generating unit-specific training as described in Requirement R8 to the greater of:~~ • ~~four applicable personnel at a single generating unit; or~~ • ~~more than 15% of its total applicable personnel.~~

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	November 13, 2014	Adopted by Board of Trustees	Merged EOP-001-2.1b, EOP-002-3.1 and EOP-003-2.
1	November 19, 2015	FERC approved EOP-011-1. Docket Nos. RM15-7-000, RM15-12-000, and RM15-13-000. Order No. 818	
2	June 11,2021	Adopted by ~~the~~ Board of Trustees	Revised under Project 2019-06
2	August 24,2021	FERC approved EOP-011-2. Docket Number RD21-5-000	
2	August 24,2021	Effective Date	4/1/ 2023
3	TBD		Revised under Project 2021-07

Attachment 1-EOP-~~011-2~~011-3 Energy Emergency Alerts

Introduction

This Attachment provides the process and descriptions of the levels used by the Reliability Coordinator in which it communicates the condition of a Balancing Authority which is experiencing an Energy Emergency.

A. General Responsibilities

1. **Initiation by Reliability Coordinator.** An Energy Emergency Alert (EEA) may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of an energy deficient Balancing Authority.

2. **Notification**. A Reliability Coordinator who declares an EEA shall notify all Balancing Authorities and Transmission Operators in its Reliability Coordinator Area. The Reliability Coordinator shall also notify all neighboring Reliability Coordinators.

B. EEA Levels

Introduction

To ensure that all Reliability Coordinators clearly understand potential and actual Energy Emergencies in the Interconnection, NERC has established three levels of EEAs. The Reliability Coordinators will use these terms when communicating Energy Emergencies to each other. An EEA is an Emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC Reliability Standards.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. **EEA 1 — All available generation resources in use. Circumstances:**

   - The Balancing Authority is experiencing conditions where all available generation resources are committed to meet firm Load, firm transactions, and reserve commitments, and is concerned about sustaining its required Contingency Reserves.

   - Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. **EEA 2 — Load management procedures in effect. Circumstances:**

   - The Balancing Authority is no longer able to provide its expected energy requirements and is an energy deficient Balancing Authority.

   - An energy deficient Balancing Authority has implemented its Operating Plan(s) to mitigate Emergencies.

- An energy deficient Balancing Authority is still able to maintain minimum Contingency Reserve requirements.

During EEA 2, Reliability Coordinators and energy deficient Balancing Authorities have the following responsibilities:

2.1 Notifying other Balancing Authorities and market participants. The energy deficient Balancing Authority shall communicate its needs to other Balancing Authorities and market participants. Upon request from the energy deficient Balancing Authority, the respective Reliability Coordinator shall post the declaration of the alert level, along with the name of the energy deficient Balancing Authority on the RCIS website.

2.2 Declaration period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators**.**

2.3 Sharing information on resource availability. Other Reliability Coordinators of Balancing Authorities with available resources shall coordinate, as appropriate, with the Reliability Coordinator that has an energy deficient Balancing Authority.

2.4 Evaluating and mitigating Transmission limitations. The Reliability Coordinator shall review Transmission outages and work with the Transmission Operator(s) to see if it's possible to return to service any Transmission Elements that may relieve the loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).

2.5 Requesting Balancing Authority actions. Before requesting an EEA 3, the energy deficient Balancing Authority must make use of all available resources; this includes, but is not limited to:

2.5.1 All available generation units are on line. All generation capable of being on line in the time frame of the Emergency is on line.

2.5.2 Demand-Side Management. Activate Demand-Side Management within provisions of any applicable agreements.

3. EEA 3 —Firm Load interruption is imminent or in progress. Circumstances:

- The energy deficient Balancing Authority is unable to meet minimum Contingency Reserve requirements.

During EEA 3, Reliability Coordinators and Balancing Authorities have the following responsibilities:

3.1 Continue actions from EEA 2. The Reliability Coordinators and the energy deficient Balancing Authority shall continue to take all actions initiated during EEA 2.

3.2 Declaration Period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities, and Transmission Operators.

3.3 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator shall evaluate the risks of revising SOLs and IROLs for the possibility of delivery of energy to the energy deficient Balancing Authority. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Transmission Operator whose Transmission Owner (TO) equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists, or as allowed by the Transmission Owner whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.3.1 Energy deficient Balancing Authority obligations. The energy deficient Balancing Authority, upon notification from its Reliability Coordinator of the situation, ~~it~~ will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding.

3.4 Returning to pre-Emergency conditions. Whenever energy is made available to an energy deficient Balancing Authority such that the Systems can be returned to its pre- Emergency SOLs or IROLs condition, the energy deficient Balancing Authority shall request the Reliability Coordinator to downgrade the alert level.

3.4.1 Notification of other parties. Upon notification from the energy deficient Balancing Authority that an alert has been downgraded, the Reliability Coordinator shall notify the neighboring Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Operators that its Systems can be returned to its normal limits.

Alert 0 - Termination. When the energy deficient Balancing Authority is able to meet its Load and Operating Reserve requirements, it shall request its Reliability Coordinator to terminate the EEA.

3.4.2 Notification. The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the neighboring Balancing Authorities and Transmission Operators.

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Exhibit A-2

Proposed Reliability Standard EOP-012-1

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 for a formal 8-day ballot period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	11/17/2021
SAR posted for comment	11/22/21 – 12/21/21
30-day formal or informal comment period with ballot	5/19/22 – 6/21/22
30-day formal or informal comment period with additional ballot	8/3/22- 9/1/22

Anticipated Actions	Date
8-day final ballot	9/23/22 – 9/30/22
Board adoption	October 2022

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):

Generator Cold Weather Critical Component - Any generating unit component or associated fixed fuel supply component, that is under the Generator Owner's control, and is susceptible to freezing issues, the occurrence of which would likely lead to a Generator Cold Weather Reliability Event.

Extreme Cold Weather Temperature – The temperature equal to the lowest 0.2 percentile of the hourly temperatures measured in December, January, and February from 1/1/2000 through the date the temperature is calculated.

Generator Cold Weather Reliability Event - One of the following events for which the apparent cause(s) is due to freezing of equipment within the Generator Owner's control and the dry bulb temperature at the time of the event was at or above the Extreme Cold Weather Temperature:

(1) a forced derate of more than 10% of the total capacity of the unit and exceeding 20 MWs for longer than four hours in duration;

(2) a start-up failure where the unit fails to synchronize within a specified start-up time; or

(3) a Forced Outage.

A. Introduction

1. **Title:** **Extreme Cold Weather Preparedness and Operations**

2. **Number:** EOP-012-1

3. **Purpose:** To address the effects of operating in extreme cold weather by ensuring each Generator Owner has developed and implemented plan(s) to mitigate the reliability impacts of extreme cold weather on its generating units.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Generator Owner

   4.1.2. Generator Operator

   4.2. Facilities:

   4.2.1 For purposes of this standard, the term "generating unit" subject to these requirements refers to the following Bulk Electric System (BES) resources:

   4.2.1.1 A Bulk Electric System generating unit that commits or is obligated to serve a Balancing Authority load pursuant to a tariff obligation, state requirement as defined by the relevant electric regulatory authority, or other contractual arrangement, rule, or regulation, for a continuous run of four hours or more at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius); or

   4.2.1.2 A Blackstart Resource

   4.2.2 Exemptions:

   4.2.2.1 Any Bulk Electric System generating unit included under Section 4.2.1 above that has a calculated Extreme Cold Weather Temperature exceeding 32 degrees Fahrenheit (zero degrees Celsius) under Requirement R3 Part 3.1 and as part of the required five year review in Requirement R4 Part 4.1 is exempt from further requirements in this standard.

   4.2.2.2 A Bulk Electric System generating unit that is not committed or obligated to operate at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius) for any continuous run of more than four hours, but is called upon to operate for more than four hours in order to assist in the mitigation of BES Emergencies, Capacity Emergencies, or Energy Emergencies during periods at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius).

5. **Effective Date:** See Implementation Plan for Project 2021-07.

B. Requirements and Measures

R1. For each generating unit(s) with a commercial operation date subsequent to [Effective Date of this requirement], the Generator Owner shall: [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning, Operations Planning*]

- Implement freeze protection measures that provide capability to operate for a period of not less than twelve (12) continuous hours at the Extreme Cold Weather Temperature for the unit(s), assuming a concurrent twenty (20) mph wind speed on any exposed Generator Cold Weather Critical Components; or

- Explain in a declaration any technical, commercial, or operational constraints, as defined by the Generator Owner, that preclude the ability to implement appropriate freeze protection measures to provide capability of operating for twelve (12) hours at the documented Extreme Cold Weather Temperature.

M1. Each Generator Owner will have dated evidence that demonstrates it has the capability to operate in accordance with Requirement R1. Acceptable evidence may include, but is not limited to, the following (electronic or hardcopy format): Documentation of cold weather preparedness plan, documentation of design features, any declaration that contains dated documentation to support constraints identified by the Generator Owner.

R2. For each generating unit(s) in commercial operation prior to [Effective Date of this requirement], the Generator Owner shall ensure its generating unit(s) add new or modify existing freeze protection measures as needed to provide the capability to operate for a period of not less than one (1) hour at the unit(s) Extreme Cold Weather Temperature. Generating unit(s) that are not capable of operating for one (1) hour at its Extreme Cold Weather Temperature shall develop a Corrective Action Plan (CAP) for the identified issues, including identification of any needed modifications to the cold weather preparedness plan required under Requirement R3. [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning, Operations Planning*]

M2. Each Generator Owner will have dated evidence that demonstrates it has freeze protection measures for its unit(s) in accordance with R2, or it has developed a CAP for the identified issues. Acceptable evidence may include the following (electronic or hardcopy format): Identification of generating units minimum temperature per Part 3.5.2 which is equal to or less than the unit's Extreme Cold Weather Temperature, documentation of freeze protection measures, cold weather preparedness plan, and CAP(s).

R3. Each Generator Owner shall implement and maintain one or more cold weather preparedness plan(s) for its generating units. The cold weather preparedness plan(s) shall include the following, at a minimum: *[Violation Risk Factor: High] [Time Horizon: Operations Planning and Real-time Operations]*

3.1 The Extreme Cold Weather Temperature for their unit(s) including the calculation date and source of temperature data;

3.2 Documentation identifying the Generator Cold Weather Critical Components;

3.3 Documentation of freeze protection measures implemented on Generator Cold Weather Critical Components which may include measures used to reduce the cooling effects of wind determined necessary by the Generator Owner to protect against heat loss, and where applicable, the effects of freezing precipitation (e.g., sleet, snow, ice, and freezing rain);

3.4 Annual inspection and maintenance of generating unit(s) freeze protection measures; and

3.5 Generating unit(s) cold weather data, to include:

3.5.1 Generating unit(s) operating limitations in cold weather to include:

3.5.1.1 Capability and availability;

3.5.1.2 Fuel supply and inventory concerns;

3.5.1.3 Fuel switching capabilities; and

3.5.1.4 Environmental constraints.

3.5.2 Generating unit(s) minimum:

- Design temperature;
- Historical operating temperature; or
- Current cold weather performance temperature determined by an engineering analysis.

M3. Each Generator Owner will have evidence documenting that its cold weather preparedness plan(s) was implemented and maintained in accordance with Requirement R3.

R4. Once every five calendar years, each Generator Owner shall for each generating unit: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning, Real-Time Operations]*

4.1 Calculate the Extreme Cold Weather Temperature, and update the cold weather preparedness plan if this temperature is now lower than the previous lowest calculation;

4.2 Review its documented generating unit(s) minimum temperature contained within its cold weather preparedness plan(s), pursuant to Part 3.5.2; and

4.3 Review whether its generating units have the freeze protection measures required to operate at the Extreme Cold Weather Temperature pursuant to R1 or R2 as applicable, and if not develop a CAP for the identified issues, including identification of any needed modifications to the cold weather preparedness plan required under Requirement R3.

M4. Each Generator Owner will have dated, documented evidence that it reviewed temperature data and updated its cold weather preparedness plan(s) in accordance with Requirement R4.

R5. Each Generator Owner in conjunction with its Generator Operator shall identify the entity responsible for providing the generating unit-specific training, and that identified entity shall provide annual training to its maintenance or operations personnel responsible for implementing the cold weather preparedness plan(s) developed pursuant to Requirement R3. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]*

M5. Each Generator Operator or Generator Owner will have documented evidence that the applicable personnel completed annual training of the Generator Owner's cold weather preparedness plan(s). This evidence may include, but is not limited to, documents such as personnel training records, training materials, date of training, agendas or learning objectives, attendance at pre-work briefings, review of work order tasks, tailboards, attendance logs for classroom training, and completion records for computer-based training in fulfillment of Requirement R5.

R6. Each Generator Owner that owns a generating unit that experiences a Generator Cold Weather Reliability Event shall develop a CAP, within 150 days or by July 1, whichever is earlier, that contains at a minimum: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

6.1 A summary of the identified cause(s) for the Generator Cold Weather Reliability Event, where applicable, and any relevant associated data;

6.2 A review of applicability to similar equipment at other generating units owned by the Generator Owner;

6.3 An identification of any temporary operating limitations or impacts to the cold weather preparedness plan, that would apply until execution of the corrective action(s) identified in the CAP.

M6. Each Generator Owner will have documented evidence that it developed a CAP in accordance with Requirement R6. Acceptable evidence may include, but is not limited to, the following dated documentation (electronic or hardcopy format): CAP(s) and updated cold weather preparedness plan(s) where indicated as needed by the CAP.

R7. Each Generator Owner shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

7.1 Implement each CAP developed pursuant to Requirements R2, R4, or R6, or explain in a declaration why corrective actions are not being implemented due to any technical, commercial, or operational constraints as defined by the Generator Owner.

7.2 Update each CAP if actions or timetables change, until completed.

M7. Each Generator Owner shall have dated evidence that demonstrates it implemented each CAP, including updating actions or timetables, or has explained in a declaration why corrective actions are not being implemented in accordance with Requirement R7. Acceptable evidence may include, but is not limited to the following dated documentation (electronic or hardcopy format): records that document the implementation of each CAP and the completion of actions for each CAP including revision history of each CAP. Evidence may also include work management program records, work orders, and maintenance records. Any declaration shall contain dated documentation to support constraints identified by the Generator Owner.

C. Compliance

1. Compliance Monitoring Process

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

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

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

- The Generator Owner shall keep data or evidence to show compliance for three years for Requirement R1, R3, and R5 and Measure M1, M3, and M5.
- The Generator Owner shall keep data or evidence to show compliance for three years, or until any Corrective Action Plan under Requirement R2 is complete, whichever timeframe is greater, for Requirement R2 and Measure M2.
- The Generator Owner shall retain the current cold weather preparedness plan(s), as evidence of review or revision history, plus each version issued since the last audit and evidence of compliance since the last audit for Requirement R4 and Measure M4. The Generator Owner shall retain any Corrective Action Plans under Requirement R4 Part 4.3 for three years or until the Corrective Action Plan is complete, whichever timeframe is greater.

- The Generator Owner shall keep data or evidence to show compliance for three years, or until any Corrective Action Plan under Requirement R6 is complete, whichever timeframe is greater, for Requirement R6 and Measure M6.
- The Generator Owner shall keep data or evidence to show compliance for three years, or until any Corrective Action Plan is complete, whichever time frame is greater, for Requirement R7 and Measure M7.

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.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 for 5% or less of its units. OR The Generator Owner did not explain in a declaration any technical, commercial, or operational constraints that preclude the ability to implement appropriate freeze protection measures for 5% or less of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 for more than 5%, but less than or equal to 10% of its units. OR The Generator Owner did not explain in a declaration any technical, commercial, or operational constraints that preclude the ability to implement appropriate freeze protection measures for more than 5%, but less than or equal to 10% of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 for more than 10%, but less than or equal to 20% of its units. OR The Generator Owner did not explain in a declaration any technical, commercial, or operational constraints that preclude the ability to implement appropriate freeze protection measures for more than 10%, but less than or equal to 20% of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 for more than 20% of its units. OR The Generator Owner did not explain in a declaration any technical, commercial, or operational constraints that preclude the ability to implement appropriate freeze protection measures for more than 20% of its units.
R2.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R2 for 5% or less of its units. OR The Generator Owner did not develop a CAP as required by	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R2 for more than 5%, but less than or equal to 10% of its units. OR The Generator Owner did not develop a CAP as required by Requirement R2 for more than	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R2 for more than 10%, but less than or equal to 20% of its units. OR The Generator Owner did not develop a CAP as required by Requirement R2 for more than	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R2 for more than 20% of its units. OR The Generator Owner did not develop a CAP as required by

	Requirement R2 for 5% or less of its units.	5%, but less than or equal to 10% of its units.	10%, but less than or equal to 20% of its units.	Requirement R2 for more than 20% of its units.
R3.	The Generator Owner implemented a cold weather preparedness plan(s), but failed to maintain it.	The Generator Owner's cold weather preparedness plan failed to include one of the applicable Parts within Requirement R3.	The Generator Owner had and maintained a cold weather preparedness plan(s), but failed to implement it. OR The Generator Owner's cold weather preparedness plan failed to include two of the applicable requirement parts within Requirement R3.	The Generator Owner does not have cold weather preparedness plan(s). OR The Generator Owner's cold weather preparedness plan failed to include three or more of the applicable requirement parts within Requirement R3.
R4.	The Generator Owner completed the actions required in Requirement R4, but was late by 30 calendar days or less.	The Generator Owner completed the actions required in Requirement R4, but was late by greater than 30 calendar days, but less than or equal to 60 calendar days.	The Generator Owner failed to complete one of the applicable requirement parts in Requirement R4 Parts 4.1 through 4.3; OR The Generator Owner completed the actions required in Requirement R4, but was late by greater than 60 calendar days.	The Generator Owner failed to complete two or more of the applicable requirement parts in Requirement R4 Parts 4.1 through 4.3.
R5.	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5 to the greater of:	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5 to the greater of:	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5 to the greater of:	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5 to the greater of:

	• one applicable personnel at a single generating unit; or • 5% or less of its total applicable personnel.	• two applicable personnel at a single generating unit; or • more than 5%, but less than or equal to 10% of its total applicable personnel.	• three applicable personnel at a single generating unit; or • more than 10%, but less than or equal to 15% of its total applicable personnel.	• four applicable personnel at a single generating unit; or • more than 15% of its total applicable personnel.
R6.	The Generator Owner developed a CAP, but not within 150 days or by July 1 as required in Requirement R6.	The Generator Owner's CAP failed to comply with one of the elements in Requirement R6, Parts 6.1 through 6.3.	The Generator Owner's CAP failed to comply with two of the elements in Requirement R6, Parts 6.1 through 6.3.	The Generator Owner's CAP failed to comply with three of the elements in Requirement R6, Parts 6.1 through 6.3. OR The Generator Owner did not develop a CAP as required by Requirement R6.
R7.	The Generator Owner implemented a CAP or explained in a declaration why corrective actions are not being implemented, but failed to update the CAP when actions or timetables changed, in accordance with Requirement R7.			The Generator Owner failed to implement a CAP or explain in a declaration why corrective actions are not being implemented in accordance with Requirement R7.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	TBD	Drafted by Project 2021-07	New

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Exhibit B

Implementation Plan

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Implementation Plan

Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination
Reliability Standards EOP-011-3 and EOP-012-1

Applicable Standard(s)

- EOP-011-3 Emergency Operations
- EOP-012-1 Extreme Cold Weather Preparedness and Operations

Requested Retirement(s)

- EOP-011-2

Prerequisite Standard(s)

- None

Proposed Definition(s)

- Generator Cold Weather Critical Component
- Extreme Cold Weather Temperature
- Generator Cold Weather Reliability Event

Applicable Entities

- See subject Reliability Standards.

Background

The purpose of Project 2021-07 is to develop Reliability Standards to enhance the reliability of the Bulk Electric System (BES) through improved operations, preparedness, and coordination during extreme cold weather, as recommended by the Federal Energy Regulatory Commission (FERC), NERC, and Regional Entity Joint Staff Inquiry into the February 2021 extreme cold weather event (the "Report").[1]

The February 2021 Event

From February 8 through 20, 2021, extreme cold weather and precipitation caused large numbers of generating units to experience outages, derates, or failures to start, resulting in energy and transmission emergencies (referred to as "the Event"). The total Event firm load shed was the

[1] *See* FERC, NERC and Regional Entity Staff Report, *The February 2021 Cold Weather Outages in Texas and the South Central United States* (Nov. 2021) (referred to as "the Report").

largest controlled firm load shed event in U.S. history and was the third largest in quantity of outaged megawatts (MW) of load after the August 2003 northeast blackout and the August 1996 west coast blackout. The Event was most severe from February 15 through February 18, 2021, and it contributed to power outages affecting millions of electricity customers throughout the regions of ERCOT, SPP, and MISO South.

Extreme cold weather has repeatedly challenged the reliable operation of the bulk-power system (BPS). The Event was the fourth in the past 10 years which jeopardized BPS reliability. In February 2011, an arctic cold front impacted the southwest U.S. and resulted in numerous generation outages, natural gas facility outages, and emergency power grid conditions with firm customer load shed. In January 2014, a polar vortex affected Texas, central and eastern U.S, which triggered many generation outages, natural gas availability issues, and resulted in emergency conditions including load shed. In January 2018, an arctic high-pressure system and below average temperatures in the south-central U.S. resulted in many generation outages and voluntary load management measures.

Project 2021-07

Project 2021-07 is a two-phase project to address the 10 sub-recommendations in Key Recommendation 1 of the Report for new or enhanced NERC Reliability Standards. This implementation plan addresses Reliability Standards EOP-011-3 and EOP-012-1, which were developed to address the first phase of Reliability Standards recommendations.

Proposed Reliability Standard EOP-012-1 is a new extreme cold weather preparedness and operations Reliability Standard that addresses Recommendations 1d, 1e, and 1f of the Report. This standard includes requirements for implementing freeze protection measures for new and existing BES generating units to operate at location-specific temperature (Requirements R1 and R2), and for addressing the causes of outages, de-rates, and failures to synchronize caused by freezing (Requirement R6). For accountability, the proposed Reliability Standard includes a requirement to implement any required Corrective Action Plans under the standard and update such plans if actions or timetables change (Requirement R7). The proposed Reliability Standard also includes requirements for cold weather preparedness plans and training (Requirements R3 and R5), originally included in Reliability Standard EOP-011-2. Proposed Reliability Standard EOP-012-1 builds upon the existing cold weather preparedness plans and training requirements by requiring entities to periodically review their local cold weather conditions to ensure the continued effectiveness of cold weather operating plans and freeze protection measures (Requirement R4) and make any updates that are needed based on changes in the local weather, and by specifying that cold weather training under Requirement R5 must be completed on an annual basis.

Proposed Reliability Standard EOP-011-3 is a revised Reliability Standard that addresses Recommendation 1j of the Report, minimizing the overlap of manual Load shed and automatic Load shed programs such as underfrequency Load shed (UFLS) and undervoltage Load shed (UVLS). This revision also removes Requirements R7 and R8, as this language was moved to the new EOP-012-1, noted above.

General Considerations

This implementation plan reflects consideration that entities will need time to develop, implement, and maintain cold weather plans and freeze protection measures. This implementation plan covers the key recommendations from the Report identified for phase one only, Recommendations 1d, 1e, 1f, and 1j.

Effective Date and Phased-In Compliance Dates

The effective dates for the proposed Reliability Standards are provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of a proposed Reliability Standard (i.e., an entire Requirement or a portion thereof), the additional time for compliance with that section is specified below. The phased-in compliance date for those particular sections represents the date 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.

Please see Figure 1 EOP-012 Implementation Timeline below for an illustration of the implementation timeline in those jurisdictions where governmental approval is required.

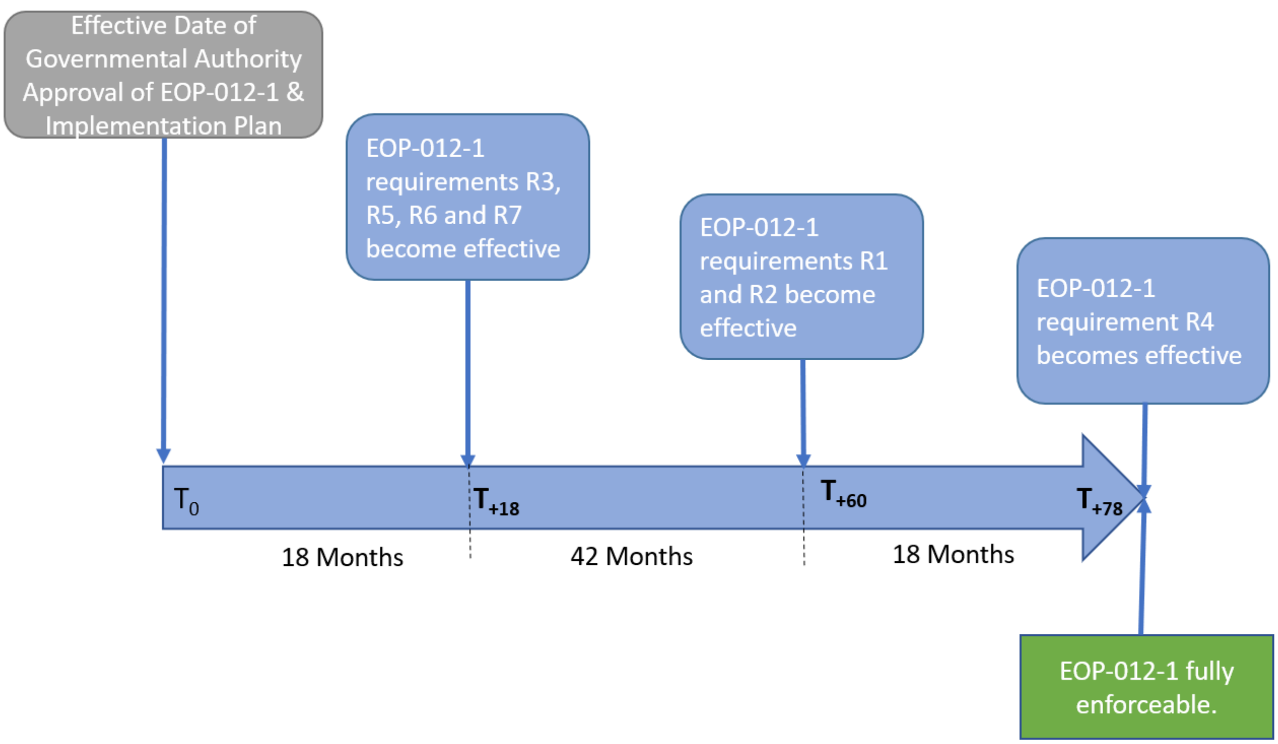

Figure 1 EOP-012 Implementation Timeline

Standard EOP-011-3

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 18 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 18 months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Standard EOP-012-1

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 18 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 18 months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Compliance Date for EOP-012-1 - Requirement R1 and R2

Entities shall not be required to comply with Requirement R1 and R2 until 42 months after the effective date of Reliability Standard EOP-012-1.

Compliance Date for EOP-012-1 - Requirement R4

Entities shall not be required to comply with Requirement R4 until 60 months after the effective date of Reliability Standard EOP-012-1.

Retirement Date

Standard EOP-011-2

Reliability Standard EOP-011-2 shall be retired immediately prior to the effective date of Reliability Standards EOP-011-3 and EOP-012-1 in the particular jurisdiction in which the revised standards are becoming effective.

Initial Performance of Periodic Requirements

Entities shall perform their first periodic review under Reliability Standard EOP-012-1 Requirement R4 by the Compliance Date (i.e. no more than 60 months after the effective date of EOP-012-1). Subsequent periodic reviews under Requirement R4 shall be performed once every five calendar years.

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Exhibit C

Technical Rationale

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Exhibit C-1

Technical Rationale
Proposed Reliability Standard EOP-011-3

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Extreme Cold Weather Preparedness

Technical Rationale and Justification for EOP-011-3

September 2022

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3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

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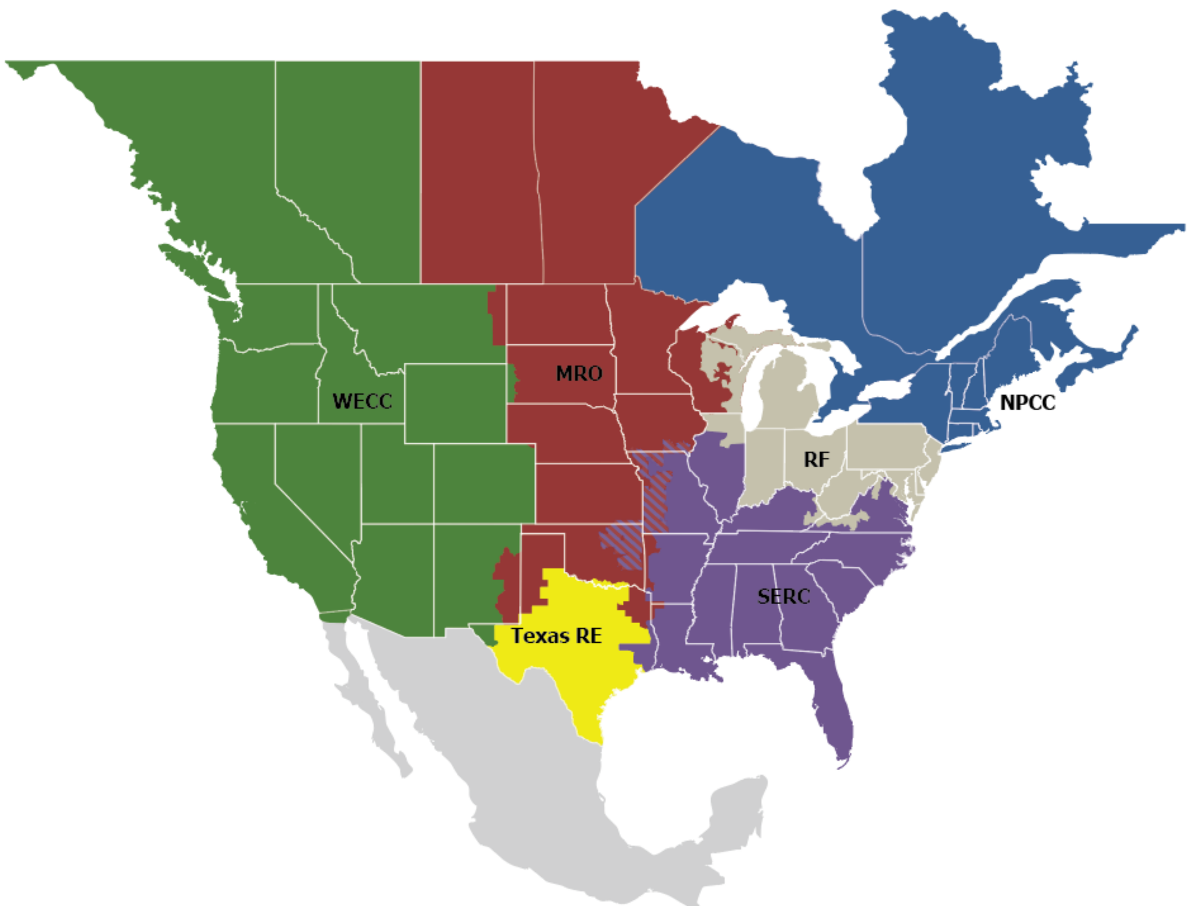
Preface

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 the North American Electric Reliability Corporation (NERC) and the six Regional Entities, is a highly reliable 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 Entity boundaries as shown in the map and 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 Standards EOP-011-3 and EOP-012-1. It provides stakeholders and the ERO Enterprise with an understanding of the technology and technical requirements in the Reliability Standard. This Technical Rationale and Justifications for EOP-011-3 and EOP-NEW is not a Reliability Standard and should not be considered mandatory and enforceable.

Background

From February 8 through February 20, 2021, extreme cold weather and precipitation caused large numbers of generating units to experience outages, derates or failures to start, resulting in energy and transmission emergencies (referred to as "the Event"). The total Event firm Load shed was the largest controlled firm Load shed event in U.S. history and was the third largest in quantity of outaged megawatts (MW) of Load after the August 2003 northeast blackout and the August 1996 west coast blackout. The Event was most severe from February 15 through February 18, 2021, and it contributed to power outages affecting millions of electricity customers throughout the regions of ERCOT, SPP and MISO South. Additionally, the February 2021 event is the fourth cold weather event in the past 10 years, which jeopardized bulk-power system reliability. A joint inquiry was conducted to discover reliability-related findings and recommendations from FERC, NERC, and Regional Entity staff. The FERC, NERC, and Regional Entity Staff Joint Staff Inquiry into the February 2021 Cold Weather Grid Operations ("Joint Inquiry Report") was published on November 16, 2021.

The scope of the proposed project is to address the ten recommendations for new or enhanced NERC Reliability Standards proposed by the Joint Inquiry Report. In November 2021, the NERC Board of Trustees (Board) approved a Board Resolution directing that new or revised Reliability Standards addressing these recommendations be completed in accordance with the timelines recommended by the joint inquiry team, as follows:

- New and revised Reliability Standards to be submitted for regulatory approval before Winter 2022/2023: development completed by September 30, 2022, for the Board's consideration in October 2022 to address Key Recommendations 1d, 1e, 1f, and 1j;
- New and revised Reliability Standards to be submitted for regulatory approval before Winter 2023/2024: development completed by September 30, 2023, for the Board's consideration in October 2023 to address Key Recommendations 1a, 1b, 1c, 1g, 1h, and 1i.

Requirement R1 and R2

R1. *Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

1.1. *Roles and responsibilities for activating the Operating Plan(s);*

1.2. *Processes to prepare for and mitigate Emergencies including:*

1.2.1. *Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency;*

1.2.2. *Cancellation or recall of Transmission and generation outages;*

1.2.3. *Transmission system reconfiguration;*

1.2.4. *Redispatch of generation request;*

1.2.5. *Operator-controlled manual Load shedding during an Emergency that accounts for each of the following:*

1.2.5.1. *Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;*

1.2.5.2. *Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that serve designated critical loads;*

1.2.5.3. *Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for underfrequency load shed (UFLS) or undervoltage load shed (UVLS); and*

1.2.5.4. *Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions.*

1.2.6. *Provisions to determine reliability impacts of:*

1.2.6.1. *cold weather conditions; and*

1.2.6.2. *extreme weather conditions.*

R2. *Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

2.1. *Roles and responsibilities for activating the Operating Plan(s);*

2.2. *Processes to prepare for and mitigate Emergencies including:*

2.2.1. *Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;*

2.2.2. *Requesting an Energy Emergency Alert, per Attachment 1;*

2.2.3. *Managing generating resources in its Balancing Authority Area to address:*

2.2.3.1. *capability and availability;*

2.2.3.2. *fuel supply and inventory concerns;*

2.2.3.3. *fuel switching capabilities; and*

2.2.3.4. *environmental constraints.*

2.2.4. *Public appeals for voluntary Load reductions;*

2.2.5. *Requests to government agencies to implement their programs to achieve necessary energy reductions;*

2.2.6. *Reduction of internal utility energy use;*

2.2.7. *Use of Interruptible Load, curtailable Load and demand response;*

2.2.8. *Provisions for Transmission Operators to implement operator-controlled manual Load shed in accordance with Requirement R1 Part 1.2.5; and*

2.2.9. *Provisions to determine reliability impacts of:*

2.2.9.1. *cold weather conditions; and*

2.2.9.2. *extreme weather conditions.*

<u>Key Recommendation 1j:</u> *In minimizing the overlap of manual and automatic load shed, the load shed procedures of Transmission Operators, Transmission Owners and Distribution Providers should separate circuits that will be used for manual load shed from circuits used for underfrequency load shedding/undervoltage load shedding or serving critical load. Underfrequency load shedding/undervoltage load shedding circuits should only be used for manual load shed as a last resort and should start with the final stage (lowest frequency).*

Requirement R1, Part 1.2.5

Minimizing the Overlap of Circuits

EOP-011 version 2, Requirement R1.2.5 states the TOP's Operating Plan shall include provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding. EOP-011-3 adds additional provisions and clarifies what the TOP must include in their Operating Plan to mitigate operating Emergencies. Specific clarifications are to minimize the overlap of manual Load shed and circuits that serve designated critical loads; minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for underfrequency load shed (UFLS) or undervoltage load shed (UVLS); and provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed.

Minimizing the overlap of manual Load shed circuits and circuits that serve critical loads is necessary to prioritize certain critical loads, which may be essential to the integrity of the electric system. The standard drafting team elected to keep the phase "minimize the overlap" instead of moving to language that specifically requires the separation of circuits in recognition of the fact that it is not always practical or warranted to completely separate circuits used for each of these purposes. This requirement can be accomplished in many different ways, such as creating separate and distinct lists for each circuit type, or by using prioritization and control-inhibit functions in an energy management system. This list is not exhaustive and there are certainly other acceptable methods of meeting this requirement.

Additionally, it is important to recognize that criticality designations must be considered in the context of the situation. Critical loads should not all receive the same level of priority, and the characteristics of a Load shed event (depth/duration/season) will impact the treatment of certain critical loads. Transmission Operators should consider establishing priorities for different types of critical loads. The critical Load designation, priority, and conditions during the event will influence which critical loads may be included in manual Load shed. For example, if system conditions continue to deteriorate and other Load shed options are exhausted, then some critical loads may need to be shed in the interest of preserving the system. It is important to have the awareness and flexibility to include or exclude certain loads based on the Load shed scenario.

The standard purposely does not state the method through which overlap is to be minimized. Transmission Operators may use a number of different approaches to satisfy this requirement. Each system is unique and will have various constraints that must be balanced in addressing these requirements.

Provisions

The term provisions, which has been carried forward from EOP-011-2, is intended to mean that it is the responsibility of the Transmission Operator to work with other entities, as necessary, to ensure that their Operating Plan is responsive to these requirements.

Limit the utilization of UFLS or UVLS for manual Load shed

In certain situations, it may be necessary and appropriate to utilize UFLS or UVLS circuits for manual Load shed. These situations may be driven by Load shed magnitudes, local constraints, or other factors. It is important for Transmission Operators to understand the circumstances where UFLS or UVLS circuits may be needed for manual Load shed. Their Operating Plans should identify system conditions that would allow for the utilization of UFLS or UVLS for manual Load shed and how it will be implemented. The Operating Plans should ensure that potential reliability impacts are appropriately considered and balanced. Three examples of such situations are discussed below.

Manual Load Shed Capabilities are Exhausted

During a major Load shed event, Transmission Operators may run out of circuits that are designated for manual Load shed. Due to the large amounts of Load shedding ordered, the duration of the Load shedding, and the exclusion of circuits serving critical Load, Transmission Operators may be forced to manually shed circuits that are utilized for UFLS or UVLS in order to maintain their obligation of total pro rata Load shed.

In such a situation, protecting system reliability requires the lesser evil of using some UFLS circuits to implement the required Load shedding. Transmission Operators should include provisions in their Operating Plans that balances the risk of the immediate emergency need to balance generation and Load to maintain reliability, with the potential for frequency disturbances in the future. In this case, Transmission Operators may elect to utilize UFLS circuits. In this scenario, the recommended practice is to start with the lowest frequency block to meet the Load shed obligations

Proactive Utilization of UFLS Circuits to Improve Outage Rotations and Balance UFLS Levels

Refer to NERC Lesson Learned on this topic:
https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20220301_Managing_UFLS_Obligations_Service_Critical_Loads_during_Energy_Emergency.pdf

Local Emergency Condition

Local emergency conditions are different from a system-wide short-supply situation. During local emergencies, it may be appropriate, and possibly necessary, to manually shed circuits that serve critical loads or that are utilized for UFLS or UVLS.

Requirement R2, Part 2.2.8

This part of R2 has been modified to refer back to Requirement R1, Part 1.2.5 in an effort to clarify that the Transmission Operator is responsible for addressing operator-controlled manual Load shed requirements in their Operating Plan. Balancing Authorities are expected to specify manual Load shed requirements for Transmission Operators within their areas in accordance with Part 1.2.5, but do not have the control or visibility to design and implement manual Load shed programs and UFLS/UVLS programs that meet the requirements of Part 1.2.5.

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Exhibit C-2

Technical Rationale
Proposed Reliability Standard EOP-012-2

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Extreme Cold Weather Preparedness

Technical Rationale and Justification for EOP-012-1

September 2022

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Atlanta, GA 30326
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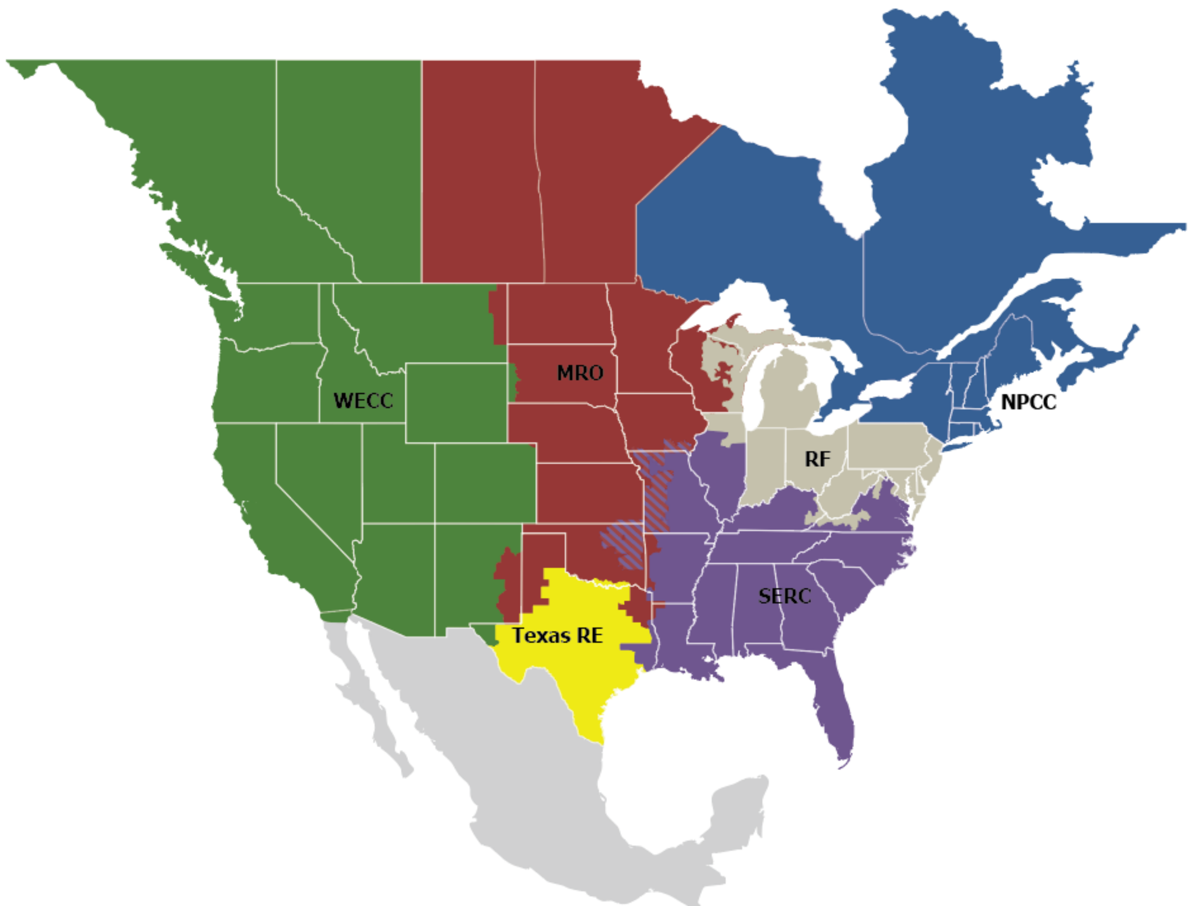
Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entity boundaries as shown in the map and 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 EOP-012-1. 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 EOP-012-1 is not a Reliability Standard and should not be considered mandatory and enforceable.

Background

From February 8 through February 20, 2021, extreme cold weather and precipitation caused large numbers of generating units to experience outages, derates or failures to start, resulting in energy and transmission emergencies (referred to as "the Event"). The total Event firm load shed was the largest controlled firm load shed event in U.S. history and was the third largest in quantity of outaged megawatts (MW) of load after the August 2003 northeast blackout and the August 1996 west coast blackout. The Event was most severe from February 15 through February 18, 2021, and it contributed to power outages affecting millions of electricity customers throughout the regions of ERCOT, SPP, and MISO South. Additionally, the February 2021 event is the fourth cold weather event in the past 10 years, which jeopardized bulk-power system reliability. A joint inquiry was conducted to discover reliability-related findings and develop recommendations from FERC, NERC, and Regional Entity staff. The FERC, NERC, and Regional Entity Staff Report into the February 2021 Cold Weather Outages ("Joint Inquiry Report") was published on November 16, 2021.

The scope of the proposed project is to address the ten recommendations for new or enhanced NERC Reliability Standards proposed by the Joint Inquiry Report. In November 2021, the NERC Board of Trustees (Board) approved a Board Resolution directing that new or revised Reliability Standards addressing these recommendations be completed in accordance with the timelines recommended by the joint inquiry team, as follows:

- New and revised Reliability Standards to be submitted for regulatory approval before Winter 2022/2023: development completed by September 30, 2022, for the Board's consideration in October 2022 to address Key Recommendations 1d, 1e, 1f, and 1j;

- New and revised Reliability Standards to be submitted for regulatory approval before Winter 2023/2024: development completed by September 30, 2023, for the Board's consideration in October 2023 to address Key Recommendations 1a, 1b, 1c, 1g, 1h, and 1i.

Facilities

4.2 Facilities:

4.2.1 For purposes of this standard, the term “generating unit” subject to these requirements refers to the following Bulk Electric System (BES) resources:

4.2.1.1 A Bulk Electric System generating unit that commits or is obligated to serve a Balancing Authority load pursuant to a tariff obligation, state requirement as defined by the relevant electric regulatory authority, or other contractual arrangement, rule, or regulation, for a continuous run of four hours or more at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius); or

4.2.1.2 A Blackstart Resource

4.2.2 Exemptions:

4.2.2.1 Any Bulk Electric System generating unit included under Section 4.2.1 above that has a calculated Extreme Cold Weather Temperature exceeding 32 degrees Fahrenheit (zero degrees Celsius) under Requirement R3 Part 3.1 and as part of the required five year review in Requirement R4 Part 4.1 is exempt from further requirements in this standard.

4.2.2.2 A Bulk Electric System generating unit that is not committed or obligated to operate at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius) for any continuous run of more than four hours, but is called upon to operate for more than four hours in order to assist in the mitigation of BES Emergencies, Capacity Emergencies, or Energy Emergencies during periods at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius).

In the Joint Inquiry Report, Key Recommendation 1f includes clarifying information, which states “consideration should be given to designing all new generation plants and designing modifications to existing plants (unless committed solely for summer peaking purposes)…[.][1] FERC staff from the Joint Inquiry Report team clarified further to the standard drafting team (SDT) that the reference to summer peaking units acknowledges that some units have not implemented freeze protection measures or may not be able to secure fuel in the winter and therefore, plan to commit solely to serve Balancing Authority load during non-winter conditions. The standard provides an Applicability section identifying which generating units are subject to the requirements, with two exemptions available if the generating unit meets two narrowly construed conditions.

The Applicability section first defines “generating unit” as a Bulk Electric System (BES) resource. The NERC Glossary of Terms provides the foundation for what BES resources are included in the definition (see Inclusions I2 through I4). The Applicability section further defines which BES resources are intended to be subject to the standards’ requirements, and explains exemptions available consistent with Key Recommendation 1f. The intent of the proposed standard is not to mandate that all generating units provide capacity in extreme cold weather, but instead to ensure that those BES resources that are obligated to serve Balancing Authority load during periods at or below freezing due to commitments pursuant to tariff obligations, state requirements defined by regulatory authorities, or other contractual arrangements, rules, or regulations are subject to the winterization requirements. The SDT chose the four-hour timeframe in consideration of generators that typically do not commit during freezing conditions but are running when conditions drop below freezing for a short period of time (under four hours) and would therefore not

[1] See Report, page 189.

automatically be subject to the standard. Additionally, Blackstart Resources are also specifically declared subject to the winterization requirements. Such Blackstart Resource, consistent with the NERC Glossary of Terms, are those units designated in the Transmission Operator's restoration plans.

Applicability section 4.2.2.1 clarifies further that a BES resource that is included pursuant to Applicability section 4.2.1 but that has a calculated Extreme Cold Weather Temperature exceeding freezing is also exempt. However, such generators must comply with the ongoing five-year review requirements of R4 Part 4.1 to ensure its ongoing exemption is appropriate. If a five-year review determines that the Extreme Cold Weather Temperature for the BES resource has fallen to freezing or below, then such BES resource will become subject to the requirements. With regards to the exemption provision contained in the Applicability section 4.2.2.2, BES resources exempt under the Applicability section but are called upon during extreme cold weather emergency contingencies should be able to respond to the Balancing Authority's commitment requests without triggering the requirements. This language ensures that this intent is satisfied for all requirements that follow.

In summary, to meet the intent of Recommendation 1f as clarified by FERC staff, a BES resources as defined by the NERC Glossary of Terms is subject to EOP-12-1 if it operates pursuant to an obligation to run for more than four continuous hours at or below freezing. However, the BES resource may be exempt from the requirements if the BES resources not be committed or otherwise obligated to run at or below freezing conditions for more than a four-hour continuous operation.

Additionally, such exclusion applies even when such generator is called upon to assist in the mitigation of a declared energy contingency (defined in the NERC Glossary of Terms as a BES Emergency, Capacity Emergency, or Energy Emergency). The language works as a blanket inclusion of all BES resources that serve Balancing Authority load for a period of more than four hours in freezing conditions, with the exemption of summer units or BES Resources that are not committed to serve load during non-winter conditions (e.g. summer peaking units); and the exemption is maintained by such BES resources when committed for a short period during energy contingencies.

Defined Terms

The SDT developed three terms to be added to the NERC Glossary to make the requirements easier to read and understand. These three terms are:

Extreme Cold Weather Temperature

The temperature equal to the lowest 0.2 percentile of the hourly temperatures measured in December, January, and February from 1/1/2000 through the date the temperature is calculated.

The definition of Extreme Cold Weather Temperature was developed by the SDT to provide clarity to the Generator Owner on determining what temperature triggers the requirement obligations. Each Generator Owner should select a reliable source of data from a recording location near the plant to determine their Extreme Cold Weather Temperature. Sources would include, for example, the National Weather Service (NWS) or National Oceanographic and Atmospheric Administration (NOAA) weather stations, Federal Aviation Administration (FAA) weather stations, or Environment and Climate Change Canada location for Canadian entities[2], etc. NOAA's National Centers for Environmental Information provides Climate Data Online (CDO) as a free resource that includes quality-controlled weather data and 30-year Climate Normals[3]. In general, Generator Owners should use the location nearest the plant, but may select a further location if geographic or local climatic patterns make a further location more representative of the weather at the generating unit. Generator Owners may use on-site weather stations if data, which reasonably matches reliable nearby off-site sources since January 1, 2000, is available. The starting period chosen by the SDT to gather data to determine the lowest temperatures that occur near a facility is based on the completion of the

[2] Environment and Climate Change Canada - Canada.ca

[3] https://www.ncei.noaa.gov/products/land-based-station/us-climate-normals

modernization of the National Weather Service project known as MAR (Modernization and Associated Restructuring). This project was completed in the year 2000. In general, the National Weather Service modernization provides weather data to be available at most large airports at a 99%+ availability. This will make it fairly accessible for companies to gather data and perform the required analysis. The December through February timeframe was selected to correspond to the meteorological winter, as defined by NOAA.[4]

The SDT discussed methods for determining an Extreme Cold Weather Temperature with engineering design professionals, and it was determined that it is typical engineering practice to use a statistical approach to determine the design temperature when implementing generation facility freeze protection measures. The SDT determined that only winter temperature values (i.e. between December and February) shall be used for the statistical approach and based on analysis of multiple sites, it was determined that by using the lowest 0.2 percentile, there will be sufficient data points to ensure that a single hour at a temperature that may not be accurate, or may be a statistical anomaly, doesn't result in an overly conservative design or preclude the ability of the Generator Owner to use historical operating data to prove compliance to the standards. The SDT selected the 0.2 percentile of winter month temperatures since 1/1/2000 to identify a temperature which has been rarely surpassed, but which allows some margin for a Generator Owner to have previously demonstrated successful operation. The SDT considered using the lowest recorded hourly ambient temperature but, upon further review of the historical weather data and generally accepted design principles, determined that the statistical approach to setting the extreme cold weather temperature for a site was more reasonable.

Generator Cold Weather Critical Component

Any generating unit component or associated fixed fuel supply component, that is under the Generator Owner's control and that is susceptible to freezing issues, the occurrence of which would likely lead to a generating unit(s): (1) forced derate of more than 10% of the total capacity of the unit and exceeding 20 MWs for longer than four hours in duration, (2) a start-up failure where the unit fails to synchronize within a specified start-up time, or (3) a Forced Outage.

The SDT felt the best method to address where freeze protection measures should be implemented was to define a term which specifies a subset of components that may be susceptible to freezing, and are critical to the operation of generating units. A fixed fuel supply component is intended to cover non-mobile equipment that supports the reliable delivery of fuel to the generating unit that is controlled by the Generator Owner. It would include gaseous, liquid, or solid fuel handling components that are installed as fixed parts of the fuel delivery system that are under the Generator Owner's control. It would not include mobile equipment such as trains, bulldozers, or other equipment that are not fixed in one location.

The SDT's intent with regard to the language "that is under the Generator's Owner's control" was to clearly delineate that cold weather events external to Generation site such as loss of fuel supply or loss of auxiliary power to the site that resulted in a Cold Weather Reliability Event would not be subject to this standard. Furthermore, ice buildup on Transmission lines would not constitute a freezing condition in the context of this Standard and therefore these Transmission Lines would not be considered a Generator Cold Weather Critical Component.

Generator Cold Weather Reliability Event

One of the following events for which the apparent cause(s) is due to freezing of equipment within the Generator Owner's control and the dry bulb temperature at the time of the event was at or above the Extreme Cold Weather Temperature:

> *(1) a forced derate of more than 10% of the total capacity of the unit and exceeding 20 MWs for longer than four hours in duration;*

[4] https://www.ncei.noaa.gov/news/meteorological-versus-astronomical-seasons

(2) a start-up failure where the unit fails to synchronize within a specified start-up time; or

(3) a Forced Outage.

The SDT is using the definition of apparent as defined in the dictionary as "clear or manifest to the understanding". For more explanation on this definition please see Requirement R6 Technical Rationale Below.

Requirement R1 and R2

R1. *For a generating unit(s) with a commercial operation date subsequent to [Effective Date of this requirement], the Generator Owner shall: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]*

- *Implement freeze protection measures that provide capability to operate for a period of not less than twelve (12) continuous hours at the Extreme Cold Weather Temperature for the unit(s), assuming a concurrent twenty (20) mph wind speed on any exposed Generator Cold Weather Critical Components; or*
- *Explain in a declaration, any technical, commercial, or operational constraints as defined by the Generator Owner that preclude the ability to implement appropriate freeze protection measures to provide capability of operating for twelve (12) hours at the documented Extreme Cold Weather Temperature.*

R2. *For each generating unit(s) in commercial operation prior to [Effective Date of this requirement], the Generator Owner shall ensure its generating unit(s) add new or modify existing freeze protection measures as needed to provide the capability to operate for a period of not less than one (1) hour at the unit(s) Extreme Cold Weather Temperature. Generating unit(s) that are not capable of operating for one (1) hour at its Extreme Cold Weather Temperature shall develop a Corrective Action Plan (CAP) for the identified issues, including identification of any needed modifications to the cold weather preparedness plan required under Requirement R3. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]*

<u>Key Recommendation 1f:</u> To require Generator Owners to retrofit existing generating units, and when building new generating units, to design them to operate to a specified ambient temperature and weather conditions (e.g., wind, freezing precipitation). The specified ambient temperature and weather conditions should be based on available extreme temperature and weather data for the generating unit's location.

General Considerations

As referenced in Key Recommendation 1f above, the specified ambient temperature and weather conditions should be based on available extreme temperature and weather data for the generating unit's location. FERC staff from the Joint Inquiry Report team clarified to the SDT that the reliability goal of the recommendation for existing generating units is to have the necessary freeze protection measures to be able to operate at extreme cold temperatures and weather for the generating unit's location. For example, those measures may consist of existing[5] or new, permanent and/or temporary measures[6] to maintain operation during extreme cold temperatures. Therefore, FERC staff clarified that the joint team's intent of the word retrofit is "to implement new, and/or make modifications to existing freeze protection measures for existing generating units."

[5] While the dictionary definition of the word retrofit includes to install (new or modified parts or equipment) in something previously manufactured or constructed, its origin suggests the need for replacing existing equipment with new technologies, which was not the intent of the joint team in this case. See Merriam-Webster definition.

[6] Some freeze protection measures may need to be removed for summer temperature operation.

In discussions with the Joint Inquiry Report team and in reading the Joint Inquiry Report itself, it is clearly stated that "consideration should be given to designing all new generation plants and designing modifications to existing plants (unless committed solely for summer peaking purposes) to be able to perform at the lowest recorded ambient temperature for the nearest city for which historical weather data is available …)". The Report went on to provide evidence that "Not only did generating units fail to perform at the lowest recorded ambient temperature for the nearest city, but many failed to perform at their own ambient design temperatures". The Joint Inquiry Report also notes that "Over 40 percent of the GOs/GOPs in the south-central U.S. regions where "freezing issues" were identified as the predominant cause of unplanned generation outages, derates or failures to start stated that they did not incorporate specific generator-related recommendations from the 2011 Report[7] or specific recommendations from the Guideline[8]."

Based on the generating unit data contained in the Joint Inquiry Report, many generating units that operate in the winter season are not properly winterized to remain in reliable service during the most extreme cold weather conditions that they may reasonably be expected to experience at their locations. As the load on the grid is the most elevated at these extreme conditions, these are the periods when it is most critical that these generating units maintain their reliability. As such, Requirement 1 ensures that generating units are proactively taking steps to design and maintain their units to maintain their reliability during extreme cold weather.

Requirement R1

The Joint Inquiry Report key recommendation 1f references recommendation 12 of the 2011 report suggesting that consideration should be given to designing all new generation plants and designing modifications to existing plants (unless committed solely for summer peaking purposes) to be able to perform at the lowest recorded ambient temperature for the nearest city for which historical weather data is available. The Joint Inquiry Report states "The Standards Drafting Team can decide what additional specificity is desirable for this requirement, for example, specifying the number of years of weather data to be considered in establishing the required ambient temperature and weather conditions, and the source of the extreme temperature and weather data". The SDT considered several options of how many years back historical data should be analyzed (e.g., 10 years, 30 years, 50 years, 100 years). There is concern that some geographical areas may not have reliable data dating back 100 years. The SDT's meteorological research finds that significant improvements were made and modernization of weather stations implemented in the early years of the 21st century. Given this, the SDT settled on the look back date of January 1, 2000.

The key recommendation identifies wind and freezing precipitation as examples of weather conditions to consider during the design of new generating units and modifications to existing plants. Realizing the many differences in weather that generator sites face across the Regions, the 2021-07 SDT developed language to provide additional context and detail around these weather conditions, while allowing flexibility for site-specific circumstances. The requirement language considers wind at a specific rate when designing new facilities. New units with commercial operation dates after the effective date of EOP-012-1 shall implement freeze protection measures such that their facilities are capable of continuous operation for not less than 12 hours at the Extreme Cold Weather Temperature assuming a concurrent twenty (20) mph wind speed on any exposed Generator Cold Weather Critical Component.

Because R1 is applicable to newly designed facilities, there is no allowance for a CAP. However, it is recognized that technical, commercial, or operational constraints may exist that prevent a new generating unit(s) from being capable of twelve (12) continuous hours of operation at their identified Extreme Cold Weather Temperature. Thus, the SDT included in R1, the option for the Generator Owner to make a declaration supporting why technical, commercial, or operational constraints preclude the ability to implement appropriate freeze protection measures. The SDT chose 12 hours of continuous operation because it is a typical length of the nighttime in winter and the maximum amount of

[7] Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011

[8] Reliability Guideline Generating Unit Winter Weather Readiness - Current Industry Practices

time that generating units would experience the Extreme Cold Weather Temperature. The SDT chose a concurrent 20 mph speed after an evaluation using the wind chill formula developed by the US National Weather Service (NWS) in the United States. Though wind chill temperature is not an exact science, it is widely understood to reflect the non-linear increased rate of convective heat loss due to air moving at different velocities. Commonly available charts show wind chill temperatures as a function of actual air temperature at various wind speeds. As it turns out, about 2/3 of the wind chill temperature drop between 0 – 60 mph is already achieved at 20 mph. Using the NWS chart, this holds true for still air temperatures starting at 40 F and dropping in 20-degree increments to -40 F. Further, 20 mph is a wind speed commonly experienced across the NERC area and yet appropriately higher than the approximate average wind speeds in the United States and Canada, 6-12 mph and 8-11 mph respectively.

Requirement R2

The SDT created a requirement to develop a CAP for generating units in commercial operation prior to the effective date of EOP-012-1 that requires either new freeze protection measures, or modification of existing freeze protection measures, to be capable of one hour of continuous operation at their identified Extreme Cold Weather Temperature. The SDT chose one hour as opposed to 12 hours for existing generation to recognize the fact that it is extremely difficult to perform the same level of design analysis, and/or documented historical operation on existing generation as on new generation. However, it is recognized that modifications or corrective actions may not be feasible under all circumstances due to technical, commercial, or operational constraints.

Additionally, the SDT considered the potential for unintended consequences, such as limiting participation by generation units in cold temperatures or accelerating generator retirements, caused by requirements to develop and implement CAPs to be capable of operations under the conditions defined in R2.

The SDT discussed setting a timeframe needed for the CAP to be completed during the drafting phase. While it is important that the CAP be completed, it would be difficult to set a definite timeframe due to the number of variables that could impact the completion of the CAP once the cause is determined. The requirements five year implementation plan is focused solely on the development of the CAP, not completion of the CAP. The SDT believes that it is more important to develop a CAP that identifies the solution and resolves the situation correctly regardless of time. Therefore, the team did not define a time when the CAP needs to be completed.

Requirement R3

R3. *Each Generator Owner shall implement and maintain one or more cold weather preparedness plan(s) for its generating units. The cold weather preparedness plan(s) shall include the following, at a minimum: [Violation Risk Factor: High] [Time Horizon: Operations Planning and Real-time Operations]*

- **3.1** *The Extreme Cold Weather Temperature for their unit(s) including the calculation date and source of temperature data;*
- **3.2** *Documentation identifying the Generator Cold Weather Critical Components;*
- **3.3** *Documentation of freeze protection measures implemented on Generator Cold Weather Critical Components which may include measures used to reduce the cooling effects of wind determined necessary by the Generator Owner to protect against heat loss, and where applicable, the effects of freezing precipitation (e.g., sleet, snow, ice, and freezing rain);*
- **3.4** *Annual inspection and maintenance of generating unit(s) freeze protection measures; and*
- **3.5** *Generating unit(s) cold weather data, to include:*
  - **3.5.1** *Generating unit(s) operating limitations in cold weather to include:*
    - **3.5.1.1** *Capability and availability;*
    - **3.5.1.2** *Fuel supply and inventory concerns;*

3.5.1.3 *Fuel switching capabilities; and*

3.5.1.4 *Environmental constraints.*

3.5.2 *Generating unit(s) minimum:*

- *Design temperature;*
- *Historical operating temperature; or*
- *Current cold weather performance temperature determined by an engineering analysis.*

General Considerations

Requirement R3 requires Generator Owners to develop and maintain cold weather preparedness plans for its unit(s) and describes the information and documentation required in such plans. It is an expansion of the cold weather preparedness plan required under Requirement R7 of EOP-011-2, and is intended to be used and reviewed regularly by the Generator Owner; R3.4 requires the GO to annually inspect the freeze protection measures. Working in concert with other parts of EOP-012, including R4 and R5, the plan will be regularly reviewed and updated and the GO is required to annually train personnel on its requirements.

Requirement R3 Part 3.1

In R3.1, the Generator Owner is required to determine the Extreme Cold Weather Temperature, as defined in the standard, for each unit using reliable source of data. The SDT believes that the GO is in the best position to select the most representative weather information relative to its generating unit.

Requirement R3 Part 3.2

In R3.2, the Generator Owner identifies the Generator Cold Weather Critical Components to help inform their decision on where to implement appropriate freeze protection measures. The document *Reliability Guideline, Generating Unit Winter Weather Readiness – Current Industry Practices*[9], NERC, 2012 presents a suggested list of components that Generator Owners may choose to utilize when developing their own Generator Cold Weather Critical Component inventory.

Requirement R3 Part 3.3

R3.3 requires GOs to document the freeze protection measures implemented on cold-weather-critical components. These freeze protection measures may include those to reduce the cooling effects of wind. Requirement R3 does not require Generator Owners to install new freeze protection measures to reduce the cooling effects of wind, but rather to document those measures. These measures would include temporary measures such as wind breaks. There is no expectation for entities to list all climate controlled areas as freeze protection measures. Similar to the cooling effects of wind, R3 requires Generator Owners to document freeze protection measures taken to reduce the effects of freezing precipitation on cold-weather-critical components, as the Generator Owners determine if necessary (e.g. water-resistant insulation, protective shielding, insulated boxes, etc.).

Requirement R3 Part 3.4

R3.4 is carried over from the previously approved EOP-011-2 standard, and requires annual inspection and maintenance of the freeze protection measures identified in the cold weather preparedness plan. This requirement ensures these freeze protection measures will be ready and serviceable when needed. Examples of documentation to demonstrate inspections and maintenance has been completed would be completed work order(s) from the Generator Owner's work management system and/or freeze protection checklists identifying the measures inspected and maintained.

[9] Reliability Guideline Generating Unit Winter Weather Readiness – Current Industry Practices

Requirement R3 Part 3.5

R3.5 is carried over from the previously approved EOP-011-2 standard, and requires the Generator Owner to document several cold weather performance parameters for the unit. This information is valuable, and in some cases, must be shared with other entities. Defining the operating limitations in R3.5.1 will make affected personnel more aware of unit capabilities and constraints as well as systems and practices that may be necessary to ensure reliability in cold weather, particularly when alternative fuels are involved. In addition, the unit minimum temperature identified in R3.5.2 is used to demonstrate compliance with R2 for existing units.

Requirement R4

R4. *Once every five calendar years, each Generator Owner shall for each generating unit: [Violation Risk Factor: Low] [Time Horizon: Operations Planning, Real-Time Operations]*

4.1 *Calculate the Extreme Cold Weather Temperature, and update the cold weather preparedness plan if this temperature is now lower than the previous lowest calculation;*

4.2 *Review its documented generating unit(s) minimum temperature contained within its cold weather preparedness plan(s), pursuant to Part 3.5.2; and*

4.3 *Review whether its generating units have the freeze protection measures required to operate at the Extreme Cold Weather Temperature pursuant to R1 or R2 as applicable, and if not develop a CAP for the identified issues, including identification of any needed modifications to the cold weather preparedness plan required under Requirement R3.*

The SDT has developed the new standard with language that supports the ongoing consideration of new technologies when protecting against extreme cold weather, and an ongoing review requirement to validate or update the Extreme Cold Weather Temperature associated with each unit. This five-year review supports the desire for Generator Owners to periodically vet these new technologies and consider whether any technical, commercial, or operational constraints are still applicable.

Requirement R5

R5. *Each Generator Owner in conjunction with its Generator Operator shall identify the entity responsible for providing the generating unit-specific training, and that identified entity shall provide annual training to its maintenance or operations personnel responsible for implementing cold weather preparedness plan(s) developed pursuant to Requirement R3. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]*

<u>Key Recommendation 1e:</u> To revise EOP-011-2, R8, to require Generator Owners and Generator Operators to conduct annual unit-specific cold weather preparedness plan training.

Project 2019-06 Cold Weather established the requirement that the Generator Owner, in conjunction with its Generator Operator, would provide generating unit-specific training for its personnel responsible for implementing cold weather preparedness plan(s) for its generating units. The Joint Inquiry Report recommended that EOP-011-2 R8 be revised to require the generating unit-specific training be provided on an "annual" basis. The report explains "Responses from the GOs/GOPs involved in the Event show that annual training is not yet universal in the Event Area." To address this recommendation, the SDT has utilized the existing language in EOP-011-2 and added the word "annual" to require the training on an annual basis. The requirement is deleted from EOP-011-3, and will be placed as a requirement in a new EOP-012-1 Reliability Standard dedicated solely to extreme cold weather preparedness.

Requirement R6

R6. *Each Generator Owner that owns a generating unit that experiences a Generator Cold Weather Reliability Event shall develop a CAP, within 150 days or by July 1, whichever is earlier, that contains at a minimum: [Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

6.1 *A summary of the identified cause(s) for the Generator Cold Weather Reliability Event where applicable and any relevant associated data;*

6.2 *A review of applicability to similar equipment at other generating units owned by the Generator Owner;*

6.3 *An identification of any temporary operating limitations or impacts to the cold weather preparedness plan, that would apply until execution of the corrective action(s) identified in the CAP.*

<u>Key Recommendation 1d:</u> To require Generator Owners that experience outages, failures to start, or derates due to freezing to review the generating unit's outage, failure to start, or derate and develop and implement a corrective action plan (CAP) for the identified equipment, and evaluate whether the CAP applies to similar equipment for its other generating units. Based on the evaluation, the Generator Owner will either revise its cold weather preparedness plan to apply the CAP to the similar equipment, or explain in a declaration (a) why no revisions to the cold weather preparedness plan are appropriate, and (b) that no further corrective actions will be taken. The standard drafting team should specify the specific timing for the CAP to be developed and implemented after the outage, derate, or failure to start, but the CAP should be developed as quickly as possible, and be completed by no later than the beginning of the next winter season.

The key recommendation from the report recommends a standard that requires Generator Owners to develop a CAP for generating units that experience outages, failures to starts, or derates due to freezing. The Report identifies that most of the outages and derates in the February 2021 event were due to freezing of instrumentation, transmitters, sensing lines, or wind turbine blades (p 166 in report). As such, the team followed the Report recommendation to require a CAP when the apparent cause of the event is freezing. The Project 2021-07 SDT has developed parameters around these events to clarify a reasonable baseline of what level of de-rate qualifies as an event, and provide additional language to identify what constitutes a start-up failure. With the additional clarifications, the SDT determined that the standard would benefit from a defined term, to clearly and efficiently state what constitutes an event. The result is to a new defined term, Generator Cold Weather Reliability Event, that defines the circumstances for which a CAP is required (i.e., when a freezing event effects the equipment within the control of the Generator Owner). The defined term will make the standard easier to understand and implement by providing clear and reasonable factors to determine whether the impact of an event requires mitigation

General Considerations for All CAPs

To simplify the proposed requirements related to creating a CAP, the SDT has modified the proposed requirements addressing the need for a CAP while better incorporating the NERC Definition of a CAP. The CAP definition reads "A list of actions and an associated timetable for implementation to remedy a specific problem." As written, the definition requires two parts for a document to qualify as a CAP, i.e., a list of items to be addressed and a timeline for completion. In the original posting, the SDT included both items in separate bullets to be included in the CAP. To simplify the requirements, the SDT has removed the bullets. As these two elements are both required for a document to qualify as a CAP, there is no need to list these items separately within the standard. A CAP without both a list of actions and the timeline to implement is not complete.

Requirement R6

The CAP requirement applies to any forced outage due to freezing, regardless of duration. Derates, which are short-lived (specified as 4 hours by the SDT) or of small capacity impact (specified as less than 20 MW by the SDT, which corresponds with the threshold for BES impacting Generation units), are excluded from the CAP requirement to limit the administrative burden to Generator Owners for events that are minimally impacting to the BES. It should be noted that nothing in this standard prevents a Generator Owner from taking its own corrective actions resulting from such events. Startup failures are defined using the GADS definition with the removal of "following an outage or reserve shutdown", since the definition of Reserve shutdown is different in GADS than it is in some of the RTO's.

R6 requires the Generator Owner to act within 150 days or by July 1 to develop the CAP. These timeframe options were chosen by the SDT to allow Generator Owner's to review multiple events holistically following a winter season if that scenario occurs, and create one CAP for components with common failure causes.

The SDT determined that CAPs will be required for any freezing event that occurs at temperatures above the site's Extreme Cold Weather Temperature. By using the site's Extreme Cold Weather Temperature, as opposed to the Generator Unit Minimum Temperature as defined by the Generator Owner as the threshold, this achieves the following:

- Provides a consistent basis for the temperature at which CAPS are required for all Generator Owners
- Provides a consistent basis for when CAPS are required for all Generation types
- Provides a consistent basis for when CAPS are required regardless of the level of effort that Generators may have applied to-date winterizing their generators such that they can operate to the Extreme Cold Weather Temperature that their sites will reasonably experience
- Removes any incentive (perceived or real) to not further winterize Generator Owner's sites to meet the Extreme Cold Weather temperature at the Generator Owner site by not providing a window where one site might not be subject to the CAP requirement while sites in the same vicinity experiencing the same temperatures are subject to this requirement
- Removes any disincentive for Generator Owner's to design the units to operate well below the Extreme Cold Weather Temperature for a site by not requiring them to perform CAPs while sites in the same vicinity experiencing the same temperatures are subject to this requirement

Requirement R7

R7. Each Generator Owner shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

7.1 Implement each CAP developed pursuant to Requirements R2, R4, or R6, or explain in a declaration why corrective actions are not being implemented due to any technical, commercial, or operational constraints as defined by the Generator Owner.

7.2 Update each CAP if actions or timetables change, until completed.

The SDT has also separated the requirement to implement a CAP from the requirement to create a CAP. This is similar in structure to PRC-004-6 R5 and R6. For CAPs developed pursuant to Requirements R2, R4, and R6 in the proposed standard, the Generator Owner creates a document with a date of approximately the time of the event/determination of the need to make changes. This shows that the Generator Owner identified issues caused by cold weather. Implementation of the CAP is demonstrated through updates to the original document or completion of the tasks listed in the CAP under a separate requirement. The separation of these distinct functions facilitates administration of the process and makes it less likely for a CAP to be written but not implemented. Requirement R7 also defines the requirement to make a declaration when technical, commercial, or operational constraints are asserted.

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Exhibit D

Order No. 672 Criteria

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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 the proposed Reliability Standards have met or exceeded the criteria.

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

The proposed Reliability Standards (proposed Reliability Standards EOP-012-1 and EOP-011-3) would advance the reliability of the Bulk-Power System ("BPS") through improved operations and generator cold weather preparedness requirements. Proposed Reliability Standard EOP-012-1 is a new Reliability Standard that builds on the cold weather preparedness plan and training requirements currently found in Reliability Standard EOP-011-2 to form a comprehensive framework for advancing the reliability of the BPS through improved generator cold weather preparedness. The proposed Reliability Standard includes requirements for freeze protection

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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.").

measures for both new and existing generation, the development of enhanced cold weather preparedness plans and annual training on those plans, and the development and implementation of Corrective Action Plans to address freezing issues. Proposed Reliability Standard EOP-011-3 builds upon the improvements reflected in Reliability Standard EOP-011-2 to improve how Transmission Operators account for the overlap of manual load shed and automatic load shed in their emergency Operating Plans.

As discussed more fully in the main section of NERC's petition, NERC developed the proposed standards to address recommendations from the FERC, NERC, and Regional Entity Staff report examining the causes of the February 2021 cold weather event affecting the south central United States.[3] The proposed Reliability Standards are designed to achieve a specific reliability goal (improved cold weather preparedness and operations), and contain 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]

The proposed Reliability Standards are clear and unambiguous as to what is required and who is required to comply, in accordance with Order No. 672. Proposed Reliability Standard EOP-012-1 would apply to Generator Owners and Generator Operators owning or operating applicable Facilities. Proposed Reliability Standard EOP-011-3 would apply to Balancing Authorities,

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3 FERC, NERC, Regional Entity Staff Report: *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 [hereinafter Joint Inquiry Report].

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.").

Reliability Coordinators, and Transmission Operators. The proposed Reliability Standards clearly articulate the actions that applicable entities must take to comply with the standards.

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 the proposed Reliability Standards comport with NERC and Commission guidelines related to their assignment, as discussed further in Exhibit E. 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 Standards include 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]

The proposed Reliability Standards contain 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]

The proposed Reliability Standards achieve their reliability goals effectively and efficiently in accordance with Order No. 672. Proposed Reliability Standard EOP-012-1 would achieve the reliability goal of improving generator preparedness for cold weather, while recognizing that what constitutes "cold weather" varies across the North American continent and that generators may take different actions to meet the performance requirements of the standard. Proposed Reliability Standard EOP-011-3 would achieve the reliability goal of improving Transmission Operator emergency Operating Plans with respect to the overlap between manual and automatic load shed circuits, while allowing for flexibility in how Transmission Operators address these matters to account for system configuration and other circumstances.

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

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[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.").

[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.").

The proposed Reliability Standards do not reflect a "lowest common denominator" approach. The proposed Reliability Standards would enhance reliability in cold weather conditions by requiring Generator Owners to implement cold weather preparedness plans and to take actions to winterize their facilities to enhance their reliability in expected cold weather conditions (EOP-012-1), and by requiring Transmission Operators to take into consideration certain factors regarding the overlap between manual and automatic load shed that could impact the reliability of the system during emergency conditions (EOP-011-3).

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 Standards would apply consistently throughout North America and do not favor one geographic area or regional model. The proposed Reliability Standards would provide sufficient flexibility to accommodate regional/geographic variations, including climate, generation type, market issues, state rules, and other considerations.

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[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.").

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

The proposed Reliability Standards 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 proposed standards would require the same performance by each of the applicable entities.

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

The proposed effective date for the proposed Reliability Standards is just and reasonable and appropriately balances the urgency in the need to implement the standards against the reasonableness of the time allowed for those who must comply to develop necessary procedures or other relevant capability. The proposed implementation plan provides that the proposed Reliability Standards would become effective on the first day of the first calendar quarter that is eighteen (18) months after applicable regulatory approval. Reliability Standard EOP-011-2, which is scheduled to come into effect on April 1, 2023, would be retired immediately prior to the effective date of the revised Reliability Standards. Generator Owners would have additional 42 months from the effective date of proposed Reliability Standard EOP-012-1 to come into compliance with the new freeze protection measures requirements in Requirements R1 and R2, and 60 months from the effective date to perform their first five-year update of the Extreme Cold

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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.").

Weather Temperature. The proposed implementation plan reflects consideration that Generator Owners would need a reasonable period of time to calculate the Extreme Cold Weather Temperature for each of their generating unit(s), identify Generator Cold Weather Critical Components, and perform the necessary engineering study and analysis to identify and implement freeze protection measures that would provide the required performance capability or else explain why such measures are precluded by technical, commercial, or operational constraints under proposed Reliability Standard EOP-012-1. The implementation plan provides additional time for entities to address proposed EOP-012-1 Requirements R1 and R2 regarding the implementation of freeze protection measures on new and existing generation, in recognition of the significant engineering, design, analysis, and implementation efforts required to support such work across all applicable units in a Generator Owner's fleet, as well as resource constraints that may make an earlier implementation especially challenging. This implementation timeline also reflects consideration that Transmission Operators would need time to develop and include in their Operating Plans provisions to address the load shed considerations discussed above in proposed Reliability Standard EOP-011-3. The proposed implementation plan is attached as **Exhibit B** to this petition.

10. The Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[12]

The proposed Reliability Standards were developed in accordance with NERC's Commission-approved, ANSI-accredited processes for developing and approving Reliability

[12] *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.").

Standards. **Exhibit F** includes a summary of the Reliability Standard development proceedings, and details the processes followed to develop the proposed Reliability Standards. These processes included, among other things, comment periods, pre-ballot review periods, and balloting periods. Additionally, all meetings of the standard drafting team were properly noticed and open to the public.

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.[13]

NERC has identified no competing public interests regarding the request for approval of these proposed Reliability Standards. No comments were received that indicated that one or more of the proposed Reliability Standards conflicts with other vital public interests.

12. Proposed Reliability Standards must consider any other appropriate factors.[14]

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

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[13] *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.").

[14] *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 E

Analysis of Violation Risk Factors and Violation Severity Levels

Violation Risk Factor and Violation Severity Level Justifications

Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination

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 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination. 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.

EOP-011-3

VRF Justification for EOP-011-3, Requirement R1

The VRF did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VSL Justification for EOP-011-3, Requirement R1

The VSL did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VRF Justification for EOP-011-3, Requirement R2

The VRF did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VSL Justification for EOP-011-3, Requirement R2

The VSL did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VRF Justification for EOP-011-3, Requirement R3

The VRF did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VSL Justification for EOP-011-3, Requirement R3

The VSL did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VRF Justification for EOP-011-3, Requirement R4

The VRF did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VSL Justification for EOP-011-3, Requirement R4

The VSL did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VRF Justification for EOP-011-3, Requirement R5

The VRF did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VSL Justification for EOP-011-3, Requirement R5

The VSL did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VRF Justification for EOP-011-3, Requirement R6
The VRF did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VSL Justification for EOP-011-3, Requirement R6
The VSL did not change from the previously FERC approved EOP-011-2 Reliability Standard.
EOP-012-1

VRF Justifications for EOP-012-1, Requirement R1	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that not designing or implementing freeze protection measures for a unit to operate during the local cold weather that can be expected could directly affect the electrical state or the capability of the bulk electric system. In addition, a violation of this 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. Therefore, it is in line with the definition of a Medium VRF.
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	This VRF is in line with the definition of a medium VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
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 EOP-012-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 for 5% or less of its units. OR The Generator Owner did not explain in a declaration any technical, commercial, or operational constraints that preclude the ability to implement appropriate freeze protection measures for 5% or less of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 for more than 5%, but less than or equal to 10% of its units. OR The Generator Owner did not explain in a declaration any technical, commercial, or operational constraints that preclude the ability to implement appropriate freeze protection measures for more than 5%, but less than or equal to 10% of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 for more than 10%, but less than or equal to 20% of its units. OR The Generator Owner did not explain in a declaration any technical, commercial, or operational constraints that preclude the ability to implement appropriate freeze protection measures for more than 10%, but less than or equal to 20% of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 for more than 20% of its units. OR The Generator Owner did not explain in a declaration any technical, commercial, or operational constraints that preclude the ability to implement appropriate freeze protection measures for more than 20% of its units.

VSL Justifications for EOP-012-1, 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 VSLs 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 VSLs 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 EOP-012-1, Requirement R2	
Proposed VRF	**Low**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that not implementing freeze protection measures for a unit to operate during the local cold weather that can be expected could directly affect the electrical state or the capability of the bulk electric system. In addition, a violation of this 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. Therefore, it is in line with the definition of a Medium VRF.
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	This VRF is in line with the definition of a medium VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
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 EOP-012-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R2 for 5% or less of its units. OR The Generator Owner did not develop a CAP as required by Requirement R2 for 5% or less of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R2 for more than 5%, but less than or equal to 10% of its units. OR The Generator Owner did not develop a CAP as required by Requirement R2 for more than 5%, but less than or equal to 10% of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R2 for more than 10%, but less than or equal to 20% of its units. OR The Generator Owner did not develop a CAP as required by Requirement R2 for more than 10%, but less than or equal to 20% of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R2 for more than 20% of its units. OR The Generator Owner did not develop a CAP as required by Requirement R2 for more than 20% of its units.

VSL Justifications for EOP-012-1, 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 VSLs 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	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.

VSL Justifications for EOP-012-1, Requirement R2	
Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs 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 Justification for EOP-012-1, Requirement R3

The VRF did not change from the previously FERC approved EOP-011-2 Requirement R7 Reliability Standard.

VSL Justification for EOP-012-1, Requirement R3

The VSL did not change from the previously FERC approved EOP-011-2 Requirement R7 Reliability Standard.

VRF Justifications for EOP-012-1, Requirement R4	
Proposed VRF	**Low**
NERC VRF Discussion	A VRF of Low is appropriate due to the fact that this 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
FERC VRF G1 Discussion	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.

VRF Justifications for EOP-012-1, Requirement R4	
Proposed VRF	**Low**
Guideline 1- Consistency with 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	This VRF is in line with the definition of a low VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
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 EOP-012-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner completed the actions required in Requirement R4, but was late by 30 calendar days or less.	The Generator Owner completed the actions required in Requirement R4, but was late by greater than 30 calendar days, but less than or equal to 60 calendar days.	The Generator Owner failed to complete one of the applicable requirement parts in Requirement R4 Parts 4.1 through 4.3; OR	The Generator Owner failed to complete two or more of the applicable requirement parts in Requirement R4 Parts 4.1 through 4.3.

		The Generator Owner completed the actions required in Requirement R4, but was late by greater than 60 calendar days.	

VSL Justifications for EOP-012-1, 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 VSLs 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 VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment	Each VSL is based on a single violation and not cumulative violations.

VSL Justifications for EOP-012-1, Requirement R4	
Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	

VRF Justification for EOP-012-1, Requirement R5
The VRF did not change from the previously FERC approved EOP-011-2 Requirement R8 Reliability Standard.

VSL Justification for EOP-012-1, Requirement R5
The VSL did not substantively change from the previously FERC approved EOP-011-2 Requirement R8 Reliability Standard. The language was only updated to reflect the annual nature of the revised requirement language.

VRF Justifications for EOP-012-1, Requirement R6	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate. If violated, this requirement to take corrective actions if a generating unit experiences a derate, failure to start or forced outage due to freezing event 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.
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.

VRF Justifications for EOP-012-1, Requirement R6	
Proposed VRF	**High**
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is in line with the definition of a high VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
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 EOP-012-1, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner developed a CAP, but not within 150 days or by July 1 as required in Requirement R6.	The Generator Owner's CAP failed to comply with one of the elements in Requirement R6, Parts 6.1 through 6.3.	The Generator Owner's CAP failed to comply with two of the elements in Requirement R6, Parts 6.1 through 6.3.	The Generator Owner's CAP failed to comply with three of the elements in Requirement R6, Parts 6.1 through 6.3. OR The Generator Owner did not develop a CAP as required by Requirement R6.

VSL Justifications for EOP-012-1, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.

VSL Justifications for EOP-012-1, Requirement R6	
Current 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 VSLs 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 EOP-012-1, Requirement R7	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of medium is appropriate due to the fact that this requirement to implement a CAP develop pursuant to Requirement R2, R4 and R6, if violated, could, directly affect the electrical state or the capability of the bulk electric

VRF Justifications for EOP-012-1, Requirement R7	
Proposed VRF	**Medium**
	system. In addition, a violation of this 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. Therefore, it is in line with the definition of a Medium VRF.
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	This VRF is in line with the definition of a medium VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
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 EOP-012-1, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner implemented a CAP or explained in a declaration why corrective actions are not being implemented, but failed to update the CAP when actions or timetables changed, in accordance with Requirement R7.	N/A	N/A	The Generator Owner failed to implement a CAP or explain in a declaration why corrective actions are not being implemented in accordance with Requirement R7.

VSL Justifications for EOP-012-1, 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 VSLs 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 do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for EOP-012-1, Requirement R7	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs 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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Exhibit F

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 Standards EOP-011-3 and EOP-012-1.

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 2021-07 SDT members is included in **Exhibit G**.

II. Standard Development History

A. Board of Trustees Action

At its November 2021 meeting, the NERC Board of Trustees took action to direct the development of Reliability Standards to address the recommendations of the 2021 FERC, NERC, and Regional Entity Joint Staff Report, *The February 2021 Cold Weather Outages in Texas and the South Central United States*[3] be completed within the timelines recommended by the joint inquiry team, as follows:

- New and revised Reliability Standards to be submitted for regulatory approval before Winter 2022/2023: development completed by September 30, 2022, for the Board's consideration in October 2022;

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

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

[3] FERC, NERC, Regional Entity Staff Report: *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.

- New and revised Reliability Standards to be submitted for regulatory approval before Winter 2023/2024: development completed by September 30, 2023, for the Board's consideration in October 2023.

B. Standard Authorization Request Development

On November 17, 2021, the Standards Committee authorized posting a Standards Authorization Request ("SAR") developed in response to the Joint Inquiry Report for a 30-day formal comment period from November 22, 2021 through December 21, 2021 and authorized the solicitation of SDT members.[4] The Standards Committee accepted the SAR on February 25, 2022.

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

On May 18, 2022, the Standards Committee approved a waiver under Section 16.0 of the Standard Processes Manual to allow shorten the usual periods for comment and ballot for Project 2021-07. Specifically, the Standards Committee approved shortening the initial formal comment and ballot period from 45 days to as little as 30 days, with ballot pools formed in the first 15 days and ballots conducted in the last 10 days, shortening the additional formal comment and ballot period(s) from 45 days to as little as 25 days, with ballot conducted during the last 10 days; and shortening the final ballot from 10 days to as little as 5 days.[5]

On May 18, 2022, the Standards Committee authorized initial posting of proposed Reliability Standards EOP-011-3 and EOP-012-1, the associated Implementation Plan and other associated documents for a 30-day formal comment period. The initial posting took place from

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[4] *See* NERC Standards Committee November 17, 2021 Agenda Package, https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/SC_Agenda_Package_November_17_2021.pdf.

[5] *See* NERC Standards Committee May 18, 2022 Meeting Minutes at 1-2, https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/SC%20May%20Meeting%20Minutes%20-%20Approved%20June%2015,%202022.pdf.

May 19, 2022 through June 21, 2022, 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 comment period from June 8, 2022 through June 21, 2022.[6] The initial ballot and non-binding poll results for the proposed Reliability Standards are as follows:

- Proposed Reliability Standard EOP-011-3 received 69.66 percent approval, reaching quorum at 94.59 percent of the ballot pool. The non-binding poll for the associated VRFs and VSLs received 78.82 percent supportive opinions, reaching quorum at 88.96 percent of the ballot pool.[7]
- Proposed Reliability Standard EOP-012-1 received 21.94 percent approval, reaching quorum at 94.27 percent of the ballot pool. The non-binding poll for the associated VRFs and VSLs received 19.52 percent supportive opinions, reaching quorum at 89.67 percent of the ballot pool.[8]
- The Implementation Plan received 57.74 percent approval, reaching quorum at 93.27 percent of the ballot pool.[9]

There were 108 sets of responses, including comments from approximately 249 different individuals and approximately 162 companies, representing all 10 industry segments.[10]

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

Proposed Reliability Standard EOP-012-1, the associated Implementation Plan and other associated documents were posted for a 29-day formal comment period from August 3, 2022

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6 *Id.* at item 20. The initial comment period and ballot was extended to June 21, 2022 due the Juneteenth holiday.

7 *Id.* at items 22, 25.

8 *Id.* at items 23, 26.

9 *Id.* at item 24.

10 *Id.* at item 28.

through September 1, 2022, with a parallel additional ballot and non-binding poll held during the last 10 days of the comment period from August 23, 2022 through September 1, 2022.[11] The additional ballot and non-binding poll results for the proposed Reliability Standard are as follows:

- Proposed Reliability Standard EOP-012-1 received 69.43 percent approval, reaching quorum at 91.4 percent of the ballot pool. The non-binding poll for the associated VRFs and VSLs received 72.36 percent supportive opinions, reaching quorum at 89 percent of the ballot pool.[12]
- The Implementation Plan received 78.7 percent approval, reaching quorum at 90.71 percent of the ballot pool.[13]

There were 100 sets of responses, including comments from approximately 237 different individuals and approximately 1587 companies, representing all 10 industry segments.[14]

E. Final Ballot

Proposed Reliability Standards EOP-011-3 and EOP-012-1 were posted for an 8-day final ballot period from September 23, 2022 through September 30, 2022.[15] The ballot for the proposed Reliability Standards and associated documents are as follows:

- Proposed Reliability Standard EOP-011-3 reached quorum at 95.86 percent of the ballot pool, receiving affirmative support from 83.64 percent of the voters.[16]

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11 *Id.* at item 41.

12 *Id.* at items 43, 45.

13 *Id.* at item 44.

14 *Id.* at item 47.

15 *Id.* at item 63.

16 *Id.* at item 64.

- Proposed Reliability Standard EOP-012-1 reached quorum at 95.54 percent of the ballot pool, receiving affirmative support from 79.04 percent of the voters.[17]
- The Implemention Plan reached quorum at 95.19 percent of the ballot pool, receiving affirmative support from 87.89 percent of the voters.[18]

F. Board of Trustees Adoption

The NERC Board of Trustees adopted proposed Reliability Standards EOP-011-3 and EOP-012-1 on October 26, 2022.[19]

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17 *Id.* at item 65.

18 *Id.* at item 66.

19 NERC, *Board of Trustees Agenda Package Oct. 26, 2022*, Agenda Item 1. (Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination), https://www.nerc.com/gov/bot/Pages/Agenda-Highlights-and-Minutes-.aspx.

Complete Record of Development

Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination

Related Files

Status

Final ballots concluded at **8 p.m. Eastern, Friday, September 30, 2022** for the following standards and implementation plan:

- EOP-011-3 – Emergency Operations
- EOP-012-1 – Extreme Cold Weather Preparedness and Operations
- Implementation Plan

Background

From February 8 - 20, 2021, extreme cold weather and precipitation affected the south central United States. Large numbers of generating units experienced outages, derates, or failures to start, resulting in energy and transmission emergencies (referred to as "the Event"). The total Event firm load shed was the largest controlled firm load shed event in U.S. history and was the third largest in quantity of outaged megawatts (MW) of load after the August 2003 northeast blackout and the August 1996 west coast blackout.

Standard(s) Affected – BAL, EOP, IRO, TOP, or Other Standards as Identified in the SAR

Purpose/Industry Need

The primary purpose of this project is to address reliability related findings from the Federal Energy Regulatory Commission (FERC), NERC, and Regional Entity Joint Staff Inquiry into the February 2021 Cold Weather Grid Operations[1]. The project scope will address nine recommendations for new or enhanced NERC Reliability Standards proposed by the report.

The NERC Board of Trustees (Board) issued a resolution in November 2021 for the development of standards under this project be completed in accordance with the staged timelines recommended by the joint inquiry team, as follows:

- New and revised Reliability Standards to be submitted for regulatory approval before Winter 2022/2023: development completed by September 30, 2022 for the Board's consideration in October 2022;
- New and revised Reliability Standards to be submitted for regulatory approval before Winter 2023/2024: development completed by September 30, 2023 for the Board's consideration in October 2023.

Subscribe to this project's observer mailing list

Select "NERC Email Distribution Lists" from the "Service" drop-down menu and specify "Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination Observer List" in the Description Box.

[1] The February 2021 Cold Weather Outages in Texas and the South Central United States | FERC, NERC and Regional Entity Staff Report | Federal Energy Regulatory Commission

Draft	Actions	Dates	Results	Consideration of Comments
Final Draft **EOP-011-3** **(48)** Clean | **(49)** Redline to Last Posted | **(50)** Redline to Last Approved **EOP-012-1** **(51)** Clean | **(52)** Redline to Last Posted **Implementation Plan** **(53)** Clean | **(54)** Redline **Supporting Materials** **Mapping Document** **(55)** Clean | **(56)** Redline **(57)** VRF/VSL Justification **Technical Rationale** **EOP-011-3** **(58)** Clean | **(59)** Redline **EOP-012-1** **(60)** Clean | **(61)** Redline	**Final Ballot** **(63)** Info Vote	09/23/22 – 09/30/22	**Ballot Results** **(64)** EOP-011-3 **(65)** EOP-012-1 **(66)** Implementation Plan	

Technical Reference Document **(62)** Calculating Extreme Cold Weather Temperature				
Draft 2 EOP-012-1 is a new standard drafted by the Project 2021-07 SDT. Requirements R1, R2, R4, R6 and R7 are new requirements. Requirements R3 and R5 are carried over from EOP-011-2, which was revised under Project 2019-06 Cold Weather. These requirements have had minor revisions. **EOP-012-1** **(29)** Clean*updated | **(30)** Redline to Last Posted **Implementation Plan** **(31)** Clean | **(32)** Redline **Supporting Materials** **(33)** Unofficial Comment Form (Word) **Mapping Document** **(34)** Clean | **(35)** Redline **(36)** VRF/VSL Justification **Technical Rationale** **(37)** EOP-012-1 **(38) Technical Reference Document***New	Additional Ballots and Non-binding Polls **(39)** Updated Info **(40)** Info Vote	08/23/22 – 09/01/22	**Ballot Results** **(43)** EOP-012-1 **(44)** Implementation Plan **Non-Binding Poll Results** **(45)** EOP-012-1	**(47)** Summary Response to Comments
	Comment Period **(41)** Updated Info **(42)** Info Submit Comments	08/03/22 – 09/01/22	**(46)** Comments Received	
Draft 1 EOP-012-1 is a new standard drafted by the Project 2021-07 SDT. Requirements R1, R2, R4, and R6 are new requirements. Requirements R3 and R5 are carried over from EOP-011-2, which was revised under Project 2019-06 Cold Weather. These requirements have had minor revisions. **EOP-011-3** **(10)** Clean | **(11)** Redline **EOP-012-1** **(12)** Clean | **(13)** Redline **(14)** Implementation Plan **Supporting Materials** **(15)** Unofficial Comment Form (Word) **(16)** Mapping Document **(17)** VRF/VSL Justification **Technical Rationale** **(18)** EOP-011-3 | **(19)** EOP-012-1	Initial Ballots and Non-binding Polls **(20)** Info (updated) Vote	06/08/22 – 06/21/22 (Extended)	**Ballot Results** **(22)** EOP-011-3 **(23)** EOP-012-1 **(24)** Implementation Plan **Non-Binding Poll Results** **(25)** EOP-011-3 **(26)** EOP-012-1	**(28)** Summary Response to Comments
	Comment Period **(21)** Info Submit Comments	05/19/22 – 06/21/22 (Extended)	**(27)** Comments Received (updated) (comments to question 8 were included in responses to question 10)	
	Join Ballot Pools	05/19/22 – 06/02/22		
Standard Authorization Request (SAR) **(8)** Clean | **(9)** Redline	The Standards Committee Executive Committee accepted the SAR on February 25, 2022			
Drafting Team Nominations **Supporting Materials** **(6)** Unofficial Nomination Form (Word)	Nomination Period **(7)** Info Submit Nominations	11/22/21 – 12/21/21		
(1) Standard Authorization Request **Supporting Materials** **(2)** Unofficial Comment Form (Word)	Comment Period **(3)** Info Submit Comments	11/22/21 – 12/21/21	**(4)** Comments Received	**(5)**Summary Response to Comments

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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:	Extreme Cold Weather Grid Operations, Preparedness, and Coordination		
Date Submitted:	10/6/2021		
SAR Requester			
Name:	Steven Noess & Kiel Lyons		
Organization:	NERC, as members of the 2021 FERC, NERC, Regional Entity Joint Inquiry into 2021 Cold Weather Grid Operations		
Telephone:	(404) 446-9691 (404) 446-9665	Email:	Steven.Noess@nerc.net Kiel.Lyons@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?):			
To enhance reliability of the BES through improved operations, preparedness, and coordination during extreme weather, as described by the Federal Energy Regulatory Commission (FERC), NERC, and Regional Entity Joint Staff Inquiry into the February 2021 Cold Weather Grid Operations. See https://www.ferc.gov/media/february-2021-cold-weather-grid-operations-preliminary-findings-and-recommendations-full. From February 8 through 20, 2021, extreme cold weather and precipitation caused large numbers of generating units to experience outages, derates or failures to start, resulting in energy and transmission emergencies (referred to as “the Event”). The total Event firm load shed was the largest controlled firm load shed event in U.S. history and was the third largest in quantity of outaged megawatts (MW) of load after the August 2003 northeast blackout and the August 1996 west coast blackout. The Event was most			

Requested information
severe from February 15 through February 18, 2021, and it contributed to power outages affecting millions of electricity customers throughout the regions of ERCOT, SPP and MISO South. Extreme cold weather is a common occurrence, and it has jeopardized the reliable operation of the bulk-power system. The February 2021 event is the fourth in the past 10 years which jeopardized bulk-power system reliability. In February 2011, an arctic cold front impacted the southwest U.S. and resulted in numerous generation outages, natural gas facility outages and emergency power grid conditions with need for firm customer load shed. In January 2014, a polar vortex affected Texas, central and eastern U.S. This 2014 event also triggered many generation outages, natural gas availability issues and resulted in emergency conditions including voluntary load shed. And in January 2018, an arctic high-pressure system and below average temperatures in the south-central U.S. resulted in many generation outages and the need for voluntary load shed emergency measures.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
The new or revised reliability standards are intended to address reliability-related findings from the 2021 joint inquiry, which in many cases are consistent with prior reports' recommendations.
Project Scope (Define the parameters of the proposed project):
The Project Scope will address nine recommendations for new or enhanced NERC Reliability Standards proposed by the Federal Energy Regulatory Commission (FERC), NERC, and Regional Entity Joint Staff Inquiry into the February 2021 Cold Weather Grid Operations. The preliminary findings and recommendations of that joint inquiry were presented at the September 23, 2021, (FERC) Open Commission Meeting. Considering the topic areas, the submitters contemplate that the Standards Committee may convene one or more standard drafting teams to address collectively the recommendations in the joint inquiry report. The drafting team(s) should also consider the final report of the joint inquiry when it is released in late 2021, as it will contain additional context and analysis that will build upon the preliminary findings and recommendations. While the inquiry team does not anticipate material changes to the Reliability Standards Recommendations or basis for them provided in the preliminary presentation, the final SAR should reflect the final recommendations in the joint inquiry report.

Requested information
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[1] 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):

Technical justification is found within the work of the FERC, NERC, Regional Entity Joint Staff Inquiry. The proposed deliverable is new or revised Reliability Standards to enhance reliability during extreme cold weather.

The specific recommendations from the inquiry team have recommended "implementation timeframes," which means in this context that the new and/or revised Reliability Standards that address the recommendation have been completed through the NERC Reliability Standards Development Process and are proposed (filed) for approval within the timeframes listed within the recommendations. For these recommendations, "Implementation Timeframe" means that the proposed Reliability Standards are complete and filed by November 1, 2022, for the Winter 2022/2023 timeframes and by November 1, 2023 for the Winter 2023/2024 timeframes. Each Reliability Standards recommendation below is accompanied by one of those two implementation timeframes.

There are nine recommendations each of which is designed to support the reliable operation of the bulk power system during cold weather conditions and/or stressed system conditions, with associated timeframes as described above:

1. Generator Owners are to identify and protect cold-weather-critical components and systems for each generating unit. Cold-weather-critical components and systems are those which are susceptible to freezing or otherwise failing due to cold weather, and which could cause the unit to trip, derate, or fail to start. **(Implementation Timeframe before Winter 2023/2024).**
2. Generator Owners are to design new or retrofit existing generating units to operate to a specified ambient temperature and weather conditions (e.g., wind, freezing precipitation). The specified ambient temperature and weather conditions should be based on available extreme temperature and weather data for the generating unit's location, and account for the effects of precipitation and accelerated cooling effect of wind. **(Implementation Timeframe before Winter 2023/2024).**
3. Generator Owners and Generator Operators are to conduct annual unit-specific cold weather preparedness plan training. **(Implementation Timeframe before Winter 2022/2023).**
4. Generator Owners that experience outages, failures to start, or derates due to freezing are to review the generating unit's outage, failure to start, or derate and develop and implement a corrective action plan for the identified equipment, and evaluate whether the plan applies to

[1] 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.

Requested information
similar equipment for its other generating units. **(Implementation Timeframe before Winter 2022/2023).** 5. The Reliability Standards should be revised to provide greater specificity about the relative roles of the Generator Owners, Generator Operators and Balancing Authorities in determining the generating unit capacity that can be relied upon during “local forecasted cold weather,” which is language from the revised Reliability Standard TOP-003-5, R2.3. -Each Generator Owner/Generator Operator should be required to provide the Balancing Authority with the percentage of the total generating unit capacity that the Generator Owner/Generator Operator reasonably believes the Balancing Authority can rely upon during the “local forecasted cold weather,” including reliability risks related to natural gas fuel contracts. -Each Balancing Authority should be required to use the data provided by the Generator Owner/Generator Operator, combined with its evaluation, based on experience, to calculate the percentage of each individual generating unit’s total capacity that it can rely upon during the “local forecasted cold weather,” and share its calculation with the Reliability Coordinator. Each Balancing Authority should be required to use that calculation of the percentage of total generating capacity that it can rely upon to “prepare its analysis functions and Real-time monitoring,” and to “manag[e] generating resources in its Balancing Authority Area to address . . . fuel supply and inventory concerns” as part of its Capacity and Energy Emergency Operating Plans. **(Implementation Timeframe before Winter 2022/2023).** 6. In EOP-011-2, R7.3.2, Generator Owners are to account for the effects of precipitation and accelerated cooling effect of wind when providing temperature data. **(Implementation Timeframe before Winter 2022/2023).** 7. To protect critical natural gas infrastructure from manual and automatic load shedding in order to avoid adversely affecting bulk-power system reliability, Balancing Authorities’ and Transmission Operators’ (TOPs) provisions for operator-controlled manual load shedding are to include processes for identifying and protecting critical natural gas infrastructure loads in their respective areas from firm load shed. Critical natural gas infrastructure loads are natural gas production, processing and intrastate and interstate pipeline facility loads which, if de-energized, could adversely affect the provision of natural gas to bulk-power system natural gas-fired generation. **(Implementation Timeframe before Winter 2023/2024).** 8. Balancing Authorities’ operating plans (for contingency reserves and to mitigate capacity and energy emergencies) are to prohibit use of critical natural gas infrastructure loads for demand response. **(Implementation Timeframe before Winter 2022/2023).** 9. In minimizing the overlap of manual and automatic load shed, the load shed procedures of Transmission Operators, Transmission Owners (TOs) and Distribution Providers (DPs) should separate the circuits that will be used for manual load shed from circuits used for underfrequency load shed (UFLS), undervoltage load shed (UVLS) or serving critical load. UFLS/UVLS circuits should only be used for manual load shed as a last resort and for UFLS

Requested information
circuits, should start with the final stage (lowest frequency). **(Implementation Timeframe before Winter 2023/2024).**
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Unknown.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
The BES facilities impacted by this proposed project will all have unique characteristics including fuel type, location, design, construction, etc. These unique characteristics need to be addressed during drafting to achieve the intended enhancements to reliability.
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):
Reliability Coordinator, Balancing Authority, Transmission Operator, Transmission Owner, Distribution Provider, Generator Operator, and Generator Owner
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
The FERC, NERC, Regional Entity Joint Staff Inquiry into the 2021 Cold Weather Grid Operations was publicly noticed by both FERC and NERC.
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)?
The proposed Reliability Standards are intended to build upon the requirements in EOP-011-2, IRO-010-4, and TOP-003-5 that were developed by Project 2019-06, and which for U.S. entities, were approved by FERC in August 2021. Additionally, several recommendations build on existing Standards related to load shedding and the development and implementation of UFLS and UVLS programs (e.g. EOP-011-2, PRC-006-5, and PRC-010-2). These Standards should be reviewed to ensure any conflicts or overlap with current requirements are mitigated.
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.
There have been several recommendations and guidelines that have developed over the prior noted events, but the events since illustrate that they are not as widely adopted as necessary to prevent reoccurrence.

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] 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.

Reliability Principles	
☒	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
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	

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	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC

☐ DRAFT SAR approved for posting by the SC	☐ 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
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

Unofficial Comment Form

Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on **Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination Standard Authorization Request (SAR)** by **8 p.m. Eastern, December 21, 2021.**

Additional information is available on the project page. If you have questions, contact Senior Standards Developer, Alison Oswald (via email), or at 404-446-9668.

Background Information

The primary purpose of this project is to address reliability related findings from the FERC, NERC, and Regional Entity Joint Staff Inquiry into the February 2021 Cold Weather Grid Operations ("Joint Inquiry"). From February 8 through February 20, 2021, extreme cold weather and precipitation caused large numbers of generating units to experience outages, derates or failures to start, resulting in energy and transmission emergencies (referred to as "the Event"). The total Event firm load shed was the largest controlled firm load shed event in U.S. history and was the third largest in quantity of outaged megawatts (MW) of load after the August 2003 northeast blackout and the August 1996 west coast blackout. The Event was most severe from February 15 through February 18, 2021, and it contributed to power outages affecting millions of electricity customers throughout the regions of ERCOT, SPP and MISO South. Additionally, the February 2021 event is the fourth cold weather event in the past 10 years which jeopardized bulk-power system reliability.

The Project Scope will address nine recommendations for new or enhanced NERC Reliability Standards proposed by the Joint Inquiry into the February 2021 Cold Weather Grid Operations which were presented at the September 23, 2021 FERC Open Meeting[1]. The final Joint Inquiry report was published on November 16, 2021[2].

[1] February 2021 Cold Weather Grid Operations: Preliminary Findings and Recommendations - Full Presentation | Federal Energy Regulatory Commission (ferc.gov)
[2] The February 2021 Cold Weather Outages in Texas and the South Central United States | FERC, NERC and Regional Entity Staff Report | Federal Energy Regulatory Commission

Questions

1. Please use the following subparts to indicate which Reliability Standards you believe should be revised to address the recommendations in the FERC/NERC Joint Inquiry report

   a. Which Reliability Standard(s) should be revised to address the recommendation: "Generator Owners are to identify and protect cold-weather-critical components and systems for each generating unit. Cold-weather-critical components and systems are those which are susceptible to freezing or otherwise failing due to cold weather, and which could cause the unit to trip, derate, or fail to start."

      Comments:

   b. Which Reliability Standard(s) should be revised to address the recommendation: "Generator Owners are to design new or retrofit existing generating units to operate to a specified ambient temperature and weather conditions (e.g., wind, freezing precipitation). The specified ambient temperature and weather conditions should be based on available extreme temperature and weather data for the generating unit's location, and account for the effects of precipitation and accelerated cooling effect of wind."

      Comments:

   c. Which Reliability Standard(s) should be revised to address the recommendation: "Generator Owners and Generator Operators are to conduct annual unit-specific cold weather preparedness plan training."

      Comments:

   d. Which Reliability Standard(s) should be revised to address the recommendation: "Generator Owners that experience outages, failures to start, or derates due to freezing are to review the generating unit's outage, failure to start, or derate and develop and implement a corrective action plan for the identified equipment, and evaluate whether the plan applies similar equipment for its other generating units."

      Comments:

   e. Which Reliability Standard(s) should be revised to address the recommendation: "The Reliability Standards should be revised to provide greater specificity about the relative roles of the Generator Owners, Generator Operators and Balancing Authorities in determining the generating unit capacity that can be relied upon during "local forecasted cold weather," which is language from the revised Reliability Standard TOP-003-5, R2.3. -Each Generator Owner/Generator Operator should be required to provide the Balancing Authority with the percentage of the total generating unit capacity that the Generator Owner/Generator Operator reasonably believes the Balancing Authority can rely upon during the "local forecasted cold weather," including reliability risks related to natural gas fuel contracts. -Each Balancing Authority should be required to use the data provided by the Generator

Owner/Generator Operator, combined with its evaluation, based on experience, to calculate the percentage of each individual generating unit's total capacity that it can rely upon during the "local forecasted cold weather," and share its calculation with the Reliability Coordinator. Each Balancing Authority should be required to use that calculation of the percentage of total generating capacity that it can rely upon to "prepare its analysis functions and Realtime monitoring," and to "manag[e] generating resources in its Balancing Authority Area to address . . . fuel supply and inventory concerns" as part of its Capacity and Energy Emergency Operating Plans."

Comments:

f. Which Reliability Standard(s) should be revised to address the recommendation: "In EOP-011-2, R7.3.2, Generator Owners are to account for the effects of precipitation and accelerated cooling effect of wind when providing temperature data."

Comments:

g. Which Reliability Standard(s) should be revised to address the recommendation: "To protect critical natural gas infrastructure from manual and automatic load shedding in order to avoid adversely affecting bulk-power system reliability, Balancing Authorities' and Transmission Operators' (TOPs) provisions for operator-controlled manual load shedding are to include processes for identifying and protecting critical natural gas infrastructure loads in their respective areas from firm load shed. Critical natural gas infrastructure loads are natural gas production, processing and intrastate and interstate pipeline facility loads which, if de-energized, could adversely affect the provision of natural gas to bulk-power system natural gas-fired generation."

Comments:

h. Which Reliability Standard(s) should be revised to address the recommendation: "Balancing Authorities' operating plans (for contingency reserves and to mitigate capacity and energy emergencies) are to prohibit use of critical natural gas infrastructure loads for demand response."

Comments:

i. Which Reliability Standard(s) should be revised to address the recommendation: "In minimizing the overlap of manual and automatic load shed, the load shed procedures of Transmission Operators, Transmission Owners (TOs) and Distribution Providers (DPs) should separate the circuits that will be used for manual load shed from circuits used for underfrequency load shed (UFLS), undervoltage load shed (UVLS) or serving critical load.

UFLS/UVLS circuits should only be used for manual load shed as a last resort and for UFLS circuits, should start with the final stage (lowest frequency).”

Comments:

2. Do you believe there are alternatives or more cost effective options to address the recommendations the in FERC/NERC Joint Inquiry report? If so, please provide your recommendation and, if appropriate, technical or procedural justification.

☐ Yes
☐ No

Comments:

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

Comments:

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination
Standard Authorization Request

Formal Comment Period Open through December 21, 2021

Now Available

A 30-day formal comment period for the **Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination** Standard Authorization Request (SAR), is open through **8 p.m. Eastern, Tuesday, December 21, 2021**.

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

For more information or assistance, contact Senior Standards Developer, Alison Oswald (via email) or at 404-446-9668. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination 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:	2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | SAR
Comment Period Start Date:	11/22/2021
Comment Period End Date:	12/21/2021
Associated Ballots:	

There were 54 sets of responses, including comments from approximately 152 different people from approximately 109 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Please use the following subparts to indicate which Reliability Standards you believe should be revised to address the recommendations in the FERC/NERC Joint Inquiry report:

a. Which Reliability Standard(s) should be revised to address the recommendation: "Generator Owners are to identify and protect cold-weather-critical components and systems for each generating unit. Cold-weather-critical components and systems are those which are susceptible to freezing or otherwise failing due to cold weather, and which could cause the unit to trip, derate, or fail to start."

b. Which Reliability Standard(s) should be revised to address the recommendation: "Generator Owners are to design new or retrofit existing generating units to operate to a specified ambient temperature and weather conditions (e.g., wind, freezing precipitation). The specified ambient temperature and weather conditions should be based on available extreme temperature and weather data for the generating unit's location, and account for the effects of precipitation and accelerated cooling effect of wind."

c. Which Reliability Standard(s) should be revised to address the recommendation: "Generator Owners and Generator Operators are to conduct annual unit-specific cold weather preparedness plan training."

d. Which Reliability Standard(s) should be revised to address the recommendation: "Generator Owners that experience outages, failures to start, or derates due to freezing are to review the generating unit's outage, failure to start, or derate and develop and implement a corrective action plan for the identified equipment, and evaluate whether the plan applies similar equipment for its other generating units."

e. Which Reliability Standard(s) should be revised to address the recommendation: "The Reliability Standards should be revised to provide greater specificity about the relative roles of the Generator Owners, Generator Operators and Balancing Authorities in determining the generating unit capacity that can be relied upon during "local forecasted cold weather," which is language from the revised Reliability Standard TOP-003-5, R2.3. -Each Generator Owner/Generator Operator should be required to provide the Balancing Authority with the percentage of the total generating unit capacity that the Generator Owner/Generator Operator reasonably believes the Balancing Authority can rely upon during the "local forecasted cold weather," including reliability risks related to natural gas fuel contracts. -Each Balancing Authority should be required to use the data provided by the Generator Owner/Generator Operator, combined with its evaluation, based on experience, to calculate the percentage of each individual generating unit's total capacity that it can rely upon during the "local forecasted cold weather," and share its calculation with the Reliability Coordinator. Each Balancing Authority should be required to use that calculation of the percentage of total generating capacity that it can rely upon to "prepare its analysis functions and Realtime monitoring," and to "manag[e] generating resources in its Balancing Authority Area to address . . . fuel supply and inventory concerns" as part of its Capacity and Energy Emergency Operating Plans."

f. Which Reliability Standard(s) should be revised to address the recommendation: "In EOP-011-2, R7.3.2, Generator Owners are to account for the effects of precipitation and accelerated cooling effect of wind when providing temperature data."

g. Which Reliability Standard(s) should be revised to address the recommendation: "To protect critical natural gas infrastructure from manual and automatic load shedding in order to avoid adversely affecting bulk-power system reliability, Balancing Authorities' and Transmission Operators' (TOPs) provisions for operator-controlled manual load shedding are to include processes for identifying and protecting critical natural gas infrastructure loads in their respective areas from firm load shed. Critical natural gas infrastructure loads are natural gas production, processing and intrastate and interstate pipeline facility loads which, if de-energized, could adversely affect the provision of natural gas to bulk-power system natural gas-fired generation."

h. Which Reliability Standard(s) should be revised to address the recommendation: "Balancing Authorities' operating plans (for contingency reserves and to mitigate capacity and energy emergencies) are to prohibit use of critical natural gas infrastructure loads for demand response."

i. Which Reliability Standard(s) should be revised to address the recommendation: "In minimizing the overlap of manual and automatic load shed, the load shed procedures of Transmission Operators, Transmission Owners (TOs) and Distribution Providers (DPs) should separate the circuits that will be used for manual load shed from circuits used for underfrequency load shed (UFLS), undervoltage load shed (UVLS) or serving critical load. UFLS/UVLS circuits should only be used for manual load shed as a last resort and for UFLS circuits, should start with the final stage (lowest frequency)."

2. Do you believe there are alternatives or more cost effective options to address the recommendations the in FERC/NERC Joint Inquiry report? If so, please provide your recommendation and, if appropriate, technical or procedural justification.

3. 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
BC Hydro and Power Authority	Adrian Andreoiu	1,3,5	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
DTE Energy - Detroit Edison Company	Adrian Raducea	3,5		DTE Energy - DTE Electric	Karie Barczak	DTE Energy - Detroit Edison Company	3	RF
					Adrian Raducea	DTE Energy - Detroit Edison	5	RF
					patricia ireland	DTE Energy	4	RF
New York Independent System Operator	Gregory Campoli	2		ISO/RTO Standards Review Committee	Gregory Campoli	New York Independent System Operator	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Michael Del Viscio	PJM	2	RF
					Charles Yeung	Southwest Power Pool, Inc. (RTO)	2	MRO
					Bobbi Welch	Midcontinent ISO, Inc.	2	RF
					Ali Miremadi	CAISO	2	WECC
					Kathleen Goodman	ISO-NE	2	NPCC
CMS Energy - Consumers Energy Company	Jeanne Kurzynowski	3,4,5	RF	Consumers Energy Company	Jeanne Kurzynowski	Consumers Energy Company	1,3,4,5	RF
					Jim Anderson	Consumers Energy Company	1	RF
					Karl Blaszkowski	Consumers Energy Company	3	RF

					Theresa Martinez	Consumers Energy Company	4	RF
					David Greyerbiehl	Consumers Energy Company	5	RF
Tacoma Public Utilities (Tacoma, WA)	Jennie Wike	1,3,4,5,6	WECC	Tacoma Power	Jennie Wike	Tacoma Public Utilities	1,3,4,5,6	WECC
					John Merrell	Tacoma Public Utilities (Tacoma, WA)	1	WECC
					Marc Donaldson	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
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	4	MRO
					Fred Meyer	Algonquin Power Co.	1	MRO
					Jamie Monette	Allete - Minnesota Power, Inc.	1	MRO
					Jodi Jensen	Western Area Power Administration - Upper Great Plains East (WAPA)	1,6	MRO
					John Chang	Manitoba Hydro	1,3,6	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
					LaTroy Brumfield	American Transmission Company, LLC	1	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
					Jeremy Voll	Basin Electric Power Cooperative	1,3,5	MRO
					Joe DePoorter	Madison Gas and Electric	4	MRO
					David Heins	Omaha Public Power District	1,3,5,6	MRO
					Bill Shultz	Southern Company Generation	5	MRO
Duke Energy	Kim Thomas	1,3,5,6	FRCC,RF,SERC,Texas RE	Duke Energy	Laura Lee	Duke Energy	1	SERC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
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

					Tricia Bynum	FirstEnergy - FirstEnergy Corporation	6	RF
					Mark Garza	FirstEnergy-FirstEnergy	4	RF
Pacific Gas and Electric Company	Michael Johnson	1,3,5	WECC	PG&E All Segments	Marco Rios	Pacific Gas and Electric Company	1	WECC
					Sandra Ellis	Pacific Gas and Electric Company	3	WECC
					James Mearns	Pacific Gas and Electric Company	5	WECC
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
					Jim Howell	Southern Company - Southern Company Services, Inc. - Gen	5	SERC
Eversource Energy	Quintin Lee	1,3		Eversource Group	Quintin Lee	Eversource Energy	1	NPCC
					Christopher McKinnon	Eversource Energy	3	NPCC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC Regional Standards Committee no NGrid	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC

Glen Smith	Entergy Services	4	NPCC
Alan Adamson	New York State Reliability Council	7	NPCC
David Burke	Orange & Rockland Utilities	3	NPCC
Helen Lainis	IESO	2	NPCC
David Kiguel	Independent	7	NPCC
Nick Kowalczyk	Orange and Rockland	1	NPCC
Joel Charlebois	AESI - Acumen Engineered Solutions International Inc.	5	NPCC
Mike Cooke	Ontario Power Generation, Inc.	4	NPCC
Salvatore Spagnolo	New York Power Authority	1	NPCC
Shivaz Chopra	New York Power Authority	5	NPCC
Deidre Altobell	Con Ed - Consolidated Edison	4	NPCC
Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
Cristhian Godoy	Con Ed - Consolidated Edison Co. of New York	6	NPCC
Nurul Abser	NB Power Corporation	1	NPCC

					Randy MacDonald	NB Power Corporation	2	NPCC
					Michael Ridolfino	Central Hudson Gas and Electric	1	NPCC
					Vijay Puran	NYSPS	6	NPCC
					ALAN ADAMSON	New York State Reliability Council	10	NPCC
					Sean Cavote	PSEG - Public Service Electric and Gas Co.	1	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Jim Grant	NYISO	2	NPCC
					John Pearson	ISONE	2	NPCC
					Nicolas Turcotte	Hydro-Qu?bec TransEnergie	1	NPCC
					Chantal Mazza	Hydro-Quebec	2	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
Dominion - Dominion Resources, Inc.	Sean Bodkin	3,5,6		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
Western Electricity Coordinating Council	Steven Rueckert	10		WECC Cold Weather SAR	Steve Rueckert	WECC	10	WECC
					Phil O'Donnell	WECC	10	WECC
					Roger Cummins	WECC	10	WECC
Santee Cooper	Tommy Curtis	1,3,5,6		Santee Cooper	Rene' Free	Santee Cooper	1,3,5,6	SERC
					Paul Camilletti	Santee Cooper	1,3,5,6	SERC
					Rodger Blakely	Santee Cooper	1,3,5,6	SERC
					LaChelle Brooks	Santee Cooper	1,3,5,6	SERC
					Jennifer Richards	Santee Cooper	1,3,5,6	SERC

1. Please use the following subparts to indicate which Reliability Standards you believe should be revised to address the recommendations in the FERC/NERC Joint Inquiry report:

a. Which Reliability Standard(s) should be revised to address the recommendation: “Generator Owners are to identify and protect cold-weather-critical components and systems for each generating unit. Cold-weather-critical components and systems are those which are susceptible to freezing or otherwise failing due to cold weather, and which could cause the unit to trip, derate, or fail to start.”

Adrian Raducea - DTE Energy - Detroit Edison Company - 3,5, Group Name DTE Energy - DTE Electric

Answer	
Document Name	

Comment

New Requirements in EOP-011-2 R7 requires that each Generator Owner shall implement and maintain one or more cold weather preparedness plan(s) for its generating units. The requirement is at unit level. **Adding component listing for cold-weather components is not necessary.**

Likes 0	
Dislikes 0	

Response

Susan Sosbe - Wabash Valley Power Association - 1,3

Answer	
Document Name	

Comment

It is our suggestion that this Requirement be added to Reliability Standard EOP-011 (Emergency Preparedness and Operations) since this Standard (most recent draft) already includes R7, requiring the Generator Owners to implement and maintain cold weather preparedness plans for its generating units. As part of this Plan, these components/systems could be identified.

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	
Document Name	

Comment

None – suggest a new NERC GO/GOP Standard to implement recommendations. It is also suggested that recently modified TOP-003-5, EOP-011-2 and IRO-010-4 standards not be modified further and consideration be given for moving Cold Weather Requirements in these Standards to the new Standard.	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	
The MRO NERC Standards Review Forum (NSRF) believes this recommendation would best be addressed in a **Facilities Design, Connections and Maintenance (FAC)** standard along with items 1, 3, 4, 5 and 6 (*see* pages 3-4 of the SAR). If this proposal is adopted, MRO NSRF recommends the Standard Drafting Team (SDT) begin work using the corresponding language currently in EOP-011-2, Requirements R7 and R8 and then retire R7 and R8 from EOP-011-2. In addition, MRO NSRF recommends a change to the scope of the SAR to recognize there may be components that Generator Owners will be unable to protect, such that these cold-weather-critical components could render the unit unavailable. Likewise, this unavailability should be reflected in the generating capacity that can be relied (*see* our response to question 1e below).	
Likes 1	Tacoma Public Utilities (Tacoma, WA), 1,3,4,5,6, Wike Jennie
Dislikes 0	
Response	
Michael Krum - Salt River Project - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
No Comment.	
Likes 0	
Dislikes 0	
Response	

Richard Jackson - U.S. Bureau of Reclamation - 1,5	
Answer	
Document Name	

Comment

Reclamation identifies that cold weather maintenance does not fit well into any existing reliability standards. Annual maintenance for generator types and geographic areas that have never had a problem with cold weather represent an added regulatory burden for a problem that these generators and geographic areas do not have. Given the performance history of facilities in northern, colder climates, annual maintenance and inspection requirements would be excessive. Reclamation recommends Generator Owners follow guidance derived from manufacturer specifications and entity evaluations of policies, procedures, and maintenance.

Many types of generation equipment are already housed indoors or otherwise have no realistic chance of freezing because these conditions were considered during the design/build phase or, in the case of hydro, the units are not affected by cold weather in any way that can be controlled. For example, efforts to prevent a river from freezing, such as with the use of chemical additives or by any device that would generate enough heat over a large enough area to thaw a freezing river, would be prohibited by environmental regulations. Small hydro facilities may have difficulties with ice buildup on screens intended to prevent large debris from entering the turbines; however, there is no equipment that can be added or removed. Instead, these small facilities already have measures in place to remove ice buildup.

Any new standard must either include exemptions for facilities that are already freeze-resistant, accept working practices already in place that correct ice-related problems, or base its applicability on the historical temperature records of the applicable facilities.

Reclamation recommends a new standard be created in the FAC family to identify “cold weather critical components” and to describe the required maintenance and minimum required maintenance frequency for each component. The new standard should provide an exemption for entities with no cold weather vulnerabilities. Reclamation recommends the format of this new standard be similar to PRC-005-6 or FAC-501-WECC-3 and offers the following example:

Example:

FAC-006-1 – Maintenance for Cold Weather Critical Components.

R1. Each Generator Owner shall establish a maintenance program for its cold weather critical components.

R1.1. The maintenance program shall identify cold-weather-critical components and systems based on:

1. Historical cold weather experiences of outages, failure to start, deratings, or supply chain impacts.
2. Minimum ambient temperature and weather conditions from NOAA hourly historical database for minimum occurrence.
3. Critical fuel supplies, essential systems for energy production, critical supply chain products, or other products critical to maintain energy production.

R1.2. The maintenance program shall identify controls to minimize inherent risks and address:

1. The maintenance to be performed.
2. The periodicity to perform the maintenance.
3. Spare parts, backup systems, or redundant systems.
4. Procedure to implement preparations for extreme weather events prior to the events occurring.

R2. Each Generator Owner shall follow its maintenance program for cold weather critical components.

R3. Each Generator Owner shall design new generating units to operate to the ambient temperature and weather conditions specified in its cold weather maintenance program.

R4. Each Generator Owner that experiences an outage, failure to start, or derate due to cold weather shall review the generating unit's outage, failure to start, or derate and develop a corrective action plan for the identified equipment.

R4.1. In cases where the outage cannot be avoided and corrective action would not prevent a similar future outage (e.g., canal freezing), notify the TOP and BA of the potential loss of generation.

R5. Each Generator Owner that develops a corrective action plan pursuant to FAC-006-1 R4 shall implement its corrective action plan.

R6. Each Generator Owner that develops a corrective action plan pursuant to FAC-006-1 R4 shall evaluate whether the plan applies to similar equipment for its other generating units.

Likes 1	Enel Green Power, 5, Johnson Natalie
Dislikes 0	

Response

Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 3,4,5 - RF, Group Name Consumers Energy Company

Answer	
Document Name	

Comment

EOP and FAC standards.

Likes 0	
Dislikes 0	

Response

George Brown - Acciona Energy North America - 5

Answer	
Document Name	

Comment

Acciona Energy believes this recommendation would be best addressed in Facilities Design, Connections and Maintenance (FAC) suite of NERC Standards. Perhaps, the most appropriate place for this recommendation would be NERC Reliability Standard FAC-008 – Facility Ratings (NERC FAC-008). NERC FAC-008 already includes the majority, if not all equipment, cold-weather-critical components and systems that would be affected by extreme cold weather, which the loss of would ultimately affect the Facility Rating.

Acciona Energy recommends that the Standards Drafting Team adopt and then retire the applicable language from NERC Reliability Standard EOP-011-2 Emergency Preparedness and Operations, Requirement R7 and R8.

Likes 1	Tacoma Public Utilities (Tacoma, WA), 1,3,4,5,6, Wike Jennie
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	
Document Name	
Comment	
Xcel Energy supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	
Document Name	
Comment	
Alliant Energy supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - ISO New England, Inc. - 2 - NPCC	
Answer	
Document Name	
Comment	

Recommend revising EOP-011 and IRO-010 and create a new defined term(s)

- Add new requirement to EOP-011:

- Each Generator Owner shall identify and protect **cold-weather-critical components and systems** for each generating unit.

- Create new defined term: **Cold-weather-critical components and systems** are those which are susceptible to freezing or otherwise failing due to cold weather and which could cause the generating unit to trip, derate, or fail to start.
- Revise IRO-010, R1.3 as shown below (revisions in red):
  - 1.3 Provisions for notification of BES generating unit(s) operating limitations during local forecasted cold and extreme weather conditions to include:
    - 1.3.x Cold-weather-critical components and systems

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6, Group Name Dominion

Answer	
Document Name	

Comment

Dominion Energy suppports the comments submitted by EEI.

Likes 0	
Dislikes 0	

Response

Carl Pineault - Hydro-Qu?bec Production - 1,5

Answer	
Document Name	

Comment

No comments

Likes 0	
Dislikes 0	

Response

Kenisha Webber - Entergy - Entergy Services, Inc. - NA - Not Applicable - SERC

Answer	
Document Name	

Comment	
EOP-011-2, Requirement R7 as part of Cold Weather plan	
Likes 0	
Dislikes 0	
Response	

Jennie Wike - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6 - WECC, Group Name Tacoma Power	
Answer	
Document Name	
Comment	
Tacoma Power does not support adding facility design, analysis or maintenance requirements to EOP Standards. This recommendation should be incorporated into FAC-008 R2.2. FAC-008 R2.2.3 currently captures evaluating Equipment Ratings for ambient conditions and could be expanded to include extreme cold weather events. An example of how this could be addressed in FAC-008 R2.2: *R2.2. The underlying assumptions, design criteria, and methods used to determine the Equipment Ratings identified in Requirement R2, Part 2.1 including identification of how each of the following were considered:* *R2.2.1. Equipment Rating standard(s) used in development of this methodology.* *R2.2.2. Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications.* *R2.2.3. Ambient conditions (for particular or average conditions or as they vary in real-time).* *R2.2.4. Operating limitations.* ***R2.2.5 Protection against extreme cold weather events***	
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 comments posted by EEI	

Likes 0	
Dislikes 0	

Response

Patricia Lynch - NRG - NRG Energy, Inc. - 5,6

Answer	
Document Name	

Comment

NRG Energy Inc. believes that the recommendation should be included as part of a new standard dedicated to Cold Weather.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE recommends adding this Key Recommendation to EOP-011, since EOP-011-2 Requirement R7 includes implementing and maintaining cold weather preparedness plans. This recommendation would add additional parts of what is needed in the plan.

Alternatively, a new Emergency Preparedness and Operations standard could be created to include the following Key Recommendations from the FERC-NERC-Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and South Central United States (Joint Inquiry): 1a, 1c,1d, 1e, and 1f. Language from future enforceable EOP-011-2 Requirements R7 and R8 could also be included in this new Emergency Preparedness and Operations standard.

Texas RE notes that in order to fully implement the Joint Inquiry recommendations, the SDT should consider the impact of extreme weather preparation requirements on the full suite of NERC Reliability Standards. Based on this principle, Texas RE also recommends the SDT consider the following additional changes:

- Revising TOP-003 and IRO-010, as in Project 2019-06, to include provisions for notifying the TOP and RC of data necessary to perform the Operational Planning Analyses, Real-time monitoring, and Real-time Assessments;

- Consider revising the EOP-004 attachment 1 to include a new event type of Critical loss due to cold weather;
- Consider revising Table 1 in TPL-001 to include cold weather;
- Consider whether cold weather should be included in the RC's SOL Methodology in accordance with proposed Reliability Standard FAC-011-4;
- Consider adding weather as a "steady-state" to Attachment 1 of MOD-032;
- Consider whether identifying critical elements should be included as part of CIP-002 for identifying high, medium, and low impact BES Cyber Systems; and
- Consider adding the term "critical elements" to the NERC Glossary as defined in the FERC Report in its execution of recommendations 1a-1g in order to provide consistency and clarity.

Likes 0	
Dislikes 0	

Response

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5

Answer	
Document Name	

Comment

Reliability Standard EOP-011-2

Likes 0	
Dislikes 0	

Response

Michael Johnson - Pacific Gas and Electric Company - 1,3,5 - WECC, Group Name PG&E All Segments

Answer	
Document Name	

Comment

PG&E has participated in the preparation and supports the comments provided by the Edison Electric Institute (EEI) for Q1a.

Likes 0	
Dislikes 0	

Response

Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5, Group Name BC Hydro

Answer	
Document Name	

Comment	
This recommendation aligns with Requirements R7 and R8 of EOP-011-2. BC Hydro recommends that a new EOP Standard(s) focusing on cold weather preparedness be developed to address this recommendation and the Requirements R7 and R8 be moved from EOP-011-2 to the new Standard in the EOP family.	
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 FERC, NERC and Regional Entity Staff Report on recent cold weather outages includes numerous recommendations for ensuring the reliability of the Bulk Electric System through potential revisions to NERC Reliability Standards and by other means. Southern Company looks forward to engaging these topics within NERC's stakeholder process. In this regard, we would like to express our general support of EEI's comments in response to the proposed Standards Authorization Request for Project 2021-07, Extreme Cold Weather Grid Operations, Preparedness, and Coordination. Southern Company offers the following remarks for consideration by the project's Standard Authorization Request Drafting Team once established. Southern Company believes the best location for all cold weather-related standards and requirements would be in a **new** standard dedicated solely to cold weather requirements. The existing related requirements of reliability standards EOP-011-2 (R7 & R8), TOP-003-5 (R1.3 & R2.3), and IRO-010-4 (R1.3) can be included in the new standard at a future revision date. This would ensure all requirements remain in effect continuously.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	
Document Name	
Comment	
EOP-011	
Likes 0	
Dislikes 0	
Response	

Andy Fuhrman - Minnkota Power Cooperative Inc. - 1,5 - MRO	
Answer	
Document Name	
Comment	
MPC supports comments submitted by the MRO NERC Standards Review Forum (NSRF).	
Likes 0	
Dislikes 0	
Response	
Rebecca Baldwin - Transmission Access Policy Study Group - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
TAPS does not take a position regarding which standard is the appropriate home for the proposed new GO/GOP requirements, but we urge the SDT to consolidate the proposed GO/GOP requirements in a single standard to the extent possible, for ease of reference.	
Likes 1	Platte River Power Authority, 5, Archie Tyson
Dislikes 0	
Response	
Alan Kloster - Evergy - 1,3,5,6 - MRO	
Answer	
Document Name	
Comment	
Evergy supports and incorporates by reference Edison Electric Institute's (EEI) response to Question 1a.	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1,3,5	

Answer	
Document Name	

Comment

We recommend this be added to EOP-011.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

GENERAL COMMENTS: EEI appreciates the efforts by FERC, NERC, and Regional Entity Staff in the development of the February 2021 Cold Weather Outages in Texas and the South-Central US report dated November 2021. EEI member companies share the desire to better address and respond to extreme cold weather. The manner and process required to achieve these goals is complex, requiring multiple tools if this effort is to be fully effective. In our comments to the SAR, we have focused on what can be addressed through NERC Reliability Standards. We also offer the following observations that should be addressed to avoid unintended and possibly harmful consequences to grid reliability.

- Generating resources are designed for operation within certain design specifications to meet and achieve certain defined grid applications. For example, generating resources designed to provide peak output during hot weather conditions will likely be limited when operating during extreme cold weather conditions. It is also likely that modifications to these resources to meet extreme cold weather conditions may create the need to derate the resource during hot weather conditions, creating different reliability issues. In short, whether a generating resource was designed for optimal use during hot or cold conditions has a bearing on whether additional reliability requirements might be beneficial or detrimental to the resource's overall performance.
- This SAR also proposes to require Generator Owners (GOs) to make modifications to their resources that would result in potentially extending their operating specification beyond their original design. This type of change also needs careful consideration vis-à-vis a NERC Reliability Standard and could impose requirements that are impractical and may go beyond what is allowed by law under the Federal Power Act.
- Responsible entities support protecting critical natural gas facilities from inadvertent load shedding. However, the information needed to identify whether a gas facility is critical understandably resides with the gas facility owners and not with the entities NERC regulates, thus modifications to NERC Reliability Standards for this purpose could be ineffectual if the gas facility owners do not provide this information.

EEI COMMENT to Question 1a:

While EOP-011-2 could be modified to include the expanded emergency preparedness recommendations contained in this recommendation, the consolidation of the GO/GOP specific extreme cold weather requirements into a single new Reliability Standard, including those developed under NERC Project 2019-06, would provide considerable efficiencies for industry and this project.

Likes 1	Platte River Power Authority, 5, Archie Tyson
Dislikes 0	

Response

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	
Document Name	
Comment	
MidAmerican Energy Company supports EEI and MRO NSRF comments	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
The NAGF believes that the recommendation should be included as part of a new standard dedicated to Cold Weather.	
Likes 0	
Dislikes 0	
Response	
LaKenya VanNorman - Florida Municipal Power Agency - 3,4,5,6 - SERC	
Answer	
Document Name	
Comment	
FMPA supports TAPS (Transmission Access Policy Study Group) comments	
Likes 0	
Dislikes 0	
Response	
Michele Mihelic - American Clean Power Association - NA - Not Applicable - NA - Not Applicable	

Answer	
Document Name	
Comment	

The American Clean Power Association (ACP), the national trade association uniting developers/owners/operators of utility scale wind, solar, storage, and transmission facilities along with allied manufacturers, construction firms, service providers, legal/financial/consulting firms and others, recommends that the most appropriate NERC Standard to address the recommendation to identify and protect cold-weather critical components would be in the Facilities Design, Connections, and Maintenance (FAC) suite. Critical components can be best addressed in this type of standard with a static design number approach.

ACP is also concerned about the use of the term 'protect' in this recommendation. Some of the examples provided (footnote 261) in the Joint Inquiry report for cold-weather-critical components cannot be "protected" against certain cold weather ambient conditions. Therefore, ACP suggests a language change to the SAR from "protect" to "protect or if unable to protect, if near-term conditions are predicted to be met that would render this cold-weather-critical component unavailable, such unavailability of this cold-weather-critical component shall be reflected in the generating capacity that can be relied on." Exceptions should be made for components that are not able to be protected.

Likes 2	Mat Bunch, N/A, Bunch Mat; Enel Green Power, 5, Johnson Natalie
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	

Minnesota Power agrees with MRO's NERC Standards Review Forum (NSRF) comments.

Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	

BPA supports the comments made by the US Bureau of Reclamation.

Likes 0	

Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	
Document Name	
Comment	

The ISO/RTO Council (IRC) Standards Review Committee (SRC) believes this recommendation would best be addressed in a **Facilities Design, Connections and Maintenance (FAC)** standard along with items 1, 3, 4, 5 and 6 (*see* pages 3-4 of the SAR).

If this proposal is adopted, IRC SRC recommends the Standard Drafting Team (SDT) begin work using the corresponding language currently in EOP-011-2, Requirements R7 and R8 and then retire R7 and R8 from EOP-011-2.

In addition, IRC SRC recommends a change to the scope of the SAR to recognize there may be components that Generator Owners will be unable to protect, such that these cold-weather-critical components could render the unit unavailable. This unavailability should be reflected in the generating capacity provided to the BA as that can be relied upon (*see* our response to question 1e below).

Likes 0	
Dislikes 0	
Response	
Travis Fisher - Electricity Consumers Resource Council (ELCON) - 7	
Answer	
Document Name	
Comment	

As Generator Owners identify and develop a plan to protect cold-weather-critical components and systems, we recommend they estimate the cost of any proposed protection (or of several protection options). NERC and FERC should understand the cost of protections before the protection activities become mandatory.

Likes 0	
Dislikes 0	
Response	
Natalie Johnson - Enel Green Power - 5	

Answer	
Document Name	

Comment

Enel North America, Inc. believes that the recommendation to identify and protect cold-weather-critical components is best addressed in the FAC-008 (Facilities Ratings) standard. Enel North America, Inc. believes that the scope of NERC FAC-008 – Facility Ratings (NERC FAC-008) addresses equipment limitations for both normal and emergency operation in winter and summer, and this is suitable to address cold-weather-critical components and systems that would be affected by extreme cold weather.

The protection of these critical components can be included in EOP-011 or are implied with the limitations listed in FAC-008. Alternatively, this can be addressed in the Facilities Design and Maintenance suite of standards. However, the most important thing for Enel North America, Inc. is that these requirements are not dispersed across a few different standards. This may therefore necessitate a separate standard within the Facilities Design and Maintenance suite. Regarding the recommendation to protect cold-weather-critical components, Enel North America, Inc. agrees with MRO that the scope of the SAR must recognize that there may be some components that are unable to be protected in all scenarios.

Critical components can be best addressed in this type of standard that involves static design numbers.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1,3,5,6

Answer	
Document Name	

Comment

Exelon concurs with the comments submitted by the EEI for this question. Additionally, should this drafting team decide to create new standard(s) specific to extreme cold weather, the SAR should allow the drafting team to move the FERC-approved requirements created by Project 2019-06 Cold Weather into the new comprehensive standard(s).

Likes 0	
Dislikes 0	

Response

Jessica Lopez - APS - Arizona Public Service Co. - 1,3,5,6

Answer	
Document Name	

Comment

AZPS agrees with the comments provided by EEI; EOP-011-2 could be modified to include this recommendation or may be added as a stand alone standard.

Likes 0	
Dislikes 0	

Response
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	
Document Name	

Comment
EOP-011-2 (effective 4/1/2023) includes a new Requirement R7 that is applicable to the Generator Owner. R7, part 7.1 states that a Generator Owner's cold weather preparedness plan(s) shall include "Generating unit(s) freeze protection measures based on geographical location and plant configuration". R7, part 7.2 states that a Generator Owner's cold weather preparedness plan(s) shall include "Annual inspection and maintenance of generating unit(s) freeze protection measures". If these sub-parts of R7 do not sufficiently address this FERC/NERC Joint Inquiry report recommendation, EOP-011-2 could be revised to address it.

Likes 0	
Dislikes 0	

Response

b. Which Reliability Standard(s) should be revised to address the recommendation: "Generator Owners are to design new or retrofit existing generating units to operate to a specified ambient temperature and weather conditions (e.g., wind, freezing precipitation). The specified ambient temperature and weather conditions should be based on available extreme temperature and weather data for the generating unit's location, and account for the effects of precipitation and accelerated cooling effect of wind."

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
EOP-011-2 (effective 4/1/2023) includes a new Requirement R7 that is applicable to the Generator Owner. R7 requires Generator Owners to "implement and maintain one or more cold weather preparedness plan(s) for its generating units", and lists the topics that must be addressed in the plan(s) at a minimum. This FERC/NERC Joint Inquiry report recommendation could possibly be addressed by revising EOP-011-2 to add another Generator Owner requirement.	
Likes 0	
Dislikes 0	
Response	

Jessica Lopez - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	
Document Name	
Comment	
AZPS agrees with the comments provided by EEI; recommending that the words "design" and "retrofit" be deleted and replaced with "specify".	
Likes 0	
Dislikes 0	
Response	

Daniel Gacek - Exelon - 1,3,5,6	
Answer	
Document Name	
Comment	
Exelon concurs with the comments submitted by the EEI for this question.	
Likes 0	

Dislikes 0	
Response	

Natalie Johnson - Enel Green Power - 5	
Answer	
Document Name	
Comment	

Enel North America, Inc. does not believe that this recommendation should be addressed within the NERC Reliability Standards. Each plant, geographic location, and transmission system is different and an attempt to try and develop one Reliability Standard for generating unit design is not the most efficient approach to increasing system reliability during extreme temperature and cold weather events. For example, for some wind generators there is not an infinite operable temperature band, meaning that if they are designed to operate at very high temperatures, they may not be able to operate at very, very low temperatures, and vice versa. Depending on the geographic location of the wind generator, the ambient weather conditions on peak load days, and whether it is located on a summer or winter peaking system, the ability to operate in extreme high temperatures may bring more reliability benefit to the system than the ability to operate under very, very low and infrequent temperatures. Further, the accuracy and availability of historic extreme weather data varies drastically across the country and a standard tied to this type of data would result in dramatically different impacts and outcomes even for generators in the same region.

Should this recommendation remain in the SAR, Enel North America, Inc. is concerned that the current language does not contain sufficient technical details, thus further research (by NERC Technical Committee(s) or other technical groups is necessary) for the industry to properly implement this recommendation across different regions, generation types, and transmission systems. It is difficult to make an assessment on operating to a certain ambient temperature and weather conditions without sufficient detail on what those temperature and weather thresholds might be. Additional definition and criteria on how these operating benchmarks will be derived still needs to be provided. Weather conditions take into account a wide range of circumstances, even within a limited geographic location; therefore, these specifications need to be clearly defined so that the industry has clear guidance. Enel North America, Inc. recommends, as a possible solution, to use a probability-based approach that takes into consideration the frequency that the lowest or highest recorded temperature occurs.

In addition, for existing sites, Enel North America, Inc. believes that in some circumstances grandfathering or exception clauses should be considered (including, but not limited to):

- Wind turbines that are built with structural steel or major components that are not rated for lower ambient temperatures. Compliance for these types of wind units would require a complete rebuild of the wind generator from scratch. In some cases (as is discussed further below), without guaranteed compensation to cover the retrofit of existing assets, the assets may exit the market altogether. This would have the opposite effect of ensuring robust supply of generation for reliability during extreme events.
- Updates to wind turbines that would trigger a complete re-study of the Balance of Plant to accommodate different operating temperatures or design limits. The design of a facility is based on certain turbine fundamentals, and any changes could cause misalignment within the facility design. These types of changes could impact generator performance, real and reactive capabilities, system modelling, and equipment functionality thereby requiring a variety of studies to be redone.
- Updates that would void original equipment manufacturer warranties. Due to the fact that the bulk of the existing wind fleet is relatively new, most units are still under warranty, and warranties are an important part of the way units are operated and maintained.

For the aforementioned reasons, Enel North America, Inc. is concerned with a one-size-fits-all approach and believes that a mechanism to consider special circumstances and exceptions should be further address and clarified.

Lastly, Enel North America, Inc. reiterates that this recommendation is not appropriate for NERC Reliability Standards due to the potentially significant and unpredictable costs of retrofits and the broader impact this could have both on electricity markets and grid reliability, given that generators potentially would be taken offline for months to re-build wind sites. FERC, States, ISO/RTOs, and other utility regulators are better positioned to evaluate the costs and benefits of retrofits for their regions and customers. Enel North America, Inc. recommends that regulators be required to provide

compensation for Generator Owner investments for any retrofits. Generator Owners cannot commit to the significant capital investment that is likely to be involved without certainty that Generator Owners will be compensated and a clear mechanism on how this will be achieved.	
Likes 0	
Dislikes 0	
Response	
Travis Fisher - Electricity Consumers Resource Council (ELCON) - 7	
Answer	
Document Name	
Comment	
Applying mandatory standards to new builds would be less invasive than asking all existing generators to retrofit to specified weather conditions. ELCON suggests a tiered approach in which NERC could develop new designs for generators that can operate to a specified ambient temperature and weather conditions while exploring the feasibility and cost of applying those new operating requirements to existing generators. Disparate treatment of new and existing assets is common in federal regulation. For example, the Environmental Protection Agency treats existing generation units differently from new units under the Clean Air Act, and the National Highway Traffic Safety Administration treats newer model vehicles differently from existing vehicles when considering fuel economy standards. The same approach makes sense here given the enormous challenge of retrofitting the entire existing generation fleet of a large portion of the United States.	
Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	
Document Name	
Comment	
The IRC SRC strongly supports the spirit and intent of this requirement and believes that this aspect must be addressed in order to achieve the reliability improvements necessary to avoid the bad outcomes experienced as a result of Winter Storm Uri. That said, it is our understanding the industry has concerns with the “design and retrofit” aspects of this recommendation, as written, and that these aspects may fall outside the scope of what NERC Reliability Standard(s) are authorized to address and may be more appropriately addressed at FERC as terms under Generator Interconnection Agreements (GIA). If that is the case, the IRC SRC asks that NERC do the following: 1. Work with FERC to ensure that action is taken to address this recommendation in the appropriate forum .	

2. Determine how NERC Reliability Standard(s) would address the balance of this requirement; i.e. to account for the effects of precipitation and accelerated cooling effect of wind on generator unit operation as these aspects are not currently included in EOP-011-2, Requirements R7 and R8.

Likes 0	
Dislikes 0	

Response
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	
Document Name	

Comment
BPA supports the comments made by the US Bureau of Reclamation.

Likes 0	
Dislikes 0	

Response
Jamie Monette - Allete - Minnesota Power, Inc. - 1

Answer	
Document Name	

Comment
Minnesota Power agrees with MRO's NERC Standards Review Forum (NSRF) comments.

Likes 0	
Dislikes 0	

Response
Michele Mihelic - American Clean Power Association - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment
ACP echoes comments filed by the Midwest Reliability Organization NERC Standards Review Forum (MRO NSRF) and others raising concerns about this recommendation. ACP does not believe this recommendation should be pursued at this time and it should be removed from the standard

authorization request (SAR). There is insufficient information and data to inform how to address and effectively implement this recommendation. And, there are implications beyond NERC reliability standards, including with respect to the ability of states to achieve their clean energy goals and regarding compensation for retrofits, which necessitates engagement with a broader universe of stakeholders than those involved in NERC reliability standards. As an interim step, ACP recommends that more detailed information, analysis, and data be developed to better define this approach, along with analysis on the feasibility of retrofits, commercial availability of retrofit options, cost, timeline to implement, potential for generator downtime to install, implications on design parameters for existing facilities etc. so at some point in the future, stakeholders can make a more informed decision on whether and how to approach this recommendation. For example, what are the specific temperatures and weather conditions that need to be considered? How frequently do they occur? How consistent is the data quality across regions? How do they differ by region and by area within a region? Are there any technologically feasible, proven, and commercially available retrofit options? If so, what is the availability of materials, staff etc. to carry out the work? To the extent there are not, what are the barriers? What would be the generator downtime to retrofit? Would generators be at risk of retirement if retrofitting is not economic and, if so, what are the impacts to reliability?

In addition, consideration needs to be given to the operating and design parameters of generators. For example, in some cases and in certain environments a wind turbine that is optimized to operate at extremely high temperatures, may not be able to also be optimized to operate at extremely low temperatures. In such situations, it makes sense to keep the focus on higher temperatures as the generators provide more reliability value than they might in designing them to respond to infrequent and/or historically low temperatures and icing conditions.

With respect to new builds, given that each power plant, geographic location, and transmission system is different, ACP recommends that the needed generator attributes can be best addressed through the Interconnection Agreement and Studies Process where all involved parties can take into consideration systems needs and generator capabilities on a case-by-case basis.

To the extent this recommendation remains in the SAR despite ACP and others recommendation to remove it, ACP requests that exceptions, or at a minimum sufficient grandfathering provisions, be provided from the requirement to retrofit in situations in which a retrofit:

1. Is not technically feasible, proven and commercially available.

2. Would require operating equipment outside its design parameters, which raises potential conflicts with warranties, safety, and regulatory requirements.

Likes 2	Mat Bunch, N/A, Bunch Mat; Enel Green Power, 5, Johnson Natalie
Dislikes 0	

Response

LaKenya VanNorman - Florida Municipal Power Agency - 3,4,5,6 - SERC

Answer	
Document Name	

Comment

FMPA supports TAPS (Transmission Access Policy Study Group) comments

Likes 0	
Dislikes 0	

Response

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	
Document Name	
Comment	

The NAGF believes that the recommendation should be included as part of a new standard dedicated to Cold Weather.

Likes 0	
Dislikes 0	
Response	

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3

Answer	
Document Name	
Comment	

MidAmerican Energy Company supports EEI and MRO NSRF comments

Likes 0	
Dislikes 0	
Response	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	
Comment	

EEI members are fully committed to ensuring that they are able to reliably operate during extreme cold weather conditions. Changes to a NERC Reliability Standards must be done within the bounds of FPA Section 215, and therefore, it is a question of law whether a NERC Reliability Standard can require GOs to retrofit existing generating resources to operate beyond their original plant design specifications. Additionally, it is a question of law whether the Federal Power Act prohibits the ERO or FERC from compelling the design of new generation. That said, GOs are already required to identify the known operating capabilities of their resources during cold weather conditions (see EOP-011-2) and provide that information during forecasted cold weather to responsible Reliability Coordinator (see IRO-010-4) and the Transmission Operator and Balancing Authority (see TOP-003-5) so that an adequate level of reliability can be maintained.

EEI suggests modifying the SAR as follows:

Generator Owners **are required to identify and** operate **their** generating units to the capabilities of their resources and provide that information to responsible Reliability Coordinators, Balancing Authorities, and Transmission Operators so that an adequate level of reliability can be maintained. This projected capability shall be based on the facility's design, past performance under similar weather conditions and accounting for the effects of precipitation and accelerated cooling effect of wind.

Obligating resource owners to make certain modifications to their resources that were not conveyed, anticipated, or agreed to prior to the design, construction, or commissioning of the resource could have unintended consequences that could impact BES reliability. As an example, wind turbines that were installed without de-icing technology, when originally built, may not be practically retrofitted in all cases. Relative to traditional synchronous resources built for operation in warmer climates, these resources are often designed for peak capacity during very hot weather conditions. To achieve this capability, these resources are often built in a manner that intentionally exposes operating components to provide greater capacity during extreme hot weather conditions. Obligating those resource owners to enclose those units/components in favor of operating conditions they were not intended to reliably operate could have negative consequences for grid reliability.

Likes 1	Platte River Power Authority, 5, Archie Tyson
Dislikes 0	

Response

Donna Wood - Tri-State G and T Association, Inc. - 1,3,5

Answer	
Document Name	

Comment

We do not think this requirement would fit into any existing standards. However, we do not agree that a new standard is appropriate for this recommendation, as it appears to go beyond FERC's authority and would instead be the GOs business decision. A possible alternative would be to require GOs to consider XX years of historical data when creating the design for a new BES generating plant.

Likes 0	
Dislikes 0	

Response

Alan Kloster - Evergy - 1,3,5,6 - MRO

Answer	
Document Name	

Comment

Evergy supports and incorporates by reference Edison Electric Institute's (EEI) response to Question 1b.

Likes 0	
Dislikes 0	

Response

Rebecca Baldwin - Transmission Access Policy Study Group - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
TAPS does not take a position regarding which standard is the appropriate home for the proposed new GO/GOP requirements, but we urge the SDT to consolidate the proposed GO/GOP requirements in a single standard to the extent possible, for ease of reference.	
Likes 0	
Dislikes 0	
Response	

Andy Fuhrman - Minnkota Power Cooperative Inc. - 1,5 - MRO	
Answer	
Document Name	
Comment	
MPC supports comments submitted by the MRO NERC Standards Review Forum (NSRF).	
Likes 0	
Dislikes 0	
Response	

David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	
Document Name	
Comment	
EOP-011	
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 appropriate standard for such a requirement should be in a new standard dedicated solely to cold weather requirements as previously mentioned in Southern Company's response to Question 1a.

Southern Company agrees that generating facilities should have the capability to operate at reasonable expected weather conditions for their location and communicate their capability to the Balancing Authority in a timely manner. However, Southern Company is concerned that the requirement for retrofitting *"existing generating units to operate to a specified ambient temperature and weather conditions (e.g., wind, freezing precipitation)"* has the potential to unduly burden the economics for some existing generating facilities and could cause the retirement of those facilities that would be impacted by the requirement. Additionally, retrofitting some existing generating facilities in excess of their original design criteria could be technically challenging and cost prohibitive.

Likes 0	
Dislikes 0	
Response	

Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5, Group Name BC Hydro

Answer	
Document Name	
Comment	

This recommendation aligns with Requirements R7 and R8 of EOP-011-2.

BC Hydro recommends that a new EOP Standard(s) focusing on cold weather preparedness be developed to address this recommendation and the Requirements R7 and R8 be moved from EOP-011-2 to the new Standard(s).

Likes 0	
Dislikes 0	
Response	

Michael Johnson - Pacific Gas and Electric Company - 1,3,5 - WECC, Group Name PG&E All Segments

Answer	
Document Name	
Comment	

PG&E has participated in the preparation and supports the comments provided by the Edison Electric Institute (EEI) for Q1b.

PG&E is also providing the additional input related to Q1b - PG&E is fully committed to the reliable operation of generating resources during cold weather events. PG&E would like to take this opportunity to reiterate the EEI comment requiring Generator Owners to design new or retrofit existing generating units to operate at a specified ambient temperature and weather conditions. Obligating generator owners to implement design changes to new resources and to retrofit existing generators should be closely evaluated to ensure that this action complies with the bounds of the Federal Power Act section 215.

Likes 0	
Dislikes 0	

Response

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5

Answer	
Document Name	

Comment

Reliability Standard EOP-011-2

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE suggests this Key Recommendation could work in EOP-011, as EOP-011-2 Requirement Part 7.3.2 already indicates generating units' cold weather data should include a minimum design temperature. Requirement R7 could be revised to be more specific as recommended in the Key Recommendations from the FERC Report.

Alternatively, a new Emergency Preparedness and Operations standard could be created to include the following Key Recommendations from the Joint Inquiry: 1a, 1c,1d, 1e, and 1f. Language from future enforceable EOP-011-2 Requirements R7 and R8 could also be included in this new Emergency Preparedness and Operations standard.

Additionally, Texas RE recommends the drafting team consider defining thresholds for ambient temperature and weather conditions, specifically for temperature, precipitation, and wind conditions. Texas RE further recommends that when that threshold of ambient temperature and weather conditions for extreme weather, specifically including precipitation and wind, are forecasted, GOPs with unstaffed units should have the unit staffed 24/7 until the freezing temperatures and precipitation end. This would ensure that the BA and TOP are notified of actual site conditions that could affect unit capacity prior to any actual derate, which would allow BA emergency operations to commence quicker.

Texas RE also recommends the following:

- Revising TOP-003 and IRO-010, as in Project 2019-06, to include provisions for notifying the TOP and RC of data necessary to perform the Operational Planning Analyses, Real-time monitoring, and Real-time Assessments;
- Consider revising the EOP-004 attachment 1 to include a new event type of Critical loss due to cold weather;
- Consider revising Table 1 in TPL-001 to include cold weather;
- Consider whether cold weather should be included in the RC's SOL Methodology in accordance with proposed Reliability Standard FAC-011-4;
- Consider adding weather as a "steady-state" to Attachment 1 of MOD-032;
- Consider whether identifying critical elements should be included as part of CIP-002 for identifying high, medium, and low impact BES Cyber Systems; and
- Consider adding the term "critical elements" to the NERC Glossary as defined in the FERC Report in its execution of recommendations 1a-1g in order to provide consistency and clarity.

Likes 0	
Dislikes 0	

Response

Patricia Lynch - NRG - NRG Energy, Inc. - 5,6

Answer	
Document Name	

Comment

NRG Energy Inc. believes that the recommendation should be included as part of a new standard dedicated to Cold Weather.

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 comments posted by EEI

Likes 0	
Dislikes 0	

Response

Jennie Wike - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6 - WECC, Group Name Tacoma Power	
Answer	
Document Name	
Comment	

Instead of prescribing specific retrofits or upgrades, Tacoma Power recommends performing a three tier risk-based approach: perform a vulnerability assessment to identify risks, develop actions to mitigate these risks, and then implement the actions. This approach would be similar to how the industry addressed GMD events in Project 2013-03.

FAC-008 and MOD-025 currently ensure that the GO and GOP know the capability and availability of their BES resources under diverse ambient conditions. Either of these Standards could be modified to include a tiered risk-based approach that would ensure facilities are rated or designed for extreme cold weather. For example, these Requirements could look like the following:

"RX. Generator Owners shall complete a benchmark Cold Weather Vulnerability Assessment at least once every 60 calendar months. [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

RY. Generator Owners shall communicate to their respective Generator Operators and Transmission Planner any vulnerabilities identified in RX that could negatively impact applicable generation facility ratings, capacity, or availability. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

RZ. Generator Owners that conclude through the Cold Weather Vulnerability Assessment conducted in Requirement RX that their generation facility has vulnerabilities that could impact generator output and availability during these conditions, shall develop a Corrective Action Plan (CAP) addressing how the vulnerabilities are mitigated. The CAP shall: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

RZ.1 Be developed within one year of completion of the Cold Weather Vulnerability Assessment.

RZ.2 Include necessary maintenance activities, cold weather preparation plans, and freeze protection methods."

Likes 0	
Dislikes 0	
Response	
Kenisha Webber - Entergy - Entergy Services, Inc. - NA - Not Applicable - SERC	
Answer	
Document Name	
Comment	

EOP-011-2, Requirement R7 as part of Cold Weather plan

Likes 0	
Dislikes 0	
Response	

Michael DePalma - Onward Energy - NA - Not Applicable - MRO,WECC,Texas RE,NPCC	
Answer	
Document Name	
Comment	
There is a question on how " specified ambient temperature and weather conditions" is determined? Sites are designed to specific weather conditions already. For Generator Owners to design new or retrofit existing generating units to operate in anything other than what they were originally designed could cost millions of dollars per site. This would make more sense for a revised Standard to read "Sites' freeze protection shall be kept functional with original design criteria for winter operations".	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6, Group Name Dominion	
Answer	
Document Name	
Comment	
Dominion Energy supports the comments submitted by EEI and is firmly ofthe opinion that equipment design specificaions are not appropriate for a results based reliability standard and are not support by both the Federal Power Act and FERC Order 672, paragraph 260.	
Likes 0	
Dislikes 0	
Response	

Keith Jonassen - ISO New England, Inc. - 2 - NPCC	
Answer	
Document Name	
Comment	

Recommend revising EOP-011 and create a new defined term

- Add new requirement to EOP-011:
    - Each Generator Owner shall design new or ensure existing generating units operate to a specified ambient temperature and weather conditions which should be based on available extreme temperature and weather data for the generating unit's location and should account for the effects of precipitation and cooling effect of wind.
- Create new defined term: **Extreme Weather** is temperatures at or exceeding the lowest (or highest) recorded temperature at the generator's physical location (or nearest location where temperature was recorded for which data exists) for a sustained period greater than or equal to one day.

Likes 0	
Dislikes 0	
Response	

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	
Document Name	
Comment	

Alliant Energy supports the comments submitted by the MRO NSRF.

Likes 0	
Dislikes 0	
Response	

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	
Document Name	
Comment	

Xcel Energy supports the comments submitted by EEI.

Likes 0	

Dislikes 0	

Response

George Brown - Acciona Energy North America - 5

Answer	
Document Name	

Comment

Acciona Energy does not believe this recommendation, as written, can or should be addressed in a NERC Reliability Standard(s) at this time. Specific information, data and details needs to be studied and provided to allow industry to either make proposals on appropriate areas to address this recommendation or develop requirements that meet reliability principles, market principles and are results-based for this recommendation.

Likes 0	
Dislikes 0	

Response

Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 3,4,5 - RF, Group Name Consumers Energy Company

Answer	
Document Name	

Comment

FAC-008-5, and possibly other FAC standards. Modify or create new.

Likes 0	
Dislikes 0	

Response

Richard Jackson - U.S. Bureau of Reclamation - 1,5

Answer	
Document Name	

Comment

Reclamation does not support a requirement to retrofit existing generator units to meet existing potential extreme weather conditions. This may not be cost effective and may create unfair market advantages if implemented. Reclamation acknowledges that when a Generator Owner builds a new generating plant, those units should be designed with the applicable potential extreme weather conditions in mind.

If this recommendation goes forward, Reclamation recommends that prescriptive cold weather design considerations apply only to new generation facilities. Refer to VAR-501-WECC-3.1 Requirement R5 for an example of an acceptable method to implement this recommendation.

Reclamation recommends a requirement for Generator Owners to design new generating units to operate to a specified ambient temperature and weather conditions be contained in the same new standard in the FAC family as that created to identify cold weather critical components and their required maintenance. Please see the example provided in the response to Question 1.a.

Likes 1	Enel Green Power, 5, Johnson Natalie
Dislikes 0	

Response

Michael Krum - Salt River Project - 1,3,5,6 - WECC

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

MRO NSRF does not believe this recommendation, as written, falls within the scope of what NERC Reliability Standard(s) are authorized to address.

As this recommendation may require Generator Owners to make a significant capital investment, resulting in increased cost to end use ratepayers, the MRO NSRF believes that Section 1201 of the Federal Powers Act (page 349) Section 215, part (3) applies, which in part states, "…the term does not include to enlarge such facilities or to construct new transmission capacity or generation capacity." MRO NSRF is also concerned that state regulators may not approve the cost associated with "design and retro fit."

If this recommendation was to be contained in a Reliability Standard, it would mandate that all current and new generation capacity would need to meet some unknown, specific ambient temperature. If the specific ambient temperature is dependant on the GO to determine, this will not meet the recommendation's intent. This would prevent entities to build needed capacity for the vast amount other seasonal times, when capacity is needed, notwithstanding during extreme (specified) ambient temperatures. As this recommendation requires investment, this recommendation may be more appropriately addressed as part of the FERC tariff as part of Generator Interconnection Agreements (GIA).

Alternatively, this may be inherently covered by the recommendation in 1d (below), where CAPs are used to address generating unit's outage, failure to start, or derates due to freezing. The intent is for generators to perform during freezing (extreme cold) temperatures. It should not matter how Generator Owners achieve this, such as in recommendation d.

If this item remains to be within a Reliability Standard, it is recommended that the GO determine what the specific ambient temperature is for BES generators.

Likes 1	Enel Green Power, 5, Johnson Natalie
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	
Document Name	

Comment

None – suggest a new NERC GO/GOP Standard to implement recommendation. It is also suggested that recently modified TOP-003-5, EOP-011-2 and IRO-010-4 standards not be modified further and consideration be given for moving Cold Weather Requirements in these Standards to the new Standard.

Likes 0	
Dislikes 0	

Response

Susan Sosbe - Wabash Valley Power Association - 1,3

Answer	
Document Name	

Comment

EOP-011, same as above.

Likes 0	
Dislikes 0	

Response

Adrian Raducea - DTE Energy - Detroit Edison Company - 3,5, Group Name DTE Energy - DTE Electric

Answer	
Document Name	

Comment	
FAC-008 Facility Ratings. R2. 2.2.3. 2.2.2. Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications. 2.2.3. Ambient conditions (for particular or average conditions or as they vary in real-time). 2.2.4. Operating limitations. **Update to specify extreme cold weather conditions.** **However, a single standard combining all the cold weather requirements that can evolve over time is preferable.**	
Likes 0	
Dislikes 0	
Response	

c. Which Reliability Standard(s) should be revised to address the recommendation: "Generator Owners and Generator Operators are to conduct annual unit-specific cold weather preparedness plan training."

Adrian Raducea - DTE Energy - Detroit Edison Company - 3,5, Group Name DTE Energy - DTE Electric	
Answer	
Document Name	
Comment	
PER-006-1 – Specific Training for Personnel The purpose clearly states this is to ensure that personnel are trained on specific topics essential to reliability to perform or support Real-time operations of the Bulk Electric System Extreme Cold Weather Grid Operations, Preparedness, and Coordination is a specific topic for reliability.	
Likes 0	
Dislikes 0	
Response	
Susan Sosbe - Wabash Valley Power Association - 1,3	
Answer	
Document Name	
Comment	
EOP-011-2 – R8 already calls for the generator specific training.	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	
Suggest modifying PER-006-1 to implement recommendation. It is also suggested that recently modified EOP-011-2 training requirements be moved to the new NERC GO/GOP Standard.	

Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	

The MRO NERC Standards Review Forum (NSRF) recommends addressing this recommendation as two (2) requirements to more accurately address the aspects required of each function:

- Generator Owner maintenance aspects in an **FAC** standard along with items 1, 3, 4, 5 and 6 (*see* pages 3-4 of the SAR).
- Generator Operator operations aspects in **PER-006**.
- If adopted, MRO NSRF recommends the SDT begin work using the corresponding language currently in EOP-011-2, Requirements R7 and R8 and then retire R7 and R8 from EOP-011-2.

Likes 0	
Dislikes 0	
Response	
Michael Krum - Salt River Project - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
No Comment.	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1,5	
Answer	
Document Name	
Comment	

Reclamation disagrees with the requirement for annual training on routine physical maintenance. No other annual maintenance activities require annual training before doing the work. For example, switching the direction of the cooling fans on unit transformers, turning on the reservoir bubblers, etc., are not activities that warrant annual training. This type of training content is not appropriate for a NERC requirement.

For geographical areas and generation types that typically experience cold weather, an annual training requirement is excessive. Generator Owners and Generator Operators in these areas should only be required to provide initial training on their cold weather preparedness plan and provide recurring training only when the plan is updated. Reclamation recommends placing a requirement for conducting training on unit-specific cold weather preparedness in PER-006. Reclamation also recommends moving EOP-011-2 Requirement R8 to PER-006. The requirement to conduct the cold weather preparedness plan training annually should be added only for geographical areas that do not typically experience cold weather.

Example:

PER-006-X

R2. Each Generator Owner, in conjunction with its Generator Operator shall provide generating unit-specific training to its maintenance and operations personnel responsible for implementing the Generator Owner's cold weather preparedness plan(s) developed pursuant to EOP-011-2 Requirement R7.

R2.1 The generating unit-specific training shall be provided initially and when the cold weather preparedness plan is updated.

Likes 0	
Dislikes 0	

Response

Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 3,4,5 - RF, Group Name Consumers Energy Company

Answer	
Document Name	

Comment

Since it is training, a modified or new PER standard.

Likes 0	
Dislikes 0	

Response

George Brown - Acciona Energy North America - 5

Answer	
Document Name	

Comment

Acciona Energy believes this recommendation would be best addressed in Facilities Design, Connections and Maintenance (FAC) suite of NERC Standards in a new standard.

Acciona Energy recommends that the Standards Drafting Team adopt and then retire the applicable language from NERC Reliability Standard EOP-011-2 Emergency Preparedness and Operations, Requirement R7 and R8.

Likes 0	
Dislikes 0	

Response

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC

Answer	
Document Name	

Comment

Xcel Energy supports the comments submitted by EEI.

Likes 0	
Dislikes 0	

Response

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4

Answer	
Document Name	

Comment

Alliant Energy supports the comments submitted by the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Keith Jonassen - ISO New England, Inc. - 2 - NPCC

Answer	
Document Name	

Comment

Recommend revising EOP-011

- Revise EOP-011, R8 (revision in bold):

○ Each Generator Owner in conjunction with its Generator Operator shall **identify the entity responsible for providing the generating unit-specific training, and that identified entity shall annually, prior to the start of the winter season, provide** the training to its maintenance or operations personnel responsible for implementing cold weather preparedness plan(s) developed pursuant to Requirement R7.	
Likes 0	
Dislikes 0	
Response	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6, Group Name Dominion	
Answer	
Document Name	
Comment	
Dominion Energy suppports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	

Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	

Kenisha Webber - Entergy - Entergy Services, Inc. - NA - Not Applicable - SERC	
Answer	
Document Name	
Comment	

EOP-011-2	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6 - WECC, Group Name Tacoma Power	
Answer	
Document Name	
Comment	
Tacoma Power recommends that all O&P standard training requirements should be in the Personnel Performance, Training and Qualifications (PER) family of standards. The existing Standard PER-006 includes training requirements for the GOP and respective plant personnel. We recommend locating this new training requirement in the PER-006 Standard with appropriate modifications to the applicability section to include both GO and GOP functions. Similarly, we also support expanding the scope of this SAR to include moving the GO/GOP training in EOP-011 R8 to PER-006-1, as was put forward by the LPPC and APPA during the Project 2019-06 commenting period. We are concerned with locating training requirements in a Standard other than the PER suite of standards. Adding training requirements to other non-training standards creates a condition that makes training requirements hard to locate. Moreover, the technical compliance personnel and training personnel often don't overlap, potentilally creating a compliance gap. Locating training requirements outside of PER Standards is also not following identified industry best practices, such as the Standards Efficiency Review recommendations and the recent Project 2007-06.2 that moved training requirements from PRC Standards to the new PER-006-1 Standard.	
Likes 1	Platte River Power Authority, 5, Archie Tyson
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter	
Answer	
Document Name	
Comment	
FirstEnergy supports comments posted by EEI	
Likes 0	
Dislikes 0	
Response	

Patricia Lynch - NRG - NRG Energy, Inc. - 5,6	
Answer	
Document Name	
Comment	
NRG Energy Inc. believes that the recommendation should be included as part of a new standard dedicated to Cold Weather or included in the existing PER-006 standard.	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE suggests that an annual requirement could be added to EOP-011 R8, which requires training of the maintenance or operations personnel for implementing the cold weather preparedness plan. Alternatively, a new Emergency Preparedness and Operations standard could be created to include the following Key Recommendations from the Joint Inquiry: 1a, 1c,1d, 1e, and 1f. Language from future enforceable EOP-011-2 Requirements R7 and R8 could also be included in this new Emergency Preparedness and Operations standard.	
Likes 0	
Dislikes 0	
Response	

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5	
Answer	
Document Name	
Comment	
Reliability Standard EOP-011-2	
Likes 0	

Dislikes 0	
Response	
Michael Johnson - Pacific Gas and Electric Company - 1,3,5 - WECC, Group Name PG&E All Segments	
Answer	
Document Name	
Comment	
PG&E has participated in the preparation and supports the comments provided by the Edison Electric Institute (EEI) for Q1c.	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5, Group Name BC Hydro	
Answer	
Document Name	
Comment	
This recommendation aligns with Requirements R7 and R8 of EOP-011-2. BC Hydro recommends that a new EOP Standard(s) focusing on cold weather preparedness be developed to address this recommendation and the Requirements R7 and R8 be moved from EOP-011-2 to the new Standard(s).	
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	
Southern Company recommends that this requirement be included at a future revision date in a new cold weather standard as previously mentioned in Southern Company's response to Question 1a.	

However, for initial inclusion, Southern Company recommends that EOP-011-2 R8 be revised to include the "annual unit-specific cold weather preparedness plan training" requirement.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

EOP-011

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Minnkota Power Cooperative Inc. - 1,5 - MRO

Answer	
Document Name	

Comment

MPC supports comments submitted by the MRO NERC Standards Review Forum (NSRF).

Likes 0	
Dislikes 0	

Response

Rebecca Baldwin - Transmission Access Policy Study Group - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

TAPS does not take a position regarding which standard is the appropriate home for the proposed new GO/GOP requirements, but we urge the SDT to consolidate the proposed GO/GOP requirements in a single standard to the extent possible, for ease of reference.

Likes 0	
Dislikes 0	

Response

Alan Kloster - Evergy - 1,3,5,6 - MRO

Answer	
Document Name	

Comment

Evergy supports and incorporates by reference Edison Electric Institute's (EEI) response to Question 1c.

Likes 0	
Dislikes 0	

Response

Donna Wood - Tri-State G and T Association, Inc. - 1,3,5

Answer	
Document Name	

Comment

We believe this is addressed by EOP-011-2 R8, with the exception of an annual periodicity. So, EOP-011-2 could be modified to add that periodicity. We also recommend consideration be given to moving it to PER-006 to keep all training together.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

EOP-011-2, Requirement R8 could be modified to address this recommendation. Also, see EEI comments to 1a.

Likes 0	
Dislikes 0	

Response

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	
Document Name	
Comment	
MidAmerican Energy Company supports EEI and MRO NSRF comments	
Likes 0	
Dislikes 0	
Response	

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
The NAGF believes that the recommendation should be included as part of a new standard dedicated to Cold Weather.	
Likes 0	
Dislikes 0	
Response	

LaKenya VanNorman - Florida Municipal Power Agency - 3,4,5,6 - SERC	
Answer	
Document Name	
Comment	

PER-006 includes training requirements for the GOP and respective plant personnel. We recommend locating this new training requirement in the PER-006 Standard with appropriate modifications to the applicability section to include both GO and GOP functions. We also support expanding the scope of this SAR to include moving the GO/GOP training in EOP-011 R8 to PER-006-1, as was put forward by the LPPC and APPA during the Project 2019-06 commenting period.

We are concerned with locating training requirements in a Standard other than the PER suite of standards. Adding training requirements to other non-training standards creates a condition that makes training requirements hard to find and easy to lose; a condition that is not conducive to a quality standard. Locating training requirements outside of PER Standards is also not following industry precedent, such as the Standards Efficiency Review recommendations and the recent Project 2007-06.2 that moved training requirements from PRC Standards to the new PER-006-1 Standard.

Likes 0	
Dislikes 0	

Response

Michele Mihelic - American Clean Power Association - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

ACP believes this can be addressed in the Facilities Design, Connections and Maintenance suite of NERC standards.

Alternatively, it could be addressed in the EOP-011 Emergency Preparedness and Operations Standard as part of the requirement to have and maintain Cold Weather Preparedness Plans (R7 for Generators).

Regardless, ACP recommends requirements for cold weather preparedness plans and training should be in the same standard rather than dispersed across multiple standards.

Likes 2	Mat Bunch, N/A, Bunch Mat; Enel Green Power, 5, Johnson Natalie
Dislikes 0	

Response

Jamie Monette - Allete - Minnesota Power, Inc. - 1

Answer	
Document Name	

Comment

Minnesota Power agrees with MRO’s NERC Standards Review Forum (NSRF) comments.

Likes 0	
Dislikes 0	

Response

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	
Document Name	

Comment	
BPA supports the comments made by the US Bureau of Reclamation.	
Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	
Document Name	
Comment	
The IRC SRC recommends addressing this recommendation as two (2) requirements to more accurately address the aspects required of each function: · Generator Owner maintenance aspects in an **FAC** standard along with items 1, 3, 4, 5 and 6 (*see* pages 3-4 of the SAR). · Generator Operator operations aspects in **PER-006**. o Expand the applicable Functional Entities to include Generator Owners and Generator Operators · If adopted, IRC SRC recommends the SDT begin work using the corresponding language currently in EOP-011-2, Requirements R7 and R8 and then retire R7 and R8 from EOP-011-2.	
Likes 0	
Dislikes 0	
Response	
Natalie Johnson - Enel Green Power - 5	
Answer	
Document Name	
Comment	
Enel North America, Inc. believes that the recommendation to conduct unit-specific cold weather preparedness plan training is best addressed in the EOP-011 Emergency Preparedness and Operations Standard as part of the requirement to have and maintain Cold Weather Preparedness Plans (R7 for Generators). The Cold Weather Preparedness Plan is the best area to address this recommendation because the recommendation relates to item a) above for both identifying and protecting cold-weather-critical components. The addition of this recommendation to the Cold Weather Preparedness Plans enables a comprehensive approach to all aspects of cold weather preparedness, including training in the required plans. In addition, the Cold Weather Preparedness Plans enable Generators to make changes, improve and enhance training more frequently than a standard such as FAC-008 Facility Ratings would facilitate. Enel North America, Inc. therefore believes that this recommendation is best addressed by requiring that it is part of the overall Cold Weather Preparedness Plans in the EOP-011 Standard. This recommendation is best addressed with a planning-based approach.	

Alternatively, this can be addressed in the Facilities Design and Maintenance suite of standards. However, the most important thing for Enel North America, Inc. is that these requirements are not dispersed across a few different standards. This may therefore necessitate a separate standard within the Facilities Design and Maintenance suite.

Likes 0	
Dislikes 0	

Response
Daniel Gacek - Exelon - 1,3,5,6

Answer	
Document Name	

Comment
Exelon concurs with the comments submitted by the EEI for this question.

Likes 0	
Dislikes 0	

Response
Jessica Lopez - APS - Arizona Public Service Co. - 1,3,5,6

Answer	
Document Name	

Comment
EOP-011-2, Requirement R8 could be modified to address this recommendation or could be in a stand alone standard.

Likes 0	
Dislikes 0	

Response
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	
Document Name	

Comment

EOP-011-2 (effective 4/1/2023) includes a new Requirement R8 that is applicable to the Generator Owner (GO) in conjunction with its Generator Operator (GOP). R8 states that the GO and GOP "shall identify the entity responsible for providing the generating unit-specific training, and that identified entity shall provide the training to its maintenance or operations personnel responsible for implementing cold weather preparedness plan(s) developed pursuant to Requirement R7". If R8 does not sufficiently address this FERC/NERC Joint Inquiry report recommendation, EOP-011-2 could be revised to address it. Alternatively, the PER-006-1 standard addresses Generator Operator training for Protection Systems and Remedial Action Schemes (RAS) and could be revised to address the recommendation.

Likes 0	
Dislikes 0	

Response

Joe McClung - JEA - 1,3,5

Answer	
Document Name	

Comment

These comments are being submitted on behalf of APPA and LPPC:

Public power believes that all standard training requirements should be in the Personnel Performance, Training and Qualifications (PER) family of standards. The standard PER-006 includes training requirements for the GOP and respective plant personnel. We recommend locating this new training requirement in the PER-006 Standard with appropriate modifications to the applicability section to include both GO and GOP functions. Similarly, we also support expanding the scope of this SAR to include moving the GO/GOP training in EOP-011 R8 to PER-006-1, as was put forward by the LPPC and APPA during the Project 2019-06 commenting period.

We are concerned with locating training requirements in a Standard other than the PER suite of standards. Adding training requirements to other non-training standards creates a condition that makes training requirements hard to locate. Moreover, the technical compliance personnel and training personnel often don't overlap, potentially creating a compliance gap; a condition that is not conducive to appropriate compliance. Locating training requirements outside of PER Standards is also not following identified efficient industry best practices, such as the Standards Efficiency Review recommendations and the recent Project 2007-06.2 that moved training requirements from PRC Standards to the new PER-006-1 Standard.

Likes 0	
Dislikes 0	

Response

Diana Torres - Imperial Irrigation District - 1,3,5,6

Answer	
Document Name	

Comment

PER-006 includes training requirements for the GOP and respective plant personnel. Imperial Irrigation District recommends locating this new training requirement in the PER-006 Standard with appropriate modifications to the applicability section to include both GO and GOP functions. Imperial

Irrigation District also supports expanding the scope of this SAR to include moving the GO/GOP training in EOP-011 R8 to PER-006-1, as was put forward by the LPPC and APPA during the Project 2019-06 commenting period. Imperial Irrigation District is concerned with locating training requirements in a Standard other than the PER suite of standards. Adding training requirements to other non-training standards creates a condition that makes training requirements easier to overlook. Locating training requirements outside of PER Standards is also not following industry precedent, such as the Standards Efficiency Review recommendations and the recent Project 2007-06.2 that moved training requirements from PRC Standards to the new PER-006-1 Standard.	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC	
Answer	
Document Name	
Comment	
PER-006 includes training requirements for the GOP and respective plant personnel. SMUD recommends locating this new training requirement in the PER-006 Standard with appropriate modifications to the applicability section to include both GO and GOP functions. SMUD also supports expanding the scope of this SAR to include moving the GO/GOP training in EOP-011 R8 to PER-006-1, as was put forward by the LPPC and APPA during the Project 2019-06 commenting period. SMUD is concerned with locating training requirements in a Standard other than the PER suite of standards. Adding training requirements to other non-training standards creates a condition that makes training requirements hard to find and easy to lose; a condition that is not conducive to a quality standard. Locating training requirements outside of PER Standards is also not following industry precedent, such as the Standards Efficiency Review recommendations and the recent Project 2007-06.2 that moved training requirements from PRC Standards to the new PER-006-1 Standard.	
Likes 0	
Dislikes 0	
Response	

d. Which Reliability Standard(s) should be revised to address the recommendation: “Generator Owners that experience outages, failures to start, or derates due to freezing are to review the generating unit’s outage, failure to start, or derate and develop and implement a corrective action plan for the identified equipment, and evaluate whether the plan applies similar equipment for its other generating units.”

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
EOP-011-2 (effective 4/1/2023) includes a new Requirement R7 that is applicable to the Generator Owner. R7 requires Generator Owners to “implement and maintain one or more cold weather preparedness plan(s) for its generating units”, and lists the topics that must be addressed in the plan(s) at a minimum. This FERC/NERC Joint Inquiry report recommendation could possibly be addressed by revising EOP-011-2 to add another Generator Owner requirement to address it.	
Likes 0	
Dislikes 0	
Response	

Jessica Lopez - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	
Document Name	
Comment	
There are no Reliability Standards currently in effect that could easily be modified to address this recommendation.	
Likes 0	
Dislikes 0	
Response	

Daniel Gacek - Exelon - 1,3,5,6	
Answer	
Document Name	
Comment	
Exelon generally concurs with the comments submitted by the EEI for this question. Exelon suggests that permissible actions taken pursuant to a corrective action plan may include revising the generating unit’s declared capability to start and operate in extreme weather conditions.	
Likes 0	

Dislikes 0	

Response

Natalie Johnson - Enel Green Power - 5

Answer	
Document Name	

Comment

Enel North America, Inc. believes that the recommendation to develop Corrective Action Plans (CAPS) is best addressed in the EOP-011 Emergency Preparedness and Operations Standard as part of the requirement to have and maintain Cold Weather Preparedness Plans (R7 for Generators). The Cold Weather Preparedness Plan is the best area to address this recommendation because the recommendation relates to item a) & c) above. The addition of this recommendation to the Cold Weather Preparedness Plans enables a comprehensive approach to all aspects of cold weather preparedness including following up with CAPs. Enel North America, Inc. recommends that a CAP only be applied in situations where temperature failures occur outside of the operating design conditions for the facility. Otherwise, the outage, failure to start, or derate would be reported through the existing TOP-003 process (see section e and f below). The Cold Weather Preparedness Plans enable Generators to make changes, update, and follow-up on CAPS more frequently than a standard such as FAC-008 Facility Ratings would facilitate. Enel North America, Inc. therefore believes that this recommendation is best addressed by requiring that it is part of the overall Cold Weather Preparedness Plans in the EOP-011 Standard. This recommendation is best addressed with a planning-based approach.

Alternatively, this can be addressed in the Facilities Design and Maintenance suite of standards. However, the most important thing for Enel North America, Inc. is that these requirements are not dispersed across a few different standards. This may therefore necessitate a separate standard within the Facilities Design and Maintenance suite.

Likes 0	
Dislikes 0	

Response

Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee

Answer	
Document Name	

Comment

The IRC SRC believes this recommendation would best be addressed in an **FAC** standard along with items 1, 3, 4, 5 and 6 (*see* pages 3-4 of the SAR).

Likes 0	
Dislikes 0	

Response

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	
Document Name	
Comment	

BPA supports the comments made by the US Bureau of Reclamation.

Likes 0	
Dislikes 0	

Response

Jamie Monette - Allete - Minnesota Power, Inc. - 1

Answer	
Document Name	

Comment

Minnesota Power agrees with MRO’s NERC Standards Review Forum (NSRF) comments.

Likes 0	
Dislikes 0	

Response

Michele Mihelic - American Clean Power Association - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

Please refer to ACP’s response for question 1c - same recommendation as above.

In addition, ACP recommends modifying the recommendation language so that Corrective Action Plans are only developed and implemented when a generating unit experiences an outage, failure to start or derate when the conditions identified in NERC Reliability Standard EOP-011-2 Emergency Preparedness and Operations, Requirement R7.3. et al. are not met.

Likes 1	Mat Bunch, N/A, Bunch Mat
Dislikes 0	

Response

LaKenya VanNorman - Florida Municipal Power Agency - 3,4,5,6 - SERC

Answer	
Document Name	
Comment	
FMPA supports TAPS (Transmission Access Policy Study Group) comments	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
The NAGF believes that the recommendation should be included as part of a new standard dedicated to Cold Weather.	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	
Document Name	
Comment	
MidAmerican Energy Company supports EEI and MRO NSRF comments	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	

Comment	
EOP-011-02 could be used for this recommendation, however, a more efficient approach would be to develop a new Extreme Cold Weather Reliability Standard. Also, see EEI comments to 1a. There are standards that require corrective action plans (e.g., TPL-007-4, PRC-004-3), and it would be a natural starting point to look at those standards when addressing this recommendation. Corrective action plans for resources that experience outages, failure to start, or derates due to equipment failures resulting from temperatures or weather conditions under which the resource was designed to operate under is important, provided that generating unit design limits are accounted for. To address these concerns and comments, EEI suggests the following modifications to the SAR: Generator resources operating within their design specifications that experience outages, failures to start, or derates due to extreme cold weather conditions shall be evaluated by the resource owner and develop and implement a corrective action plan to maintain or restore resource capability.	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1,3,5	
Answer	
Document Name	
Comment	
This appears to fit in EOP-011. However, it should be clear that if the unit operated as designed, no corrective action plan would be necessary.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Evergy - 1,3,5,6 - MRO	
Answer	
Document Name	
Comment	
Evergy supports and incorporates by reference Edison Electric Institute's (EEI) response to Question 1d.	
Likes 0	
Dislikes 0	
Response	

Rebecca Baldwin - Transmission Access Policy Study Group - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
TAPS does not take a position regarding which standard is the appropriate home for the proposed new GO/GOP requirements, but we urge the SDT to consolidate the proposed GO/GOP requirements in a single standard to the extent possible, for ease of reference.	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Minnkota Power Cooperative Inc. - 1,5 - MRO	
Answer	
Document Name	
Comment	
MPC supports comments submitted by the MRO NERC Standards Review Forum (NSRF).	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	
Document Name	
Comment	
EOP-011, Ameren does this currently.	
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 appropriate standard for such a requirement should be in a new standard dedicated solely to cold weather requirements as previously mentioned in Southern Company's response to Question 1a.

Of concern to Southern Company is the timeline to develop and implement corrective actions, e.g., a large number of wind turbines may need new equipment and the subsequent lead time for equipment and contract labor could be problematic.

Likes 0	
Dislikes 0	

Response

Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5, Group Name BC Hydro

Answer	
Document Name	

Comment

BC Hydro recommends that a new Standard(s) focusing on cold weather preparedness be developed to address this recommendation.

Likes 0	
Dislikes 0	

Response

Michael Johnson - Pacific Gas and Electric Company - 1,3,5 - WECC, Group Name PG&E All Segments

Answer	
Document Name	

Comment

PG&E has participated in the preparation and supports the comments provided by the Edison Electric Institute (EEI) for Q1d.

Likes 0	
Dislikes 0	

Response

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5

Answer	
Document Name	
Comment	

Reliability Standard EOP-011-2

Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	
Comment	

Texas RE suggests this Key Recommendation could be added as an additional requirement to EOP-011. Texas RE recommends including a timeline requirement for the corrective action plan (CAP) in order to be effective.

Alternatively, a new Emergency Preparedness and Operations standard could be created to include the following Key Recommendations from the Joint Inquiry: 1a, 1c,1d, 1e, and 1f. Language from future enforceable EOP-011-2 Requirements R7 and R8 could also be included in this new Emergency Preparedness and Operations standard.

Texas RE also recommends the following:

- Revising the EOP-004 attachment 1 to include a new event type of critical loss due to cold weather.

Likes 0	
Dislikes 0	
Response	

Patricia Lynch - NRG - NRG Energy, Inc. - 5,6

Answer	
Document Name	
Comment	

NRG Energy Inc. believes that the recommendation should be included as part of a new standard dedicated to Cold Weather.

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 comments posted by EEI

Likes 0	
Dislikes 0	

Response

Jennie Wike - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6 - WECC, Group Name Tacoma Power

Answer	
Document Name	

Comment

Instead of prescribing specific retrofits or upgrades, Tacoma Power recommends performing a three tier approach: perform a vulnerability assessment to identify risks, develop actions to mitigate these risks, and then implement the actions. This risk-based approach would also require entities to re-evaluate their vulnerability assessment if failures occur that weren't identified in the assessment. This approach would be similar to how the industry addressed GMD events in Project 2013-03.

Tacoma Power also suggests modifying FAC-008 R2.2 to include a subpart to evaluate facility ratings for extreme cold weather failures, as noted in comment 1a.

Likes 0	
Dislikes 0	

Response

Kenisha Webber - Entergy - Entergy Services, Inc. - NA - Not Applicable - SERC

Answer	
Document Name	

Comment

EOP-011-2, Requirement R7 as part of Cold Weather plan

Likes 0	
Dislikes 0	

Response

Carl Pineault - Hydro-Qu?bec Production - 1,5

Answer	
Document Name	

Comment

No comments

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6, Group Name Dominion

Answer	
Document Name	

Comment

Dominion Energy suppports the comments submitted by EEI.

Likes 0	
Dislikes 0	

Response

Keith Jonassen - ISO New England, Inc. - 2 - NPCC

Answer	
Document Name	

Comment

Recommend adding a new requirement to EOP-011

- Add new requirement to EOP-011:
    - "Generator Owners that experience outages, failures to start, or derates due to freezing (or other impacts of Extreme Weather) are to review the generating unit's outage, failure to start, or derate and develop and implement a corrective action plan for the identified equipment, and evaluate whether the plan applies similar equipment for its other generating units.

- Alternatively, this could also be included in the sub-requirements for R7 as "Corrective Action Plan for reviewing outages, failures to start, or derates due to cold weather or freezing.

Likes 0	
Dislikes 0	

Response

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4

Answer	
Document Name	

Comment

Alliant Energy supports the comments submitted by the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC

Answer	
Document Name	

Comment

Xcel Energy supports the comments submitted by EEI.

Likes 0	
Dislikes 0	

Response

George Brown - Acciona Energy North America - 5

Answer	
Document Name	

Comment

Acciona Energy believes this recommendation would be best addressed in Facilities Design, Connections and Maintenance (FAC) suite of NERC Standards in a new standard.

Likes 0	
Dislikes 0	

Response

Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 3,4,5 - RF, Group Name Consumers Energy Company

Answer	
Document Name	

Comment

EOP and FAC standards; possibly a new PRC standard.

Likes 0	
Dislikes 0	

Response

Richard Jackson - U.S. Bureau of Reclamation - 1,5

Answer	
Document Name	

Comment

Please see the response to question 1.a. The proposed example is R4.

Likes 0	
Dislikes 0	

Response

Michael Krum - Salt River Project - 1,3,5,6 - WECC

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 MRO NERC Standards Review Forum (NSRF) believes this recommendation would best be addressed in an **FAC** standard along with items 1, 3, 4, 5 and 6 (*see* pages 3-4 of the SAR).	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	
None – suggest a new NERC GO/GOP Standard to implement recommendation. It is also suggested that recently modified TOP-003-5, EOP-011-2 and IRO-010-4 standards not be modified further and consideration be given for moving Cold Weather Requirements in these Standards to the new Standard.	
Likes 0	
Dislikes 0	
Response	
Susan Sosbe - Wabash Valley Power Association - 1,3	
Answer	
Document Name	
Comment	
We suggest TOP-003-5, Operational Reliability Data: Both the TOP and the BA must maintain a documented specification for data necessary for it to perform its analysis functions and Real-Time Monitoring. Under 2.3.2, this includes generating unit data. Under R5.2, there must be a mutually agreed upon process for resolving data conflicts, so couldn't the CAP requirement be added here?	
Likes 0	

Dislikes 0	
Response	
Adrian Raducea - DTE Energy - Detroit Edison Company - 3,5, Group Name DTE Energy - DTE Electric	
Answer	
Document Name	
Comment	
Similar to FAC-003 R5, PRC-002 R12 which require Corrective Action Plans, include Corrective Action Plan requirement in EOP-11.	
Likes 0	
Dislikes 0	
Response	

e. Which Reliability Standard(s) should be revised to address the recommendation: "The Reliability Standards should be revised to provide greater specificity about the relative roles of the Generator Owners, Generator Operators and Balancing Authorities in determining the generating unit capacity that can be relied upon during "local forecasted cold weather," which is language from the revised Reliability Standard TOP-003-5, R2.3. -Each Generator Owner/Generator Operator should be required to provide the Balancing Authority with the percentage of the total generating unit capacity that the Generator Owner/Generator Operator reasonably believes the Balancing Authority can rely upon during the "local forecasted cold weather," including reliability risks related to natural gas fuel contracts. -Each Balancing Authority should be required to use the data provided by the Generator Owner/Generator Operator, combined with its evaluation, based on experience, to calculate the percentage of each individual generating unit's total capacity that it can rely upon during the "local forecasted cold weather," and share its calculation with the Reliability Coordinator. Each Balancing Authority should be required to use that calculation of the percentage of total generating capacity that it can rely upon to "prepare its analysis functions and Realtime monitoring," and to "manag[e] generating resources in its Balancing Authority Area to address . . . fuel supply and inventory concerns" as part of its Capacity and Energy Emergency Operating Plans."

Adrian Raducea - DTE Energy - Detroit Edison Company - 3,5, Group Name DTE Energy - DTE Electric

Answer	
Document Name	
Comment	
TOP-003-5 and EOP-011-3	
Likes 0	
Dislikes 0	
Response	

Susan Sosbe - Wabash Valley Power Association - 1,3

Answer	
Document Name	
Comment	
We suggest TOP-003-5: Since the language is already in this Standard, shouldn't the specificity be outlined in this Standard as well? Also see "d" above.	
Likes 0	
Dislikes 0	
Response	

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	
Document Name	

Comment	
None – suggest a new NERC GO/GOP Standard to implement recommendation. It is also suggested that recently modified TOP-003-5, EOP-011-2 and IRO-010-4 standards not be modified further and consideration be given for moving Cold Weather Requirements in these Standards to the new Standard.	
Likes 0	
Dislikes 0	
Response	

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	

Requested by 2022/2023

MRO NSRF's response has been categorized based on the applicable functional entity and task:

- Generator Owner and capacity that can be relied upon during 'local forecasted cold weather:'

MRO NSRF seeks clarification. As both the Generator Owner (GO) and Generator Operator (GOP) are both cited in this recommendation, what is the proposed action for each function; i.e. for the GO portion of this proposed requirement, is the intent to provide a **"static" design number for planning purposes**? If so, the MRO NERF believes this recommendation would best be performed by Generator Owners and addressed in a new FAC standard.

If this aspect is retained in the scope of the SAR, MRO NSRF recommends the SDT address this recommendation in an **FAC** standard along with items 1, 3, 4, 5 and 6 (*see* pages 3-4 of the SAR) and begin work using the corresponding language currently in EOP-011-2, Requirements R7 and R8 and then retire R7 and R8 from EOP-011-2.

In addition, the scope of the SAR should be updated to require that the capacity number provided to the Balancing Authority should reflect the inoperability of any cold-weather-critical components that can not be protected, and therefore cannot be relied upon (*see* our response to question 1a above).

- Generator Operator and capacity that can be relied upon during 'local forecasted cold weather:'

MRO NSRF seeks clarification. As both the GO and GOP are both cited in this recommendation, what is the proposed action for each function; i.e. for the GOP portion of this proposed requirement, is the intent to provide a **"dynamic" real-time number for operating purposes**? If so, MRO NSRF recommends this be retained in TOP-003-5.

In addition, the scope of the SAR should be updated to require that the capacity number provided to the Balancing Authority should reflect the inoperability of any cold-weather-critical components that can not be protected, and therefore cannot be relied upon (*see* our response to question 1a above).

- Balancing Authority and calculation of capacity that it can rely upon during 'local forecasted cold weather:

MRO NSRF believes TOP-002-4, R4, Part 4.4 would be a best fit location. Justification. R4. Each BA shall have an Operating Plan for the next-day that addresses: 4.4 Capacity and energy reserve requirements, including deliverability capability.

Likes 0	
Dislikes 0	

Response

Michael Krum - Salt River Project - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

No Comment.

Likes 0	
Dislikes 0	

Response

Richard Jackson - U.S. Bureau of Reclamation - 1,5

Answer	
Document Name	

Comment

Reclamation recommends any additional information required in a Balancing Authority's data specification should be contained in TOP-003 Requirement R2.

Reclamation recommends additional requirements for what Balancing Authorities should do with the information they receive pursuant to their data specifications should be contained in TOP-002.

Likes 0	
Dislikes 0	

Response

Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 3,4,5 - RF, Group Name Consumers Energy Company

Answer	
Document Name	

Comment	
We believe this is a MISO Generator Verification Capacity Testing issue. If new/revised standard(s) is developed, it really needs to be in the same standard that will address question 1.a.b. and d.	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	
Document Name	
Comment	

The response has been categorized by task:

- Generator Owner/Operator determining the generating units reliable capacity

Acciona Energy believes this recommendation would be best addressed in Facilities Design, Connections and Maintenance (FAC) suite of NERC Standards. Perhaps, the most appropriate place for this recommendation would be NERC Reliability Standard FAC-008 – Facility Ratings (NERC FAC-008). NERC FAC-008 already includes the majority, if not all equipment, cold-weather-critical components and systems that would be affected by extreme cold weather, which the loss of would ultimately affect the Facility Rating.

- Communicating the generating unit's reliable capacity to the Balancing Authority and Reliability Coordinator:

Acciona Energy believes this recommendation would be best addressed in NERC Reliability Standard TOP-003 – Operational Reliability Data.

- Balancing Authority determining the generating units reliable capacity and managing resources:

Acciona Energy supports Midwest Reliability Organization's (MRO) NERC Standards Review Forum's (NSRF) comments on this question as it relates to Balancing Authorities.

Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	
Document Name	
Comment	

Xcel Energy supports the comments submitted by EEI.

Likes 0	
Dislikes 0	

Response

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4

Answer	
Document Name	

Comment

Alliant Energy supports the comments submitted by the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Keith Jonassen - ISO New England, Inc. - 2 - NPCC

Answer	
Document Name	

Comment

Recommend revising TOP-003-5, TOP-002-4, and EOP-011-2

- Add new requirement to TOP-003-5 which would be applicable to GO/GOPs:
  - Each Generator Owner/Generator Operator should be required to provide the Balancing Authority with the percentage of the total generating unit capacity that the Generator Owner/Generator Operator reasonably believes the Balancing Authority can rely upon during the “local forecasted cold weather,” including reliability risks related to natural gas fuel contracts
- Add new requirement to which would be applicable to BAs:
  - Each Balancing Authority should be required to use the data provided by the Generator Owner/Generator Operator, combined with its evaluation, based on experience, to calculate the percentage of each individual generating unit’s total capacity that it can rely upon during the “local forecasted cold weather,” and share its calculation with the Reliability Coordinator
- Add new requirement to TOP-002-4 which would be applicable to BAs:
  - Each Balancing Authority should be required to use a calculation of the percentage of total generating capacity that it can rely upon to prepare its analysis functions and Realtime monitoring, and to “manage generating resources in its Balancing Authority Area to address . . . fuel supply and inventory concerns” as part of its Capacity and Energy Emergency Operating Plans
- Add new requirement to EOP-011-2 which would be applicable to BAs:
  - Each Balancing Authority should be required to use a calculation of the percentage of total generating capacity that it can rely upon to manag[e] generating resources in its Balancing Authority Area to address fuel supply and inventory concerns as part of its Capacity and Energy Emergency Operating Plans

Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6, Group Name Dominion	
Answer	
Document Name	
Comment	
Dominion Energy suppports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	
Michael DePalma - Onward Energy - NA - Not Applicable - MRO,WECC,Texas RE,NPCC	
Answer	
Document Name	
Comment	
We believe the section: **Each Generator Owner/Generator Operator should be required to provide the Balancing Authority with the percentage of the total generating unit capacity that the Generator Owner/Generator Operator reasonably believes the Balancing Authority can rely upon during the "local forecasted cold weather," including reliability risks related to natural gas fuel contracts** *is already covered in existing TOP standards. Our generation assets report available capacity accurately. We request this section be removed from future Standard changes.*	

Likes 0	
Dislikes 0	

Response

Jennie Wike - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6 - WECC, Group Name Tacoma Power

Answer	
Document Name	

Comment

Tacoma Power suggests housing these recommendations either in TOP-003 or IRO-010. Specifically, any information that must be provided to the RC should be housed in IRO-010.

Likes 1	Platte River Power Authority, 5, Archie Tyson
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

FirstEnergy supports comments posted by EEI

Likes 0	
Dislikes 0	

Response

Patricia Lynch - NRG - NRG Energy, Inc. - 5,6

Answer	
Document Name	

Comment

NRG Energy Inc. believes that the recommendation should be included as part of a new standard dedicated to Cold Weather.

Likes 0	
Dislikes 0	

Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE suggests TOP-003 would be an appropriate standard for this Key Recommendation as noted in the Joint Inquiry. Additionally, the drafting team should consider revising IRO-010 as well, since it would be helpful for the RC to have this information. Texas RE also recommends considering a revision to Table 1 in TPL-001 to include cold weather so the PA/PC have the most accurate information in planning studies.	
Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Pacific Gas and Electric Company - 1,3,5 - WECC, Group Name PG&E All Segments	
Answer	
Document Name	
Comment	
PG&E has participated in the preparation and supports the comments provided by the Edison Electric Institute (EEI) for Q1e.	
Likes 0	
Dislikes 0	
Response	

Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5, Group Name BC Hydro	
Answer	
Document Name	
Comment	
BC Hydro suggests that this recommendation will impact TOP-002 R4 (BA) and IRO-014 R1 (RC) as it will impact Energy and Capacity Operating Plans; also due to data required to develop these Plans, TOP-003 and IRO-010 could be impacted. BC Hydro also suggests that considerations be given to FAC-008, FAC-011 and FAC-014 as the operating limits or inputs to operating limits may be impacted by this recommendation.	
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 appropriate standard for such a requirement should be in a new standard dedicated solely to cold weather requirements as previously mentioned in Southern Company's response to Question 1a. The intent of the requirement should be focused on timely and accurate communications as risks to generation availability are identified by the GO/GOP. We see this proposed enhanced requirement as an event-based, real-time communication of changes in the capability data provided in TOP-005-5, R2.3.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	
Document Name	
Comment	
Since the referenced language is from TOP-003-5, we believe it should be put in this standard.	

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Minnkota Power Cooperative Inc. - 1,5 - MRO

Answer	
Document Name	

Comment

MPC supports comments submitted by the MRO NERC Standards Review Forum (NSRF).

Likes 0	
Dislikes 0	

Response

Rebecca Baldwin - Transmission Access Policy Study Group - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

TAPS does not take a position regarding which standard is the appropriate home for the proposed new GO/GOP requirements, but we urge the SDT to consolidate the proposed GO/GOP requirements in a single standard to the extent possible, for ease of reference.

Likes 0	
Dislikes 0	

Response

Alan Kloster - Evergy - 1,3,5,6 - MRO

Answer	
Document Name	

Comment

Evergy supports and incorporates by reference Edison Electric Institute's (EEI) response to Question 1e.

Likes 0	
Dislikes 0	

Response	
Donna Wood - Tri-State G and T Association, Inc. - 1,3,5	
Answer	
Document Name	
Comment	

For the Balancing Authority (BA) role, we think either TOP-002-4, R4, Part 4.4, or TOP-003-5 R2 would be an appropriate place to describe the BA role.

For the Generator Owner (GO) role, we think EOP-011-2, R7, Part 7.3 would be the best fit.

Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	

The SDT should evaluate whether TOP-003 is the best solution for this recommendation. Also, see EEI's comments for question 1a. EEI also offers the following revised language to the SAR:

The Reliability Standards should be revised to provide greater specificity about the relative roles of the Generator Owners, Generator Operators and Balancing Authorities in determining the generating unit capacity that can be relied upon during "local forecasted cold weather," which is language from the revised Reliability Standard TOP-003-5, R2.3. Each Generator Owner/Generator Operator should be required to provide the Balancing Authority with the percentage of the total generating unit capacity that the Generator Owner/Generator Operator reasonably believes the Balancing Authority can rely upon during the "local forecasted cold weather," including reliability risks related to natural gas fuel contracts. -Each Balancing Authority should be required to use the data provided by the Generator Owner/Generator Operator, combined with its evaluation, based on experience, to calculate the percentage of each individual generating unit's total capacity that it can rely upon during the "local forecasted cold weather," and share its calculation with the Reliability Coordinator. Each Balancing Authority **is to consider that resource capacity projections provided by the GO cannot be provided with precision. Entity estimates are based on the historical performance of the resource under similar operating condition and the variability of weather conditions can result in errors in these projections. Armed with this knowledge, the BA** should **be required to use those projection**s in their calculations of the percentage of total generating capacity that it can rely upon to "prepare its analysis functions and Realtime monitoring," and to "manag[e] generating resources in its Balancing Authority Area to address . . . fuel supply and inventory concerns" as part of its Capacity and Energy Emergency Operating Plans.

Likes 0	
Dislikes 0	
Response	

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	
Document Name	
Comment	
MidAmerican Energy Company supports EEI and MRO NSRF comments	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
The NAGF believes that the recommendation should be included as part of a new standard dedicated to Cold Weather.	
Likes 0	
Dislikes 0	
Response	
LaKenya VanNorman - Florida Municipal Power Agency - 3,4,5,6 - SERC	
Answer	
Document Name	
Comment	
FMPA supports TAPS (Transmission Access Policy Study Group) comments	
Likes 0	
Dislikes 0	
Response	
Michele Mihelic - American Clean Power Association - NA - Not Applicable - NA - Not Applicable	

Answer	
Document Name	
Comment	

ACP members believe that the determination of Generation Unit capacity during local forecasted cold weather is best addressed in the Facility Ratings standard (FAC-008). This requirement already addresses equipment capabilities and limitations. NERC FAC-008 already includes the majority, if not all equipment, cold-weather-critical components and systems that would be affected by extreme cold weather, which the loss of would ultimately affect the Facility Rating. This is a static design number that would not require frequent enhancements and improvements such as the Cold Weather Preparedness Plans might. ACP recommends the equipment listing approach, as it is more suitable for this type of activity.

ACP recommends the communication of the generating unit's reliable capability to the Balancing Authority and Reliability Coordinator would be best addressed in NERC Reliability Standard TOP-003 – Operational Reliability Data, where this additional information can be added to the outage and derate process, which already exists.

ACP does not have a recommendation on this question as it relates to the BA.

Likes 2	Mat Bunch, N/A, Bunch Mat; Enel Green Power, 5, Johnson Natalie
Dislikes 0	
Response	

Jamie Monette - Allete - Minnesota Power, Inc. - 1

Answer	
Document Name	
Comment	

Minnesota Power agrees with MRO's NERC Standards Review Forum (NSRF) comments.

Likes 0	
Dislikes 0	
Response	

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	
Document Name	
Comment	

BPA supports the comments made by the US Bureau of Reclamation.

Likes 0	

Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	
Document Name	
Comment	

IRC SRC has categorized its response based on the applicable functional entity and task:

· **Generator Owner** - capacity that can be relied upon during 'local forecasted cold weather'

IRC SRC seeks clarification. As both the Generator Owner (GO) and Generator Operator (GOP) are both cited in this recommendation, what is the proposed action for each function; i.e. for the GO portion of this proposed requirement, is the intent to provide a **"static" design number for planning purposes**? If so, the IRC SRC believes this recommendation would best be performed by Generator Owners and addressed in a new FAC standard.

If this aspect is retained in the scope of the SAR, IRC SRC recommends the SDT address this recommendation in an **FAC** standard along with items 1, 3, 4, 5 and 6 (*see* pages 3-4 of the SAR) and begin work using the corresponding language currently in EOP-011-2, Requirements R7 and R8 and then retire R7 and R8 from EOP-011-2.

In addition, the scope of the SAR should be updated to require that the capacity number provided to the Balancing Authority should reflect the inoperability of any cold-weather-critical components that can not be protected, and therefore cannot be relied upon (*see* our response to question 1a above).

· **Generator Operator** - capacity that can be relied upon during 'local forecasted cold weather'

IRC SRC seeks clarification. As both the GO and GOP are both cited in this recommendation, what is the proposed action for each function; i.e. for the GOP portion of this proposed requirement, is the intent to provide a **"dynamic" real-time number for operating purposes**? If so, IRC SRC recommends this be retained in TOP-003-5.

In addition, the scope of the SAR should be updated to require that the capacity number provided to the Balancing Authority should reflect the inoperability of any cold-weather-critical components that can not be protected, and therefore cannot be relied upon (*see* our response to question 1a above).

· **Balancing Authority** - calculation of capacity that can be relied upon during 'local forecasted cold weather'

IRC SRC believes TOP-003-5 would be a best fit location.

R4. Each BA shall have an Operating Plan for the next-day that addresses:

4.4 Capacity and energy reserve requirements, including deliverability capability.

Likes 0	
Dislikes 0	
Response	

Travis Fisher - Electricity Consumers Resource Council (ELCON) - 7	
Answer	
Document Name	
Comment	
ELCON disagrees that Generator Owners are in the best position to judge the reliability risks related to natural gas fuel contracts. The onus should be on natural gas suppliers to estimate the probability of a failure to deliver fuel, or on FERC to prevent natural gas pipelines from withholding available gas from generators with firm contracts (the "price majeure" phenomenon).	
Likes 0	
Dislikes 0	
Response	
Natalie Johnson - Enel Green Power - 5	
Answer	
Document Name	
Comment	
The determination of Generation Unit capacity during local forecasted cold weather is best addressed in the Facility Ratings standard (FAC-008), as this requirement already addresses equipment capabilities and limitations and is a static design number that would not require frequent enhancements and improvements such as the Cold Weather Preparedness Plans might. An equipment listing approach is more suitable for this type of activity involving static design numbers and how they are impacted by cold weather. Communication of the generating unit's reliable capability to the Balancing Authority and Reliability Coordinator is best addressed in the TOP-003 for reliability data. This additional information can be added to the outage and derate process that already exists.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1,3,5,6	
Answer	
Document Name	
Comment	
Exelon concurs with the comments submitted by the EEI for this question.	

Likes 0	
Dislikes 0	

Response

Jessica Lopez - APS - Arizona Public Service Co. - 1,3,5,6

Answer	
Document Name	

Comment

AZPS agrees with the comments provided by EEI; EEI does not agree that TOP-005 as it would not be a good solution for this recommendation. The SDT should consider this recommendation to be included as a stand alone standard in which the Generator Operator is able to provide the data on exceptions.

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	
Document Name	

Comment

TOP-003-5 (effective 4/1/2023) addresses the operational reliability data needs of the Balancing Authorities in Requirements R2 (BA) and R5 (GO, GOP). We suggest this standard be revised to address the part of the recommendation regarding the GO/GOP's consideration of "local forecasted cold weather" impacts when providing their generating unit capability data to the BA (with corresponding change to EOP-011-2, R7). The part of the recommendation that indicates the BA "should be required to use the data provided by the Generator Owner/Generator Operator, combined with its evaluation,….to calculate the percentage of each individual generating unit's total capacity that it can rely upon during the "local forecasted cold weather", could be addressed in a revision to TOP-002-4 (R4). The part of the recommendation that the BA "share its calculation with the Reliability Coordinator" could also be addressed in a revision to TOP-002-4 (R7). The part of the recommendation that the BA "use that calculation of the percentage of total generating capacity that it can rely upon to "prepare its analysis functions and Realtime monitoring," and to "manag[e] generating resources in its Balancing Authority Area to address . . . fuel supply and inventory concerns" as part of its Capacity and Energy Emergency Operating Plans" could be addressed in a revision to TOP-010-1(i) and EOP-011-2, respectively.

Likes 0	
Dislikes 0	

Response

f. Which Reliability Standard(s) should be revised to address the recommendation: "In EOP-011-2, R7.3.2, Generator Owners are to account for the effects of precipitation and accelerated cooling effect of wind when providing temperature data."

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
EOP-011-2 (effective 4/1/2023) and the corresponding data specification requirements in IRO-010-4 (R1 part 1.3.2) and TOP-003-5 (R1 part 1.3.2; R2 part 2.3.2).	
Likes 0	
Dislikes 0	
Response	

Jessica Lopez - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	
Document Name	
Comment	
AZPS agrees with the comments provided by EEI; EOP-011-2, Requirement 7, subpart 7.3 could be modified to address the recommentations.	
Likes 0	
Dislikes 0	
Response	

Daniel Gacek - Exelon - 1,3,5,6	
Answer	
Document Name	
Comment	
Exelon concurs with the comments submitted by the EEI for this question. Additionlly, accounting for the effects of precipitation and the accelerated cooling effect of wind will result in a range of possible minimum operating temperatures for each generating unit. Exelon suggests the drafting team allow generator owners to assign tolerances to declared design temperature data.	
Likes 0	
Dislikes 0	

Response	
Natalie Johnson - Enel Green Power - 5	
Answer	
Document Name	
Comment	
With respect to accounting for the effect of precipitation and the cooling effect of wind, Enel North America, Inc. recommends this be incorporated in NERC Reliability Standard FAC-008 – Facility Ratings, as this requirement already addresses equipment capabilities and limitations and is a static design number that would not require frequent enhancements and improvements such as the Cold Weather Preparedness Plans might. Communication of the generating unit's reliable capability to the Balancing Authority and Reliability Coordinator is best addressed in the TOP-003 for reliability data. This additional information can be added to the outage and derate process that already exists. Better forecasting tools to predict the effects of precipitation and accelerated cooling effect of wind (such as NOAA) would help Generators better manage, plan, and incorporate this into their temperature data.	
Likes 0	
Dislikes 0	
Response	
Travis Fisher - Electricity Consumers Resource Council (ELCON) - 7	
Answer	
Document Name	
Comment	
ELCON believes question 1(a) takes care of this question—Generator Owners already must identify and protect cold-weather-critical components and systems for each generating unit, which should include accounting for the effects of precipitation and accelerated cooling effect of wind.	
Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	
Document Name	
Comment	

Similar to IRC SRC's response to question 1e above, our response has been categorized based on the applicable functional entity and task:

· Accounting for effects of precipitation and accelerated cooling effect of wind:

IRC SRC believes this recommendation would best be performed by Generator Owners and addressed in a new FAC standard along with items 1, 3, 4, 5 and 6 (*see* pages 3-4 of the SAR).

If this proposal is adopted, IRC SRC recommends the Standard Drafting Team (SDT) begin work using the corresponding language currently in EOP-011-2, Requirements R7 and R8 and then retire R7 and R8 from EOP-011-2.

· Providing temperature data:

IRC SRC believes this recommendation would best be performed by Generator Operators and addressed in TOP-003.

Likes 0	
Dislikes 0	

Response

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

BPA supports the comments made by the US Bureau of Reclamation.

Likes 0	
Dislikes 0	

Response

Jamie Monette - Allete - Minnesota Power, Inc. - 1

Answer	
Document Name	

Comment

Minnesota Power agrees with MRO's NERC Standards Review Forum (NSRF) comments.

Likes 0	
Dislikes 0	

Response	
Michele Mihelic - American Clean Power Association - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
With respect to accounting for the effect of precipitation and the cooling effect of wind, ACP recommends this recommendation be incorporated in NERC Reliability Standard FAC-008 – Facility Ratings. NERC FAC-008 already includes the majority, if not all equipment, cold-weather-critical components and systems that would be affected by extreme cold weather, which the loss of would ultimately affect the Facility Rating. ACP recommends that the Standards Drafting Team adopt and then remove the applicable language from NERC Reliability Standard EOP-011-2 Emergency Preparedness and Operations, Requirement R7 and R8. With respect to reporting temperature data, ACP believe this is best addressed in the TOP-003 Operational Reliability Data.	
Likes 2	Mat Bunch, N/A, Bunch Mat; Enel Green Power, 5, Johnson Natalie
Dislikes 0	
Response	
LaKenya VanNorman - Florida Municipal Power Agency - 3,4,5,6 - SERC	
Answer	
Document Name	
Comment	
FMPA supports TAPS (Transmission Access Policy Study Group) comments	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
The NAGF believes that the recommendation should be included as part of a new standard dedicated to Cold Weather.	

Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	
Document Name	
Comment	
MidAmerican Energy supports EEI and MRO NSRF comments	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
While EEI supports the recommendation to require GOs to account for the effects of precipitation and accelerated cooling effects when providing capacity projections, this information is based on original design specifications and historical unit performance during similar operating conditions and therefore cannot be precisely established. EOP-011-2, Requirement R7, subpart 7.3 could be modified to address this recommendation. Also, see EEI's comments to question 1a.	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1,3,5	
Answer	
Document Name	
Comment	
We recommend this be added to EOP-011-2, R2	

Likes 0	
Dislikes 0	

Response

Alan Kloster - Evergy - 1,3,5,6 - MRO

Answer	
Document Name	

Comment

Evergy supports and incorporates by reference Edison Electric Institute's (EEI) response to Question 1f.

Likes 0	
Dislikes 0	

Response

Rebecca Baldwin - Transmission Access Policy Study Group - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

TAPS does not take a position regarding which standard is the appropriate home for the proposed new GO/GOP requirements, but we urge the SDT to consolidate the proposed GO/GOP requirements in a single standard to the extent possible, for ease of reference.

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Minnkota Power Cooperative Inc. - 1,5 - MRO

Answer	
Document Name	

Comment

MPC supports comments submitted by the MRO NERC Standards Review Forum (NSRF).

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

Since the referenced language is from EOP-011-2, it should be put in 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

Southern Company recommends that this requirement along with all cold weather standards be included at a future revision date in a new cold weather standard as previously mentioned in Southern Company's response to Question 1a.

However, for initial inclusion, Southern Company recommends that EOP-011-2 R7 be revised and consider revising IRO-010-4, R1 and TOP-003-4, R1 to include the additional weather parameters.

Likes 0	
Dislikes 0	

Response

Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5, Group Name BC Hydro

Answer	
Document Name	

Comment

This recommendation aligns with Requirements R7 and R8 of EOP-011-2.

BC Hydro recommends that a new EOP Standard(s) focusing on cold weather preparedness be developed to address this recommendation and the Requirements R7 and R8 be moved from EOP-011-2 to the new Standard(s).	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Pacific Gas and Electric Company - 1,3,5 - WECC, Group Name PG&E All Segments	
Answer	
Document Name	
Comment	
PG&E has participated in the preparation and supports the comments provided by the Edison Electric Institute (EEI) for Q1f.	
Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5	
Answer	
Document Name	
Comment	
Reliability Standard EOP-011-2	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE suggests this Key Recommendation could be included in EOP-011. Alternatively, a new Emergency Preparedness and Operations standard could be created to include the following Key Recommendations from the Joint Inquiry: 1a, 1c,1d, 1e, and 1f. Language from future enforceable EOP-011-2 Requirements R7 and R8 could also be included in this new Emergency Preparedness and Operations standard.

Texas RE also recommends the drafting team consider whether cold weather should be included in the RC's SOL Methodology in accordance with proposed Reliability Standard FAC-011-4.

Likes 0	
Dislikes 0	

Response

Patricia Lynch - NRG - NRG Energy, Inc. - 5,6

Answer	
Document Name	

Comment

NRG Energy Inc. believes that the recommendation should be included as part of a new standard dedicated to Cold Weather.

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 comments posted by EEI

Likes 0	
Dislikes 0	

Response

Jennie Wike - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6 - WECC, Group Name Tacoma Power

Answer	

Document Name	

Comment
See comments for item 1b with respect to modifying FAC-008 R2.2. Also, Tacoma Power suggests the SDT consider how this recommendation (as currently written) applies to all generation types, such as hydrogeneration.

Likes 0	
Dislikes 0	

Response

Michael DePalma - Onward Energy - NA - Not Applicable - MRO,WECC,Texas RE,NPCC	
Answer	
Document Name	

Comment
There is ambiquitity as to how a Generator Owner would account for thie described weather/atmospheric effects. Would NERC or other Regiona Entities also measure thiese effects for comparison? Are engineering studies to be required by Generator Owners, or would an attestation or other statement assuring the Generator Owner has accoutned for these effects be acceptable? Who is expected to provide the raw "Temperature Data"?

Likes 0	
Dislikes 0	

Response

Kenisha Webber - Entergy - Entergy Services, Inc. - NA - Not Applicable - SERC	
Answer	
Document Name	

Comment
EOP-011-2

Likes 0	
Dislikes 0	

Response

Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	

Document Name	
Comment	

No comments

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6, Group Name Dominion

Answer	
Document Name	

Comment

Dominion Energy suppports the comments submitted by EEI.

Likes 0	
Dislikes 0	

Response

Keith Jonassen - ISO New England, Inc. - 2 - NPCC

Answer	
Document Name	

Comment

Recommend revising EOP-011-2 R7

Revise EOP-011-2, R7.3.2 to state:

- 7.3.2 In a manner which accounts for the effects of precipitation (i.e. icing and snowpack) and the accelerated cooling effect of wind, generating unit(s) minimum:
  - 7.3.2.1. design temperature; or
  - 7.3.2.2. historical operating temperature; or
  - 7.3.2.3 current cold weather performance temperature determined by an engineering analysis.

Likes 0	
Dislikes 0	

Response

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	
Document Name	
Comment	
Alliant Energy supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	
Document Name	
Comment	
Xcel Energy supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	

George Brown - Acciona Energy North America - 5

Answer

Document Name

Comment

The response has been categorized by task:

- Accounting for effects of precipitation and accelerated cooling effect of wind:

Acciona Energy believes this recommendation would be best addressed in Facilities Design, Connections and Maintenance (FAC) suite of NERC Standards. Perhaps, the most appropriate place for this recommendation would be NERC Reliability Standard FAC-008 – Facility Ratings (NERC FAC-008). NERC FAC-008 already includes the majority, if not all equipment, cold-weather-critical components and systems that would be affected by extreme cold weather, which the loss of would ultimately effect the Facility Rating.

Acciona Energy recommends that the Standards Drafting Team adopt and then retire the applicable language from NERC Reliability Standard EOP-011-2 Emergency Preparedness and Operations, Requirement R7 and R8.

- Providing temperature data:

Acciona Energy believes this recommendation would be best addressed in NERC Reliability Standard TOP-003 – Operational Reliability Data.

Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 3,4,5 - RF, Group Name Consumers Energy Company	
Answer	
Document Name	
Comment	
FAC or MOD standards. This needs to be modeled ahead of time as part of facility ratings. Waiting until you are in Emergency conditions is too late.	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1,5	
Answer	
Document Name	
Comment	
Reclamation recommends EOP-011 Requirement R7.3.2 could be revised to clarify this information.	
Likes 0	
Dislikes 0	
Response	
Michael Krum - Salt River Project - 1,3,5,6 - WECC	
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

Similar to MRO NSRF's response to question 1e above, our response has been categorized based on the applicable functional entity and task:

- Accounting for effects of precipitation and accelerated cooling effect of wind:

MRO NSRF believes this recommendation would best be performed by Generator Owners and addressed in a new FAC standard along with items 1, 3, 4, 5 and 6 (*see* pages 3-4 of the SAR).

If this proposal is adopted, MRO NSRF recommends the Standard Drafting Team (SDT) begin work using the corresponding language currently in EOP-011-2, Requirements R7 and R8 and then retire R7 and R8 from EOP-011-2.

- Providing temperature data:

MRO NSRF believes this recommendation would best be performed by Generator Operators and addressed in TOP-003.

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	
Document Name	

Comment

None – suggest a new NERC GO/GOP Standard to implement recommendation. It is also suggested that recently modified TOP-003-5, EOP-011-2 and IRO-010-4 standards not be modified further and consideration be given for moving those Cold Weather Requirements in these Standards to the new Standard.

Likes 0	
Dislikes 0	

Response

Susan Sosbe - Wabash Valley Power Association - 1,3	
Answer	
Document Name	
Comment	
Rather than updating another Standard, shouldn’t the language stay in EOP-011-2 and perhaps be revised for clarity?	
Likes 0	
Dislikes 0	
Response	

Adrian Raducea - DTE Energy - Detroit Edison Company - 3,5, Group Name DTE Energy - DTE Electric	
Answer	
Document Name	
Comment	
Include in EOP-011-3 in R7.3.2	
Likes 0	
Dislikes 0	
Response	

g. Which Reliability Standard(s) should be revised to address the recommendation: “To protect critical natural gas infrastructure from manual and automatic load shedding in order to avoid adversely affecting bulk-power system reliability, Balancing Authorities’ and Transmission Operators’ (TOPs) provisions for operator-controlled manual load shedding are to include processes for identifying and protecting critical natural gas infrastructure loads in their respective areas from firm load shed. Critical natural gas infrastructure loads are natural gas production, processing and intrastate and interstate pipeline facility loads which, if de-energized, could adversely affect the provision of natural gas to bulk-power system natural gas-fired generation.”

Adrian Raducea - DTE Energy - Detroit Edison Company - 3,5, Group Name DTE Energy - DTE Electric

Answer	
Document Name	

Comment

PRC-006-5 could possibly be modified to address the cold weather recommendations by clarifying or adding design requirements for the Planning Coordinators to consider when developing the criteria for UFLS.

Likes 0	
Dislikes 0	

Response

Susan Sosbe - Wabash Valley Power Association - 1,3

Answer	
Document Name	

Comment

We would suggest EOP-011-2.

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	
Document Name	

Comment

Suggest revising approved NERC Standard EOP-011-2 R1.2.5 to implement recommendation.

Likes 0	

Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	

The following is broke down by Applicable Entity and either Manual or Automatic load shedding.

Manual load shedding.

TOP. Expand EOP-011-2, R1, Part 1.2.5 (or within a new Standard). Justification, 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency;

BA. Expand EOP-011-2, R2, Part 2.2.8 (or within a new Standard). Justification, 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency;

Automatic load shedding.

TO. Expand PRC-006-5 and any other relevant regional UFLS standards.

DP. Expand PRC-006-5 and any other relevant regional UFLS standards

Likes 0	
Dislikes 0	
Response	
Michael Krum - Salt River Project - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	

No Comment.

Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1,5	

Answer	
Document Name	
Comment	
Reclamation identifies this recommendation does not fit well into any existing reliability standards. Reclamation suggests a new standard in the EOP family to compliment EOP-005 (generator blackstart) might appropriately address this recommendation. Facilities that might be subjected to load shedding should be required to have an alternate, independent power source.	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 3,4,5 - RF, Group Name Consumers Energy Company	
Answer	
Document Name	
Comment	
We believe this is a MISO/gas issue. Who is going to be responsible for coordination? RC/ISO, BA, TOP? The answer determines what standard(s) will require modification. Could be IRO or TOP standards.	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	
Document Name	
Comment	
Acciona Energy supports Midwest Reliability Organization's (MRO) NERC Standards Review Forum's (NSRF) comments on this question.	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	

Answer	
Document Name	
Comment	
Xcel Energy supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	
Document Name	
Comment	
Alliant Energy supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - ISO New England, Inc. - 2 - NPCC	
Answer	
Document Name	
Comment	

Recommend revising EOP-011-2

- Revise EOP-011-2, R2 with new sub-requirement that states:
    - Balancing Authorities' provisions for operator-controlled manual load shedding are to include processes for identifying and protecting critical natural gas infrastructure loads in their respective areas from firm load shed.
- Revise EOP-011-2, R1 with new sub-requirement that states:
    - Transmission Operators' (TOPs) provisions for operator-controlled manual load shedding are to include processes for identifying and protecting critical natural gas infrastructure loads in their respective areas from firm load shed.
- Create new defined term: **Critical natural gas infrastructure loads** are natural gas production, processing and intrastate and interstate pipeline facility loads which, if de-energized, could adversely affect the provision of natural gas to bulk-power system natural gas-fired generation.

Likes 0	
Dislikes 0	

Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6, Group Name Dominion	
Answer	
Document Name	
Comment	
Dominion Energy suppports the comments submitted by EEI. In addition, Dominion Energy does not support BAs or TOPs attempting to identify critical natural gas infrastructure. The gas pipeline owners have that responsibility and any requirements regarding identification should be in a tarriff and not a reliability standard.	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6 - WECC, Group Name Tacoma Power	
Answer	
Document Name	
Comment	
Tacoma Power suggests adding this recommendation to EOP-011, where there are existing load shedding Requirements. Tacoma Power also recommends that when drafting this Requirement, the SDT should create a separate standalone Requirement, rather than adding a sub-part to an existing Requirement. This makes it easier for TOPs and BAs that don’t have natural gas infrastructure in their footprint to classify the entire Requirement as “Do Not Own” and avoid complicated RSAW narratives describing what sub-parts do and do not apply.	
Likes 1	Platte River Power Authority, 5, Archie Tyson

Dislikes 0	

Response

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

Answer	
Document Name	

Comment

FirstEnergy supports comments posted by EEI

Likes 0	
Dislikes 0	

Response

Patricia Lynch - NRG - NRG Energy, Inc. - 5,6

Answer	
Document Name	

Comment

NRG Energy Inc. has no comment regarding this recommendation as it is not related to GO/GOPs.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE recommends the drafting team consider addressing Key Recommendations 1i, 1h, and 1j from the Joint Inquiry in a similar manner as they are all related to one another. The drafting team could consider the following standard categories:

- Emergency Preparedness and Operations (EOP), since manual load shed is an emergency measure;
- Protection and Control (PRC), since the PRC standards already include undervoltage load shed and under frequency load shed;
- Transmission Operations (TOP), since the TOP would be the responsible entity for identifying and protecting critical natural gas infrastructure loads in their respective areas from firm load shed;

- Transmission Planning (TPL), since it would be helpful for the Transmission Planners to understand which natural gas infrastructure loads are deemed critical for planning; and
- Any combination of EOP, PRC, TOP, and TPL standards the drafting team sees fit.

Additionally, Texas RE recommends including a requirement for corrective action during System restoration so it does not affect natural gas loads that are to be protected from firm load shed. This could be included in the TOPs' system restoration plans, as required in EOP-005.

In addition to having a process for identifying and protecting critical natural gas infrastructure loads from firm load, Texas RE recommends including other critical loads such as law enforcement, hospitals, and 24-Hour emergency services facilities such as fire and rescue garages.

Likes 0	
Dislikes 0	

Response

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Michael Johnson - Pacific Gas and Electric Company - 1,3,5 - WECC, Group Name PG&E All Segments

Answer	
Document Name	

Comment

PG&E has participated in the preparation and supports the comments provided by the Edison Electric Institute (EEI) for Q1g.

Likes 0	
Dislikes 0	

Response

Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5, Group Name BC Hydro	
Answer	
Document Name	
Comment	
BC Hydro suggest that EOP-011 and possibly PRC-006 could be modified to address this recommendation.	
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	
Southern Company recommends dividing this requirement amongst the following two standards as load shedding and the need to protect critical gas infrastructure could occur during other seasons; therefore, including it in existing non-cold weather standards is appropriate. • EOP-011-2: Add **manual load shedding** requirements to R1 for the Transmission Operator and R2 for the Balancing Authority. • PRC-006-5: Revise **automatic load shedding** requirements to include provisions for the Transmission Operator and Distribution Provider.	
Likes 0	
Dislikes 0	
Response	

David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	
Document Name	
Comment	
EOP-011, PRC-006, and regional PRC-006 where applicable.	
Likes 0	
Dislikes 0	
Response	

Andy Fuhrman - Minnkota Power Cooperative Inc. - 1,5 - MRO	
Answer	
Document Name	
Comment	
MPC supports comments submitted by the MRO NERC Standards Review Forum (NSRF).	
Likes 0	
Dislikes 0	
Response	

Gul Khan - Oncor Electric Delivery - 1 - Texas RE	
Answer	
Document Name	
Comment	
EOP-011-1	
Likes 0	
Dislikes 0	
Response	

Quintin Lee - Eversource Energy - 1,3, Group Name Eversource Group	
Answer	
Document Name	
Comment	
EOP-011 is the Reliability Standard that should be revised to address the recommendation. **Note:** GO/GOPs not TOPs should be required to provide the gas infrastructure that is necessary to run their plants to their associated DPs. DPs then can be required to pass the identified circuits to the TOPs.	
Likes 0	
Dislikes 0	
Response	

Alan Kloster - Evergy - 1,3,5,6 - MRO	
Answer	
Document Name	
Comment	
Evergy supports and incorporates by reference Edison Electric Institute's (EEI) response to Question 1g.	
Likes 0	
Dislikes 0	
Response	

Donna Wood - Tri-State G and T Association, Inc. - 1,3,5	
Answer	
Document Name	
Comment	
We do not agree that this recommendation should fall entirely on NERC registered entities. Instead, we believe that natural gas providers should be required to provide a list of their critical facilities to the utilities and maintain it as facilities change in the future. The companion NERC requirements, to incorporate such lists into our load shedding plans, could be treated as modifications to the following requirements: For Manual Load Shedding: Transmission Operators (TOP) – expand EOP-011-2, R1 Balancing Authorities (BA) – expand EOP-011-2, R2 For Automatic load shedding: Transmission Owners (TO) that own UFLS – expand PRC-006-5 and any other relevant regional UFLS standards to include a new requirement(s) to address this recommendation.	
Likes 0	
Dislikes 0	
Response	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	

EOP-011-2 could be a suitable Reliability Standard to ensure necessary oversight of manual and automatic load shedding programs are designed and implemented by responsible entities to ensure the protection of critical natural gas infrastructure from inadvertent manual or automatic load shedding in order to avoid adversely affecting bulk-power system reliability. However, without some mechanism for natural gas infrastructure owners to identify and report which of their facilities are critical, a NERC Reliability Standard may not be effective. (See our General Comments above) Moreover, it is possible that individual state regulations and retail tariffs may already define what load is considered critical and what can and cannot be shed during emergency operating conditions. NERC should also recognize that separating identified critical natural gas infrastructure for this purpose is a consequential task that could be difficult or impractical to accomplish. For example, the facility may be served by the only available distribution feeder in that area and separating that one facility might require the installation of a new distribution line or rerouting another feeder for the sole purpose of supplying what otherwise might be considered a small load.

Alternatively, EOP-011-2 could address the oversight and planning issues, while PRC-006-5 (UFLS) and PRC-010-2-5 (UVLS) could be used for the implementation part avoiding adding the TOs and DPs to EOP-011-2. Regardless of the approach, information from the natural gas infrastructure owners is needed. Additionally, Transmission Service Providers may be a potential source for information regarding which natural gas facilities might be critical since they are responsible for administering transmission tariffs and providing transmission service to transmission customers.

Likes 0	
Dislikes 0	

Response

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3

Answer	
Document Name	

Comment

MidAmerican Energy Company supports EEI and MRO NSRF comments

Likes 0	
Dislikes 0	

Response

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	
Document Name	

Comment

The NAGF has no comment regarding this recommendation.

Likes 0	
Dislikes 0	

Response

Michele Mihelic - American Clean Power Association - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
ACP does not have a recommendation on this question.	
Likes 0	
Dislikes 0	
Response	

Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
Minnesota Power agrees with MRO’s NERC Standards Review Forum (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
BPA agrees with the comments submitted by the US Bureau of Reclamation with additional comments. BPA believes there is an opportunity to alleviate future issues by requiring Critical natural gas facility design to include on-site back-up generator(s) and Auto-Restoration plan(s).	
Likes 0	
Dislikes 0	
Response	

Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	
Document Name	
Comment	

IRC SRC has categorized its response by Applicable Entity and Manual or Automatic load shedding.

Manual load shed

Transmission Operator (TOP): Expand EOP-011-2, R1, Part 1.2.5

1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency;

Balancing Authority (BA): Expand EOP-011-2, R2, Part 2.2.8

2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency;

Automatic load shed

Transmission Owners (TO) that own UFLS: Expand PRC-006-5 and any other relevant regional UFLS standards.

Distribution Providers (DP) that own UFLS: Expand PRC-006-5 and any other relevant regional UFLS standards

Likes 0	
Dislikes 0	
Response	
Natalie Johnson - Enel Green Power - 5	
Answer	
Document Name	
Comment	

Enel North America, Inc. supports Midwest Reliability Organization's (MRO) NERC Standards Review Forum's (NSRF) comments on this question.

Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1,3,5,6	
Answer	

Document Name	
Comment	

Exelon concurs with the comments submitted by the EEI for this question.

Likes 0	
Dislikes 0	
Response	

Jessica Lopez - APS - Arizona Public Service Co. - 1,3,5,6

Answer	
Document Name	
Comment	

AZPS agrees with the comments provided by EEI such that PRC-006 may be the solution to incorporate the recommendation. However, AZPS does not agree with the recommendation as written as it is may not be feasible or economically advisable on how this would be implemented, more specifically "to protect critical natural gas infrastructure loads in our respective areas from firm load shed."

Likes 0	
Dislikes 0	
Response	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	
Document Name	
Comment	

EOP-011-2 (effective 4/1/2023). For the Transmission Operator (TOP), Requirement 1, part 1.2.5 requires the TOP's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area to include "provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency". For the Balancing Authority (BA), Requirement 2, part 2.2.8 requires the BA's Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area to include "provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency". A revision of these requirements could address this recommendation.

Likes 0	
Dislikes 0	
Response	

h. Which Reliability Standard(s) should be revised to address the recommendation: "Balancing Authorities' operating plans (for contingency reserves and to mitigate capacity and energy emergencies) are to prohibit use of critical natural gas infrastructure loads for demand response."

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
EOP-011-2 (effective 4/1/2023). Requirement 2, part 2.2.7 requires the BA's Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area to include "use of Interruptible Load, curtailable Load and demand response". A revision of this requirement could address this recommendation. However, it should be considered that the Balancing Authority may not be the entity that "designs" demand response programs with the end-use customers. Are all BA's positioned to prohibit use of critical natural gas infrastructure loads for demand response?	
Likes 0	
Dislikes 0	
Response	

Jessica Lopez - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	
Document Name	
Comment	
AZPS agrees with the comments provided by EEI; demand response programs are voluntary programs and we are unaware of any Relaibility Standards that could address this recommendation. Additionally, as Demand Response Programs are contractual agreements, it may be difficult to revise already established DR Programs.	
Likes 0	
Dislikes 0	
Response	

Daniel Gacek - Exelon - 1,3,5,6	
Answer	
Document Name	
Comment	

Exelon concurs with the comments submitted by the EEI for this question.

Likes 0	
Dislikes 0	

Response

Natalie Johnson - Enel Green Power - 5	
Answer	
Document Name	

Comment
Requiring Balancing Authorities to prohibit a commercial program such as Demand Response is outside the scope of NERC's jurisdiction and therefore should not be addressed in a NERC Reliability Standard. In 2012, NERC created a working group to assess whether Demand Response is an applicable entity for NERC Reliability Standards. The Functional Model Working Group (FMWG) formed a Functional Model Demand Response Advisory Team (FMDRAT) to assess the need to include a Demand Response (DR) Functional Entity in the Functional Model Version 6. The Working Group released a report that concluded, "Imposing reliability standards to force entities responsible for DR operations to comply with commercial agreements would be inappropriate, may not achieve the desired outcome, and in fact may discourage entities from participating in DR programs." As Demand Response is essentially a business arrangement, improvements from the February 2021 cold weather event are best addressed through the commercial mechanisms already in place to drive desired outcomes. Since NERC has previously investigated this issue resulting in concrete conclusions, it would be arbitrary to act in opposition of their conclusions without first conducting a new investigation.

Likes 0	
Dislikes 0	

Response

Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	
Document Name	

Comment
IRC SRC recommends this recommendation be addressed in TOP-002-4, R4, Part 4.4. **R4.** Each BA shall have an Operating Plan for the next-day that addresses: **4.4** Capacity and energy reserve requirements, including deliverability capability. IRC SRC notes that to ensure this recommendation is effective in producing the results anticipated, a corresponding requirement on those entities providing the Balancing Authority with demand response data; e.g. Distribution Providers, would also be necessary.

Likes 0	
Dislikes 0	

Response

Travis Fisher - Electricity Consumers Resource Council (ELCON) - 7

Answer	
Document Name	

Comment

We disagree that natural gas infrastructure loads should be prohibited—apparently in a blanket fashion and at all times—from being used as demand response resources. These resources are a valuable tool both from a reliability and an economic perspective and should not be prohibited from offering demand response.

Likes 0	
Dislikes 0	

Response

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

BPA supports the comments made by the US Bureau of Reclamation.

Likes 0	
Dislikes 0	

Response

Jamie Monette - Allete - Minnesota Power, Inc. - 1

Answer	
Document Name	

Comment

Minnesota Power agrees with MRO’s NERC Standards Review Forum (NSRF) comments.

Likes 0	

Dislikes 0	

Response

Michele Mihelic - American Clean Power Association - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

ACP does not have a recommendation on this question.

Likes 0	
Dislikes 0	

Response

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	
Document Name	

Comment

The NAGF has no comment regarding this recommendation.

Likes 0	
Dislikes 0	

Response

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3

Answer	
Document Name	

Comment

MidAmerican Energy supports EEI and MRO NSRF comments

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

Given that demand response programs are voluntary, demand-side programs developed to incent customers to voluntarily reduce energy consumption during periods of peak demand, during high energy prices, and during extreme weather conditions, we are unaware of any Reliability Standard that could address this recommendation. This recommendation may be more suitable to be addressed by state retail electric tariffs.

Likes 0	
Dislikes 0	

Response

Donna Wood - Tri-State G and T Association, Inc. - 1,3,5

Answer	
Document Name	

Comment

We recommend incorporating into TOP-002-4, R4.

Likes 0	
Dislikes 0	

Response

Alan Kloster - Evergy - 1,3,5,6 - MRO

Answer	
Document Name	

Comment

Evergy supports and incorporates by reference Edison Electric Institute’s (EEI) response to Question 1h.

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Minnkota Power Cooperative Inc. - 1,5 - MRO	
Answer	
Document Name	
Comment	
MPC supports comments submitted by the MRO NERC Standards Review Forum (NSRF).	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	
Document Name	
Comment	
This could possibly go under an IRO 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	
Southern Company recommends that EOP-011-2 be revised to address the recommendation pertaining to the Balancing Authority operating plans related to the use of critical natural gas infrastructure loads for demand response.	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5, Group Name BC Hydro	
Answer	

Document Name	
Comment	
BC Hydro suggest that TOP-002 and EOP-011 could be modified to address this recommendation.	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Pacific Gas and Electric Company - 1,3,5 - WECC, Group Name PG&E All Segments	
Answer	
Document Name	
Comment	
PG&E has participated in the preparation and supports the comments provided by the Edison Electric Institute (EEI) for Q1h.	
Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE recommends the drafting team consider addressing Key Recommendations 1i, 1h, and 1j from the Joint Inquiry in a similar manner as they are all related to one another. The drafting team could consider the following standard categories:

- Protection and Control (PRC), since the PRC standards already include undervoltage load shed and under frequency load shed;
- Transmission Operations (TOP), since the TOP would be the responsible entity for be identifying and protecting critical natural gas infrastructure loads in their respective areas from firm load shed;
- Transmission Operations (TOP), since the BA would be the responsible entity for specifying the identification (and maintaining protection for) critical natural gas infrastructure loads in their respective areas to perform its analysis functions and Real-time monitoring;
- Transmission Planning (TPL), since it would be helpful for the Transmission Planners to understand which natural gas infrastructure loads are deemed critical for planning;
- Emergency Preparedness and Operations (EOP), since this activity is most likely to occur during an emergency; and
- Any combination of PRC, TOP, TPL, and EOP standards the drafting team sees fit.

Additionally, Texas RE recommends including a requirement for corrective action during System restoration so it does not affect natural gas loads that are to be protected from firm load shed. This could be included in the TOPs' system restoration plans, as required in EOP-005.

Likes 0	
Dislikes 0	

Response

Patricia Lynch - NRG - NRG Energy, Inc. - 5,6

Answer	
Document Name	

Comment

NRG Energy Inc. has no comment regarding this recommendation as it is not related to GO/GOPs.

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 comments posted by EEI

Likes 0	
Dislikes 0	

Response

Carl Pineault - Hydro-Qu?bec Production - 1,5

Answer	
Document Name	

Comment

No comments

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6, Group Name Dominion

Answer	
Document Name	

Comment

Dominion Energy suppports the comments submitted by EEI. In addition, the prohibition on demand response is a market issue and shoudl be defined in a tarriff or market rules, not a reliability standard governing plans.

Likes 0	
Dislikes 0	

Response

Keith Jonassen - ISO New England, Inc. - 2 - NPCC

Answer	
Document Name	

Comment

Recommend revising EOP-011-2

- Revise EOP-011-2, R2 with new sub-requirement that states:
    - Balancing Authorities' operating plans (for contingency reserves and to mitigate capacity and energy emergencies) are to prohibit use of critical natural gas infrastructure loads for demand response."

Likes 0	
Dislikes 0	
Response	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	
Document Name	
Comment	
Alliant Energy supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	
Document Name	
Comment	
Xcel Energy supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	
Document Name	
Comment	
Acciona Energy supports Midwest Reliability Organization’s (MRO) NERC Standards Review Forum’s (NSRF) comments on this question.	
Likes 0	
Dislikes 0	

Response	
Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 3,4,5 - RF, Group Name Consumers Energy Company	
Answer	
Document Name	
Comment	
BAL-502 possibly. Better to include in a new extreme weather standard that addresses all the above questions.	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1,5	
Answer	
Document Name	
Comment	
Reclamation recommends BAL-502-RF-03 be leveraged as the basis for a continent-wide standard to address this recommendation.	
Likes 0	
Dislikes 0	
Response	
Michael Krum - Salt River Project - 1,3,5,6 - WECC	
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	
MRO NSRF recommends this recommendation be addressed in TOP-002-4, R4, Part 4.4. Justification, R4. Each BA shall have an Operating Plan for the next-day that addresses: 4.4 Capacity and energy reserve requirements, including deliverability capability. MRO NSRF notes that to ensure this recommendation is effective in producing the results anticipated, a corresponding requirement on those entities providing the Balancing Authority with demand response data; e.g. Distribution Providers, would also be necessary.	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	
Suggest revising approved NERC Standard EOP-011-2 R2.2.1 and R2.2.8 to implement recommendation.	
Likes 0	
Dislikes 0	
Response	
Susan Sosbe - Wabash Valley Power Association - 1,3	
Answer	
Document Name	
Comment	
We would suggest EOP-011-2.	
Likes 0	
Dislikes 0	
Response	

Adrian Raducea - DTE Energy - Detroit Edison Company - 3,5, Group Name DTE Energy - DTE Electric	
Answer	
Document Name	
Comment	
EOP-011-3	
Likes 0	
Dislikes 0	
Response	

i. Which Reliability Standard(s) should be revised to address the recommendation: "In minimizing the overlap of manual and automatic load shed, the load shed procedures of Transmission Operators, Transmission Owners (TOs) and Distribution Providers (DPs) should separate the circuits that will be used for manual load shed from circuits used for underfrequency load shed (UFLS), undervoltage load shed (UVLS) or serving critical load. UFLS/UVLS circuits should only be used for manual load shed as a last resort and for UFLS circuits, should start with the final stage (lowest frequency)."

Adrian Raducea - DTE Energy - Detroit Edison Company - 3,5, Group Name DTE Energy - DTE Electric	
Answer	
Document Name	
Comment	
PRC-006-5 could possibly be modified to address the cold weather recommendations by clarifying or adding design requirements for the Planning Coordinators to consider when developing the criteria for UFLS.	
Likes 0	
Dislikes 0	
Response	
Susan Sosbe - Wabash Valley Power Association - 1,3	
Answer	
Document Name	
Comment	
Our suggestion is PRC-010-2 as 4.1.3 requires UVLS entities to be responsible for the ownership, operation, or control of UVLS equipment as required by the UVLS Program established by the TP or PC. R1 could be expanded to include the language above. R2 already requires UVLS entities to adhere to the UVLS Program specifications determined by its PC and TP, so if this additional responsibility was added to R1, the requirement to comply with it is already contained in R2. **For UFLS, our suggestion is to add this language to PRC-006-5 as this Standard contains the UFLS Program Requirements. Reliability Standard PRC-006-5 needs to be revised in any case so that we have consistency between Regions and not separate Regional Standards.**	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	

None – this recommendation is redundant and does not require additional consideration; currently covered in EOP-011-2 R1.2.5.

Likes 0	
Dislikes 0	

Response

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	
Document Name	

Comment

Same as recommendation 1.g., The following is broke down by Applicable Entity and either Manual or Automatic load shedding.

Manual load shedding.

TOP. Expand EOP-011-2, R1, Part 1.2.5 (or within a new Standard). Justification, 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency;

BA. Expand EOP-011-2, R2, Part 2.2.8 (or within a new Standard). Justification, 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency;

Automatic load shedding.

TO. Expand PRC-006-5 and any other relevant regional UFLS standards.

DP. Expand PRC-006-5 and any other relevant regional UFLS standards.

Likes 0	
Dislikes 0	

Response

Michael Krum - Salt River Project - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

No Comment.

Likes 0	

Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1,5	
Answer	
Document Name	
Comment	
Reclamation recommends the existing UFLS/UVLS standards be modified to address this recommendation, specifically, PRC-006 and PRC-010.	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 3,4,5 - RF, Group Name Consumers Energy Company	
Answer	
Document Name	
Comment	
PRC standards.	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	
Document Name	
Comment	
Acciona Energy supports Midwest Reliability Organization's (MRO) NERC Standards Review Forum's (NSRF) comments on this question.	
Likes 0	
Dislikes 0	
Response	

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC

Answer	
Document Name	

Comment
Xcel Energy supports the comments submitted by EEI.

Likes 0	
Dislikes 0	

Response
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4

Answer	
Document Name	

Comment
Alliant Energy supports the comments submitted by the MRO NSRF.

Likes 0	
Dislikes 0	

Response
Keith Jonassen - ISO New England, Inc. - 2 - NPCC

Answer	
Document Name	

Comment
Clarify existing requirement R1.2.5 under EOP-011-2

Likes 0	
Dislikes 0	

Response
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6, Group Name Dominion

Answer	
Document Name	
Comment	
Dominion Energy suppports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	
Document Name	
Comment	
No comments	
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 comments posted by EEI	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6 - WECC, Group Name Tacoma Power	
Answer	
Document Name	

Comment	
Tacoma Power suggests adding this recommendation to EOP-011, where there are existing load shedding Requirements. Specifically, Tacoma Power suggests either revising R1.2.5 and R2.2.8 to incorporate this recommendation, or creating a new standalone Requirement that combines this new recommendation with R1.2.5 and R2.2.8.	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5,6	
Answer	
Document Name	
Comment	
NRG Energy Inc. has no comment regarding this recommendation as it is not related to GO/GOPs.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE recommends the drafting team consider addressing Key Recommendations 1i, 1h, and 1j from the Joint Inquiry in a similar manner as they are all related to one another. The drafting team could consider the following standard categories:

- Protection and Control (PRC), since the PRC standards already include undervoltage load shed and under frequency load shed;
- Transmission Operations (TOP), since the TOP would be the responsible entity for identifying and protecting critical natural gas infrastructure loads in their respective areas from firm load shed;
- Transmission Planning (TPL), since it would be helpful for the Transmission Planners to understand which natural gas infrastructure loads are deemed critical for planning;
- Revising the EOP-004 attachment 1 to include a new event type of critical loss due to cold weather; and
- Any combination of PRC, TOP, TPL, and EOP standards the drafting team sees fit.

Additionally, Texas RE recommends including a requirement for corrective action during System restoration so it does not affect natural gas loads that are to be protected from firm load shed. This could be included in the TOPs' system restoration plans, as required in EOP-005.

Likes 0	
Dislikes 0	

Response

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Michael Johnson - Pacific Gas and Electric Company - 1,3,5 - WECC, Group Name PG&E All Segments

Answer	
Document Name	

Comment

PG&E has participated in the preparation and supports the comments provided by the Edison Electric Institute (EEI) for Q1i.

Likes 0	
Dislikes 0	

Response

Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5, Group Name BC Hydro

Answer	
Document Name	

Comment

BC Hydro suggests that EOP-011, PRC-006 and PRC-010 could be modified to address this recommendation.

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	

As outlined in Question 1g, Southern Company recommends dividing load shedding requirements amongst the following two standards:

- EOP-011-2: Add **manual load shedding** requirements to R1 for the Transmission Operator and R2 for the Balancing Authority.
- PRC-006-5: Revise **automatic load shedding** requirements to include provisions for the Transmission Operator and Distribution Provider.

Additonally, Southern Company recommends revising PRC-010-2 for UVLS criteria.

Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	
Document Name	
Comment	

EOP-011, PRC-006, regional PRC-006 where applicable.

Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Minnkota Power Cooperative Inc. - 1,5 - MRO	
Answer	
Document Name	
Comment	

MPC supports comments submitted by the MRO NERC Standards Review Forum (NSRF).	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Evergy - 1,3,5,6 - MRO	
Answer	
Document Name	
Comment	
Evergy supports and incorporates by reference Edison Electric Institute's (EEI) response to Question 1i.	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1,3, Group Name Eversource Group	
Answer	
Document Name	
Comment	
EOP-011 is the Reliability Standard that should be revised to address the recommendation.. **Note:** Need to define what 'critical load' is so that these programs can work. As a suggestion, the sentence could be changed to: 'should separate the circuits that will be used for manual load shed from circuits used for underfrequency load shed (UFLS), undervoltage load shed (UVLS) or serving critical loads**. (i.e., loads that would adversely impact the reliable operation of the BES within 15 minutes if shed.)**	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Oncor Electric Delivery - 1 - Texas RE	
Answer	
Document Name	

Comment	
EOP-011-1	
Likes 0	
Dislikes 0	
Response	

Donna Wood - Tri-State G and T Association, Inc. - 1,3,5	
Answer	
Document Name	
Comment	
For Manual Load Shedding: Transmission Operators (TOP) – expand EOP-011-2, R1 For Automatic load shedding: Transmission Owners (TO) that own UFLS – expand PRC-006-5 and any other relevant regional UFLS standards to include a new requirement(s) to address this recommendation Distribution Providers (DP) that own UFLS - expand PRC-006-5 and any other relevant regional UFLS standards to include a new requirement(s) to address this recommendation	
Likes 0	
Dislikes 0	
Response	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
EOP-011-2 would be a suitable Reliability Standard to ensure and minimize the overlap of manual and automatic load shed programs, processes and procedures of Transmission Operators, Transmission Owners (TOs) and Distribution Providers (DPs). Although the actual separate of the circuits that will be used for manual load shed from circuits used for underfrequency load shed (UFLS), undervoltage load shed (UVLS) or serving critical load would be the TOs and DPs, the planning and oversight should come from the responsible TOPs. While there are a number of PRC Reliability Standards that address load shedding, none of those standards address both UVLS and UFLS and their oversight planning and coordination. For this reason, EOP-011-2 appears to be the best choice to address this recommendation.	
Likes 0	

Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	
Document Name	
Comment	
MidAmerican Energy Company supports EEI and MRO NSRF comments	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
The NAGF has no comment regarding this recommendation.	
Likes 0	
Dislikes 0	
Response	
Michele Mihelic - American Clean Power Association - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
ACP does not have a recommendation on this question.	
Likes 0	
Dislikes 0	
Response	

Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
Minnesota Power agrees with MRO's NERC Standards Review Forum (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
BPA's UFLS plans avoid Natural Gas and other critical loads. If BPA issues a Manual Load Shed directive, it is up to the recipient of that directive to make an informed decision regarding which loads to shed within their distribution area. BPA prescribes a certain amount of MW load, within a certain amount of time, in the Manual Load Shed plan. Then, the recipient of the directive (Public Utility, etc.) decides which loads to shed. In order for BPA to meet the minimum requirements, for both Manual and Automatic Load Shed, it would equate to roughly ¾ of the load in BPA's Balancing Authority Area. BPA believes it is not practical or feasible to completely minimize overlap between the Manual and Automatic Load Shed plans. BPA disagrees with the report's recommendation pertaining to this issue, thus, does not recommend modifying any current Reliability Standards (PRC-006, PRC-010, etc.) at this time.	
Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee	
Answer	
Document Name	
Comment	
IRC SRC has categorized its response by Applicable Entity and Manual or Automatic load shedding. **Manual load shed**	

Transmission Operator (TOP): Expand EOP-011-2, R1, Part 1.2.5

1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency;

Balancing Authority (BA): Expand EOP-011-2, R2, Part 2.2.8

2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency;

Automatic load shed

Transmission Owners (TO) that own UFLS: Expand PRC-006-5 and any other relevant regional UFLS standards.

Distribution Providers (DP) that own UFLS: Expand PRC-006-5 and any other relevant regional UFLS standards

Likes 0	
Dislikes 0	

Response

Natalie Johnson - Enel Green Power - 5

Answer	
Document Name	

Comment

Enel North America, Inc. supports Midwest Reliability Organization's (MRO) NERC Standards Review Forum's (NSRF) comments on this question.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1,3,5,6

Answer	
Document Name	

Comment

Exelon concurs with the comments submitted by the EEI for this question.

Likes 0	
Dislikes 0	

Response	
Jessica Lopez - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
EOP-011-2 (effective 4/1/2023) Requirement 1, part 1.2.5 requires the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area to include "provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency". A revision of this requirement could partially address this recommendation. Revisions to PRC-006-5 (Automatic Underfrequency Load Shedding) and PRC-010-2 (Undervoltage Load Shedding) should also be considered to address involvement of the UFLS and UVLS owning entities (Transmission Owner, Distribution Provider, UFLS-Only Distribution Provider).	
Likes 0	
Dislikes 0	
Response	

2. Do you believe there are alternatives or more cost effective options to address the recommendations the in FERC/NERC Joint Inquiry report? If so, please provide your recommendation and, if appropriate, technical or procedural justification.

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power agrees with MRO's NERC Standards Review Forum (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Michele Mihelic - American Clean Power Association - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
ACP does not have a recommendation on this question beyond the points made elsewhere in these comments.	
Likes 0	
Dislikes 0	
Response	

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	No
Document Name	
Comment	
MidAmerican Energy Company supports MRO NSRF comments	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1,3,5	
Answer	No
Document Name	
Comment	
We recommend that any retrofitting of existing generating units (recommendation b) be handled by the state jurisdictions, instead of incorporating into any NERC reliability standards. Otherwise, entities may be in a position where they must retrofit their unit to comply with a NERC requirement, but the costs associated are not approved by their state jurisdiction.	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Minnkota Power Cooperative Inc. - 1,5 - MRO	
Answer	No
Document Name	
Comment	
MPC supports comments submitted by the MRO NERC Standards Review Forum (NSRF).	
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 recomments that the SDT ensure that standard requirements are written to accomplish the desired results in the most cost-effective manner.	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Pacific Gas and Electric Company - 1,3,5 - WECC, Group Name PG&E All Segments	
Answer	No
Document Name	
Comment	
At this point in the SAR development, PG&E cannot make a determination on alternatives or the cost effectiveness of the recommendations.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter	
Answer	No
Document Name	
Comment	
No additional comments	
Likes 0	
Dislikes 0	
Response	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	No
Document Name	

Comment	
Alliant Energy supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	

MRO NSRF recommends item 2 (page 3 of the SAR) be stricken from the scope of the SAR. The cost to design new or retrofit existing generators based on an unknown, specified ambient temperature could require extensive investment and cost. MRO NSRF also questions how this would be audited by NERC as generators are complex machines and may fail to start, experience a derate, etc., for various reasons during extreme cold weather, including times where the root cause may not be due to cold weather conditions.

The current FERC/NERC Joint Inquiry report and all preceding reports related to cold-weather events contain many recommendations. Inasmuch, MRO NSRF encourages NERC to proceed systematically through these recommendations, as many are dependent on each other. **Due to the short timeframe and the number of recommendations that will be addressed under the scope of this SAR**, rather than have one large standards development project, **MRO NSRF recommends NERC form several Standard Drafting Teams to accomplish this task in an efficient manner. MRO NSRF recommends this be done using the existing SAR, avoiding the need to create multiple SARs, similar to what was done under the umbrella SAR for Project 2016-02: Modifications to CIP Standards.** MRO NSRF recommends the SAR batch like concepts together and break the project into the following segments:

1. Generator Owner, Generator Operator and Balancing Authority SDT Project:

- Item 1 (page 3 of the SAR)
- Item 3 (page 3 of the SAR)
- Item 4 (pages 3-4 of the SAR)
- Item 5 (page 4 of the SAR)
- Item 6 (page 4 of the SAR)

2. Load Shedding and Demand Response SDT Project:

- Item 7 (page 4 of the SAR)
- Item 8 (page 4 of the SAR)
- Item 9 (page 4 of the SAR)

3. Future SDT Project:

- Item 2 (page 3 of the SAR); see comments below for further information

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	

Susan Sosbe - Wabash Valley Power Association - 1,3	
Answer	No
Document Name	
Comment	
We appreciate that NERC is evaluating revising specific Standards and not adding another Standard specific to Cold Weather Preparedness, which would have overlapping requirements with existing Reliability Standards. We hope there will be a Risk Assessment associated with these revisions based upon unit size, location, etc. as Plans for small units may not need to be as extensive as for large units, or for units in parts of the country with a high probability of severe freeze impacts.	
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 Regional Standards Committee no NGrid	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Daniel Gacek - Exelon - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Evergy - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kenisha Webber - Entergy - Entergy Services, Inc. - NA - Not Applicable - SERC	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Keith Jonassen - ISO New England, Inc. - 2 - NPCC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Natalie Johnson - Enel Green Power - 5	
Answer	Yes
Document Name	
Comment	

Interregional planning studies should evaluate the most cost effective approach to promote the desired resiliency, with criteria set out by FERC for a minimum level of resilience (on a probabilistic basis). Transmission (which has other known benefits that would also need to be included) should be compared to generator weatherization (including blended generation along with transmission approaches). The most cost effective approach should be considered for each Region (and sub-region where geographic diversity is significant). If generator weatherization upgrades are required, these should be viewed as a recoverable expense to load, similar to how reliability upgrades to the transmission system are billed to load.

Another option is to provide market incentives that would urge Generator Owners to implement cold weather enhancements. Similar to other market incentives to provide grid reliability services such as Black Start or Ancillary Services, Generators that are able to operate to certain ambient temperatures could be paid a premium for that service thereby covering the cost for their investments and the costs of providing this reliability service.

Enel North America, Inc.'s Texas solar facility did not experience icing or ambient temperature problems during the 2021 February event. During the event, the site was taken offline due to cold weather issues with the interconnecting transmission line. The design and configuration of Enel North America, Inc.'s solar site enabled its facility to perform well during this February event. The solar site performed well due to the following attributes:

- Solar PV modules have operating ranges from -40C to +85C. Most inverters will derate at around +45C to +50C.
- All systems are tilted to have the optimal angle to the sun. The tilting promotes ice and snow melt and is therefore self-cleaning. The tilting is already a design feature for solar panels that aids in shedding snow and ice.
- All solar plants must be designed to comply with ASCE 7 wind loads, which are defined by a 3-second wind gust, at 33ft above ground with a 300-year return period. This wind speed varies with location, and ranges from 95 to 107 mph for the Texas region.
- Enel North America, Inc.'s solar fleet utilizes bifacial module technology, which can produce power even when the top of the panels is covered. This allows for electrical current flow, and subsequently creates heat that aids in clearing panels of ice and snow.

Different fuel types have different strengths and the above attributes of solar farms that have these design features could be part of the solution to cold weather events.

Demand Response

Demand Response provides numerous benefits to the grid, including reducing the likelihood of blackouts and reducing every-day reliance on fossil fuel generators. Therefore, it is to the grid's best interest to allow for as much demand response participation to the extent it does not threaten reliability.

Curtailment Service Providers ("CSPs") enable end-use retail customers participation in wholesale market demand response programs. CSPs with critical natural gas infrastructure customers understand the concerns raised by FERC/NERC but offer alternative options to mitigating reliability shortcomings without fully banning participation of these customers in Demand Response programs.

- First, in place of a prohibition, NERC should instead require facilities with critical gas infrastructure to demonstrate that they are not signed up for demand response programs during cold weather months. Critical natural gas facilities that participate in demand response programs already opt-out of demand response participation in cold weather months due to the potential for freezing and reliability issues. Critical natural gas facilities can make this demonstration as part of the reporting requirements in the recommendation for critical natural gas facility reporting outlined on page 18 of the FERC/NERC Cold Weather Report.
- Second, any ban on natural gas facilities participating in Demand Response programs should apply only to what is critical to maintaining natural gas supply.
    - Multiple loads may be behind one Electric Service Identifier associated with a natural gas facility and not all of them are critical to maintaining supply. Non-critical loads should therefore still be allowed to participate in DR programs.
    - Any BA considering such a rule should first execute a survey of natural gas facilities in their footprint to determine what loads are critical to natural gas supply. This type of assessment is currently underway in Texas by the State PUC and Railroad Commission (RRC).
    - During the February 2021 cold weather event in Texas, a majority of the natural gas that was curtailed was due to utility rolling blackouts that shut off power to natural gas facilities. A full accounting of load critical gas facilities to maintaining adequate natural gas supply would have prevented this.
- Third, BAs should consider the difference in load shedding requirements for different types of Demand Response programs.
    - For example, Demand Response participation in PJM's Synchronized Reserve Market ("SRM") only requires load shedding for a maximum of 30 minutes (average of 9 minutes). For a natural gas compressor station, this short of a duration would not result in a sustained drop in pressure that could lead to a freezing event as was seen in Texas.
    - Furthermore, since compressor stations often carry a large electric load, their participation in the SRM is critical to support to the PJM electric grid during unexpected system disruptions.
    - Therefore, participation via demand response of critical natural gas infrastructure should not be prohibited in markets that require short dispatch times such as PJM's SRM.
- Lastly, BAs should allow critical natural gas facilities from participating in demand response programs during warmer months when the probability of a freezing event is near zero.
    - A full survey of how critical natural gas facilities participate in demand response programs would show that these companies are already choosing not to use load critical to their gas supply during cold weather. Contributing to the reliable delivery of natural gas is sole focus of these facilities. The risks and financial penalties of failing to meet their obligations due demand response program are severe.
    - Placing seasonal limitations on these facilities participating in demand response programs would be codifying a practice that is already commonplace.

Given the many benefits demand response can provide the grid and the various ways in which critical natural gas facilities participate in demand response programs, Enel North America, Inc. recommends that any final recommendations on the topic ask for further studying of the issue in place of a comprehensive prohibition.

Likes 0	
Dislikes 0	

Response

Travis Fisher - Electricity Consumers Resource Council (ELCON) - 7	
Answer	Yes
Document Name	
Comment	
ELCON recommends that NERC review each proposed change to its standards to ensure consistency with—or at least avoid conflict with—local, state, and regional policies under development. For example, in State Bill 3, Texas required that its Public Utilities Commission (PUCT) implement winter weatherization requirements, and the PUCT in October issued new 16 Texas Administrative Code §25.55 relating to weather emergency preparedness. Although ELCON agrees with FERC and NERC that the Event was unacceptable and that regulatory changes must be implemented, NERC should take care to align with and not to disrupt the important changes already established by local, state, and regional policymakers.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA supports the comments made by the US Bureau of Reclamation.	
Likes 0	
Dislikes 0	
Response	
LaKenya VanNorman - Florida Municipal Power Agency - 3,4,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
FMPA supports TAPS (Transmission Access Policy Study Group) comments	
Likes 0	
Dislikes 0	
Response	

Dana Showalter - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT believes that splitting this effort into multiple projects distinguished by concepts, as suggested by the SRC, would allow for more targeted teams that have appropriate expertise.	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
SAR Recommendation #2 The NAGF believes that existing generation facilities should not be mandated to retrofit/upgrade equipment to operate in extreme weather conditions. Such retrofits can be very expensive and not economically feasible for certain facilities, causing them to be retired rather than investing in such retrofits/upgrades. Therfore, the NAGF recommends that exitsing generation facilities be provided the flexibility to revise their extreme weather temperature information given existing equipment capabilities and operating experience.	
Likes 1	Platte River Power Authority, 5, Archie Tyson
Dislikes 0	
Response	
Gul Khan - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Oncor recommends that the above items 1.g. and 1.i. would be more appropriately addressed through the development of a Reliability Guideline that provides an in-depth assessment and discussion of load shed considerations. Each system is different and will have varying constraints that must be considered in the development of load shed procedures. A blanket and “one-size-fits-all” approach likely will not achieve the end goal of having entities understand the nuances/capabilities of their system and develop necessarily adaptable load shed procedures that fit a variety of circumstances. The	

development of a Reliability Guideline on this topic will allow for the documentation of the "why" so that entities can appropriately understand and adopt meaningful changes to their load shed procedures that address their individual constraints.

Likes 0	
Dislikes 0	

Response

Rebecca Baldwin - Transmission Access Policy Study Group - NA - Not Applicable - NA - Not Applicable

Answer	Yes
Document Name	

Comment

Recommendation 1b ("Generator Owners are to design new or retrofit existing generating units to operate to a specified ambient temperature and weather conditions…. The specified ambient temperature and weather conditions should be based on available extreme temperature and weather data for the generating unit's location, and account for the effects of precipitation and accelerated cooling effect of wind") does not indicate which entity should determine the "specified ambient temperature and weather conditions." This responsibility should lie with the Generator Owner: each GO should determine the conditions to which it can economically retrofit each generating unit, in light of available extreme weather and temperature data, and inform its BA of its limitations. The BA can then plan accordingly. GOs' decisions regarding the conditions to which they retrofit or design their units may well have implications for capacity markets, resource adequacy requirements, etc. Any such market and resource adequacy implications, however, are explicitly beyond NERC's purview, and must be addressed by entities with responsibility for those areas.

The alternative—charging a different entity, such as the BA or RC, with determining the specified ambient temperature and weather conditions—may be superficially appealing, but TAPS is concerned that doing so would aggravate resource adequacy issues by causing the retirement of economically marginal generators that could otherwise continue to provide reliable service under most weather conditions. So long as entities with planning responsibilities are aware of and account for generators' limitations, it is better to have a generator that can reliably operate in *most* weather, than to lose that generator in *all* weather.

TAPS notes as well that, even aside from the counterproductive effect noted above, designating the local record low as the "specified ambient temperature" for all generators is not a reasonable solution: given current weather trends, records may well change over the life of a generator. A reliability standard should not force every generator to undergo another round of retrofitting each time a new record is set; those decisions should be made on a case-by-case basis in light of the then-current generation mix and winter capacity needs of the region.

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

We believe the only alternative that would also address the findings of the joint inquiry would be to leverage the recently FERC approved EOP-011-2 that will require Generator Owners to implement and maintain one or more cold weather preparedness plan(s), including freeze protection measures, inspection and maintenance, cold weather data and operating limitations, and training. EOP-011-2 already covers many of the inquiry recommendations and becomes effective in 2023.

Likes 0	
Dislikes 0	

Response

Patricia Lynch - NRG - NRG Energy, Inc. - 5,6

Answer	Yes
Document Name	

Comment

NRG Energy Inc is in agreement with the NAGF's position as stated:

The NAGF Forum believes that existing generation facilities should not be mandated to retrofit/upgrade equipment to operate in extreme weather conditions. Such retrofits can be very expensive and not economically feasible for certain facilities, causing them to be retired rather than investing in such retrofits/upgrades. Therefore, the NAGF recommends that existing generation facilities be provided the flexibility to revise their extreme weather temperature information given existing equipment capabilities and operating experience.

NRG Energy Inc. would like to submit additional comments regarding seasonal mothball units that are not operated during winter periods. The SDT should consider exemptions for those units regarding retrofits if these units are removed from service for operation in the winter periods. In addition, retrofits require outages to implement the required freeze protection which would be taken during high load periods to meet the standard enforcement dates. This further decreases reliability of the grid at a time it is needed most.

Likes 0	
Dislikes 0	

Response

Jennie Wike - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6 - WECC, Group Name Tacoma Power

Answer	Yes
Document Name	

Comment

As noted in Tacoma Power's comments to item 1b, using a risk-based tiered approach would be a more cost effective solution than prescribing specific modifications. Those entities that perform an assessment and do not identify vulnerabilities would not be required to implement corrective actions, thus eliminating additional burden. Additionally, those entities who perform an assessment and determine that extreme cold weather events are not feasible for their region would not be required to perform any further actions.

This risk-based approach would ensure that vulnerabilities are identified at facilities that experience cold weather while minimizing burden to those facilities who do not have vulnerabilities or cold weather climates.

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6, Group Name Dominion

Answer	Yes
Document Name	

Comment

A number of the proposed reliability standard modifications are more appropriate to tarriffs or market rules.

Likes 0	
Dislikes 0	

Response

George Brown - Acciona Energy North America - 5

Answer	Yes
Document Name	

Comment

The FERC/NERC Joint Inquiry report and all preceding reports related to cold-weather operations contain many recommendations. Inasmuch, Acciona Energy encourages NERC to proceed systematically through these recommendations, as many are dependent on each other. Rather than have one large standards development project, Acciona Energy recommends the following Standard Drafting Team projects:

1. Generator Owner/Operator & Balancing Authority SDT Project:

- FERC/NERC Joint Inquiry report, Key Recommendation 1a, SAR Recomendation 1, item 1a of this Comment Form,
- FERC/NERC Joint Inquiry report, Key Recommendation 1c, SAR Recomendation 6, item 1f of this Comment Form
- FERC/NERC Joint Inquiry report, Key Recommendation 1d, SAR Recomendation 4, item 1d of this Comment Form
- FERC/NERC Joint Inquiry report, Key Recommendation 1e, SAR Recomendation 3, item 1c of this Comment Form, and
- FERC/NERC Joint Inquiry report, Key Recommendation 1g, SAR Recomendation 5, item 1e of this Comment Form.

2. Load Shedding & Demand Response SDT Project:

- FERC/NERC Joint Inquiry report, Key Recommendation 1h, SAR Recomendation 8, item 1h of this Comment Form,
- FERC/NERC Joint Inquiry report, Key Recommendation 1i, SAR Recomendation 7, item 1g of this Comment Form, and
- FERC/NERC Joint Inquiry report, Key Recommendation 1j, SAR Recomendation 9, item 1i of this Comment Form.

3. Future SDT Project:

- FERC/NERC Joint Inquiry report, Key Recommendation 1f, SAR Recomendation 2, item 1b of this Comment Form. Please see comments below for further information.

Likes 0	
Dislikes 0	
Response	
Michael Krum - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
No Comment.	
Likes 0	
Dislikes 0	
Response	
Jessica Lopez - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Adrian Raducea - DTE Energy - Detroit Edison Company - 3,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	

Response

Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee

Answer	
Document Name	

Comment

The current FERC/NERC Joint Inquiry report and all preceding reports related to cold-weather events contain many recommendations. Due to the short timeframe and the number of recommendations that will be addressed under the scope of thisSAR, rather than have one large standards development project, the IRC SRC recommends NERC form several Standard Drafting Teams (SDTs) to accomplish this task in an efficient manner. The IRC SRC recommends this be done using the existing SAR, avoiding the need to create multiple SARs, similar to what was done under the umbrella SAR for Project 2016-02: Modifications to CIP Standards. Finally, IRC SRC recommends the SDT consider batching like concepts together and breaking the SAR into the following segments:

1. Generator Owner, Generator Operator and Balancing Authority SDT Project:

· Item 1 (page 3 of the SAR)

· Item 2 (page 3 of the SAR) if retained

· Item 3 (page 3 of the SAR)

· Item 4 (pages 3-4 of the SAR)

· Item 5 (page 4 of the SAR)

· Item 6 (page 4 of the SAR)

2. Load Shedding and Demand Response SDT Project:

· Item 7 (page 4 of the SAR)

· Item 8 (page 4 of the SAR)

· Item 9 (page 4 of the SAR)

3. Future SDT Project:

· see comments below for further information

Likes 0	
Dislikes 0	

Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5, Group Name BC Hydro	
Answer	
Document Name	
Comment	
BC Hydro does not have a position in response to the SDT’s question and an associated recommendation for alternatives at this time. However, BC Hydro suggests that part of implementing these recommendations, criteria and/or guidelines (implementation and/or compliance) to help define an Extreme Cold Weather condition be also developed. Geographical location, historical vs. forecast data, statistical-based design conditions, etc. can have a great impact when it comes to operationalization of these new Reliability Standard Requirements.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	

Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	
Document Name	
Comment	
Xcel Energy supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1,5	
Answer	
Document Name	
Comment	
Reclamation identifies that extreme cold weather has only caused problems in areas that rarely experience such weather and are therefore not normally prepared for such conditions. Reclamation observes that continent-wide requirements to address regional phenomena are overly burdensome for regions that normally experience extreme cold weather and create an unnecessary administrative burden for entities in those regions to create compliance documentation of normal business operations. Reclamation also recommends that future cold weather modifications be fully scoped to avoid constant churn of reliability standards. Specifically, Reclamation observes that none of the recommendations pertain to cold weather preparations for transmission systems.	
Likes 0	
Dislikes 0	
Response	

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

Adrian Raducea - DTE Energy - Detroit Edison Company - 3,5, Group Name DTE Energy - DTE Electric	
Answer	
Document Name	
Comment	
Create a stand alone NERC Reliability Standard for Extreme Cold Weather Grid Operations, Preparedness, and Coordination instead of revising multiple NERC Standards except place the training requirements in PER-006-1.	
Likes 0	
Dislikes 0	
Response	
Susan Sosbe - Wabash Valley Power Association - 1,3	
Answer	
Document Name	
Comment	
Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Patti Metro - National Rural Electric Cooperative Association - 3,4	
Answer	
Document Name	
Comment	
NRECA, on behalf of the Cooperative Sector, supports the need for the SAR Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination. The Cooperative Sector recognizes the importance of expeditiously taking action to implement the recommendations in the Joint FERC/NERC Inquiry Final Report on the February 2021 Freeze event. NRECA will work with its members to provide technical input during the standards development process.	
Likes 0	
Dislikes 0	

Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	Copy of MRO NSRF_Proposed Standard Placement_Cold Weather Recommendations_MATRIX_12-07-21.xlsx
Comment	

MRO NSRF notes that the recommendations contained within the Cold Weather Joint Inquiry report are merely that, recommendations. In light of the fact that there is no FERC directive, NERC should prioritize and evaluate each of the recommendations from the report and move forward only with those recommendations truly needed to support BES reliability. By simply taking all of the recommendations at face value and asking "what Standard does it belong in" makes everything a priority. This approach has not worked well in the past as evidenced by the SER and P81 projects.

In addition, as the SAR sets the scope of a project in accordance with the ANSI process as agreed upon by industry, MRO NSRF asks that NERC and the SAR Drafting Team consider the following comments:

- Regarding item 1 (page 3 of the SAR)

MRO NSRF is concerned about the use of the term 'protect.' Some of the examples provided in the Joint Inquiry report for cold-weather-critical components (footnote 261) cannot be 'protected' against certain cold weather ambient conditions.

To address this, MRO NSRF suggests a language change in the SAR to recognize and allow for this circumstance; i.e. to protect or otherwise provide criteria as to why a cold-weather critical component cannot be protected against certain cold weather ambient conditions.

- Regarding item 2 (page 3 of the SAR)

As noted in our response to question 1b above, MRO NSRF recommends removing this recommendation from the SAR.

A methodical approach needs to be taken to address this recommendation as it has the potential to oppose or discourage local, state and national energy objectives. As this recommendation is currently written, it has the potential to thwart progress of other recommendations that would have a more immediate positive effect on reliability. Further, this recommendation is linked to the FERC/NERC Joint Inquiry report, Key Recommendation 2, which requires a project with participation beyond NERC stakeholders.

- Regarding item 4 (pages 3-4 of the SAR)

MRO NSRF recommends modifying the recommendation language so that Corrective Action Plans are only developed and implemented when a generating unit experiences an outage, failure to start or derate when the conditions identified in NERC Reliability Standard EOP-011-2 Emergency Preparedness and Operations, Requirement R7.3. et al. (or its successors; e.g. if this language is transitioned to an FAC standard) are not met.

Finally, MRO NSRF provides a corresponding summary of the above recommendations as a table submitted as attachment, “MRO NSRF_Proposed Standard Placement_Cold Weather Recommendations_MATRIX_12-07-21.xlsx.”

Likes 0	
Dislikes 0	

Response

Michael Krum - Salt River Project - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

No Comment.

Likes 0	
Dislikes 0	

Response

Richard Jackson - U.S. Bureau of Reclamation - 1,5

Answer	
Document Name	

Comment

Reclamation disagrees with continent-wide reliability requirements to address cold weather preparation. The problem with continent-wide cold weather requirements is the universal application of a compliance burden to solve a problem that only exists in a limited geographic area and is limited to certain types of generation facilities. Information to identify these areas and facilities should be available in the GADS database.

Different geographic locations require different levels of cold weather preparation. Entities in geographic locations that commonly experience cold weather may already have adequate preparations in place but are now required to provide extra documentation of these preparations simply to support compliance. This is an administrative burden that does not directly improve reliability and is therefore inappropriate for continent-wide requirements.

Reclamation recommends entities that are already inherently protected against cold weather do not need reliability requirements for cold weather protections. Entities that are *not* inherently protected against cold weather need clear, definitive requirements to ensure electric reliability during extreme cold weather. This objective is appropriately achieved by regional reliability standards or by excluding certain geographic locations and/or certain types of generators.

Cold weather is seasonal and expected. Cold weather losses historically do not occur in areas that are accustomed to annual freezing temperatures. For areas of the country and types of generators that routinely prepare for and experience cold weather, requirements to document plans and provide training are administrative and financial burdens with low potential for increases to reliability. Regional requirements that target affected generation types and localities would be more economical and effective than continent-wide requirements. Specific regional requirements would better address the issues seen in the areas that have been affected.

Hydroelectric plants already have local cold weather plans (e.g., seasonal plants, water restrictions due to temperature, etc.) and have been operating reliably in various extreme temperature bands for over 100 years. Reclamation recommends excluding hydroelectric generators from cold weather requirements as they are secured inside climate-controlled buildings and rely on water operations, for which cold weather considerations are already accounted by local operations and maintenance procedures. Reclamation recommends limiting the applicability of cold weather requirements to entities located in geographic areas that don't normally see harsh winter conditions.

Reclamation recommends the SDT consider modifications to address the bigger picture, which is extreme conditions in general. If other extreme operating conditions are addressed simultaneously with cold weather conditions, it will alleviate the churn caused by the current cold weather modifications.

Likes 0	
Dislikes 0	

Response

George Brown - Acciona Energy North America - 5

Answer	
Document Name	

Comment

Acciona Energy provides the following additional comments on the recommendations from the FERC/NERC Joint Inquiry report.

- The FERC/NERC Joint Inquiry report, Key Recommendation 1a, SAR Recommendation 1, item 1a of this Comment Form.

Acciona Energy is concerned about the use of the term 'protect' in this recommendation. Some of the examples provided (footnote 261) in the Joint Inquiry report for cold-weather-critical components cannot be 'protected' against certain cold weather ambient conditions.

Acciona Energy would suggest a language change to the SAR from 'protect' to 'protect or if unable to protect, if near-term conditions are predicted to be met that would render this cold-weather-critical component unavailable, such unavailability of this cold-weather-critical component shall be reflected in the generating capacity that can be relied on'.

- The FERC/NERC Joint Inquiry report, Key Recommendation 1f, SAR Recommendation 2, item 1b of this Comment Form.

Acciona Energy recommends removing this recommendation from this SAR.

A methodical approach needs to be taken to address this recommendation as it has the potential to oppose or discourage local, state and national energy objectives. As this recommendation is currently written, it has the potential to thwart progress of other recommendations that would have a more immediate positive effect on reliability. Further, this recommendation is linked to the FERC/NERC Joint Inquiry report, Key Recommendation 2, which requires a project with participation beyond NERC stakeholders.

- The FERC/NERC Joint Inquiry report, Key Recommendation 1d, SAR Recommendation 4, item 1d of this Comment Form.

Acciona Energy recommends modifying the recommendation language so that Corrective Action Plans are only developed and implemented when a generating unit experiences an outage, failure to start or derate when the conditions identified in NERC Reliability Standard EOP-011-2 Emergency Preparedness and Operations, Requirement R7.3. et al. are not met.

Likes 0	
Dislikes 0	

Response

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4

Answer	
Document Name	

Comment

Alliant Energy supports the comments submitted by the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Keith Jonassen - ISO New England, Inc. - 2 - NPCC

Answer	
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6, Group Name Dominion

Answer	
Document Name	

Comment

Dominion Energy suppports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Michael DePalma - Onward Energy - NA - Not Applicable - MRO,WECC,Texas RE,NPCC	
Answer	
Document Name	
Comment	
For each weatherization standard modification, we request the following be considered: Focus additional requirements and punitive measures on those GO/GOPs that have not shown compliance with existing weatherization standards; Address natural gas suppliers' ability to get product to market; with adequate fuel stock availbility much of the outages seen in February 2021 could have been avoided; Interconnection between regions (e.g. TRE and others) may be incentivized through NERC reliability standards, which would allow for improved energy flow to areas where it is needed during emergencies	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	
Document Name	
Comment	
HQP hydro production groups are located where extremely cold ambient temperatures often occur during winter periods. Specific Design requirements are intrinsically implemented to ensure that extreme ambient temperature does not affect production.	
Likes 0	
Dislikes 0	
Response	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 3,5,6	
Answer	
Document Name	
Comment	

AEP appreciates the perceived urgency of the proposed SAR and the recommendations and concerns which drove it, however we do not believe that the SAR's obligations suggested by recommendations #1 through #6 are necessary for inclusion within new or revised NERC standards. The Requirements suggested by Recommendations 1, 3, 4, 5, and 6 are addressed at a high level in the recently approved cold weather standards from Project 2019-06. We believe what is being suggested by this SAR's recommendations is already being planned and executed as a result of developing cold weather plans. Recommendation 2 may be reasonable to implement for new installations or modifications to existing facilities, provided that the standard design criteria is clear and consistent over time. Part of Recommendation 2 is related to the retrofitting of existing units to meet new cold weather standards, and this may not be a realistic expectation based on the design and age of some units. This needs to be investigated further to see if it is even feasible to so do. If it *is* determined to be feasible, industry would need sufficient time and opportunity make the necessary changes. We believe the plan for the existing units should instead revolve around corrective action plans for identified weaknesses, as opposed to a wholesale unit design basis change. In summary, we do not believe the strategy envisioned for those obligations would be a prudent or effective way to address those concerns.

Project 2019-06 resulted in new obligations within TOP-003, IRO-010, and EOP-011, and addressed Cold Weather preparedness, plans, procedures, and awareness. AEP fully supported the efforts of this project, and cast affirmative ballots driven by that support. The benefits of these new obligations have yet to be fully realized, and though they were not drafted to specifically address the February 2021 events, we believe that they will prove very beneficial when fully implemented. AEP recommends not pursuing the proposed SAR for Project 2021-07, and instead, allow opportunity for the new obligations drafted under Project 2019-06 to yield their full effect.

There may be potential benefits in pursuing recommendations #7 through #9 for both the reliability of the BES and for the customer as well. A major obstacle in pursuing them however, is the challenge of achieving true visibility of critical gas infrastructure loads, especially from a Transmission Operator point of view. For example, while the Distribution Provider does have the means to identify some of these facilities as part of the service connection process, there may also be details of which they would not be aware. For example, they may not know a) the degree to which the gas supply is non-firm only, b) if gas compressor backups are available or c) what the affect might be of losing multiple compressor stations along the pipelines. Also, the GO would need to work with their gas suppliers to identify the risk to their plants for the loss of the pipeline electrical supply. The complexity of these contracts among gas suppliers and the risk to the generation needs to be the responsibility of the generator or following BA processes (which don't presently exist) to clearly communicate to the Distribution Provider and/or the TOP. A number of self-reporting mechanisms and ties would be integral for this information to flow appropriately, but these mechanisms do not currently exist. At the very least, any obligations driven by

Recommendation #7 would need to include the Distribution Provider and Generator Owner.

Minimum system operating specifications and thresholds at the generator level could be explicitly stated within new or revised interconnection agreements. These agreements might be the appropriate mechanism, along with ongoing improvements being made to FAC-001 and FAC-002, rather than within NERC Standards obligations for such commitments to be met. In addition, it should be noted that unit-hardening techniques cannot be generalized across all units, as this would not be an effective approach. Rather, these should be determined on a unit-specific basis.

The degree to which an individual unit is hardened is not the sole guarantor of success. If those hardened units are not available or do not have reserve or emergency resource capacity, they could not be called upon as inferred by this SAR. The configuration of the system, i.e. what facilities are in or out of service, and system operating limits and how close you are to them will all play a crucial role.

AEP believes many entities are currently following prudent, localized strategies in preparing for cold weather, and are already incentivized by the market to develop and execute prudent procedures based on existing market demands. Any entities who did not already have prudent procedures in place will certainly be mandated to do so by the obligations developed in Project 2019-06. Rather than the course proposed in the draft SAR, AEP believes the best path forward involves the RTOs (presumably serving as the Balancing Authority) working directly with generating entities within their footprint, and to follow up with them individually and directly when issues are identified. RTOs are in the best position to provide this service, as they fully understand the system constraints, geography, weather patterns, and customers for their area. RTOs often provide their own guidance in this regard, for example, PJM's Manual 14D Attachment N: Cold Weather Preparation Guideline and Checklist. This is one of several guidance documents that is already available, and which emphasizes the reviewing of lessons learned after each event and implementations of defenses to prevent recurrence. Once in place, this creates an ongoing effort that focuses improvements in areas of specific need that directly translate to continual improvement of the process that is in place. In addition, we are seeing that REs are heading in a similar direction as well. AEP believes these established processes have proven their effectiveness, and will continue to be valuable going forward. Not only does this relationship between the RTOs and their generating entities help to develop prudent preparatory steps in regard to cold weather, it also allows the RTO to work more closely with those generators who may need to improve the methods they already have in place. Such a working relationship naturally fosters a good communication between the generator and the BA and/or RC which we believe is the spirit behind this new SAR. Rather than pursue rule making that applies to all entities, many of which have prudent cold weather procedures already in place, RTOs should instead work more closely with those entities where additional effort may need to be made. By doing so, the RTOs can more accurately determine exactly what deficiencies need to be addressed within these specific entities, and recommend appropriate entity-specific strategies accordingly.

The content of this proposed SAR was developed solely in response to the preliminary version of the findings and recommendation document, and its recommendations and timelines do not always correlate with the final version of the findings and recommendation document (including some implementation timeframes which are shorter in the draft SAR than in the final version of the findings and recommendations document). In addition, the draft SAR and request for industry comment was made less than a week after the final findings and recommendations were issued. We believe NERC and the future Standards Drafting Team would have been much better served if the SAR authors would have withheld the proposed draft SAR until it had been updated to reflect the final findings and recommendations. In addition, industry has not had sufficient opportunity to review the final findings and recommendations, which may prove problematic in providing quality, substantive industry feedback on the SAR. While issuing the draft SAR without taking the final findings and recommendations into account, and requesting those comments before the holidays, might both appear to be a short term benefit in terms of expediency, we believe it may negatively impact the effectiveness of the project in the long term. The future Standards Drafting Team will need ample, high quality feedback to perform their work and we are concerned that the compressed timeline for providing feedback will be problematic for them.

Likes 0	
Dislikes 0	

Response

Patricia Lynch - NRG - NRG Energy, Inc. - 5,6

Answer	
Document Name	

Comment	
NRG Energy Inc is in agreement with the NAGF's position as stated: *The NAGF presents the following comments for consideration:* *a. The NAGF supports the recommendation that new generation facilities be designed to operate to historical wind chill temperature and precipitation worst-case conditions, but does not believe existing generating units should be required to upgrade equipment to meet these criteria.* *b. Generator Owners and Generator Operators should not be required to perform fuel supply risk analysis as fuel supply is out of Generators' control and responsibility and logically belongs to the fuel suppliers.* *c. Pre-starting generation facilities prior to the onset of cold weather events will help ensure resources are on-line and available to serve load.* *d. NRG Energy Inc. offers suggestions to Recommendation 6 as there is ambiguity related to impact of precipitation related to minimum operating temperature. NRG recommends that further clarification is provided to the industry regarding this.* *e. NRG Energy Inc. has concerns about consistency in defining minimum operating temperature across the specific regions. NRG Energy Inc would like the SDT to consider how will this be implemented and managed.* *f. NRG Energy Inc. has a question to the SDT on Recommendation #5 concerning projection of capacity that is at risk due to fuel supply and weather. Will there be sanctions if projections are off? Who will be accountable and how will this be enforceable?*	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE appreciates and supports the drafting team's effort on this project. Texas RE noticed that some of the recommendations in the Joint Inquiry are not present in the SAR. Texas RE recommends incorporating the following Key Recommendations from the Joint Inquiry specifically into the SAR:

- Key Recommendation 1b - Texas RE understands this recommendation to be related to Key Recommendation 1a.
- Key Recommendation 4 - Texas RE strongly recommends Key Recommendation 4 be included in the SAR. Consistent with this recommendation, Texas RE believes the drafting team should specify that GOs should implement one or more cold weather preparedness plans "*seasonally prior to the expected onset of winter conditions, and review annually*." The will clarify that timely preparation and implementation of winter weather protections should occur in advance of potential cold weather events, including actions that could require longer lead-times.
- Key Recommendation 8 - Texas RE recommends this be included in the SAR since the Joint Inquiry Report states "this recommendation is a necessary predecessor to Key Recommendation 1h".
- Key Recommendation 9 - Texas RE further recommends the SAR drafting team consider including this recommendation as a planning requirement.

The drafting team may also wish to consider standard implications of Key Recommendations 10-23.

Likes 0	
Dislikes 0	

Response

Michael Johnson - Pacific Gas and Electric Company - 1,3,5 - WECC, Group Name PG&E All Segments

Answer	
Document Name	

Comment

PG&E has participated in the preparation and supports the comments provided by the Edison Electric Institute (EEI) for Q3.

PG&E also supports the "GENERAL COMMENTS" (text and 3 bullets) provided by the EEI related to the "following observations that should be addressed to avoid unintended and possibly harmful consequences to grid reliability".

Likes 0	
Dislikes 0	

Response

Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5, Group Name BC Hydro

Answer	
Document Name	

Comment

BC Hydro notes other extreme weather conditions, such as extremely high temperatures, widespread forest fires and extremely dense smoke, extreme wind and extreme precipitations. BC Hydro suggest that there might be an opportunity to consider these broader impacts in addition to extreme cold weather impacts.

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

In keeping with the NERC standard efficiency review, where possible, a single cold-weather related standard would be more efficient and effective from a creation and implementation perspective. Some items listed would be applicable for all seasons such as the questions (1g, 1i, 1h) and could be easily included in the existing applicable standards.

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Minnkota Power Cooperative Inc. - 1,5 - MRO

Answer	
Document Name	

Comment

MPC supports comments submitted by the MRO NERC Standards Review Forum (NSRF).

Likes 0	
Dislikes 0	

Response

Tommy Curtis - Santee Cooper - 1,3,5,6, Group Name Santee Cooper

Answer	
Document Name	

Comment

Of the 9 recommendations contained in the SAR, 5 have an implementation period that begins before the FERC approved EOP-011-2 Implementation Plan. Is it the intent of the SAR's author to change the approved implementation date of April 1, 2023?

Likes 0	
Dislikes 0	

Response

Alan Kloster - Evergy - 1,3,5,6 - MRO

Answer	
Document Name	

Comment

Evergy supports and incorporates by reference Edison Electric Institute’s (EEI) response to Question 3.

Likes 0	
Dislikes 0	

Response

Donna Wood - Tri-State G and T Association, Inc. - 1,3,5

Answer	
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

The following appear to be discrepancies between the SAR and the FERC - NERC - Regional Entity Staff- Report:

- **Key Recommendation 1a** appears to largely align with SAR Recommendation 1 but the word "protect" appears in SAR Recommendation 1 but not in Key Recommendation 1a. While this word is missing, we agree that its addition makes sense.
- **Key Recommendation 1b** appears to not be fully addressed in the SAR recommendations. While the addition of the work "protect" in SAR Recommendation 1 may have been added to address some of the language in this key recommendation, we specifically do not find any language in the SAR to address "Generator Owner should consider previous freeze-related issues experienced by the generating unit, and any corrective or mitigation actions taken in response. At an interval of time to be determined by the Balancing Authority, the Generator Owner should analyze whether the list of identified cold-weather-critical components and systems remains accurate, and whether any additional freeze protection measures are necessary."
- **Key Recommendation 1c** aligns with the SAR Recommendation 6, however, the implementation timeframe does not align with the recommendations in the Joint Report.
- **Key Recommendation 1d** generally aligns with SAR recommendation 4 but does not require entities to apply the similar corrective action plans (CAPs) to similar equipment or require entities to provide justifications if they have not applied these CAPs to the similar equipment. Additionally, the SAR does not appear to require CAP timeframes.
- **Key Recommendation 1e** aligns with SAR Recommendation 3.
- **Key Recommendation 1f** aligns with SAR Recommendation 2 but the implementation timeframe does not align.
- **Key Recommendation 1g** aligns with SAR Recommendation 5 but the implementation timeframe does not align.
- **Key Recommendation 1h** aligns with SAR Recommendation 8 but the implementation timeframe does not align.
- **Key Recommendation 1i** and SAR Recommendation 7 somewhat align but the NERC draft SAR contains language that potentially expands the scope of this project well beyond what was proposed in the Joint Report. Specifically, the Joint report proposes to take actions that will avoid adversely affecting Bulk Electric System reliability while SAR 7 incorrectly identified the Bulk Power System, which is substantially greater in scope. We also did not see language in the SAR that:
    - Would obligate load shedding entities to request natural gas infrastructure entities to identify critical natural gas facilities; or
    - Would obligate load shedding entities to incorporate into their plans and procedures for protection against manual or automatic load shedding;or
    - Additionally, in the SAR the BA and TOP appear to have obligations that are reserved for the load shedding entities in the Joint Report.
- **Key Recommendation 1j** aligns with SAR Recommendation 9 but the implementation timeframe does not align.
- **Key Recommendation 4** does not appear to be addressed in the SAR.

Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	
Document Name	
Comment	
MidAmerican Energy Company supports EEI and MRO NSRF comments	
Likes 0	
Dislikes 0	
Response	

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	

The NAGF presents the following comments for consideration:

a. The NAGF supports the recommendation that new generation facilities be designed to operate to historical wind chill temperature and precipitation worst-case conditions, but does not believe existing generating units should be required to upgrade equipment to meet these criteria.

b. Generator Owners and Generator Operators should not be required to perform fuel supply risk analysis.

c. Pre-starting generation facilities prior to the onset of cold weather events will help ensure resources are on-line and available to serve load. The proposed actions and sharing of generator information as identified per the nine recommendations will help improve BA/TOP situational awareness of generator response and operation during cold weather events. In addition, it will allow the BAs and TOPs to make better informed decisions for starting generator units prior to cold weather events.

Likes 0	
Dislikes 0	
Response	

Dana Showalter - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	

ERCOT believes the SAR should provide flexibility for the drafting teams to determine where to put these new requirements—whether into existing standards or by creating new standards if necessary—rather than identifying which existing standards should be revised. When a standard is identified, the drafting team should explain why that standard was selected.

With respect to the recommendation that GOs should design their equipment to operate at a certain ambient temperature and for certain weather conditions, ERCOT notes that any standard that imposes this requirement will need to specify what entity will determine the relevant temperature or weather conditions, if the standard itself does not specify the temperature and conditions.

In relation to BA or RC requirements that may arise, ERCOT suggests that the SDT maintain the distinction that normal operations should be addressed in TOP standards while emergency operations should be addressed in EOP standards. Further, any standards that require BAs or RCs to take actions that depend on information provided by GOs, GOPs, TOs, or TOPs, should explicitly state that the action required by the BA or RC is based on the information provided to the BA or RC.

Additionally, ERCOT notes that the standard will need to specify what natural gas facilities are considered "critical natural gas infrastructure," or how that determination will be made.

Likes 0	

Dislikes 0	
Response	
Michele Mihelic - American Clean Power Association - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	

ACP strongly reiterates the points we make in response to 1.b above.

ACP does not believe the recommendation related to retroactivity should be pursued at this time. There is insufficient information and data to inform how to address and effectively implement this recommendation. And, there are implications beyond NERC reliability standards, including to the ability of states to achieve their clean energy goals and regarding compensation for retrofits, which necessitates engagement with a broader universe of stakeholders than those involved in NERC reliability standards. As an interim step, ACP recommends that more detailed information, analysis, and data be developed to better define this approach, along with analysis on the feasibility of retrofits, commercial availability of retrofit options, cost, timeline to implement, potential for generator downtime to install, implications on design parameters for existing facilities etc. so at some point in the future, stakeholders can make a more informed decision on how to approach this recommendation. For example, what are the specific temperatures and weather conditions that need to be considered? How frequently do they occur? How consistent is the data quality across regions? How do they differ by region and by area within a region? Are there any technologically feasible, proven, and commercially available retrofit options? If so, what is the availability of materials, staff etc. to carry out the work? To the extent there are not, what are the barriers? What would be the generator downtime to retrofit? Would generators be at risk of retirement if retrofitting is not economic and, if so, what are the impacts to reliability?

In addition, consideration needs to be given to the operating and design parameters of generators. For example, in some cases and in certain environments a wind turbine that is optimized to operate at extremely high temperatures, may not be able to also be optimized to operate at extremely low temperatures. In such situations, it makes sense to keep the focus on higher temperatures as the generators provide more reliability value than they might in designing them to respond to infrequent and/or historically low temperatures and icing conditions.

To the extent this recommendation remains in the SAR despite ACP and others recommendation to remove it, ACP requests that exceptions be provided from the requirement to retrofit in situations in which a retrofit:

1. Is not technically feasible, proven and commercially available.

2. Would require operating equipment outside its design parameters, which raises potential conflicts with warranties, safety, and regulatory requirements.

Likes 1	Enel Green Power, 5, Johnson Natalie
Dislikes 0	
Response	
Jack Cashin - American Public Power Association - 4	
Answer	
Document Name	
Comment	

To ensure the efficiencies developed during the Standards Efficiency Review (SER) standard training requirements should be maintained in the Personnel Performance, Training and Qualifications (PER) family of standards. APPA concurs and supports the comments submitted by the Large Public Power Council (LPPC).

Likes 0	
Dislikes 0	
Response	

Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
Minnesota Power agrees with MRO's NERC Standards Review Forum (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
BPA supports the comments made by the US Bureau of Reclamation.	
Likes 0	
Dislikes 0	
Response	

Travis Fisher - Electricity Consumers Resource Council (ELCON) - 7	
Answer	
Document Name	
Comment	

Where possible, NERC should take a tiered approach in which reporting requirements and Generator Owner self-assessments are the first step, to be followed by estimates of the cost of any proposed changes, particularly retrofits of existing facilities. Standards should be proposed only after NERC and Generator Owners have a better understanding of the associated costs. NERC should present such cost data to FERC to allow it to assess whether any change in standards is just, reasonable, not unduly discriminatory or preferential, is in the public interest, and satisfies the requirements of Section 215(c) of the Federal Power Act.

Likes 0	
Dislikes 0	

Response

Natalie Johnson - Enel Green Power - 5

Answer	
Document Name	Enel_2021-07_Cold Weather SAR_Comment_Form_112221 Final.docx

Comment

Enel North America, Inc. also recommends a review of obstacles that may prevent cold weather enhancements such as the tariff structures on intermittent resources. In some regions, tariffs penalize generators for station load or parasitic load. Any cold weather enhancement performed on a site will increase its parasitic load.

Additionally, Enel North America, Inc. recommends language be added to ensure that the importance of safety is addressed throughout the updates and changes for cold weather preparedness. For example, as other requirements include statements such as; *unless compliance cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements*.

Lastly, Enel North America, Inc. urges NERC to consider factors such as the scope and time of retrofit work, availability of components and workers, impact of coincident outages, etc. as new reliability standards are developed and implemented. Consideration must be given to the potential unintended consequences such as generators choosing to retire rather than retrofit, generators needing to take outages to complete retrofits, unavailability of parts or labor to complete retrofits, lack of commercially available solutions, etc. Given these factors and potential unintended consequences, it may be necessary for a phased-in implementation approach (addressed in the Implementation Plan) to allow GOs with a large number of generation facilities to implement requirements over time while prioritizing the highest impact changes.

Likes 0	
Dislikes 0	

Response

Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee

Answer	
Document Name	

Comment

IRC SRC asks that the SDT consider the following comments:

· Additional clarity regarding item 1 (page 3 of the SAR)

IRC SRC is concerned about the use of the term ‘protect.’ Some of the examples provided in the Joint Inquiry report for cold-weather-critical components (footnote 261) cannot be ‘protected’ against certain cold weather ambient conditions.

To address this, IRC SRC suggests a language change in the SAR to recognize and allow for this circumstance; i.e. to protect or otherwise provide criteria as to why a cold-weather critical component cannot be protected against certain cold weather ambient conditions.

· Additional clarity surrounding item 4 (pages 3-4 of the SAR)

IRC SRC recommends modifying the recommendation language so that Corrective Action Plans are only developed and implemented when a generating unit experiences an outage, failure to start or derate under the conditions specified with EOP-011-2 Emergency Preparedness and Operations, Requirement R7.3. et al. (or its successors; e.g. if this language is transitioned to an FAC standard) are not met.

· Additional recommendations from the final report that may be included:

(should be included in the current SAR) Recommendation #4: In following EOP-011-2, R7, Generator Owners' plans should specify times for performing inspection and maintenance of freeze protection measures, including at a minimum, the following times: (1) prior to the winter season, (2) during the winter season, and (3) pre-event readiness reviews, to be activated when specific cold weather events are forecast.

(may be considered for a future SDT Project) Recommendation #27: Beyond Recommendation 13 (Generator Owners within ERCOT review potential for units to trip due to low frequency or high rate-of-change of frequency conditions), the team recognized that generating units tripping due to low frequency or high rate-of-change of frequency conditions could occur in the Eastern and Western Interconnections as well. Therefore, the team recommends that FERC, NERC, and the Regional Entities, in cooperation with Generator Owners, study the ERCOT low frequency for protective relay settings associated with generator underfrequency relays, balance of plant relays, and tuning parameters associated with control systems on generating units to trip generating units during low frequency or high rate-of-change of frequency conditions in the other Interconnections, and determine the whether a new Reliability Standard is warranted, or whether other actions can best protect the reliability of the Bulk Electric System.

Also, are there other fuels or infrastructure at jeopardy of curtailment that if cut off can impact electric energy production? Storage? Fuel oil? Coal? If so, the requirement for “critical natural gas infrastructure from manual and automatic load shedding” should be expanded to include any fuel types which rely on electric power for transportation to electric generators. Although natural gas capacity is the focal point of the FERC NERC Joint report, the same principle of not curtailing electric energy to interdependent infrastructure used to supply fuel for electric generation should be applied.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1,3,5,6

Answer	
Document Name	

Comment

Exelon concurs with the comments submitted by the EEI for this question.

Likes 0	

Dislikes 0	

Response

Jessica Lopez - APS - Arizona Public Service Co. - 1,3,5,6

Answer	
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	
Document Name	

Comment

General comments

Question #1 asks which standards should be revised to address the recommendations in the FERC/NERC Joint Inquiry report. Rather than revising existing standards to address all of the recommendations, we believe that a new standard within the Facilities Design, Connections and Maintenance (FAC) standards family would be a better approach to address some of them (suggested title - FAC-0XX-1, Generating Facility Preparedness for Freezing Conditions). Specifically, the GO/GOP recommendations cited in questions 1.a, 1.b, 1.c, 1.d, 1.e and 1.f above could be addressed in this new FAC standard. EOP-011-2 Requirements R7 and R8 could also be pulled into it. This would return EOP-011 to a true "Emergency Operations" standard applicable to the BA, RC, and TOP. The goal of these recommendations, and those previously addressed in Project 2019-06, should be to address the majority of generation issues that can arise during freezing conditions in advance (preventative measures), and to learn from and correct freezing issues that result in unit loss when they occur. Once an emergency operations scenario is entered into as a result of generation loss due to freezing conditions, there may be little the GO/GOP can do in the Real-time Operations time horizon to help preserve/restore the reliability of the bulk electric system. Addressing the GO/GOP recommendations in the EOP-011 standard also casts all cold weather generating issues as being "Emergency" in nature. Emergency operations scenarios should only occur when multiple generating units are impacted. However, each Generator Owner should evaluate all "outages, failures to start, or derates due to freezing" to identify available corrective actions (recommendation cited in 1.d above), even if an isolated event that does not propagate into a system Emergency.

Definition Considerations

Recommendation #2 (1.b) states that "The specified ambient temperature and weather conditions should be based on available extreme temperature and weather data for the generating unit's location, and account for the effects of precipitation and accelerated cooling effect of wind". A definition for "extreme temperature" or "extreme weather" should be considered as an addition to the SAR. The definition should include a frequency of the historical records search, and bound the values with probability…such as: last fifty years of data for the location of the generating unit and within a 98% probability. Without the bounds, some GOs could consider 100 year values, and another 5 year values. The definition of 'extreme' as an adjective is - "existing in a very high degree; going to great or exaggerated lengths; exceeding the ordinary, usual, or expected." (Merriam-Webster). "Extreme", to a *lot of people would not be the upper ends of a ten, twenty, or even a thirty year weather pattern. The SAR should be more specific. It should define extreme frequency (number of years to search for upper and lower conditions).*

Recommendation #9 (1.i) states that "In minimizing the overlap of manual and automatic load shed, the load shed procedures of Transmission Operators, Transmission Owners (TOs) and Distribution Providers (DPs) should separate the circuits that will be used for manual load shed from circuits used for underfrequency load shed (UFLS), undervoltage load shed (UVLS) or serving critical load. UFLS/UVLS circuits should only be used for manual load shed as a last resort and for UFLS circuits, should start with the final stage (lowest frequency)." The SAR drafting team should consider whether a definition of "critical load" needs to be added to the SAR, or whether it will be left to the applicable entities judgement.

Likes 0	
Dislikes 0	

Response

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination

Comments Received Summary

There were 54 sets of responses, including comments from approximately 152 different people from approximately 109 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, 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 the Vice President of Engineering and Standards, Howard Gugel (via email) or at (404) 446-9693.

Consideration of Comments

The Project 2021-07 SAR Drafting Team (SAR DT) thanks all of industry for your time and comments. The SAR DT revised the SAR based on industry comment and the final FERC, NERC, and Regional Entity Staff Report ("Joint Report"). Language was added to the SAR to clearly provide the Standard Drafting Team (SDT) with the flexibility needed to develop practicable Reliability Standards that address the reliability objectives of the recommendations. Due to the similar nature of multiple comments received during the SAR comment period, the SAR DT has chosen to respond to comments in summary format as provided for by section 4.2 of the Standard Processes Manual.

NERC Jurisdiction

The SAR DT received multiple comments regarding the authority of FERC and NERC to make some of the recommendations as standard revisions. Recommendation 1f was of concern and the language around "*design new or retrofit existing generating units*" solicited multiple entity responses. In addition, recommendation 1h also received comments.

The SAR DT recognizes the jurisdictional concerns raised by some entities, but declines to strike any recommendations from the SAR or to offer any opinion on legal issues regarding NERC's jurisdiction under Section 215 of the FPA. It is the opinion of the SAR DT that the SAR provides flexibility to the drafting team to develop NERC Reliability Standards that address the reliability objectives of the recommendations, and the comments will be forwarded to the SDT for their consideration in that context. The SAR DT does not believe it is appropriate for the SAR DT to resolve legal questions regarding NERC's jurisdiction under Section 215 of the FPA.

Standards to be Revised/New Cold Weather Standard

The SAR DT received comments suggesting current standards to revise, multiple suggestions to write a standalone cold weather standard, and suggestions to write a cold weather standard but keep training in existing standards (e.g., PER-006). In addition, comments were received asking for multiple definitions, e.g., critical elements or critical components.

The industry suggestions have been reviewed by the SAR DT and language has been added to the SAR, listing the standards that "should be reviewed by the Standard Drafting Team (SDT) and may be revised to meet the recommendations". If necessary and appropriate, the drafting team may develop a new standard(s) to address all or part of the recommendations. Preference will be given to the EOP or FAC suite of standards based on the industry comments that we received. The suggestion to draft a new cold weather standard while retaining training requirements in existing standards was received from industry multiple times and will be considered by the SDT. The SAR DT has included the "Add, Modify or Retire a Glossary Term" on the SAR to allow the SDT to have discussion of definitions. All comments that propose defining terms shall be forwarded to the SDT for consideration.

The SAR DT received multiple comments containing draft reliability standard language to address the recommendations.

The SAR DT would like to thank entities that included draft reliability standard language within their comments. Although the SAR DT declines to include examples of specific reliability standard language within the SAR, all comments that propose draft reliability standard language to address specific recommendation(s) shall be forwarded to the SDT for consideration.

Specific Language in the Recommendations

Multiple comments were received regarding specific language used in the recommendations listed in the SAR. For example, concerns were raised about recommendation 1a and 1b around "*the use of the term 'protect' in this recommendation. Some of the examples provided (footnote 261) in the Joint Inquiry report for cold-weather-critical components cannot be "protected" against certain cold weather ambient conditions.*" In addition, there was a comment that *"Key Recommendation 1b appears to not be fully addressed in the SAR recommendations.*"

The SAR DT recognizes the concerns regarding specific language (e.g., protect) used in the recommendations included in the initial SAR. These concerns will be forwarded on to the SDT for consideration when drafting actual standard language.

The recommendations in the initial SAR were sourced from the preliminary findings and recommendations presentation, which included nine recommendations. In the final Joint Report, recommendation 1 was expanded to be Key Recommendation 1a and 1b. In addition, implementation time frames for recommendations 1c, 1f, 1g, 1h and 1j were adjusted from the preliminary presentation to the final report. The SAR DT has updated the SAR to use the ten recommendations and the implementation timeframes included in the final Joint Report. In some cases, the recommendation language in the final Joint Report has been modified from the recommendation language in the preliminary presentation and the modified recommendation language (e.g., identify and implement freeze protection measures) addresses many of the concerns voiced in the comments provided for the initial SAR. The SAR DT discussed the recommendations and the use of the word "prioritize" instead of protect in relation to recommendation 1i.

The SAR DT retained the recommendation language from the final Joint Report in full. Language was added to the SAR to clearly provide the SDT with the flexibility needed to develop practicable Reliability Standards that address the reliability objective of the recommendations.

Impact on the 2019-06 Standards

A comment was received stating that the implementation period for FERC approved EOP-011-2 is set for April 1, 2023 and asked if the SAR would change that approved implementation date.

The standards drafted by the 2019-06 SDT will be effective April 1, 2023. The effective date of the standards revised or drafted by this drafting team will have an effective date based on the implementation plan developed by the 2021-07 SDT and approved by FERC.

Additional comments suggested that this project, 2021-07, be delayed until the 2019-06 approved standards are in effect.

Project 2021-07 has a phase one deadline of September 30, 2022 and cannot be delayed until the 2019-06 effective date of April 1, 2023. NERC's rules do not prohibit multiple projects to work concurrently on the same standards or revisions to standards not yet in effect. The drafting teams coordinate and take into account the work of other projects.

Multiple comments received suggested retiring EOP-011 R7 and R8 and using the language in different standards to meet the SAR for this project.

The 2021-07 team will build upon and compliment the work done by the 2019-06 drafting team to address the reliability objectives contained in the Joint Report. The suggestion of retiring requirements will be forwarded to the SDT.

The SAR DT received comments that additional recommendations are in the Joint Report that are not addressed in the SAR. Specifically, "*In addition, it was noted that Key Recommendation 4 does not appear in the SAR.*"

The Joint Report list the recommendations that should be addressed through NERC standards revisions in Recommendation 1 and its subparts. Recommendation 4 is intended to provide guidance to the Generator Owner for inclusion in their plan, not a revision to the standard.

Cost Impact

The SAR comment form contained a question around cost effective options and alternatives to address the recommendations in the Report. Multiple comments were received, specifically recommendation 1f

was of concern and the language around "*design new or retrofit existing generating units*" solicited multiple entity responses.

The Project 2021-07 Extreme Cold Weather SAR DT recognizes that numerous industry comments to the proposed SAR identified concerns with the technical and economic implications of new or revised NERC standards which may result from the Joint Report key recommendations. Such concerns include the practicality of some technical solutions as well as the potential for forced retirement of generating assets if mandatory actions prove uneconomic. These concerns are recognized; cost and technical feasibility are important components of the standards drafting process. The SDT will be guided by all applicable NERC processes and principles, including the Market Interface Principles.

Expanding Beyond Cold Weather

The SAR DT received a comment "*that there might be an opportunity to consider these (extremely high temperatures, widespread forest fires and extremely dense smoke, wind and precipitations) broader impacts in addition to extreme cold weather impacts.*"

The Joint Report highlights four cold weather events impacting reliability: 2011 ERCOT and Southwest, 2014 Polar Vortex, 2018 South Central U.S., and the most recent February 2021 cold weather in Texas and the South-Central U.S. These events show how impactful extreme cold weather can be. These recent events do not discount events such as forest fires and extreme high temperatures and their potential effects. If these types of events prove to be at the same level of impact, they can be addressed by future drafting teams. However, at this time, in alignment with the SAR, the drafting team will address the specific recommendations in the Joint Report.

SAR Recommendation Grouping

The SAR DT received comments suggesting the recommendations found in the Report be grouped based on concept. The following groupings were suggested:

Generator Owner, Generator Operator and Balancing Authority SDT Project	Load Shedding and Demand Response SDT Project	Future SDT Project
Item 1 (page 3 of the SAR)	Item 7 (page 4 of the SAR)	Item 2 (page 3 of the SAR);
Item 3 (page 3 of the SAR)	Item 8 (page 4 of the SAR)	
Item 4 (pages 3-4 of the SAR)	Item 9 (page 4 of the SAR)	
Item 5 (page 4 of the SAR)		
Item 6 (page 4 of the SAR)		

The SAR DT has organized the recommendations into two phases based on the timeframes listed in the Joint Report. Only one drafting team has been seated, so this drafting team will take on the entirety of the recommendations. The SDT is aware of the NERC Standards Efficiency Review project and will make every effort to align our work with the intent of that project.

Unofficial Nomination Form

Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination
Standard Authorization Request Drafting Team

Do not use this form for submitting nominations. Use the electronic form to submit nominations for **Project 2021-07 Cold Weather Grid Operations, Preparedness, and Coordination** Standard Authorization Request (SAR) drafting team members by **8 p.m. Eastern, Tuesday, December 21, 2021.** This unofficial version is provided to assist nominees in compiling the information necessary to submit the electronic form.

Additional information is available on the project page. If you have questions, contact Senior Standards Developer, Alison Oswald (via email), or at 404-446-9668.

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

Previous drafting or review team experience is beneficial, but not required. A brief description of the desired qualifications, expected commitment, and other pertinent information is included below.

Background
The Project Scope will address nine recommendations for new or enhanced NERC Reliability Standards proposed by the Federal Energy Regulatory Commission (FERC), NERC, and Regional Entity Joint Staff Inquiry into the February 2021 Cold Weather Grid Operations[1].

From February 8 - 20, 2021, extreme cold weather and precipitation affected the south central United States. Large numbers of generating units experienced outages, derates, or failures to start, resulting in energy and transmission emergencies (referred to as “the Event”). The total Event firm load shed was the largest controlled firm load shed event in U.S. history and was the third largest in quantity of outaged megawatts (MW) of load after the August 2003 northeast blackout and the August 1996 west coast blackout.

The NERC Board of Trustees (Board) issued a resolution in November 2021 for the development of standards under this project be completed in accordance with the staged timelines recommended by the joint inquiry team, as follows:

- New and revised Reliability Standards to be submitted for regulatory approval before Winter 2022/2023: development completed by September 30, 2022 for the Board’s consideration in October 2022;

[1] February 2021 Cold Weather Grid Operations: Preliminary Findings and Recommendations - Full Presentation | Federal Energy Regulatory Commission (ferc.gov)

- New and revised Reliability Standards to be submitted for regulatory approval before Winter 2023/2024: development completed by September 30, 2023 for the Board's consideration in October 2023.

Standards affected: BAL, EOP, IRO, TOP, or Other Standards as Identified in the SAR
Drafting Team activities include participation in technical conferences, stakeholder communications and outreach events, periodic drafting team meetings and conference calls. To meet the deadlines set in the SAR and by the NERC Board, the team will meet regularly, up to twice a week on conference calls, with face-to-face meetings scheduled as the members' schedule and the pandemic allow, to meet the agreed-upon timeline the drafting team sets forth.

For this project, NERC is seeking individuals who possess experience with cold weather preparation, such as through performing or developing processes to address the following tasks:

- Performing inspection and identification of critical components on generating units that are susceptible to freezing and retrofitting generating units to operate at extreme temperatures;
- Conducting winter-specific and plant-specific operator awareness and preparedness training;
- Determining the causes of outages, failure to start or derates for generating units during cold weather conditions, and developing and implementing corrective action plans;
- Determining and communicating with the appropriate entities a generating unit's capacity during forecasted cold weather, including the accelerated cooling effect of wind;
- Developing or implementing Balancing Authority operating plans for contingency reserves and to mitigate capacity and energy emergencies;
- Developing or implementing load shed procedures of Transmission Operators, Transmission Owners, Distribution Providers and Balancing Authorities;
- Other tasks for the reliable planning and operation of the BPS during cold weather conditions.

Name:	
Organization:	
Address:	
Telephone:	
Email:	

Please briefly describe your experience and qualifications to serve on the requested SAR 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):

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[2] 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:		Email:	
Name:		Telephone:	
Organization:		Email:	

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:	

[2] These functions are defined in the NERC Functional Model, which is available on the NERC web site.

Standards Announcement

Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination

Nomination Period Open through December 21, 2021

Now Available

Nominations are being sought for Standard Authorization Request (SAR) drafting team members through **8 p.m. Eastern, Tuesday, December 21, 2021**.

Use the electronic form to submit a nomination. Contact Linda Jenkins 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.

This team is will meet regularly, up to twice a week on conference calls, with face-to-face meetings scheduled as the members' schedule and the pandemic allow, to meet the agreed-upon timeline the drafting team sets forth. Team members may also have side projects, either individually or by sub-group, to present for discussion and review. Lastly, an important component of the team effort is outreach. Members of the team will be expected to conduct industry outreach during the development process to support a successful ballot.

Previous drafting 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 SAR drafting team in February 2022. 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 Senior Standards Developer, Alison Oswald (via email) or at 404-446-9668. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify "Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination 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

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:	Extreme Cold Weather Grid Operations, Preparedness, and Coordination		
Date Submitted:	10/6/2021 (Revised 02/09/2022)		
SAR Requester			
Name:	Steven Noess & Kiel Lyons (Revised by the 2021-07 SAR Drafting Team)		
Organization:	NERC, as members of the 2021 FERC, NERC, Regional Entity Joint Inquiry into 2021 Cold Weather Grid Operations		
Telephone:	(404) 446-9691 (404) 446-9665	Email:	Steven.Noess@nerc.net Kiel.Lyons@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?):			
To enhance reliability of the BES through improved operations, preparedness, and coordination during extreme weather, as described by the Federal Energy Regulatory Commission (FERC), NERC, and Regional Entity Joint Staff Inquiry into the February 2021 extreme cold weather event. See The February 2021 Cold Weather Outages in Texas and the South Central United States | FERC, NERC and Regional Entity Staff Report | Federal Energy Regulatory Commission (referred to as "the Report"). From February 8 through 20, 2021, extreme cold weather and precipitation caused large numbers of generating units to experience outages, derates or failures to start, resulting in energy and transmission emergencies (referred to as "the Event"). The total Event firm load shed was the largest controlled firm load shed event in U.S. history and was the third largest in quantity of outaged megawatts (MW) of load after the August 2003 northeast blackout and the August 1996 west coast blackout. The Event was most			

Requested information
severe from February 15 through February 18, 2021, and it contributed to power outages affecting millions of electricity customers throughout the regions of ERCOT, SPP and MISO South. Extreme cold weather has repeatedly jeopardized the reliable operation of the bulk-power system. The February 2021 event is the fourth in the past 10 years which jeopardized bulk-power system reliability. In February 2011, an arctic cold front impacted the southwest U.S. and resulted in numerous generation outages, natural gas facility outages and emergency power grid conditions with need for firm customer load shed. In January 2014, a polar vortex affected Texas, central and eastern U.S. This 2014 event also triggered many generation outages, natural gas availability issues and resulted in emergency conditions including load shed. And in January 2018, an arctic high-pressure system and below average temperatures in the south-central U.S. resulted in many generation outages and voluntary load management measures.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
The new or revised NERC Reliability Standards are intended to address reliability-related findings from the Report.
Project Scope (Define the parameters of the proposed project):
The Project Scope will address the reliability objectives in the ten recommendations from Key Recommendation 1 for new or enhanced NERC Reliability Standards proposed in the Report, which are listed below in the Detailed Description. Considering the topic areas, the submitters contemplate that the Standards Committee may convene one or more standard drafting teams to address collectively the recommendations in the Report.
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[1] 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):
Technical justification and additional information, including analysis, support, and related recommendation information is found within the Report. The proposed deliverable is new or revised Reliability Standards to enhance reliability during extreme cold weather. Any proposed NERC Reliability Standards shall be cost-effective, consensus based standards to address the reliability objectives in the following recommendations from the Report. Key Recommendation 1, from the inquiry team, contains ten recommendations which are designed to support the reliable operation of the bulk power system during cold weather conditions and/or stressed system conditions through revisions to NERC Reliability Standards. These recommendations each have a recommended implementation timeframe. Within the context of the Report, the term “implementation timeframes” refers to the period of time in which the new and/or revised Reliability Standards that

[1] 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.

Requested information
address the recommendations have been completed through the NERC Reliability Standards Development Process and are proposed (filed) for approval with FERC. For the purpose of the SAR, the recommendations will have an associated Standard Development Timeframe. The recommendations will be addressed through the Standard development process in two phases. Phase 1 Standards Development Timeframe means that the proposed Reliability Standards have passed industry ballot by September 30, 2022, are submitted to NERC Board in October 2022 and are filed by November 1, 2022 with FERC and addresses recommendations associated with “Winter 2022/2023” from the Report. The following recommendations will be addressed during Phase 1: 1. Generator Owners that experience outages, failures to start, or derates due to freezing are to review the generating unit’s outage, failure to start, or derate and develop and implement a corrective action plan (CAP) for the identified equipment, and evaluate whether the CAP applies to similar equipment for its other generating units. Based on the evaluation, the Generator Owner will either revise its cold weather preparedness plan to apply the CAP to the similar equipment, or explain in a declaration (a) why no revisions to the cold weather preparedness plan are appropriate, and (b) that no further corrective actions will be taken. The Standards Drafting Team should specify the specific timing for the CAP to be developed and implemented after the outage, derate or failure to start, but the CAP should be developed as quickly as possible, and be completed by no later than the beginning of the next winter season. (Report Key Recommendation 1d) 2. To revise EOP-011-2, R8, to require Generator Owners and Generator Operators are to conduct annual unit-specific cold weather preparedness plan training. (Report Key Recommendation 1e) 3. To require Generator Owners to retrofit existing generating units, and when building new generating units, to design them, to operate to a specified ambient temperature and weather conditions (e.g., wind, freezing precipitation). The specified ambient temperature and weather conditions should be based on available extreme temperature and weather data for the generating unit’s location. (Report Key Recommendation 1f) 4. In minimizing the overlap of manual and automatic load shed, the load shed procedures of Transmission Operators, Transmission Owners (TOs) and Distribution Providers (DPs) should separate the circuits that will be used for manual load shed from circuits used for underfrequency load shed (UFLS)/undervoltage load shed (UVLS) or serving critical load. UFLS/UVLS circuits should only be used for manual load shed as a last resort and should start with the final stage (lowest frequency). (Report Key Recommendation 1j) Phase 2 Standards Development Timeframe means that the proposed Reliability Standards have passed industry ballot by September 30, 2023, are submitted to NERC Board in October 2023 and are filed by November 1, 2023 with FERC and addresses recommendations associated with “Winter 2023/2024” from the Report. The following recommendations will be addressed during Phase 2:

Requested information
5. To require Generator Owners to identify cold-weather-critical components and systems for each generating unit. Cold-weather-critical components and systems are those which are susceptible to freezing or otherwise failing due to cold weather, and which could cause the unit to trip, derate, or fail to start. (Report Key Recommendation 1a) 6. To require Generator Owners to identify and implement freeze protection measures for the cold-weather-critical components and systems. The Generator Owner should consider previous freeze-related issues experienced by the generating unit, and any corrective or mitigation actions taken in response. At an interval of time to be determined by the Balancing Authority, the Generator Owner should analyze whether the list of identified cold-weather-critical components and systems remains accurate, and whether any additional freeze protection measures are necessary. (Report Key Recommendation 1b) 7. To revise EOP-011-2, R7.3.2, to require Generator Owners to account for the effects of precipitation and the accelerated cooling effect of wind when providing temperature data. (Report Key Recommendation 1c) 8. The Reliability Standards should be revised to provide greater specificity about the relative roles of the Generator Owners, Generator Operators and Balancing Authorities in determining the generating unit capacity that can be relied upon during “local forecasted cold weather,” in TOP-003-5: -Based on its understanding of the “full reliability risks related to the contracts and other arrangements [Generator Owners/Generator Operators] have made to obtain natural gas commodity and transportation for generating units,” each Generator Owner/Generator Operator should be required to provide the Balancing Authority with data on the percentage of the generating unit’s capacity that the Generator Owner/Generator Operator reasonably believes the Balancing Authority can rely upon during the “local forecasted cold weather”. -Each Balancing Authority should be required to use the data provided by the Generator Owner/Generator Operator, combined with its evaluation, based on experience, to calculate the percentage of total generating capacity that it can rely upon during the “local forecasted cold weather,” and share its calculation with the Reliability Coordinator. -Each Balancing Authority should be required to use its calculation of the percentage of total generating capacity that it can rely upon to “prepare its analysis functions and Real-time monitoring,” and to “manag[e] generating resources in its Balancing Authority Area to address . . . fuel supply and inventory concerns” as part of its Capacity and Energy Emergency Operating Plans. (Report Key Recommendation 1g) 9. To require Balancing Authorities’ operating plans (for contingency reserves and to mitigate capacity and energy emergencies) to prohibit use for demand response of critical natural gas infrastructure loads. (Report Key Recommendation 1h) 10. To protect critical natural gas infrastructure loads from manual and automatic load shedding (to avoid adversely affecting Bulk Electric System reliability):

Requested information
-To require Balancing Authorities' and Transmission Operators' (TOPs) provisions for operator-controlled manual load shedding to include processes for identifying and protecting critical natural gas infrastructure loads in their respective areas; -To require Balancing Authorities', Transmission Operators', Planning Coordinators', and Transmission Planners' respective provisions and programs for manual and automatic (e.g., underfrequency load shedding, undervoltage load shedding) load shedding to protect identified critical natural gas infrastructure loads from manual and automatic load shedding by manual and automatic load shed entities within their footprints; -To require manual and automatic load shed entities to distribute criteria to natural gas infrastructure entities that they serve and request the natural gas infrastructure entities to identify their critical natural gas infrastructure loads; and -To require manual and automatic load shed entities to incorporate the identified critical natural gas infrastructure loads into their plans and procedures for protection against manual and automatic load shedding. (Report Key Recommendation 1i) During the SAR process, the SAR DT discussed all recommendations. Proposed language for the Standard Drafting Team (SDT) to consider during the standard revision phase was discussed for recommendation 1f, 1g, 1i, and 1j. The SAR DT decided to leave the recommendations as stated in the Report, and allow the SDT to determine the appropriate language to address the reliability objectives in all the recommendations. Therefore, the SDT should also review comments and suggestions submitted in the SAR comment period when considering revisions. Industry comments suggest the following Reliability Standards should be reviewed by the SDT and may be revised to meet the recommendations from the Report: BAL-002, EOP-004, EOP-011, , FAC-001, FAC-002, FAC-008, FAC-011, FAC-014, IRO-010, MOD-025, MOD-032, PER-005, PER-006, PRC-006, PRC-010, TOP-001, TOP-002, TOP-003, and TPL-001. Additionally, based on industry comment, if necessary and appropriate, the drafting team may develop a new standard(s) to address all or part of the recommendations and preference would be given to the FAC or EOP suite of standards.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Unknown.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
The BES facilities impacted by this proposed project will all have unique characteristics including fuel type, location, design, construction, etc. These unique characteristics may need to be addressed during drafting to achieve the intended enhancements to reliability.
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

Requested information
Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Reliability Coordinator, Balancing Authority, Transmission Operator, Transmission Owner, Transmission Planner, Planning Coordinator, Distribution Provider, Generator Operator, and Generator Owner
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
The Report was publicly noticed by both FERC and NERC.
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)?
The proposed Reliability Standards are intended to build (replace, supplement, etc.) upon the requirements in EOP-011-2, IRO-010-4, and TOP-003-5 that were developed by Project 2019-06, and which for U.S. entities, were approved by FERC in August 2021. Additionally, several recommendations build on existing Standards related to load shedding and the development and implementation of UFLS and UVLS programs (e.g. EOP-011-2, PRC-006-5, and PRC-010-2). These Standards should be reviewed to ensure any conflicts, or overlap with current requirements, are mitigated. The Standard Drafting team should coordinate with other projects impacting the same standards which might include 2020-05, 2021-01, 2021-06, 2021-08 and 2022-02.
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.
There have been several recommendations and guidelines that have developed over the prior noted events, but the Event illustrates that NERC Reliability Standards are needed.

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.

[2] 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.

Reliability Principles	
☒	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
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	

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
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

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.

<table>
<tr><th colspan="4">Requested information</th></tr>
<tr><td>SAR Title:</td><td colspan="3">Extreme Cold Weather Grid Operations, Preparedness, and Coordination</td></tr>
<tr><td>Date Submitted:</td><td colspan="3">10/6/2021 (Revised 02/09/2022)</td></tr>
<tr><td colspan="4">SAR Requester</td></tr>
<tr><td>Name:</td><td colspan="3">Steven Noess & Kiel Lyons (Revised by the 2021-07 SAR Drafting Team)</td></tr>
<tr><td>Organization:</td><td colspan="3">NERC, as members of the 2021 FERC, NERC, Regional Entity Joint Inquiry into 2021 Cold Weather Grid Operations</td></tr>
<tr><td>Telephone:</td><td>(404) 446-9691
(404) 446-9665</td><td>Email:</td><td>Steven.Noess@nerc.net
Kiel.Lyons@nerc.net</td></tr>
<tr><td colspan="4">SAR Type (Check as many as apply)</td></tr>
<tr><td colspan="2">☒ New Standard
☒ Revision to Existing Standard
☒ Add, Modify or Retire a Glossary Term
~~☐~~ ☒ Withdraw/retire an Existing Standard</td><td colspan="2">☐ Imminent Action/ Confidential Issue (SPM Section 10)
~~☐~~ ☒ Variance development or revision
☐ Other (Please specify)</td></tr>
<tr><td colspan="4">Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)</td></tr>
<tr><td colspan="2">☒ Regulatory Initiation
☐ Emerging Risk (Reliability Issues Steering Committee) Identified
☐ Reliability Standard Development Plan</td><td colspan="2">☐ NERC Standing Committee Identified
☐ Enhanced Periodic Review Initiated
☐ Industry Stakeholder Identified</td></tr>
<tr><td colspan="4">Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):</td></tr>
<tr><td colspan="4">To enhance reliability of the BES through improved operations, preparedness, and coordination during extreme weather, as described by the Federal Energy Regulatory Commission (FERC), NERC, and Regional Entity Joint Staff Inquiry into the February 2021 ~~Cold Weather Grid Operations. See https://www.ferc.gov/media/february-2021-cold-weather-grid-operations-preliminary-findings-and-recommendations-full.~~ extreme cold weather event. See The February 2021 Cold Weather Outages in Texas and the South Central United States | FERC, NERC and Regional Entity Staff Report | Federal Energy Regulatory Commission (referred to as “the Report”).

From February 8 through 20, 2021, extreme cold weather and precipitation caused large numbers of generating units to experience outages, derates or failures to start, resulting in energy and transmission emergencies (referred to as “the Event”). The total Event firm load shed was the largest controlled firm load shed event in U.S. history and was the third largest in quantity of outaged megawatts (MW) of load</td></tr>
</table>

Requested information
after the August 2003 northeast blackout and the August 1996 west coast blackout. The Event was most severe from February 15 through February 18, 2021, and it contributed to power outages affecting millions of electricity customers throughout the regions of ERCOT, SPP and MISO South. Extreme cold weather ~~is a common occurrence, and it has~~has repeatedly jeopardized the reliable operation of the bulk-power system. The February 2021 event is the fourth in the past 10 years which jeopardized bulk-power system reliability. In February 2011, an arctic cold front impacted the southwest U.S. and resulted in numerous generation outages, natural gas facility outages and emergency power grid conditions with need for firm customer load shed. In January 2014, a polar vortex affected Texas, central and eastern U.S. This 2014 event also triggered many generation outages, natural gas availability issues and resulted in emergency conditions including ~~voluntary~~ load shed. And in January 2018, an arctic high-pressure system and below average temperatures in the south-central U.S. resulted in many generation outages and ~~the need for~~ voluntary load ~~shed emergency~~management measures.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
The new or revised ~~reliability standards~~NERC Reliability Standards are intended to address reliability-related findings from the ~~2021 joint inquiry, which in many cases are consistent with prior reports' recommendations~~Report.
Project Scope (Define the parameters of the proposed project):
The Project Scope will address ~~nine~~the reliability objectives in the ten recommendations from Key Recommendation 1 for new or enhanced NERC Reliability Standards proposed ~~by the Federal Energy Regulatory Commission (FERC), NERC, and Regional Entity Joint Staff Inquiry into the February 2021 Cold Weather Grid Operations. The preliminary findings and recommendations of that joint inquiry were presented at~~in the ~~September 23, 2021, (FERC) Open Commission Meeting.~~Report, which are listed below in the Detailed Description. Considering the topic areas, the submitters contemplate that the Standards Committee may convene one or more standard drafting teams to address collectively the recommendations in the ~~joint inquiry report.~~ ~~The drafting team(s) should also consider the final report of the joint inquiry when it is released in late 2021, as it will contain additional context and analysis that will build upon the preliminary findings and recommendations. While the inquiry team does not anticipate material changes to the Reliability Standards Recommendations or basis for them provided in the preliminary presentation, the final SAR should reflect the final recommendations in the joint inquiry report.~~ Report.

Requested information
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[1] 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):
Technical justification and additional information, including analysis, support, and related recommendation information is found within the ~~work of the FERC, NERC, Regional Entity Joint Staff Inquiry~~Report. The proposed deliverable is new or revised Reliability Standards to enhance reliability during extreme cold weather. Any proposed NERC Reliability Standards shall be cost-effective, consensus based standards to address the reliability objectives in the following recommendations from the Report. ~~The specific recommendations from the inquiry team have recommended "implementation timeframes," which means in this context that the new and/or revised Reliability Standards that address the recommendation have been completed through the NERC Reliability Standards Development Process and are proposed (filed) for approval within the timeframes listed within the recommendations. For these recommendations, "Implementation Timeframe" means that the proposed Reliability Standards are complete and filed by November 1, 2022, for the Winter 2022/2023 timeframes and by November 1, 2023 for the Winter 2023/2024 timeframes. Each Reliability Standards recommendation below is accompanied by one of those two implementation timeframes.~~ ~~There are nine recommendations each of which is~~Key Recommendation 1, from the inquiry team, contains ten recommendations which are designed to support the reliable operation of the bulk power system during cold weather conditions and/or stressed system conditions~~, with associated timeframes as described above:~~ through revisions to NERC Reliability Standards. These recommendations each have a recommended implementation timeframe. Within the context of the Report, the term "implementation timeframes" refers to the period of time in which the new and/or revised Reliability Standards that address the recommendations have been completed through the NERC Reliability Standards Development Process and are proposed (filed) for approval with FERC. ~~Generator Owners are to identify and protect~~ For the purpose of the SAR, the recommendations will have an associated Standard Development Timeframe. The recommendations will be addressed through the Standard development process in two phases. Phase 1 Standards Development Timeframe means that the proposed Reliability Standards have passed industry ballot by September 30, 2022, are submitted to NERC Board in October 2022 and are filed by November 1, 2022 with FERC and addresses recommendations associated with "Winter 2022/2023" from the Report. The following recommendations will be addressed during Phase 1:

[1] 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.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Requested information
1. Generator Owners that experience outages, failures to start, or derates due to freezing are to review the generating unit's outage, failure to start, or derate and develop and implement a corrective action plan (CAP) for the identified equipment, and evaluate whether the CAP applies to similar equipment for its other generating units. Based on the evaluation, the Generator Owner will either revise its cold weather preparedness plan to apply the CAP to the similar equipment, or explain in a declaration (a) why no revisions to the cold weather preparedness plan are appropriate, and (b) that no further corrective actions will be taken. The Standards Drafting Team should specify the specific timing for the CAP to be developed and implemented after the outage, derate or failure to start, but the CAP should be developed as quickly as possible, and be completed by no later than the beginning of the next winter season. (Report Key Recommendation 1d) 2. To revise EOP-011-2, R8, to require Generator Owners and Generator Operators are to conduct annual unit-specific cold weather preparedness plan training. (Report Key Recommendation 1e) 3. To require Generator Owners to retrofit existing generating units, and when building new generating units, to design them, to operate to a specified ambient temperature and weather conditions (e.g., wind, freezing precipitation). The specified ambient temperature and weather conditions should be based on available extreme temperature and weather data for the generating unit's location. (Report Key Recommendation 1f) 4. In minimizing the overlap of manual and automatic load shed, the load shed procedures of Transmission Operators, Transmission Owners (TOs) and Distribution Providers (DPs) should separate the circuits that will be used for manual load shed from circuits used for underfrequency load shed (UFLS)/undervoltage load shed (UVLS) or serving critical load. UFLS/UVLS circuits should only be used for manual load shed as a last resort and should start with the final stage (lowest frequency). (Report Key Recommendation 1j) Phase 2 Standards Development Timeframe means that the proposed Reliability Standards have passed industry ballot by September 30, 2023, are submitted to NERC Board in October 2023 and are filed by November 1, 2023 with FERC and addresses recommendations associated with "Winter 2023/2024" from the Report. The following recommendations will be addressed during Phase 2: ~~1.~~5. To require Generator Owners to identify cold-weather-critical components and systems for each generating unit. Cold-weather-critical components and systems are those which are susceptible to freezing or otherwise failing due to cold weather, and which could cause the unit to trip, derate, or fail to start. ~~**(Implementation Timeframe before Winter 2023/2024).**~~(Report Key Recommendation 1a) 6. To require Generator Owners ~~are~~ to ~~design new or retrofit existing~~ identify and implement freeze protection measures for the cold-weather-critical components and systems. The Generator Owner should consider previous freeze-related issues experienced by the generating ~~units to operate to a specified ambient temperature and weather conditions (e.g., wind, freezing precipitation). The specified ambient temperature and~~ unit, and any corrective or mitigation

Requested information
actions taken in response. At an interval of time to be determined by the Balancing Authority, the Generator Owner should analyze whether the list of identified cold-weather~~ conditions should be based on available extreme temperature and weather data for the generating unit's location,~~ critical components and systems remains accurate, and whether any additional freeze protection measures are necessary. (Report Key Recommendation 1b) ~~2.~~7. To revise EOP-011-2, R7.3.2, to require Generator Owners to account for the effects of precipitation and the accelerated cooling effect of wind~~. (Implementation Timeframe before Winter 2023/2024).~~ when providing temperature data. (Report Key Recommendation 1c) ~~3. Generator Owners and Generator Operators are to conduct annual unit-specific cold weather preparedness plan training. (Implementation Timeframe before Winter 2022/2023).~~ ~~4. Generator Owners that experience outages, failures to start, or derates due to freezing are to review the generating unit's outage, failure to start, or derate and develop and implement a corrective action plan for the identified equipment, and evaluate whether the plan applies to similar equipment for its other generating units. (Implementation Timeframe before Winter 2022/2023).~~ ~~5.~~8. The Reliability Standards should be revised to provide greater specificity about the relative roles of the Generator Owners, Generator Operators and Balancing Authorities in determining the generating unit capacity that can be relied upon during "local forecasted cold weather," ~~which is language from the revised Reliability Standard~~in TOP-003-5~~, R2.3.~~: -~~Each~~Based on its understanding of the "full reliability risks related to the contracts and other arrangements [Generator Owners/Generator Operators] have made to obtain natural gas commodity and transportation for generating units," each Generator Owner/Generator Operator should be required to provide the Balancing Authority with data on the percentage of the ~~total~~ generating ~~unit~~unit's capacity that the Generator Owner/Generator Operator reasonably believes the Balancing Authority can rely upon during the "local forecasted cold weather~~,~~" ~~including reliability risks related to natural gas fuel contracts."~~. -Each Balancing Authority should be required to use the data provided by the Generator Owner/Generator Operator, combined with its evaluation, based on experience, to calculate the percentage of ~~each individual~~total generating~~ unit's total~~ capacity that it can rely upon during the "local forecasted cold weather," and share its calculation with the Reliability Coordinator. -Each Balancing Authority should be required to use ~~that~~its calculation of the percentage of total generating capacity that it can rely upon to "prepare its analysis functions and Real-time monitoring," and to "manag[e] generating resources in its Balancing Authority Area to address . . . fuel supply and inventory concerns" as part of its Capacity and Energy Emergency Operating Plans. (Report Key Recommendation 1g) ~~(Implementation Timeframe before Winter 2022/2023).~~ ~~6. In EOP-011-2, R7.3.2, Generator Owners are to account for the effects of precipitation and accelerated cooling effect of wind when providing temperature data. (Implementation Timeframe before Winter 2022/2023).~~

Requested information
9. To require Balancing Authorities' operating plans (for contingency reserves and to mitigate capacity and energy emergencies) to prohibit use for demand response of critical natural gas infrastructure loads. (Report Key Recommendation 1h) 10. To protect critical natural gas infrastructure loads from manual and automatic load shedding ~~in order~~ (to avoid adversely affecting ~~bulk-power system~~Bulk Electric System reliability~~,~~): -To require Balancing Authorities' and Transmission Operators' (TOPs) provisions for operator-controlled manual load shedding ~~are~~ to include processes for identifying and protecting critical natural gas infrastructure loads in their respective areas~~from firm load shed. Critical natural gas infrastructure loads are natural gas production, processing and intrastate and interstate pipeline facility loads which, if de-energized, could adversely affect the provision of natural gas to bulk-power system natural gas-fired generation.~~ ~~**(Implementation Timeframe before Winter 2023/2024).**~~; ~~7.~~ -To require Balancing Authorities' ~~operating plans (for contingency reserves~~, Transmission Operators', Planning Coordinators', and Transmission Planners' respective provisions and programs for manual and automatic (e.g., underfrequency load shedding, undervoltage load shedding) load shedding to ~~mitigate capacity and energy emergencies) are to prohibit use of~~protect identified critical natural gas infrastructure loads ~~for demand response.~~ ~~**(Implementation Timeframe before Winter 2022/2023).**~~ ~~In minimizing the overlap of~~ from manual and automatic load shedding by manual and automatic load shed~~, the load shed procedures of Transmission Operators, Transmission Owners (TOs) and Distribution Providers (DPs) should separate the circuits that will be used for manual load shed from circuits used for underfrequency load shed (UFLS), undervoltage load shed (UVLS) or serving critical load. UFLS/UVLS circuits should only be used for manual load shed as a last resort and for UFLS circuits, should start with the final stage (lowest frequency).~~ ~~**(Implementation Timeframe before Winter 2023/2024).**~~ entities within their footprints; -To require manual and automatic load shed entities to distribute criteria to natural gas infrastructure entities that they serve and request the natural gas infrastructure entities to identify their critical natural gas infrastructure loads; and -To require manual and automatic load shed entities to incorporate the identified critical natural gas infrastructure loads into their plans and procedures for protection against manual and automatic load shedding. (Report Key Recommendation 1i) During the SAR process, the SAR DT discussed all recommendations. Proposed language for the Standard Drafting Team (SDT) to consider during the standard revision phase was discussed for recommendation 1f, 1g, 1i, and 1j. The SAR DT decided to leave the recommendations as stated in the Report, and allow the SDT to determine the appropriate language to address the reliability objectives in all the recommendations. Therefore, the SDT should also review comments and suggestions submitted in the SAR comment period when considering revisions.

Requested information
Industry comments suggest the following Reliability Standards should be reviewed by the SDT and may be revised to meet the recommendations from the Report: BAL-002, EOP-004, EOP-011, , FAC-001, FAC-002, FAC-008, FAC-011, FAC-014, IRO-010, MOD-025, MOD-032, PER-005, PER-006, PRC-006, PRC-010, TOP-001, TOP-002, TOP-003, and TPL-001. Additionally, based on industry comment, if necessary and appropriate, the drafting team may develop a new standard(s) to address all or part of the recommendations and preference would be given to the FAC or EOP suite of standards.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Unknown.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
The BES facilities impacted by this proposed project will all have unique characteristics including fuel type, location, design, construction, etc. These unique characteristics may need to be addressed during drafting to achieve the intended enhancements to reliability.
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):
Reliability Coordinator, Balancing Authority, Transmission Operator, Transmission Owner, Transmission Planner, Planning Coordinator, Distribution Provider, Generator Operator, and Generator Owner
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
The ~~FERC, NERC, Regional Entity Joint Staff Inquiry into the 2021 Cold Weather Grid Operations~~Report was publicly noticed by both FERC and NERC.
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)?
~~The proposed Reliability Standards are intended to build upon the requirements in EOP-011-2, IRO-010-4, and TOP-003-5 that were developed by Project 2019-06, and which for U.S. entities, were approved by FERC in August 2021. Additionally, several recommendations build on existing Standards related to load shedding and the development and implementation of UFLS and UVLS programs (e.g. EOP-011-2, PRC-006-5, and PRC-010-2). These Standards should be reviewed to ensure any conflicts or overlap with current requirements are mitigated.~~
~~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.~~
The proposed Reliability Standards are intended to build (replace, supplement, etc.) upon the requirements in EOP-011-2, IRO-010-4, and TOP-003-5 that were developed by Project 2019-06, and which for U.S. entities, were approved by FERC in August 2021. Additionally, several recommendations

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build on existing Standards related to load shedding and the development and implementation of UFLS and UVLS programs (e.g. EOP-011-2, PRC-006-5, and PRC-010-2). These Standards should be reviewed to ensure any conflicts, or overlap with current requirements, are mitigated. The Standard Drafting team should coordinate with other projects impacting the same standards which might include 2020-05, 2021-01, 2021-06, 2021-08 and 2022-02.
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.
There have been several recommendations and guidelines that have developed over the prior noted events, but the ~~events since illustrate~~Event illustrates that ~~they~~NERC Reliability Standards are ~~not as widely adopted as necessary to prevent reoccurrence~~needed.

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
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

Market Interface Principles	
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Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
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For Use by NERC Only

SAR Status Tracking (Check off as appropriate).	
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4	February 25, 2020	Standards Information Staff	Updated template footer

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

This is the first draft of the proposed standard for a formal 30-day comment period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR)	11/17/2021
SAR posted for comment	11/22/21 – 12/21/21

Anticipated Actions	Date
30-day formal comment period with ballot	May – June 2022
30- day formal comment period with additional ballot	August – September 2022
10-day final ballot	September 2022
NERC Board of Trustees (Board) adoption	October 2022

A. Introduction

1. **Title:** **Emergency Operations**

2. **Number:** **EOP-011-3**

3. **Purpose:** To address the effects of operating Emergencies by ensuring each Transmission Operator and Balancing Authority has developed plan(s) to mitigate operating Emergencies and that those plans are implemented and coordinated within the Reliability Coordinator Area as specified within the requirements.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Reliability Coordinator

   4.1.3 Transmission Operator

5. **Effective Date:** See Implementation Plan for Project 2021-07.

B. Requirements and Measures

R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

1.1. Roles and responsibilities for activating the Operating Plan(s);

1.2. Processes to prepare for and mitigate Emergencies including:

1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency;

1.2.2. Cancellation or recall of Transmission and generation outages;

1.2.3. Transmission system reconfiguration;

1.2.4. Redispatch of generation request;

1.2.5. Operator-controlled manual load shedding during an Emergency that accounts for each of the following:

1.2.5.1. Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;

1.2.5.2. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that serve designated critical loads;

1.2.5.3. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for underfrequency load shed (UFLS) or undervoltage load

shed (UVLS); and

1.2.5.4. Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions.

1.2.6. Provisions to determine reliability impacts of:

1.2.6.1. cold weather conditions; and

1.2.6.2. extreme weather conditions.

M1. Each Transmission Operator will have a dated Operating Plan(s) developed in accordance with Requirement R1 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R1.

R2. Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

2.1. Roles and responsibilities for activating the Operating Plan(s);

2.2. Processes to prepare for and mitigate Emergencies including:

2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;

2.2.2. Requesting an Energy Emergency Alert, per Attachment 1;

2.2.3. Managing generating resources in its Balancing Authority Area to address:

2.2.3.1. capability and availability;

2.2.3.2. fuel supply and inventory concerns;

2.2.3.3. fuel switching capabilities; and

2.2.3.4. environmental constraints.

2.2.4. Public appeals for voluntary Load reductions;

2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions;

2.2.6. Reduction of internal utility energy use;

2.2.7. Use of Interruptible Load, curtailable Load and demand response;

2.2.8. Provisions for Transmission Operators to implement operator-controlled

manual Load shed in accordance with Requirement R1 Part 1.2.5; and

2.2.9. Provisions to determine reliability impacts of:

2.2.9.1. cold weather conditions; and

2.2.9.2. extreme weather conditions.

M2. Each Balancing Authority will have a dated Operating Plan(s) developed in accordance with Requirement R2 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R2.

R3. The Reliability Coordinator shall review the Operating Plan(s) to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority regarding any reliability risks that are identified between Operating Plans. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

3.1. Within 30 calendar days of receipt, the Reliability Coordinator shall:

3.1.1. Review each submitted Operating Plan(s) on the basis of compatibility and inter-dependency with other Balancing Authorities' and Transmission Operators' Operating Plans;

3.1.2. Review each submitted Operating Plan(s) for coordination to avoid risk to Wide Area reliability; and

3.1.3. Notify each Balancing Authority and Transmission Operator of the results of its review, specifying any time frame for resubmittal of its Operating Plan(s) if revisions are identified.

M3. The Reliability Coordinator will have documentation, such as dated emails or other correspondences that it reviewed, Transmission Operator and Balancing Authority Operating Plans, within 30 calendar days of submittal in accordance with Requirement R3.

R4. Each Transmission Operator and Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R3 and resubmit its Operating Plan(s) to its Reliability Coordinator within a time period specified by its Reliability Coordinator. *[Violation Risk Factor: High] [Time Horizon: Operation Planning]*

M4. The Transmission Operator and Balancing Authority will have documentation, such as dated emails or other correspondence, with an Operating Plan(s) version history showing that it responded and updated the Operating Plan(s) within the timeframe identified by its Reliability Coordinator in accordance with Requirement R4.

R5. Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and

neighboring Reliability Coordinators. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M5. Each Reliability Coordinator that receives an Emergency notification from a Balancing Authority or Transmission Operator within its Reliability Coordinator Area will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that will be used to determine if the Reliability Coordinator communicated, in accordance with Requirement R5, with other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators.

R6. Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M6. Each Reliability Coordinator, with a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area, will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that it declared an Energy Emergency Alert, as detailed in Attachment 1, in accordance with Requirement R6.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

"Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with the 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 CEA may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

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

- The Transmission Operator shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R1 and R4 and Measures M1 and M4.

- The Balancing Authority shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R2 and R4, and Measures M2 and M4.
- The Reliability Coordinator shall maintain evidence of compliance since the last audit for Requirements R3, R5, and R6 and Measures M3, M5, and M6.

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.

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real-time Operations, Operations Planning, Long-term Planning	High	N/A	The Transmission Operator developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to maintain it.	The Transmission Operator developed an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to have it reviewed by its Reliability Coordinator.	The Transmission Operator failed to develop an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. OR The Transmission Operator developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to implement it.
R2	Real-time Operations, Operations	High	N/A	The Balancing Authority developed a Reliability Coordinator-	The Balancing Authority developed an Operating Plan(s) to mitigate operating	The Balancing Authority failed to develop an

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	Planning, Long-term Planning			reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to maintain it.	Emergencies within its Balancing Authority Area, but failed to have it reviewed by its Reliability Coordinator.	Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area. OR The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to implement it.
R3	Operations Planning	High	N/A	N/A	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission Operator.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					Operator within 30 calendar days.	
R4	Operations Planning	High	N/A	N/A	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator within the timeframe specified by its Reliability Coordinator.	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator.
R5	Real-time Operations	High	N/A	N/A	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority did notify neighboring Reliability Coordinators, Balancing Authorities	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority failed to notify neighboring Reliability Coordinators, Balancing Authorities

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					and Transmission Operators, but failed to notify within 30 minutes from the time of receiving notification.	and Transmission Operators.
R6	Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to declare an Energy Emergency Alert.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	November 13, 2014	Adopted by Board of Trustees	Merged EOP-001-2.1b, EOP-002-3.1 and EOP-003-2.
1	November 19, 2015	FERC approved EOP-011-1. Docket Nos. RM15-7-000, RM15-12-000, and RM15-13-000. Order No. 818	
2	June 11,2021	Adopted by Board of Trustees	Revised under Project 2019-06
2	August 24,2021	FERC approved EOP-011-2. Docket Number RD21-5-000	
2	August 24,2021	Effective Date	4/1/ 2023
3	TBD		Revised under Project 2021-07

Attachment 1-EOP-011-3
Energy Emergency Alerts

Introduction

This Attachment provides the process and descriptions of the levels used by the Reliability Coordinator in which it communicates the condition of a Balancing Authority which is experiencing an Energy Emergency.

A. General Responsibilities

1. **Initiation by Reliability Coordinator.** An Energy Emergency Alert (EEA) may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of an energy deficient Balancing Authority.
2. **Notification**. A Reliability Coordinator who declares an EEA shall notify all Balancing Authorities and Transmission Operators in its Reliability Coordinator Area. The Reliability Coordinator shall also notify all neighboring Reliability Coordinators.

B. EEA Levels

Introduction

To ensure that all Reliability Coordinators clearly understand potential and actual Energy Emergencies in the Interconnection, NERC has established three levels of EEAs. The Reliability Coordinators will use these terms when communicating Energy Emergencies to each other. An EEA is an Emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC Reliability Standards.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. **EEA 1 — All available generation resources in use. Circumstances:**
   - The Balancing Authority is experiencing conditions where all available generation resources are committed to meet firm Load, firm transactions, and reserve commitments, and is concerned about sustaining its required Contingency Reserves.
   - Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. **EEA 2 — Load management procedures in effect. Circumstances:**
   - The Balancing Authority is no longer able to provide its expected energy requirements and is an energy deficient Balancing Authority.
   - An energy deficient Balancing Authority has implemented its Operating Plan(s) to mitigate Emergencies.

- An energy deficient Balancing Authority is still able to maintain minimum Contingency Reserve requirements.

During EEA 2, Reliability Coordinators and energy deficient Balancing Authorities have the following responsibilities:

2.1 **Notifying other Balancing Authorities and market participants**. The energy deficient Balancing Authority shall communicate its needs to other Balancing Authorities and market participants. Upon request from the energy deficient Balancing Authority, the respective Reliability Coordinator shall post the declaration of the alert level, along with the name of the energy deficient Balancing Authority on the RCIS website.

2.2 **Declaration period.** The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators**.**

2.3 **Sharing information on resource availability.** Other Reliability Coordinators of Balancing Authorities with available resources shall coordinate, as appropriate, with the Reliability Coordinator that has an energy deficient Balancing Authority.

2.4 **Evaluating and mitigating Transmission limitations**. The Reliability Coordinator shall review Transmission outages and work with the Transmission Operator(s) to see if it's possible to return to service any Transmission Elements that may relieve the loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).

2.5 **Requesting Balancing Authority actions.** Before requesting an EEA 3, the energy deficient Balancing Authority must make use of all available resources; this includes, but is not limited to:

2.5.1 **All available generation units are on line**. All generation capable of being on line in the time frame of the Emergency is on line.

2.5.2 **Demand-Side Management**. Activate Demand-Side Management within provisions of any applicable agreements.

3. **EEA 3 —Firm Load interruption is imminent or in progress. Circumstances:**

- The energy deficient Balancing Authority is unable to meet minimum Contingency Reserve requirements.

During EEA 3, Reliability Coordinators and Balancing Authorities have the following responsibilities:

3.1 **Continue actions from EEA 2**. The Reliability Coordinators and the energy deficient Balancing Authority shall continue to take all actions initiated during EEA 2.

3.2 Declaration Period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities, and Transmission Operators.

3.3 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator shall evaluate the risks of revising SOLs and IROLs for the possibility of delivery of energy to the energy deficient Balancing Authority. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Transmission Operator whose Transmission Owner (TO) equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists, or as allowed by the Transmission Owner whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.3.1 Energy deficient Balancing Authority obligations. The energy deficient Balancing Authority, upon notification from its Reliability Coordinator of the situation, will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding.

3.4 Returning to pre-Emergency conditions. Whenever energy is made available to an energy deficient Balancing Authority such that the Systems can be returned to its pre- Emergency SOLs or IROLs condition, the energy deficient Balancing Authority shall request the Reliability Coordinator to downgrade the alert level.

3.4.1 Notification of other parties. Upon notification from the energy deficient Balancing Authority that an alert has been downgraded, the Reliability Coordinator shall notify the neighboring Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Operators that its Systems can be returned to its normal limits.

Alert 0 - Termination. When the energy deficient Balancing Authority is able to meet its Load and Operating Reserve requirements, it shall request its Reliability Coordinator to terminate the EEA.

3.4.2 Notification. The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the neighboring Balancing Authorities and Transmission Operators.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

This is the first draft of the proposed standard for a formal 30-day comment period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR)	11/17/2021
SAR posted for comment	11/22/21 – 12/21/21

Anticipated Actions	Date
30-day formal comment period with ballot	May – June 2022
30-day formal comment period with additional ballot	August – September 2022
10-day final ballot	September 2022
NERC Board of Trustees (Board) adoption	October 2022

~~B.~~A. Introduction

1. **Title:** **Emergency ~~Preparedness and~~ Operations**
2. **Number:** **EOP-011-~~3~~2**
3. **Purpose:** To address the effects of operating ~~e~~Emergencies by ensuring each Transmission Operator~~,~~ and Balancing Authority~~, and Generator Owner~~ has developed plan(s) to mitigate operating Emergencies and that those plans are implemented and coordinated within the Reliability Coordinator Area as specified within the requirements.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1** Balancing Authority
     - **4.1.2** Reliability Coordinator
     - **4.1.3** Transmission Operator
     - ~~**2.5.0** Generator Owner~~
     - ~~**2.6.0** Generator Operator'~~
   - ~~**7.0. Facilities**~~
     - ~~**8.0.0** For the purpose of this standard, the term "generating unit" means all Bulk Electric System generators.~~

~~9.~~5. **Effective Date:** See Implementation Plan for Project ~~2019-06~~2021-07.

~~C.~~B. Requirements and Measures

R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

1.1. Roles and responsibilities for activating the Operating Plan(s);

1.2. Processes to prepare for and mitigate Emergencies including:

1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency;

1.2.2. Cancellation or recall of Transmission and generation outages;

1.2.3. Transmission system reconfiguration;

1.2.4. Redispatch of generation request;

1.2.5. Operator-controlled manual load shedding during an Emergency that accounts for each of the following:

1.2.5.1. Provisions for ~~operator-controlled~~ manual Load shedding ~~that~~

~~minimizes the overlap with automatic Load shedding and are~~ capable of being implemented in a timeframe adequate for mitigating the Emergency;

1.2.5.2. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that serve designated critical loads;

1.2.5.3. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for underfrequency load shed (UFLS) or undervoltage load shed (UVLS); and

~~**1.2.4.2.**~~**1.2.5.4.** Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions.

~~**1.2.5.**~~**1.2.6.** Provisions to determine reliability impacts of:

~~**1.2.5.1.**~~**1.2.6.1.** cold weather conditions; and

~~**1.2.5.2.**~~**1.2.6.2.** extreme weather conditions.

M1. Each Transmission Operator will have a dated Operating Plan(s) developed in accordance with Requirement R1 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R1.

R2. Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

2.1. Roles and responsibilities for activating the Operating Plan(s);

2.2. Processes to prepare for and mitigate Emergencies including:

2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;

2.2.2. Requesting an Energy Emergency Alert, per Attachment 1;

2.2.3. Managing generating resources in its Balancing Authority Area to address:

2.2.3.1. capability and availability;

2.2.3.2. fuel supply and inventory concerns;

2.2.3.3. fuel switching capabilities; and

2.2.3.4. environmental constraints.

2.2.4. Public appeals for voluntary Load reductions;

2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions;

2.2.6. Reduction of internal utility energy use;

2.2.7. Use of Interruptible Load, curtailable Load and demand response;

2.2.8. Provisions for Transmission Operators to implement operator-controlled manual Load shed~~ding~~ in accordance with Requirement R1 Part 1.2.5 ~~that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency~~; and

2.2.9. Provisions to determine reliability impacts of:

2.2.9.1. cold weather conditions; and

2.2.9.2. extreme weather conditions.

M2. _Each Balancing Authority will have a dated Operating Plan(s) developed in accordance with Requirement R2 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R2.

R3. The Reliability Coordinator shall review the Operating Plan(s) to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority regarding any reliability risks that are identified between Operating Plans. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

3.1. Within 30 calendar days of receipt, the Reliability Coordinator shall:

3.1.1. Review each submitted Operating Plan(s) on the basis of compatibility and inter-dependency with other Balancing Authorities' and Transmission Operators' Operating Plans;

3.1.2. Review each submitted Operating Plan(s) for coordination to avoid risk to Wide Area reliability; and

3.1.3. Notify each Balancing Authority and Transmission Operator of the results of its review, specifying any time frame for resubmittal of its Operating Plan(s) if revisions are identified.

M3. _The Reliability Coordinator will have documentation, such as dated e-mails or other correspondences that it reviewed Transmission Operator and Balancing Authority Operating Plans within 30 calendar days of submittal in accordance with Requirement R3.

R4. Each Transmission Operator and Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R3 and resubmit its Operating Plan(s) to its Reliability Coordinator within a time period specified by its Reliability Coordinator. *[Violation Risk Factor: High] [Time Horizon: Operation Planning]*

M4. _The Transmission Operator and Balancing Authority will have documentation, such as dated emails or other correspondence, with an Operating Plan(s) version history showing that it responded and updated the Operating Plan(s) within the timeframe identified by its Reliability Coordinator in accordance with Requirement R4.

R5. Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and

neighboring Reliability Coordinators. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M5. Each Reliability Coordinator that receives an Emergency notification from a Balancing Authority or Transmission Operator within its Reliability Coordinator Area will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that will be used to determine if the Reliability Coordinator communicated, in accordance with Requirement R5, with other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators.

R6. Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M6. Each Reliability Coordinator, with a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area, will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that it declared an Energy Emergency Alert, as detailed in Attachment 1, in accordance with Requirement R6.

~~R7.~~ [R7 Moved to EOP-012]

~~Each Generator Owner shall implement and maintain one or more cold weather preparedness plan(s) for its generating units. The cold weather preparedness plan(s) shall include the following, at a minimum: [*Violation Risk Factor: High*] [*Time Horizon: Operations Planning and Real-Time Operations*]~~

~~**7.1.** Generating unit(s) freeze protection measures based on geographical location and plant configuration;~~

~~Annual inspection and maintenance of generating unit(s) freeze protection measures;~~

~~**7.2.** Generating unit(s) cold weather data, to include:~~

~~**7.2.0.** Generating unit(s) operating limitations in cold weather to include:~~

~~**7.2.0.0.** capability and availability;~~

~~**7.2.0.0.** fuel supply and inventory concerns;~~

~~**7.2.0.0.** fuel switching capabilities; and~~

~~**7.2.0.0.** environmental constraints.~~

~~**7.2.0.** Generating unit(s) minimum:~~

~~**7.2.0.0.** design temperature; or~~

~~**7.2.0.0.** historical operating temperature; or~~

~~**7.3.1.3.** current cold weather performance temperature determined by an engineering analysis.~~

~~**M7.** Each Generator Owner will have evidence documenting that its cold weather preparedness plan(s) was implemented and maintained in accordance with Requirement R7.~~

~~**R8.**~~ **[R8 Moved to EOP-012]** ~~Each Generator Owner in conjunction with its Generator Operator shall identify the entity responsible for providing the generating unit-specific training, and that identified entity shall provide the training to its maintenance or operations personnel responsible for implementing cold weather preparedness plan(s) developed pursuant to Requirement R7. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]*~~

~~**M8.** Each Generator Operator or Generator Owner will have documented evidence that the applicable personnel completed training of the Generator Owner's cold weather preparedness plan(s). This evidence may include, but is not limited to, documents such as personnel training records, training materials, date of training, agendas or learning objectives, attendance at pre-work briefings, review of work order tasks, tailboards, attendance logs for classroom training, and completion records for computer-based training in fulfillment of Requirement R8.~~

~~D.~~C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

"Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with the 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~~CEA may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

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

- The Transmission Operator shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R1 and R4 and Measures M1 and M4.
- The Balancing Authority shall retain the current Operating Plan(s), evidence

of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R2 and R4, and Measures M2 and M4.

- The Reliability Coordinator shall maintain evidence of compliance since the last audit for Requirements R3, R5, and R6 and Measures M3, M5, and M6.
- ~~The Generator Owner shall retain the cold weather preparedness plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirement R7 and Measure M7.~~

~~1.4.~~**1.3.** ~~The Generator Owner or Generator Operator shall keep data or evidence to show compliance for three years or since its last compliance audit, whichever timeframe is greater, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation, for Requirement R8 and Measure M8.~~ **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.

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real-time Operations, Operations Planning, Long-term Planning	High	N/A	The Transmission Operator developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to maintain it.	The Transmission Operator developed an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to have it reviewed by its Reliability Coordinator.	The Transmission Operator failed to develop an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. OR The Transmission Operator developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission~~s~~ Operator Area, but failed to implement it.
R2	Real-time Operations, Operations	High	N/A	The Balancing Authority developed a Reliability Coordinator-	The Balancing Authority developed an Operating Plan(s) to mitigate operating	The Balancing Authority failed to develop an

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	Planning, Long-term Planning			reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to maintain it.	Emergencies within its Balancing Authority Area, but failed to have it reviewed by its Reliability Coordinator.	Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area. OR The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to implement it.
R3	Operations Planning	High	N/A	N/A	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission Operator.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					Operator within 30 calendar days.	
R4	Operations Planning	High	N/A	N/A	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator within the timeframe specified by its Reliability Coordinator.	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator.
R5	Real-time Operations	High	N/A	N/A	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority did notify neighboring Reliability Coordinators, Balancing Authorities	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority failed to notify neighboring Reliability Coordinators, Balancing Authorities

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					and Transmission Operators, but failed to notify within 30 minutes from the time of receiving notification.	and Transmission Operators.
R6	Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to declare an Energy Emergency Alert.
~~**R7**~~	~~Operations Planning and Real-time Operations~~	~~High~~	~~The Generator Owner implemented a cold weather preparedness plan(s) but failed to maintain it.~~	~~The Generator Owner's cold weather preparedness plan failed to include one of the applicable requirement Parts within Requirement R7.~~	~~The Generator Owner had and maintained a cold weather preparedness plan(s) but failed to fully implement it.~~ ~~OR~~	~~The Generator Owner does not have a cold weather preparedness plan.~~ ~~OR~~ ~~The Generator Owner has a cold~~

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					~~The Generator Owner's cold weather preparedness plan failed to include two of the applicable requirement Parts within Requirement R7.~~	~~weather preparedness plan, but failed to include any of the applicable requirement Parts within Requirement R7.~~
~~R8~~	~~Operations Planning and Real-time Operations~~	~~Medium~~	~~The Generator Owner or Generator Operator failed to provide generating unit-specific training as described in Requirement R8 to the greater of:~~ • ~~one applicable personnel at a single generating unit; or~~ • ~~5% or less of its total applicable personnel.~~	~~The Generator Owner or Generator Operator failed to provide generating unit-specific training as described in Requirement R8 to the greater of:~~ • ~~two applicable personnel at a single generating unit; or~~ • ~~more than 5% or less than or equal to 10% of its total applicable personnel.~~	~~The Generator Owner or Generator Operator failed to provide generating unit-specific training as described in Requirement R8 to the greater of:~~ • ~~three applicable personnel at a single generating unit; or~~ • ~~more than 10% or less than or equal to 15% of its total applicable personnel.~~	~~The Generator Owner or Generator Operator failed to provide generating unit-specific training as described in Requirement R8 to the greater of:~~ • ~~four applicable personnel at a single generating unit; or~~ • ~~more than 15% of its total applicable personnel.~~

~~E.~~D. Regional Variances

None.

~~F.~~E. Interpretations

None.

~~G.~~F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	November 13, 2014	Adopted by Board of Trustees	Merged EOP-001-2.1b, EOP-002-3.1 and EOP-003-2.
1	November 19, 2015	FERC approved EOP-011-1. Docket Nos. RM15-7-000, RM15-12-000, and RM15-13-000. Order No. 818	
2	June 11, 2021	Adopted by ~~the~~ Board of Trustees	Revised under Project 2019-06
2	August 24, 2021	FERC approved EOP-011-2. Docket Number RD21-5-000	
2	August 24, 2021	Effective Date	4/1/ 2023
3	TBD		Revised under Project 2021-07

Attachment 1-EOP-011-~~2~~3 Energy Emergency Alerts

Introduction

This Attachment provides the process and descriptions of the levels used by the Reliability Coordinator in which it communicates the condition of a Balancing Authority which is experiencing an Energy Emergency.

A. General Responsibilities

1. **Initiation by Reliability Coordinator.** An Energy Emergency Alert (EEA) may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of an energy deficient Balancing Authority.

2. **Notification**. A Reliability Coordinator who declares an EEA shall notify all Balancing Authorities and Transmission Operators in its Reliability Coordinator Area. The Reliability Coordinator shall also notify all neighboring Reliability Coordinators.

B. EEA Levels

Introduction

To ensure that all Reliability Coordinators clearly understand potential and actual Energy Emergencies in the Interconnection, NERC has established three levels of EEAs. The Reliability Coordinators will use these terms when communicating Energy Emergencies to each other. An EEA is an Emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC Reliability Standards.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. **EEA 1 — All available generation resources in use. Circumstances:**

   - The Balancing Authority is experiencing conditions where all available generation resources are committed to meet firm Load, firm transactions, and reserve commitments, and is concerned about sustaining its required Contingency Reserves.

   - Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. **EEA 2 — Load management procedures in effect. Circumstances:**

   - The Balancing Authority is no longer able to provide its expected energy requirements and is an energy deficient Balancing Authority.

   - An energy deficient Balancing Authority has implemented its Operating Plan(s) to mitigate Emergencies.

- An energy deficient Balancing Authority is still able to maintain minimum Contingency Reserve requirements.

During EEA 2, Reliability Coordinators and energy deficient Balancing Authorities have the following responsibilities:

2.1 **Notifying other Balancing Authorities and market participants**. The energy deficient Balancing Authority shall communicate its needs to other Balancing Authorities and market participants. Upon request from the energy deficient Balancing Authority, the respective Reliability Coordinator shall post the declaration of the alert level, along with the name of the energy deficient Balancing Authority on the RCIS website.

2.2 **Declaration period.** The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators**.**

2.3 **Sharing information on resource availability.** Other Reliability Coordinators of Balancing Authorities with available resources shall coordinate, as appropriate, with the Reliability Coordinator that has an energy deficient Balancing Authority.

2.4 **Evaluating and mitigating Transmission limitations**. The Reliability Coordinator shall review Transmission outages and work with the Transmission Operator(s) to see if it's possible to return to service any Transmission Elements that may relieve the loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).

2.5 **Requesting Balancing Authority actions.** Before requesting an EEA 3, the energy deficient Balancing Authority must make use of all available resources; this includes, but is not limited to:

2.5.1 **All available generation units are on line**. All generation capable of being on line in the time frame of the Emergency is on line.

2.5.2 **Demand-Side Management**. Activate Demand-Side Management within provisions of any applicable agreements.

3. EEA 3 —Firm Load interruption is imminent or in progress. Circumstances:

- The energy deficient Balancing Authority is unable to meet minimum Contingency Reserve requirements.

During EEA 3, Reliability Coordinators and Balancing Authorities have the following responsibilities:

3.1 **Continue actions from EEA 2**. The Reliability Coordinators and the energy deficient Balancing Authority shall continue to take all actions initiated during EEA 2.

3.2 Declaration Period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities, and Transmission Operators.

3.3 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator shall evaluate the risks of revising SOLs and IROLs for the possibility of delivery of energy to the energy deficient Balancing Authority. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Transmission Operator whose Transmission Owner (TO) equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists, or as allowed by the Transmission Owner whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.3.1 Energy deficient Balancing Authority obligations. The energy deficient Balancing Authority, upon notification from its Reliability Coordinator of the situation, ~~it~~ will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding.

3.4 Returning to pre-Emergency conditions. Whenever energy is made available to an energy deficient Balancing Authority such that the Systems can be returned to its pre- Emergency SOLs or IROLs condition, the energy deficient Balancing Authority shall request the Reliability Coordinator to downgrade the alert level.

3.4.1 Notification of other parties. Upon notification from the energy deficient Balancing Authority that an alert has been downgraded, the Reliability Coordinator shall notify the neighboring Reliability Coordinators (via the RCIS), Balancing Authorities and Transmission Operators that its Systems can be returned to its normal limits.

Alert 0 - Termination. When the energy deficient Balancing Authority is able to meet its Load and Operating Reserve requirements, it shall request its Reliability Coordinator to terminate the EEA.

3.4.2 Notification. The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the neighboring Balancing Authorities and Transmission Operators.

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 first draft of the proposed standard for a formal 30-day comment period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	11/17/2021
SAR posted for comment	11/22/21 – 12/21/21

Anticipated Actions	Date
30-day formal or informal comment period with ballot	May – June 2022
30-day formal or informal comment period with additional ballot	August – September 2022
10-day final ballot	September 2022
Board adoption	October 2022

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):

None

A. Introduction

1. **Title:** **Extreme Cold Weather Preparedness and Operations**
2. **Number:** EOP-012-1
3. **Purpose:** To address the effects of operating in extreme cold weather by ensuring each Generator Owner has developed and implemented plan(s) to mitigate the reliability impacts of extreme cold weather on its generating units.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Generator Owner

   4.1.2. Generator Operator

   4.2. Facilities: For purposes of this standard, the term "generating unit" means those Bulk Electric System generators that plan to operate during the winter season. The winter season will be determined by the generating unit's applicable Balancing Authority. The term excludes those generators that do not operate during the winter season except when called upon by the Balancing Authority to be available during Capacity Emergencies or Energy Emergencies.

5. **Effective Date:** See Implementation Plan for Project 2021-07.

B. Requirements and Measures

R1. Each Generator Owner shall ensure generating units implement freeze protection measures based on the following minimum criteria: [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning, Operations Planning*]

1.1. Each generating unit shall be designed and maintained to be capable of continuous operations at the documented minimum hourly temperature experienced at its location since 1/1/1975 or a lesser period if reliable data is not available to 1975;

1.2. The generating unit design shall account for the cooling effect of wind;

1.3. The generating unit design shall account for the impacts on operations due to precipitation (e.g., sleet, snow, ice, and freezing rain); and

1.4. For each existing generating unit that requires either new freeze protection measures or modification of existing freeze protection measures, the Generator Owner shall develop and implement a Corrective Action Plan (CAP) which includes the following at a minimum:

1.4.1. An identification of corrective action (s) for the affected unit(s), including any necessary modifications to the Generator Owner's cold weather preparedness plan(s);

1.4.2. A timetable for implementing the corrective action(s) from Part 1.4.1 which considers any technical, commercial, or operational constraints, as defined by the Generator Owner;

1.4.3. An identification of any temporary operating limitations that would apply until execution of the corrective action(s) identified in the CAP; and

1.4.4. A declaration, where deemed appropriate by the Generator Owner based on the review of Parts 1.4.1 through 1.4.3, that no revisions to the cold weather preparedness plan(s) are required and that no further corrective actions will be taken. The Generator Owner shall document technical, commercial, or operational constraints as defined by the Generator Owner as support for such declaration.

M1. Each Generator Owner will have dated evidence that demonstrates it has freeze protection measures for its unit(s) in accordance with R1. Acceptable evidence may include the following (electronic or hardcopy format): Documentation of extreme temperature used for the freeze protection design, documentation of freeze protection measures, Facility cold weather preparedness plan, and CAP(s).

R2. Each Generator Owner that is not able to implement freeze protection measures for new generating unit(s) as required by Requirement R1 due to technical, commercial, or operational constraints as defined by the Generator Owner shall: *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

2.1. Document its determination and the constraints on implementation; and

2.2. Review its determination every five calendar years to determine whether the documented constraints on implementation remain applicable.

M2. Each Generator Owner will have dated evidence that demonstrates it documented constraints on implementation of freeze protection measures and conducted a review of its units in accordance with Requirement R2. Acceptable evidence may include the following dated documentation (electronic or hardcopy format): Documentation of technical, commercial, or operational constraint. Documentation of five calendar year reviews as applicable.

R3. Each Generator Owner shall implement and maintain one or more cold weather preparedness plan(s) for its generating units. The cold weather preparedness plan(s) shall include the following, at a minimum: *[Violation Risk Factor: High] [Time Horizon: Operations Planning and Real-time Operations]*

3.1. Documented minimum hourly temperature experienced at its location since 1/1/1975 or a lesser period if reliable data is not available to 1975;

3.2. Documented generating unit(s) freeze protection measures based on geographical location and plant configuration;

3.3. Annual inspection and maintenance of generating unit(s) freeze protection measures; and

3.4. Generating unit(s) cold weather data, to include:

3.4.1. Generating unit(s) operating limitations in cold weather to include:

3.4.1.1. Capability and availability;

3.4.1.2. Fuel supply and inventory concerns;

3.4.1.3. Fuel switching capabilities; and

3.4.1.4. Environmental constraints.

3.4.2. Generating unit(s) minimum:

- Design temperature;
- Historical operating temperature; or
- Current cold weather performance temperature determined by an engineering analysis.

M3. Each Generator Owner will have evidence documenting that its cold weather preparedness plan(s) was implemented and maintained in accordance with Requirement R3.

R4. Once every five calendar years, each Generator Owner shall: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning, Real-Time Operations]*

4.1. Review the documented minimum hourly temperature developed pursuant to Part 3.1, and update the cold weather preparedness plan with the lowest temperature as necessary;

4.2. Review its documented cold weather minimum temperature contained within its cold weather preparedness plan(s) for its generating units, pursuant to Part 3.4.2; and

4.3. Review whether its generating units have the freeze protection measures required to operate at the lowest temperature established pursuant to Requirement R1 and, if not, implement appropriate modifications per the requirements of Part 1.4.

M4. Each Generator Owner will have evidence documenting that it reviewed documented temperature data and updated its cold weather preparedness plan(s) accordance with Requirement R4.

R5. Each Generator Owner in conjunction with its Generator Operator shall identify the entity responsible for providing the generating unit-specific training, and that identified entity shall provide annual training to its maintenance or operations personnel responsible for implementing cold weather preparedness plan(s) developed pursuant to Requirement R3. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]*

M5. Each Generator Operator or Generator Owner will have documented evidence that the applicable personnel completed annual training of the Generator Owner's cold weather preparedness plan(s). This evidence may include, but is not limited to, documents such as personnel training records, training materials, date of training, agendas or learning objectives, attendance at pre-work briefings, review of work order tasks, tailboards, attendance logs for classroom training, and completion records for computer-based training in fulfillment of Requirement R5.

R6. Each Generator Owner that owns a generating unit that experiences an event resulting in a derate of more than 10% of the total capacity of the unit for longer than four hours in duration, a start-up failure where the unit fails to synchronize within a specified start-up time, or a Forced Outage for which (i) the apparent cause(s) of the event is due to freezing of the Generator Owner's equipment within the Generator Owner's control, and (ii) the ambient conditions at the site at the time of the event are at or above the temperature documented in Part 3.4.2 shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

6.1. No later than 150 days subsequent to the event or by July 1 that follows the event, whichever is earlier, develop a CAP.

6.2. The CAP shall contain at a minimum:

6.2.1. A summary of the identified cause(s) for the equipment freezing event where applicable and any relevant associated data;

6.2.2. A review of applicability to similar equipment at other generating units owned by the Generator Owner;

6.2.3. An identification of corrective action(s) for the affected unit(s) and identified similar units, including any necessary modifications to the Generator Owner's cold weather preparedness plan(s);

6.2.4. A timetable for implementing the identified corrective action(s) from Part 6.2.3 which considers any technical, commercial, or operational constraints as defined by the Generator Owner;

6.2.5. An identification of any temporary operating limitations that would apply until execution of the corrective action(s) identified in the CAP; and

6.2.6. A declaration, where deemed appropriate by the Generator Owner based on the review of Parts 6.2.1 through 6.2.5 that no revisions to the cold weather preparedness plan are required and that no further corrective actions will be taken. The Generator Owner shall document technical, commercial, or operational constraints as defined by the Generator Owner as support for such declaration.

M6. Acceptable evidence for these requirements may include, but is not limited to, the following dated documentation (electronic or hardcopy format): CAP(s) and updated cold weather preparedness plan(s) where indicated as needed by the CAP.

C. Compliance

1. **Compliance Monitoring Process**

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

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

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

   - The Generator Owner shall keep data or evidence to show compliance for three years or until any Corrective Action Plan under Part 1.4 is complete, whichever timeframe is greater, for Requirement R1 and Measure M1.
   - The Generator Owner shall keep data or evidence to show compliance for three years for Requirement R2, R3, and R5 and Measure M2, M3, and M5.
   - The Generator Owner shall retain the current cold weather preparedness plan(s), as evidence of review or revision history, plus each version issued since the last audit and evidence of compliance since the last audit for Requirement R4 and Measure M4.
   - The Generator Owner shall keep data or evidence to show compliance for three years, or until any Corrective Action Plan under 6.2 is complete, whichever timeframe is greater, for Requirement R6 and Measure M6.

   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.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 Parts 1.1 – 1.3 for up to 5% of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 Parts 1.1 – 1.3 for more than 5%, but less than or equal to 10% of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 Parts 1.1 – 1.3 for more than 10%, but less than or equal to 20% of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 Parts 1.1 – 1.3 for more than 20% of its units; OR The Generator Owner did not develop or implement a CAP as required by Requirement R1.
R2.	The Generator Owner completed the review required in Requirement R2, but was late by 30 calendar days or less. OR The Generator Owner did not document its determination and the constraints described in Requirement R2 Part 2.1 for up to 5% of its units.	The Generator Owner completed the review required in Requirement R2, but was late by greater than 30 calendar days, but less than or equal to 60 calendar days. OR The Generator Owner did not document its determination and the constraints described in Requirement R1 Part 2.1 for more than 5%, but less than or equal to 10% of its units.	The Generator Owner completed the review required in Requirement R2, but was late by greater than 60 calendar days. OR The Generator Owner did not document its determination and the constraints described in Requirement R1 Part 2.1 for more than 10%, but less than or equal to 20% of its units.	The Generator Owner did not complete a review. OR The Generator Owner did not document its determination and the constraints described in Requirement R1 Part 2.1 for more than 20% of its units.

R3.	The Generator Owner implemented a cold weather preparedness plan(s), but failed to maintain it.	The Generator Owner's cold weather preparedness plan failed to include one of the applicable Parts within Requirement R3.	The Generator Owner had and maintained a cold weather preparedness plan(s), but failed to implement it. OR The Generator Owner's cold weather preparedness plan failed to include two of the applicable requirement parts within Requirement R3.	The Generator Owner does not have cold weather preparedness plan(s). OR The Generator Owner has a cold weather preparedness plan, but failed to include any of the applicable requirement parts within Requirement R3.
R4.	The Generator Owner completed the review required in Requirement R4, but was late by 30 calendar days or less.	The Generator Owner completed the review required in Requirement R4, but was late by greater than 30 calendar days, but less than or equal to 60 calendar days.	The Generator Owner's review failed to include one of the applicable requirement parts in Requirement R4 Parts 4.1 through 4.3; OR The Generator Owner completed the review required in Requirement R4, but was late by greater than 60 calendar days.	The Generator Owner's review failed to include two or more of the applicable requirement parts in Requirement R4 Parts 4.1 through 4.3; OR The Generator Owner does not have a completed review. OR The Generator Owner did not update the cold weather preparedness plan.
R5.	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5 to the greater of:	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5 to the greater of:	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5 to the greater of:	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5 to the greater of:

	• one applicable personnel at a single generating unit; or • 5% or less of its total applicable personnel.	• two applicable personnel at a single generating unit; or • more than 5%, but less than or equal to 10% of its total applicable personnel.	• three applicable personnel at a single generating unit; or • more than 10%, but less than or equal to 15% of its total applicable personnel.	• four applicable personnel at a single generating unit; or • more than 15% of its total applicable personnel.
R6.	The Generator Owner did not develop a CAP meeting the elements in Requirement R6 parts 6.1 and 6.2 for 5% or less of its total events listed in Requirement R6.	The Generator Owner did not develop a CAP meeting the elements in Requirement R6 parts 6.1 and 6.2 for more than 5%, but less than or equal to 10% of its total events listed in Requirement R6.	The Generator Owner did not develop a CAP meeting the elements in Requirement R6 parts 6.1 and 6.2 for more than 10%, but less than or equal to 15% of its total events listed in Requirement R6.	The Generator Owner did not develop a CAP meeting the elements in Requirement R6 parts 6.1 and 6.2 for more than15% of its total events listed in Requirement R6.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	TBD	Drafted by Project 2021-07	New

Standard Development Timeline

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Description of Current Draft

This is the first draft of the proposed standard for a formal 30-day comment period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	11/17/2021
SAR posted for comment	11/22/21 – 12/21/21

Anticipated Actions	Date
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10-day final ballot	September 2022
Board adoption	October 2022

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):
None

A. Introduction

1. **Title:** **Extreme Cold Weather Preparedness and Operations**

2. **Number:** EOP-012-1

3. **Purpose:** To address the effects of operating in extreme cold weather by ensuring each Generator Owner has developed and implemented plan(s) to mitigate the reliability impacts of extreme cold weather on its generating units.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Generator Owner

   4.1.2. Generator Operator

   4.2. Facilities: For purposes of this standard, the term "generating unit" means those Bulk Electric System generators that plan to operate during the winter season. The winter season will be determined by the generating unit's applicable Balancing Authority. The term excludes those generators that do not operate during the winter season except when called upon by the Balancing Authority to be available during Capacity Emergencies or Energy Emergencies.

5. **Effective Date:** See Implementation Plan for Project 2021-07.

B. Requirements and Measures

R1. Each Generator Owner shall ensure generating units implement freeze protection measures based on the following minimum criteria: [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning, Operations Planning*]

1.1. Each generating unit shall be designed and maintained to be capable of continuous operations at the documented minimum hourly temperature experienced at its location since 1/1/1975 or a lesser period if reliable data is not available to 1975;

1.2. The generating unit design shall account for the cooling effect of wind;

1.3. The generating unit design shall account for the impacts on operations due to precipitation (e.g., sleet, snow, ice, and freezing rain); and

1.4. For each existing generating units that require either new freeze protection measures or modification of existing freeze protection measures, the Generator Owner shall develop and implement a Corrective Action Plan (CAP) which includes the following at a minimum:

1.4.1. An identification of corrective action (s) for the affected unit(s), including any necessary modifications to the Generator Owner's cold weather preparedness plan(s);

1.4.2. A timetable for implementing the corrective action(s) from Part 1.4.1 which considers any technical, commercial, or operational constraints, as defined by the Generator Owner;

1.4.3. An identification of any temporary operating limitations that would apply until execution of the corrective action(s) identified in the CAP; and

1.4.4. A declaration, where deemed appropriate by the Generator Owner based on the review of Parts 1.4.1 through 1.4.3, that no revisions to the cold weather preparedness plan(s) are required and that no further corrective actions will be taken. The Generator Owner shall document technical, commercial, or operational constraints as defined by the Generator owner as support for such declaration.

M1. Each Generator Owner will have dated evidence that demonstrates it has freeze protection measures for its unit(s) in accordance with R1. Acceptable evidence may include the following (electronic or hardcopy format): Documentation of extreme temperature used for the freeze protection design, documentation of freeze protection measures, Facility cold weather preparedness plan, and CAP(s).

R2. Each Generator Owner that is not able to implement freeze protection measures for new generating unit(s) as required by Requirement R1 due to technical, commercial, or operational constraints as defined by the Generator Owner shall: *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

2.1. Document its determination and the constraints on implementation; and

2.2. Review its determination every five calendar years to determine whether the documented constraints on implementation remain applicable.

M2. Each Generator Owner will have dated evidence that demonstrates it documented constraints on implementation of freeze protection measures and conducted a review of its units in accordance with Requirement R2. Acceptable evidence may include the following dated documentation (electronic or hardcopy format): Documentation of technical, commercial, or operational constraint. Documentation of five calendar year reviews as applicable.

~~R1.~~R3. Each Generator Owner shall implement and maintain one or more cold weather preparedness plan(s) for its generating units. The cold weather preparedness plan(s) shall include the following, at a minimum: *[Violation Risk Factor: High] [Time Horizon: Operations Planning and Real-time Operations]*

3.1. Documented minimum hourly temperature experienced at its location since 1/1/1975 or a lesser period if reliable data is not available to 1975;

~~**1.1.**~~**3.2.** Documented generating unit(s) freeze protection measures based on geographical location and plant configuration;

~~**1.2.**~~**3.3.** Annual inspection and maintenance of generating unit(s) freeze protection measures; and

~~**1.3.**~~**3.4.** Generating unit(s) cold weather data, to include:

~~**1.3.1.**~~**3.4.1.** Generating unit(s) operating limitations in cold weather to include:

~~**1.3.1.1.**~~**3.4.1.1.** Capability and availability;

~~**1.3.1.2.**~~**3.4.1.2.** Fuel supply and inventory concerns;

~~**1.3.1.3.**~~**3.4.1.3.** Fuel switching capabilities; and

~~**1.3.1.4.**~~**3.4.1.4.** Environmental constraints.

~~**1.3.2.**~~**3.4.2.** Generating unit(s) minimum:

- Design temperature; ~~or~~
- Historical operating temperature; or
- Current cold weather performance temperature determined by an engineering analysis.

~~**M1.**~~**M3.** Each Generator Owner will have evidence documenting that its cold weather preparedness plan(s) was implemented and maintained in accordance with Requirement R3~~7~~.

R4. Once every five calendar years, each Generator Owner shall: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning, Real-Time Operations]*

4.1. Review the documented minimum hourly temperature developed pursuant to Part 3.1, and update the cold weather preparedness plan with the lowest temperature as necessary;

4.2. Review its documented cold weather minimum temperature contained within its cold weather preparedness plan(s) for its generating units, pursuant to Part 3.4.2; and

4.3. Review whether its generating units have the freeze protection measures required to operate at the lowest temperature established pursuant to Requirement R1 and, if not, implement appropriate modifications per the requirements of Part 1.4.

M4. Each Generator Owner will have evidence documenting that it reviewed documented temperature data and updated its cold weather preparedness plan(s) accordance with Requirement R4.

~~**R2.**~~**R5.** Each Generator Owner in conjunction with its Generator Operator shall identify the entity responsible for providing the generating unit-specific training, and that identified entity shall provide annual training to its maintenance or operations personnel responsible for implementing cold weather preparedness plan(s) developed pursuant to Requirement R3~~7~~. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]*

~~**M2.**~~**M5.** Each Generator Operator or Generator Owner will have documented evidence that the applicable personnel completed annual training of the Generator Owner's cold weather preparedness plan(s). This evidence may include, but is not limited to, documents such as personnel training records, training materials, date of training, agendas or learning objectives, attendance at pre-work briefings, review of work order tasks, tailboards, attendance logs for classroom training, and completion records for computer-based training in fulfillment of Requirement R5~~8~~.

R6. Each Generator Owner that owns a generating unit that experiences an event resulting in a derate of more than 10% of the total capacity of the unit for longer than four hours in duration, a start-up failure where the unit fails to synchronize within a specified start-up time, or a Forced Outage for which (i) the apparent cause(s) of the event is due to freezing of the Generator Owner's equipment within the Generator Owner's control, and (ii) the ambient conditions at the site at the time of the event are at or above the temperature documented in Part 3.4.2 shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

6.1. No later than 150 days subsequent to the event or by July 1 that follows the event, whichever is earlier, develop a CAP.

6.2. The CAP shall contain at a minimum:

6.2.1. A summary of the identified cause(s) for the equipment freezing event where applicable and any relevant associated data;

6.2.2. A review of applicability to similar equipment at other generating units owned by the Generator Owner;

6.2.3. An identification of corrective action(s) for the affected unit(s) and identified similar units, including any necessary modifications to the Generator Owner's cold weather preparedness plan(s);

6.2.4. A timetable for implementing the identified corrective action(s) from Part .6.2.3 which considers any technical, commercial, or operational constraints as defined by the Generator Owner;

6.2.5. An identification of any temporary operating limitations that would apply until execution of the corrective action(s) identified in the CAP; and

6.2.6. A declaration, where deemed appropriate by the Generator Owner based on the review of Parts 6.2.1 through 6.2.5 that no revisions to the cold weather preparedness plan are required and that no further corrective actions will be taken. The Generator Owner shall document technical, commercial, or operational constraints as defined by the Generator Owner as support for such declaration.

M6. Acceptable evidence for these requirements may include, but is not limited to, the following dated documentation (electronic or hardcopy format): CAP(s) and updated cold weather preparedness plan(s) where indicated as needed by the CAP.

~~A.~~C. Compliance

1. **Compliance Monitoring Process**

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

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

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

   - The Generator Owner shall keep data or evidence to show compliance for three years or until any Corrective Action Plan under Part 1.4 is complete, whichever timeframe is greater, for Requirement R1 and Measure M1.
   - The Generator Owner shall keep data or evidence to show compliance for three years for Requirement R2, R3, and R5 and Measure M2, M3 and M5.
   - The Generator Owner shall retain the current cold weather preparedness plan(s), as evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirement R4 and Measure M4.
   - The Generator Owner shall keep data or evidence to show compliance for three years or until any Corrective Action Plan under 6.2 is complete, whichever timeframe is greater, for Requirement R6 and Measure M6.

   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.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 Parts 1.1 – 1.3 for up to 5% its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 Parts 1.1 – 1.3 for more than 5% but less than or equal to 10% of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 Parts 1.1 – 1.3 for more than 10% but less than or equal to 20% of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 Parts 1.1 – 1.3 for more than 20% of its units; OR The Generator Owner did not develop or implement a CAP as required by Requirement R1.
R2.	The Generator Owner completed the review required in Requirement R2, but was late by 30 calendar days or less. OR The Generator Owner did not document its determination and the constraints described in Requirement R2 Part 2.1 for up to 5% its units.	The Generator Owner completed the review required in Requirement R2, but was late by greater than 30 calendar days but less than or equal to 60 calendar days. OR The Generator Owner did not document its determination and the constraints described in Requirement R1 Part 2.1 for more than 5% but less than or equal to 10% of its units.	The Generator Owner completed the review required in Requirement R2, but was late by greater than 60 calendar days. OR The Generator Owner did not document its determination and the constraints described in Requirement R1 Part 2.1 for more than 10% but less than or equal to 20% of its units.	The Generator Owner did not complete a review. OR The Generator Owner did not document its determination and the constraints described in Requirement R1 Part 2.1 for more than 20% of its units.

R3.	The Generator Owner implemented a cold weather preparedness plan(s) but failed to maintain it.	The Generator Owner's cold weather preparedness plan failed to include one of the applicable Parts within Requirement R3~~7~~.	The Generator Owner had and maintained a cold weather preparedness plan(s) but failed to ~~fully~~ implement it. OR The Generator Owner's cold weather preparedness plan failed to include two of the applicable requirement parts within Requirement R3~~7~~.	The Generator Owner does not have cold weather preparedness plan(s). OR The Generator Owner has a cold weather preparedness plan but failed to include any of the applicable requirement parts within Requirement R3~~7~~.
R4.	The Generator Owner completed the review required in Requirement R4, but was late by 30 calendar days or less.	The Generator Owner completed the review required in Requirement R4, but was late by greater than 30 calendar days but less than or equal to 60 calendar days.	The Generator Owner's review failed to include one of the applicable requirement parts in Requirement R4 Parts 4.1 through 4.3; OR The Generator Owner completed the review required in Requirement R4, but was late by greater than 60 calendar days.	The Generator Owner's review failed to include two or more of the applicable requirement parts in Requirement R4 Parts 4.1 through 4.3; OR The Generator Owner does not have a completed review. OR The Generator Owner did not update the cold weather preparedness plan.
R5.	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5~~8~~ to the greater of:	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5~~8~~ to the greater of:	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5~~8~~ to the greater of:	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5~~8~~ to the greater of:

	• one applicable personnel at a single generating unit; or • 5% or less of its total applicable personnel.	• two applicable personnel at a single generating unit; or • more than 5% but less than or equal to 10% of its total applicable personnel.	• three applicable personnel at a single generating unit; or • more than 10% but less than or equal to 15% of its total applicable personnel.	• four applicable personnel at a single generating unit; or • more than 15% of its total applicable personnel.
R6.	The Generator Owner did not develop a CAP meeting the elements in Requirement R6 parts 6.1 and 6.2 for 5% or less of its total events listed in Requirement R6.	The Generator Owner did not develop a CAP meeting the elements in Requirement R6 parts 6.1 and 6.2 for more 5% but less than or equal to 10% of its total events listed in Requirement R6.	The Generator Owner did not develop a CAP meeting the elements in Requirement R6 parts 6.1 and 6.2 for more 10% but less than or equal to 15% of its total events listed in Requirement R6.	The Generator Owner did not develop a CAP meeting the elements in Requirement R6 parts 6.1 and 6.2 for more 15% of its total events listed in Requirement R6.

~~B.~~D. Regional Variances

None.

~~C.~~E. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	TBD	Drafted by Project 2021-07	New

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination
Reliability Standards EOP-011-3 and EOP-012-1

Applicable Standard(s)

- EOP-011-3 Emergency Preparedness and Operations
- EOP-012-1 Extreme Cold Weather Preparedness and Operations

Requested Retirement(s)

- EOP-011-2

Prerequisite Standard(s)

- None

Applicable Entities

- See subject Reliability Standards.

Background

The purpose of Project 2021-07 is to develop Reliability Standards to enhance the reliability of the Bulk Electric System (BES) through improved operations, preparedness, and coordination during extreme cold weather, as recommended by the Federal Energy Regulatory Commission (FERC), NERC, and Regional Entity Joint Staff Inquiry into the February 2021 extreme cold weather event.[1]

From February 8 through 20, 2021, extreme cold weather and precipitation caused large numbers of generating units to experience outages, derates, or failures to start, resulting in energy and transmission emergencies (referred to as "the Event"). The total Event firm load shed was the largest controlled firm load shed event in U.S. history and was the third largest in quantity of outaged megawatts (MW) of load after the August 2003 northeast blackout and the August 1996 west coast blackout. The Event was most severe from February 15 through February 18, 2021, and it contributed to power outages affecting millions of electricity customers throughout the regions of ERCOT, SPP, and MISO South.

Extreme cold weather has repeatedly challenged the reliable operation of the bulk-power system (BPS). The Event is the fourth in the past 10 years which jeopardized BPS reliability. In February

[1] *See* FERC, NERC and Regional Entity Staff Report, *The February 2021 Cold Weather Outages in Texas and the South Central United States* (Nov. 2021) (referred to as "the Report").

2011, an arctic cold front impacted the southwest U.S. and resulted in numerous generation outages, natural gas facility outages, and emergency power grid conditions with firm customer load shed. In January 2014, a polar vortex affected Texas, central and eastern U.S, which triggered many generation outages, natural gas availability issues, and resulted in emergency conditions including load shed. In January 2018, an arctic high-pressure system and below average temperatures in the south-central U.S. resulted in many generation outages and voluntary load management measures.

Project 2021-07 is a two-phase project to address the 10 sub-recommendations in Key Recommendation 1 of the Report for new or enhanced NERC Reliability Standards. This implementation plan addresses Reliability Standards EOP-011-3 and EOP-012-1, which were developed to address the first phase of Reliability Standards recommendations.

Proposed Reliability Standard EOP-012-1 is a new extreme cold weather preparedness and operation Reliability Standard that addresses Recommendations 1d, 1e, and 1f of the Report. This standard includes requirements for implementing freeze protection measures for new and existing BES generating units to operate at location-specific temperature (Requirements R1 and R2), and for addressing the causes of outages, de-rates, and failures to synchronize caused by freezing (Requirement R6). The proposed Reliability Standard also includes requirements for cold weather preparedness plans and training (Requirements R3 and R5), originally included in Reliability Standard EOP-011-2 by Project 2019-06, Cold Weather Preparedness and Communication Requirements between Functional Entities. Proposed Reliability Standard EOP-012-1 builds upon the existing cold weather preparedness plans and training requirements by requiring entities to periodically review their local cold weather conditions to ensure the continued validity of cold weather operating plans and freeze protection measures (Requirement R4) and by specifying that cold weather training under Requirement R5 must be completed on an annual basis.

Proposed Reliability Standard EOP-011-3 is a revised Reliability Standard that addresses Recommendation 1j of the Report, minimizing the overlap of manual Load shed and automatic Load shed programs such as underfrequency Load shed (UFLS) and undervoltage Load shed (UVLS). This revision also removes R7 and R8, as this language was moved to the new EOP-012-1, noted above.

General Considerations

This implementation plan reflects consideration that entities will need time to develop, implement, and maintain cold weather plans and freeze protection measures. This implementation plan covers the key recommendations from the Report identified for phase one only, Recommendations 1d, 1e 1f, and 1j.

Effective Date and Phased-In Compliance Dates

The effective dates for the proposed Reliability Standards are provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of a proposed Reliability Standard (i.e., an entire Requirement or a portion thereof), the additional time for compliance with that section is specified below. The phased-in compliance date for those particular sections represents the date 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.

Standard EOP-011-3

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 18 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 18 months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Standard EOP-012-1

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 18 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 18 months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Compliance Date for EOP-012-1 - Requirement R1 and R2

Entities shall not be required to comply with Requirement R1 and R2 until 42 months after the effective date of Reliability Standard EOP-012-1.

Retirement Date

Standard EOP-011-2

Reliability Standard EOP-011-2 shall be retired immediately prior to the effective date of Reliability Standard EOP-011-3 in the particular jurisdiction in which the revised standard is becoming effective.

Unofficial Comment Form

Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on **Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination** by **8 p.m. Eastern, June 17, 2022.**

Additional information is available on the project page. If you have questions, contact Senior Standards Developer, Alison Oswald (via email), or at 404-446-9668.

Background Information

From February 8 through February 20, 2021, extreme cold weather and precipitation caused large numbers of generating units to experience outages, derates or failures to start, resulting in energy and transmission emergencies (referred to as "the Event"). The total Event firm Load shed was the largest controlled firm Load shed event in U.S. history and was the third largest in quantity of outaged megawatts (MW) of Load after the August 2003 northeast blackout and the August 1996 west coast blackout. The Event was most severe from February 15 through February 18, 2021, and it contributed to power outages affecting millions of electricity customers throughout the regions of ERCOT, SPP and MISO South. Additionally, the February 2021 event is the fourth cold weather event in the past 10 years, which jeopardized bulk-power system reliability. A joint inquiry was conducted to discover reliability-related findings and recommendations from FERC, NERC, and Regional Entity staff. The FERC, NERC, and Regional Entity staff Joint Staff Inquiry into the February 2021 Cold Weather Grid Operations ("Joint Inquiry Report") was published on November 16, 2021.

The scope of the proposed project is to address the ten recommendations for new or enhanced NERC Reliability Standards proposed by the Joint Inquiry Report. In November 2021, the NERC Board of Trustees (Board) approved a Board Resolution directing that new or revised Reliability Standards addressing these recommendations be completed in accordance with the timelines recommended by the joint inquiry team, as follows:

- New and revised Reliability Standards to be submitted for regulatory approval before Winter 2022/2023: development completed by September 30, 2022, for the Board's consideration in October 2022 to address Key Recommendations 1d, 1e, 1f, and 1j;
- New and revised Reliability Standards to be submitted for regulatory approval before Winter 2023/2024: development completed by September 30, 2023, for the Board's consideration in October 2023 to address Key Recommendations 1a, 1b, 1c, 1g, 1h, and 1i.

Questions

1. The SDT revised EOP-011-3 requirements R1 and R2 for the TOP to minimize the overlap of UFLS and UVLS circuits from those used for manual load shed or those that serve critical loads. Should PRC-006-5 Requirement R7 and PRC-010-2 Requirement R8 also be modified to include a Requirement that Planning Coordinators shall provide UFLS and/or UVLS (as applicable) program database data to Transmission Operator's upon request, in order to ensure that all TOPs have the necessary data to minimize the overlap of circuits as required in the newly proposed EOP-011-3 Requirement R1.2.5.3? Please provide any explanation with your response.
   ☐ Yes
   ☐ No

   Comments:

2. Should the BA be the entity to determine the "winter season", which is used to define applicable generating units in proposed EOP-012-1 Section 4.2 Facilities? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.
   ☐ Yes
   ☐ No

   Comments:

3. The SDT proposes to include as applicable Facilities in EOP-012-1 only those generating units that operate during the winter weather season, while exempting those units utilized for summer peaking purposes only (and without penalizing such units that may be called upon by the BA during winter weather in response to energy emergencies). Do you agree with the applicability of EOP-012-1 as drafted? If you do not agree, please provide recommended language for how to address from the standard's applicability consistent with the recommendations of The Report.
   ☐ Yes
   ☐ No

   Comments:

4. Does the proposed language in EOP-012-1 requirement R1 that require existing units to implement new freeze protection measures or modification of existing freeze protection measures, raise any stakeholder concerns? If so, please provide details of the concern, suggestions to the proposed language that addresses the risk presented in recommendation 1f, and if appropriate, technical or procedural justification.
   ☐ Yes
   ☐ No

   Comments:

5. The SDT has proposed that owners of new generation that determine that they are not able to implement freeze protection measures due to technical, commercial, or operational constraints review their determination every five years for EOP-012-1 Requirement R2. Is this separate

requirement for “new” generation necessary, given that proposed Requirement R4 provides for Generator Owners to perform a similar review every five years to address the ongoing need to review freeze protection measures and historical cold weather temperatures? Please provide any explanation with your response.

☐ Yes
☐ No

Comments:

6. The Standard, as proposed, would require Generator Owners to develop plans for modifying generating units to operate to the minimum hourly temperature over the next five years after Commission approval. While Generator Owners identify those generating units that need modifications, develop corrective action plans, and implement modifications, it is important for the ERO Enterprise to have aggregated data about the status of Generation Owners’ extreme cold weather preparedness for its generating units for use in its reliability oversight activities.

   The SDT believes that there is benefit to having the ERO Enterprise collect information on progress of Generator Owner plans for modifying generating units. The information could be collected through reporting under mandatory Reliability Standard requirements, through a Periodic Data Submittal under Section 400 of the Rules of Procedure (which may or may not be specified in the Compliance section of the standard), or through a request for data under Section 1600 of the Rules of Procedure. Which of these options do you believe is the best procedural option for collecting this information?

   Comments:

7. The drafting team has developed a proposed data collection framework which could form the basis for a periodic data submittal. If you have any comments or edits to the suggested language, please propose an alternative to address the identified risk during the phased-in compliance period.

Collection framework:

- The Generator Owner will submit an annual summary table **by October 1 of each year** to its Regional Entity regarding the status of its generating units (as that term is used in EOP-012-1 4.2 Facilities) having freeze protection measures in accordance with Requirements R1 and R2, along with a nine-year projection of status based on the timetables it has determined for Requirement R1. All projections will be based on the Generator Owner’s timetables under Requirement R1.4.2; if timetables are not complete for all units, some MW can be designated as “to be determined.” The summary table shall contain:
  - Status year (for current year, and future years 1-9);
  - Sum of capacities (in MW) of all generating units applicable under Facilities, section 4.2;
  - Sum of capacities (MW) of generating units meeting (for current year) and projected to meet (for each of the future years 1-9) the criteria of Requirement R1.1;

- Sum of capacities (MW) of generating units not meeting (for current year) and projected to not meet (for each of the future years 1-9) the criteria of Requirement R1.1;
- Sum of the capacities (MW) of existing generating units declared for no action under Requirement R1 (for current year, and projected for future years 1-9);
- Sum of the capacities (MW) of new generating units identified for no action under Requirement R2 (for current year, and projected for future years 1-9).

Comments:

8. The SDT proposes that the modifications in EOP-011-3 and the newly drafted EOP-012-1 meet the key recommendations in The Report 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. The SDT is proposing an 18-month implementation time frame for all revised and new requirements except EOP-012-1 Requirements R1 and R2 which have a 5-year implementation time frame. Do you agree with this implementation time frame? If you think an alternate timeframe is needed, please propose an alternate implementation plan and time period, and provide a detailed explanation of actions planned to meet the implementation deadline.

☐ Yes
☐ No

Comments:

10. Provide any additional comments for the standard drafting team to consider, including the provided technical rationale document, if desired.

Comments:

Mapping Document

Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination

Summary

This mapping document maps the recommendations from the February 2021 Cold Weather Outages in Texas and the South Central United States report (The Report) to the creation of new standard EOP-012-1 as well as the revised EOP-011-3.

Recommendation 1d

Generator Owners that experience outages, failures to start, or derates due to freezing are to review the generating unit's outage, failure to start, or derate and develop and implement a corrective action plan (CAP) for the identified equipment, and evaluate whether the CAP applies to similar equipment for its other generating units. Based on the evaluation, the Generator Owner will either revise its cold weather preparedness plan to apply the CAP to the similar equipment, or explain in a declaration (a) why no revisions to the cold weather preparedness plan are appropriate, and (b) that no further corrective actions will be taken. The standard drafting team should specify the specific timing for the CAP to be developed and implemented after the outage, derate or failure to start, but the CAP should be developed as quickly as possible, and be completed by no later than the beginning of the next winter season.

Standard: EOP-012-1		
Requirement in Approved Standard	**Transition to New Standard or Other Action**	**Description and Change Justification**
This requirement does not exist in an already approved standard. It is new to EOP-012-1.	**EOP-012-1 Requirement R6** **R6.** Each Generator Owner that owns a generating unit that experiences an event resulting in a derate of more than 10% of the total capacity of the unit for longer than four hours in duration, a start-up failure where the unit fails to synchronize within a specified start-up time, or a Forced Outage for which (i) the apparent cause(s) of the event is due to freezing of the Generator	This requirement addresses recommendation 1d for Generator Owners to develop and implement a CAP based on a unit's outage, failure to start or derate. The CAP requirement applies to any forced outage due to freezing, regardless of duration. Derates, which are short-lived or of small capacity impact, are excluded from the CAP requirement. R6 requires the GO to act within 150 days or July 1 to develop the CAP or document that no corrective action is appropriate. This timeframe was chosen to allow GO's to review multiple events holistically following a winter

	Owner's equipment within the Generator Owner's control, and (ii) the ambient conditions at the site at the time of the event are at or above the temperature documented in Part 3.4.2 shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]* **6.1.** No later than 150 days subsequent to the event or by July 1 that follows the event, whichever is earlier, develop a CAP. **6.2.** The CAP shall contain at a minimum: **6.2.1.** A summary of the identified cause(s) for the equipment freezing event where applicable and any relevant associated data; **6.2.2.** A review of applicability to similar equipment at other generating units owned by the Generator Owner; **6.2.3.** An identification of corrective action(s) for the affected unit(s) and identified similar units, including any necessary modifications to the Generator Owner's cold weather preparedness plan(s); **6.2.4.** A timetable for implementing the identified corrective	season, and create one CAP for equipment with common failure causes while meeting the recommendation charge to be "developed as quickly as possible". Requirement R6.2 define the requirements for a CAP and the requirements for a declaration when technical, commercial, or operational constraints are present.

	action(s) from Part 6.2.3 which considers any technical, commercial, or operational constraints as defined by the Generator Owner; **6.2.5.** An identification of any temporary operating limitations that would apply until execution of the corrective action(s) identified in the CAP; and **6.2.6.** A declaration, where deemed appropriate by the Generator Owner based on the review of Parts 6.2.1 through 6.2.5 that no revisions to the cold weather preparedness plan are required and that no further corrective actions will be taken. The Generator Owner shall document technical, commercial, or operational constraints as defined by the Generator Owner as support for such declaration.	

Recommendation 1e

To revise EOP-011-2, R8, to require Generator Owners and Generator Operators to conduct annual unit-specific cold weather preparedness plan training.

Standard: EOP-012-1		
Requirement in Approved Standard	**Transition to New Standard or Other Action**	**Description and Change Justification**
EOP-011-2 Requirement R8 **R8.** Each Generator Owner in conjunction with its Generator Operator shall identify the entity responsible for providing the generating unit-specific training, and that identified entity shall provide the training to its maintenance or operations personnel responsible for implementing cold weather preparedness plan(s) developed pursuant to Requirement R7.	**EOP-012-1 Requirement R5** **R5.** Each Generator Owner in conjunction with its Generator Operator shall identify the entity responsible for providing the generating unit-specific training, and that identified entity shall provide ~~the~~ annual training to its maintenance or operations personnel responsible for implementing cold weather preparedness plan(s) developed pursuant to Requirement R3.	EOP-011-2 Requirement R8 was moved to new standard EOP-012-1 Requirement R5. The language remains the same with the addition of the word annual to meet the charge in recommendation 1e of The Report.

Recommendation 1f

To require Generator Owners to retrofit existing generating units, and when building new generating units, to design them, to operate to a specified ambient temperature and weather conditions (e.g., wind, freezing precipitation). The specified ambient temperature and weather conditions should be based on available extreme temperature and weather data for the generating unit's location.

Standard: EOP-012-1		
Requirement in Approved Standard	**Transition to New Standard**	**Description and Change Justification**
This requirement does not exist in an already approved standard. It is new to EOP-012-1.	**EOP-012-1 Requirement R1** **R1.** Each Generator Owner shall ensure generating units implement freeze protection measures based on the following minimum criteria: [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning, Operations Planning*]	This requirement addresses new build generation as well as existing generation to have freeze protection measures. Parts 1.1 through 1.3 lay out the requirements for unit design and Part 1.4 is a CAP requirement for any unit that has to implement new or modify existing freeze protection measure to meet the design requirements in Part 1.1 through 1.3. The SDT understands that the reliability goal of the

	1.1. Each generating unit shall be designed and maintained to be capable of continuous operations at the documented minimum hourly temperature experienced at its location since 1/1/1975 or a lesser period if reliable data is not available to 1975; **1.2.** The generating unit design shall account for the cooling effect of wind; **1.3.** The generating unit design shall account for the impacts on operations due to precipitation (e.g., sleet, snow, ice, and freezing rain); and **1.4.** For each existing generating units that require either new freeze protection measures or modification of existing freeze protection measures, the Generator Owner shall develop and implement a Corrective Action Plan (CAP) which includes the following at a minimum: **1.4.1.** An identification of corrective action (s) for the affected unit(s), including any necessary modifications to the Generator Owner's cold weather preparedness plan(s); **1.4.2.** A timetable for implementing the corrective action(s) from Part 1.4.1 which considers any technical, commercial, or operational constraints, as defined by the Generator Owner;	recommendation for existing generating units is to have the necessary freeze protection measures to be able to operate at extreme cold temperatures and weather for the generating unit's location. For example, those measures may consist of existing or new, permanent and/or temporary measures to maintain operation during extreme cold temperatures.

	1.4.3. An identification of any temporary operating limitations that would apply until execution of the corrective action(s) identified in the CAP; and **1.4.4.** A declaration, where deemed appropriate by the Generator Owner based on the review of Parts 1.4.1 through 1.4.3, that no revisions to the cold weather preparedness plan(s) are required and that no further corrective actions will be taken. The Generator Owner shall document technical, commercial, or operational constraints as defined by the Generator owner as support for such declaration.	

Recommendation 1j
In minimizing the overlap of manual and automatic load shed, the load shed procedures of Transmission Operators, Transmission Owners (TOs) and Distribution Providers (DPs) should separate the circuits that will be used for manual load shed from circuits used for underfrequency load shed (UFLS)/undervoltage load shed (UVLS) or serving critical load. UFLS/UVLS circuits should only be used for manual load shed as a last resort and should start with the final stage (lowest frequency).

Standard: EOP-011-3		
Requirement in Approved Standard	**Transition to New Standard or Other Action**	**Description and Change Justification**
EOP-011-2 Requirement R1 Part 1.2.5 **1.2.5** Provisions for operator-controlled manual Load shedding that minimizes	**EOP-011-3 Requirement R1 Part 1.2.5**	EOP-011-3 adds additional provisions and clarifies what the TOP must include in their Operating Plan to mitigate

the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and	**1.2.5.** Operator-controlled manual Load shedding during an Emergency that accounts for each of the following: **1.2.5.1.** Provisions for ~~operator-controlled~~ manual Load shedding ~~that minimizes the overlap with automatic Load shedding and are~~ capable of being implemented in a timeframe adequate for mitigating the Emergency; ~~and~~ **1.2.5.2.** Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that serve designated critical loads; **1.2.5.3.** Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for underfrequency load shed (UFLS) or undervoltage load shed (UVLS); and **1.2.5.4.** Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions.	operating Emergencies. Specific clarifications are to minimizing the overlap of manual Load shed and circuits that serve designated critical loads; minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for underfrequency load shed (UFLS) or undervoltage load shed (UVLS); and provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed. The SDT elected to keep the phase “minimize the overlap” instead of moving to language that specifically requires the separation of circuits in recognition of the fact that it is not always practical or warranted to completely separate circuits used for each of these purposes.

EOP-011-2 Requirement R2 Part 2.2.8 **2.2.8.** Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and	**EOP-011-3 Requirement R2 Part 2.2.8** **2.2.8.** Provisions for Transmission Operators to implement operator-controlled manual Load shed~~ding~~ in accordance with Requirement R1 Part 1.2.5~~that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency~~; and	This part of R2 has been modified to refer back to Requirement R1, Part 1.2.5 in an effort to clarify that the Transmission Operator is responsible for addressing operator-controlled manual load shed requirements in their Operating Plan. Balancing Authorities are expected to specify manual load shed requirements for Transmission Operators within their areas in accordance with Part 1.2.5, but do not have the control or visibility to design and implement manual load shed programs and UFLS/UVLS programs that meet the requirements of Part 1.2.5.

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Violation Risk Factor and Violation Severity Level Justifications

Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination

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 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination. 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.

EOP-011-3

VRF Justification for EOP-011-3, Requirement R1

The VRF did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VSL Justification for EOP-011-3, Requirement R1

The VSL did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VRF Justification for EOP-011-3, Requirement R2

The VRF did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VSL Justification for EOP-011-3, Requirement R2

The VSL did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VRF Justification for EOP-011-3, Requirement R3

The VRF did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VSL Justification for EOP-011-3, Requirement R3

The VSL did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VRF Justification for EOP-011-3, Requirement R4

The VRF did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VSL Justification for EOP-011-3, Requirement R4

The VSL did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VRF Justification for EOP-011-3, Requirement R5

The VRF did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VSL Justification for EOP-011-3, Requirement R5

The VSL did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VRF Justification for EOP-011-3, Requirement R6
The VRF did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VSL Justification for EOP-011-3, Requirement R6
The VSL did not change from the previously FERC approved EOP-011-2 Reliability Standard.

EOP-012-1

VRF Justifications for EOP-012-1, Requirement R1	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that not designing or implementing freeze protection measures for a unit to operate during the local cold weather, that can be expected, could directly affect the electrical state or the capability of the bulk electric system, but 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. Therefore, it is consistent with the definition of a Medium VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent 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 consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a medium VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
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 EOP-012-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 Parts 1.1 – 1.3 for up to 5% its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 Parts 1.1 – 1.3 for more than 5%, but less than or equal to 10% of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 Parts 1.1 – 1.3 for more than 10%, but less than or equal to 20% of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 Parts 1.1 – 1.3 for more than 20% of its units; OR The Generator Owner did not develop or implement a CAP as required by Requirement R1.

VSL Justifications for EOP-012-1, 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 VSLs 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 VSLs 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 EOP-012-1, Requirement R2	
Proposed VRF	**Low**
NERC VRF Discussion	A VRF of Low is appropriate due to the fact that this 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.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent 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 consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a low VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
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 EOP-012-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner completed the review required in Requirement R2, but was late by 30 calendar days or less. OR The Generator Owner did not document its determination and the constraints described in Requirement R2 Part 2.1 for up to 5% its units.	The Generator Owner completed the review required in Requirement R2, but was late by greater than 30 calendar days but less than or equal to 60 calendar days. OR The Generator Owner did not document its determination and the constraints described in Requirement R1 Part 2.1 for more than 5%, but less than or equal to 10% of its units.	The Generator Owner completed the review required in Requirement R2, but was late by greater than 60 calendar days. OR The Generator Owner did not document its determination and the constraints described in Requirement R1 Part 2.1 for more than 10%, but less than or equal to 20% of its units.	The Generator Owner did not complete a review. OR The Generator Owner did not document its determination and the constraints described in Requirement R1 Part 2.1 for more than 20% of its units.

VSL Justifications for EOP-012-1, 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 VSLs 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	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.

VSL Justifications for EOP-012-1, Requirement R2	
for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs 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 Justification for EOP-012-1, Requirement R3

The VRF did not change from the previously FERC approved Reliability Standard EOP-011-2 Requirement R7.

VSL Justification for EOP-012-1, Requirement R3

The VSLs did not substantively change from the previously FERC approved Reliability Standard EOP-011-2 Requirement R7. A minor clarification was made to remove the word “fully” from the High VSL.

VRF Justifications for EOP-012-1, Requirement R4	
Proposed VRF	**Low**
NERC VRF Discussion	A VRF of Low is appropriate due to the fact that this requirement 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

VRF Justifications for EOP-012-1, Requirement R4	
Proposed VRF	**Low**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent 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 consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a low VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
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 EOP-012-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner completed the review required in Requirement R4, but was late by 30 calendar days or less.	The Generator Owner completed the review required in Requirement R4, but was late by greater than 30 calendar days but	The Generator Owner's review failed to include one of the applicable requirement parts in	The Generator Owner's review failed to include two or more of the applicable requirement parts in

	less than or equal to 60 calendar days.	Requirement R4 Parts 4.1 through 4.3; OR The Generator Owner completed the review required in Requirement R4, but was late by greater than 60 calendar days.	Requirement R4 Parts 4.1 through 4.3; OR The Generator Owner does not have a completed review. OR The Generator Owner did not update the cold weather preparedness plan.

VSL Justifications for EOP-012-1, 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 VSLs 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	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore,

VSL Justifications for EOP-012-1, Requirement R4	
Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	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 Justification for EOP-012-1, Requirement R5

The VRF did not change from the previously FERC approved EOP-011-2 Requirement R8 Reliability Standard.

VSL Justification for EOP-012-1, Requirement R5

The VSL did not substantively change from the previously FERC approved Reliability Standard EOP-011-2 Requirement R8. The language was updated to reflect the addition of "annual", consistent with the revised requirement language for the periodicity of the required generating unit-specific training.

VRF Justifications for EOP-012-1, Requirement R6	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate due to the fact that this requirement to take corrective actions if a generating unit experiences a derate, failure to start or forced outage due to freezing event 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.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.

VRF Justifications for EOP-012-1, Requirement R6	
Proposed VRF	**High**
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 consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a high VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
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. There for the VRF reflects the risk of the whole requirement.

VSLs for EOP-012-1, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner did not develop a CAP meeting the elements in Requirement R6 parts 6.1 and 6.2 for 5% or less of its total events listed in Requirement R6.	The Generator Owner did not develop a CAP meeting the elements in Requirement R6 parts 6.1 and 6.2 for more 5%, but less than or equal to 10% of its total events listed in Requirement R6.	The Generator Owner did not develop a CAP meeting the elements in Requirement R6 parts 6.1 and 6.2 for more 10%, but less than or equal to 15% of its total events listed in Requirement R6.	The Generator Owner did not develop a CAP meeting the elements in Requirement R6 parts 6.1 and 6.2 for more 15% of its total events listed in Requirement R6.

VSL Justifications for EOP-012-1, 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 VSLs 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 VSLs 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

Extreme Cold Weather Preparedness

Technical Rationale and Justification for EOP-011-3

May 2022

RELIABILITY | RESILIENCE | SECURITY




3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

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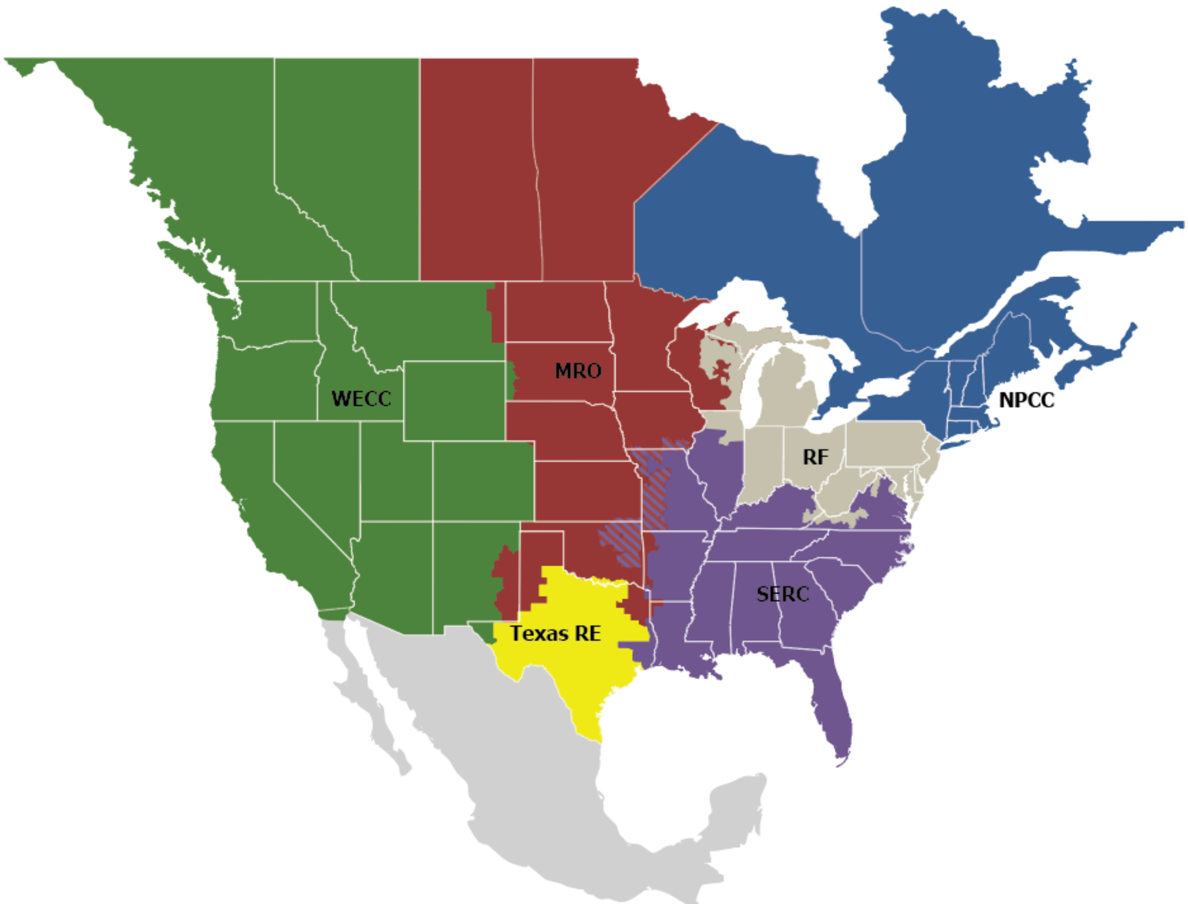
Preface

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 the North American Electric Reliability Corporation (NERC) and the six Regional Entities, is a highly reliable 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 Entity boundaries as shown in the map and 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 Standards EOP-011-3 and EOP-012-1. It provides stakeholders and the ERO Enterprise with an understanding of the technology and technical requirements in the Reliability Standard. This Technical Rationale and Justifications for EOP-011-3 and EOP-NEW is not a Reliability Standard and should not be considered mandatory and enforceable.

Background

From February 8 through February 20, 2021, extreme cold weather and precipitation caused large numbers of generating units to experience outages, derates or failures to start, resulting in energy and transmission emergencies (referred to as "the Event"). The total Event firm Load shed was the largest controlled firm Load shed event in U.S. history and was the third largest in quantity of outaged megawatts (MW) of Load after the August 2003 northeast blackout and the August 1996 west coast blackout. The Event was most severe from February 15 through February 18, 2021, and it contributed to power outages affecting millions of electricity customers throughout the regions of ERCOT, SPP and MISO South. Additionally, the February 2021 event is the fourth cold weather event in the past 10 years, which jeopardized bulk-power system reliability. A joint inquiry was conducted to discover reliability-related findings and recommendations from FERC, NERC, and Regional Entity staff. The FERC, NERC, and Regional Entity Staff Joint Staff Inquiry into the February 2021 Cold Weather Grid Operations ("Joint Inquiry Report") was published on November 16, 2021.

The scope of the proposed project is to address the ten recommendations for new or enhanced NERC Reliability Standards proposed by the Joint Inquiry Report. In November 2021, the NERC Board of Trustees approved a Board Resolution directing that new or revised Reliability Standards addressing these recommendations be completed in accordance with the timelines recommended by the joint inquiry team, as follows:

- New and revised Reliability Standards to be submitted for regulatory approval before Winter 2022/2023: development completed by September 30, 2022, for the Board's consideration in October 2022 to address Key Recommendations 1d, 1e, 1f and 1j;
- New and revised Reliability Standards to be submitted for regulatory approval before Winter 2023/2024: development completed by September 30, 2023, for the Board's consideration in October 2023 to address Key Recommendations 1a, 1b, 1c, 1g, 1h and 1i.

Requirement R1 and R2

R1. *Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

1.1. *Roles and responsibilities for activating the Operating Plan(s);*

1.2. *Processes to prepare for and mitigate Emergencies including:*

1.2.1. *Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency;*

1.2.2. *Cancellation or recall of Transmission and generation outages;*

1.2.3. *Transmission system reconfiguration;*

1.2.4. *Redispatch of generation request;*

1.2.5. *Operator-controlled manual load shedding during an Emergency that accounts for each of the following:*

1.2.5.1. *Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;*

1.2.5.2. *Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that serve designated critical loads;*

1.2.5.3. *Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for underfrequency load shed (UFLS) or undervoltage load shed (UVLS); and*

1.2.5.4. *Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions.*

1.2.6. *Provisions to determine reliability impacts of:*

1.2.6.1. *cold weather conditions; and*

1.2.6.2. *extreme weather conditions.*

R2. *Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

2.1. *Roles and responsibilities for activating the Operating Plan(s);*

2.2. *Processes to prepare for and mitigate Emergencies including:*

2.2.1. *Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;*

2.2.2. *Requesting an Energy Emergency Alert, per Attachment 1;*

2.2.3. *Managing generating resources in its Balancing Authority Area to address:*

2.2.3.1. *capability and availability;*

2.2.3.2. *fuel supply and inventory concerns;*

2.2.3.3. *fuel switching capabilities; and*

2.2.3.4. *environmental constraints.*

2.2.4. *Public appeals for voluntary Load reductions;*

2.2.5. *Requests to government agencies to implement their programs to achieve necessary energy reductions;*

2.2.6. *Reduction of internal utility energy use;*

2.2.7. *Use of Interruptible Load, curtailable Load and demand response;*

2.2.8. *Provisions for Transmission Operators to implement operator-controlled manual Load shed in accordance with Requirement R1 Part 1.2.5; and*

2.2.9. *Provisions to determine reliability impacts of:*

2.2.9.1. *cold weather conditions; and*

2.2.9.2. *extreme weather conditions.*

Key Recommendation 1j: In minimizing the overlap of manual and automatic load shed, the load shed procedures of Transmission Operators, Transmission Owners and Distribution Providers should separate circuits that will be used for manual load shed from circuits used for underfrequency load shedding/undervoltage load shedding or serving critical load. Underfrequency load shedding/undervoltage load shedding circuits should only be used for manual load shed as a last resort and should start with the final stage (lowest frequency).

Requirement R1, Part 1.2.5

Minimizing the Overlap of Circuits

EOP-011 version 2, Requirement R1.2.5 states the TOP's Operating Plan shall include provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding. EOP-011-3 adds additional provisions and clarifies what the TOP must include in their Operating Plan to mitigate operating Emergencies. Specific clarifications are to minimize the overlap of manual Load shed and circuits that serve designated critical loads; minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for underfrequency load shed (UFLS) or undervoltage load shed (UVLS); and provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed.

Minimizing the overlap of manual Load shed circuits and circuits that serve critical loads is necessary to prioritize certain critical loads which may be essential to the integrity of the electric system, public health, or the welfare of the community. The standard drafting team elected to keep the phase "minimize the overlap" instead of moving to language that specifically requires the separation of circuits in recognition of the fact that it is not always practical or warranted to completely separate circuits used for each of these purposes. This requirement can be accomplished in many different ways, such as creating separate and distinct lists for each circuit type, or by using prioritization and control-inhibit functions in an energy management system. This list is not exhaustive and there are certainly other acceptable methods of meeting this requirement.

Additionally, it is important to recognize that criticality designations must be considered in the context of the situation. Critical loads should not all receive the same level of priority, and the characteristics of a Load shed event (depth/duration/season) will impact the treatment of certain critical loads. Transmission Operators should consider establishing priorities for different types of critical loads. The critical Load designation, priority, and conditions during the event will influence which critical loads may be included in manual Load shed. For example, if system conditions continue to deteriorate and other Load shed options are exhausted, then some critical loads may need to be shed in the interest of preserving the system. It is important to have the awareness and flexibility to include or exclude certain loads based on the Load shed scenario.

The standard purposely does not state the method through which overlap is to be minimized. Transmission Operators may use a number of different approaches to satisfy this requirement. Each system is unique and will have various constraints that must be balanced in addressing these requirements.

Provisions

The term provisions, which has been carried forward from EOP-011-2, is intended to mean that it is the responsibility of the Transmission Operator to work with other entities, as necessary, to ensure that their Operating Plan is responsive to these requirements.

Limit the utilization of UFLS or UVLS for manual Load shed

In certain situations, it may be necessary and appropriate to utilize UFLS or UVLS circuits for manual Load shed. These situations may be driven by Load shed magnitudes, local constraints, or other factors. It is important for Transmission Operators to understand the circumstances where UFLS or UVLS circuits may be needed for manual Load shed. Their Operating Plans should identify system conditions that would allow for the utilization of UFLS or UVLS for manual Load shed and how it will be implemented. The Operating Plans should ensure that potential reliability impacts are appropriately considered and balanced. Three examples of such situations are discussed below.

Manual Load Shed Capabilities are Exhausted

During a major Load shed event, Transmission Operators may run out of circuits that are designated for manual Load shed. Due to the large amounts of Load shedding ordered, the duration of the Load shedding, and the exclusion of circuits serving critical Load, Transmission Operators may be forced to manually shed circuits that are utilized for UFLS or UVLS in order to maintain their obligation of total pro rata Load shed.

In such a situation, protecting system reliability requires the lesser evil of using some UFLS circuits to implement the required Load shedding. Transmission Operators should include provisions in their Operating Plans that balances the risk of the immediate emergency need to balance generation and Load to maintain reliability, with the potential for frequency disturbances in the future. In this case, Transmission Operators may elect to utilize UFLS circuits. In this scenario, the recommended practice is to start with the lowest frequency block to meet the Load shed obligations

Proactive Utilization of UFLS Circuits to Improve Outage Rotations and Balance UFLS Levels

Refer to NERC Lesson Learned on this topic:
https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20220301_Managing_UFLS_Obligations_Service_Critical_Loads_during_Energy_Emergency.pdf

Local Emergency Condition

Local emergency conditions are different from a system-wide short-supply situation. During local emergencies, it may be appropriate, and possibly necessary, to manually shed circuits that serve critical loads or that are utilized for UFLS or UVLS.

Requirement R2, Part 2.2.8

This part of R2 has been modified to refer back to Requirement R1, Part 1.2.5 in an effort to clarify that the Transmission Operator is responsible for addressing operator-controlled manual Load shed requirements in their Operating Plan. Balancing Authorities are expected to specify manual Load shed requirements for Transmission Operators within their areas in accordance with Part 1.2.5, but do not have the control or visibility to design and implement manual Load shed programs and UFLS/UVLS programs that meet the requirements of Part 1.2.5.

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Extreme Cold Weather Preparedness

Technical Rationale and Justification for EOP-012-1

May 2022

RELIABILITY | RESILIENCE | SECURITY

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

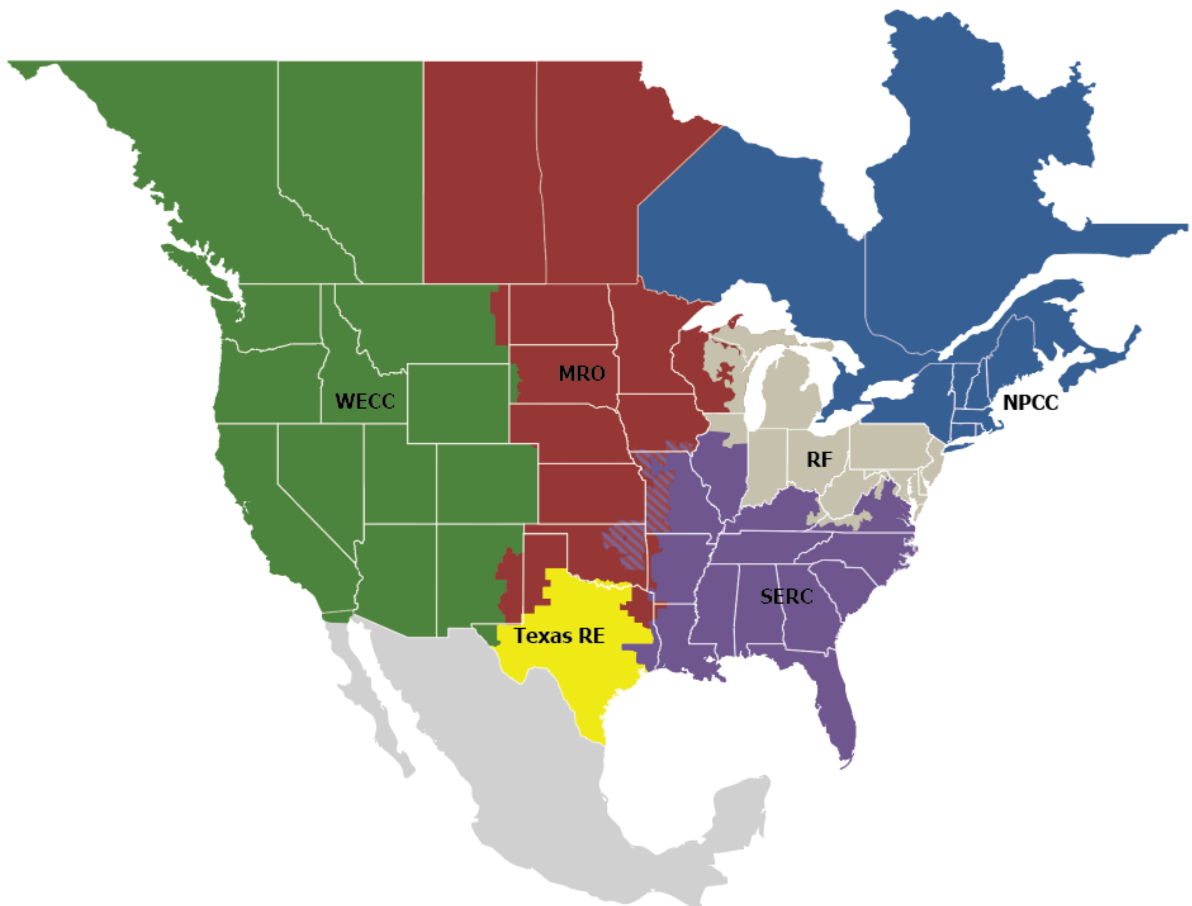
Table of Contents

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 the North American Electric Reliability Corporation (NERC) and the six Regional Entities, is a highly reliable 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 Entity boundaries as shown in the map and 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 EOP-012-1. 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 EOP-012-1 is not a Reliability Standard and should not be considered mandatory and enforceable.

Background

From February 8 through February 20, 2021, extreme cold weather and precipitation caused large numbers of generating units to experience outages, derates or failures to start, resulting in energy and transmission emergencies (referred to as “the Event”). The total Event firm load shed was the largest controlled firm load shed event in U.S. history and was the third largest in quantity of outaged megawatts (MW) of load after the August 2003 northeast blackout and the August 1996 west coast blackout. The Event was most severe from February 15 through February 18, 2021, and it contributed to power outages affecting millions of electricity customers throughout the regions of ERCOT, SPP, and MISO South. Additionally, the February 2021 event is the fourth cold weather event in the past 10 years, which jeopardized bulk-power system reliability. A joint inquiry was conducted to discover reliability-related findings and recommendations from FERC, NERC, and Regional Entity staff. The FERC, NERC, and Regional Entity Staff Report into the February 2021 Cold Weather Outages (“Joint Inquiry Report”) was published on November 16, 2021.

The scope of the proposed project is to address the ten recommendations for new or enhanced NERC Reliability Standards proposed by the Joint Inquiry Report. In November 2021, the NERC Board of Trustees (Board) approved a Board Resolution directing that new or revised Reliability Standards addressing these recommendations be completed in accordance with the timelines recommended by the joint inquiry team, as follows:

- New and revised Reliability Standards to be submitted for regulatory approval before Winter 2022/2023: development completed by September 30, 2022, for the Board’s consideration in October 2022 to address Key Recommendations 1d, 1e, 1f, and 1j;
- New and revised Reliability Standards to be submitted for regulatory approval before Winter 2023/2024: development completed by September 30, 2023, for the Board’s consideration in October 2023 to address Key Recommendations 1a, 1b, 1c, 1g, 1h, and 1i.

Facilities

For purposes of this standard, the term "generating unit" means those Bulk Electric System generators that plan to operate during the winter season. The winter season will be determined by the generating unit's applicable Balancing Authority. The term excludes those generators that do not operate during the winter season except when called upon by the Balancing Authority to be available during Capacity Emergencies or Energy Emergencies.

In the Joint Inquiry Report, Key Recommendation 1f includes support information, which states "consideration should be given to designing all new generation plants and designing modifications to existing plants (unless committed solely for summer peaking purposes) to be able to perform at the lowest recorded ambient temperature for the nearest city for which historical weather data is available …).[1] FERC staff from the Joint Inquiry Report team emphasized to the standard drafting team (SDT) that the reference to summer peaking units was intended to acknowledge that some units are not designed or planned to operate in winter conditions. The intent of the proposed standard as a reliability-focused standard is not to mandate that all generating units provide capacity in extreme cold weather, but instead to ensure that those units that plan to operate in the winter season be able to provide this capacity in a reliable fashion. This language ensures that this intent is captured for all requirements that follow.

Requirement R1 and R2

R1. *Each Generator Owner shall ensure generating units implement freeze protection measures based on the following minimum criteria: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]*

1.1. *Each generating unit shall be designed and maintained to be capable of continuous operations at the documented minimum hourly temperature experienced at its location since 1/1/1975 or a lesser period if reliable data is not available to 1975;*

1.2. *The generating unit design shall account for the cooling effect of wind;*

1.3. *The generating unit design shall account for the impacts on operations due to precipitation (e.g., sleet, snow, ice, and freezing rain); and*

1.4. *For each existing generating unit that requires either new freeze protection measures or modification of existing freeze protection measures, the Generator Owner shall develop and implement a Corrective Action Plan (CAP) which includes the following at a minimum:*

1.4.1. *An identification of corrective action (s) for the affected unit(s), including any necessary modifications to the Generator Owner's cold weather preparedness plan(s);*

1.4.2. *A timetable for implementing the corrective action(s) from Part 1.4.1 which considers any technical, commercial, or operational constraints, as defined by the Generator Owner;*

1.4.3. *An identification of any temporary operating limitations that would apply until execution of the corrective action(s) identified in the CAP; and*

1.4.4. *A declaration, where deemed appropriate by the Generator Owner based on the review of Parts 1.4.1 through 1.4.3, that no revisions to the cold weather preparedness plan(s) are required and that no further corrective actions will be taken. The Generator Owner shall document technical, commercial, or operational constraints as defined by the Generator Owner as support for such declaration.*

[1] See Report, page 189.

R2. *Each Generator Owner that is not able to implement freeze protection measures for new generating unit(s) as required by Requirement R1 due to technical, commercial, or operational constraints as defined by the Generator Owner shall: [Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

2.1. *Document its determination and the constraints on implementation; and*

2.2. *Review its determination every five calendar years to determine whether the documented constraints on implementation remain applicable.*

Key Recommendation 1f: *To require Generator Owners to retrofit existing generating units, and when building new generating units, to design them, to operate to a specified ambient temperature and weather conditions (e.g., wind, freezing precipitation). The specified ambient temperature and weather conditions should be based on available extreme temperature and weather data for the generating unit's location.*

General Considerations

As referenced in Key Recommendation 1f above, the specified ambient temperature and weather conditions should be based on available extreme temperature and weather data for the generating unit's location. FERC staff from the Joint Inquiry Report team clarified to the SDT that the reliability goal of the recommendation for existing generating units is to have the necessary freeze protection measures to be able to operate at extreme cold temperatures and weather for the generating unit's location. For example, those measures may consist of existing[2] or new, permanent and/or temporary measures[3] to maintain operation during extreme cold temperatures. Therefore, FERC staff clarified that the joint team's intent of the word retrofit is "to implement new, and/or make modifications to existing freeze protection measures for existing generating units."

In discussions with the Joint Inquiry Report team and in reading the Joint Inquiry Report itself, it is clearly stated that "consideration should be given to designing all new generation plants and designing modifications to existing plants (unless committed solely for summer peaking purposes) to be able to perform at the lowest recorded ambient temperature for the nearest city for which historical weather data is available …)". The Report went on to provide evidence that "Not only did generating units fail to perform at the lowest recorded ambient temperature for the nearest city, but many failed to perform at their own ambient design temperatures". The Joint Inquiry Report also notes that "Over 40 percent of the GOs/GOPs in the south central U.S. regions where "freezing issues" were identified as the predominant cause of unplanned generation outages, derates or failures to start stated that they did not incorporate specific generator-related recommendations from the 2011 Report or specific recommendations from the Guideline."

Based on the generating unit data contained in the Report, many generating units that operate in the winter season are not properly winterized to remain in reliable service during the most extreme cold weather conditions that they may reasonably be expected to experience at their locations. As the load on the grid is the most elevated at these extreme conditions, these are the periods when it is most critical that these generating units maintain their reliability. As such, Requirement 1 ensures that generating units are proactively taking steps to design and maintain their units to maintain their reliability during extreme cold weather.

Requirement R1 Part 1.1

The Joint Inquiry Report key recommendation 1f references recommendation 12 of the 2011 report suggesting that consideration should be given to designing all new generation plants and designing modifications to existing plants

[2] While the dictionary definition of the word retrofit includes to install (new or modified parts or equipment) in something previously manufactured or constructed, its origin suggests the need for replacing existing equipment with new technologies, which was not the intent of the joint team in this case. See Merriam-Webster definition.

[3] Some freeze protection measures may need to be removed for summer temperature operation.

(unless committed solely for summer peaking purposes) to be able to perform at the lowest recorded ambient temperature for the nearest city for which historical weather data is available. The Joint Inquiry Report states "The Standards Drafting Team can decide what additional specificity is desirable for this requirement, for example, specifying the number of years of weather data to be considered in establishing the required ambient temperature and weather conditions, and the source of the extreme temperature and weather data". The SDT considered several options of how many years back historical data should be analyzed (e.g., 10 years, 30 years, 50 years, 100 years). There is concern that some geographical areas may not have reliable data dating back 100 years. The SDT does not think 10 or 30 years of historical ambient temperature data is enough to support the intent of the recommendation. The SDT is also concerned if the lowest recorded coldest ambient temperature rolled off outside the historical parameter, it would give a new build generating unit a lesser cold weather criteria/standard to build to. Ultimately, the SDT decided to make 1975 the earliest historical date for the lowest recorded ambient temperature. Most would have historical data back to this date and the coldest temperature from 1975 would never roll off. This makes all new build and existing units to have to winterize to the same criteria in similar locations. Generator Owners should select a reliable source of data from a recording location near the plant. Examples would include National Weather Service or National Oceanographic and Atmospheric Administration weather stations, Federal Aviation Administration weather stations, etc. Generator Owners may use on-site weather stations if data, which reasonably matches reliable nearby off-site sources since 1975, is available.

Requirement R1 Parts 1.2 and 1.3

The key recommendation identifies wind and freezing precipitation as specific examples of weather conditions to consider during the design of new generating units and modifications to existing plants. Realizing the many differences in weather that generator sites face across the Regions, the 2021-07 SDT developed language to provide additional context and detail around these weather conditions, while allowing flexibility for site-specific circumstances. The key recommendation language was revised within the requirement language to be specific to the cooling effect of wind. Additionally, the 2021-07 SDT provided example precipitation types to prevent the focus being solely on one form, such as ice, and again, allowing flexibility for site-specific issues.

Requirement R1 Part 1.4

The SDT created a requirement to develop a Corrective Action Plan (CAP) for existing generating units that require either new freeze protection measures, or modification of existing freeze protection measures, to be capable of continuous operation under the conditions defined in Part 1.1. However, it is recognized that modifications or corrective actions may not be feasible under all circumstances due to technical, commercial, or operational constraints.

Additionally, the SDT considered the potential for unintended consequences, such as limiting winter participation or accelerating generator retirements, caused by requirements to develop and implement CAPs to be capable of continuous operations under the conditions defined in Part 1.1 in all circumstances. Thus, the SDT included Part 1.4.4, which allows the Generator Owner to make a declaration supporting why technical, commercial, or operational constraints result in a determination that no revisions to the cold weather preparedness plan are required and that no further corrective actions will be taken.

The SDT discussed setting a timeframe needed for the CAP to be completed during the drafting phase. While it is important that the CAP be completed, it would be difficult to set a definite timeframe due to the number of variables that could impact the completion of the CAP once the cause is determined. The SDT believes that it is more important to develop a CAP that identifies the solution and resolves the situation correctly regardless of time. Therefore, the team did not define a time when the CAP needs to be completed.

Requirement R2

The SDT has developed the new Extreme Cold Weather Preparedness and Operation standard with language that supports the ongoing consideration of new technologies when protecting against extreme cold weather. This five-year review of the determination supports the desire for utilities to periodically vet these new technologies and consider whether the technical, commercial, or operational constraint is still applicable.

Requirement R5

R5. *Each Generator Owner in conjunction with its Generator Operator shall identify the entity responsible for providing the generating unit-specific training, and that identified entity shall provide annual training to its maintenance or operations personnel responsible for implementing cold weather preparedness plan(s) developed pursuant to Requirement R3. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]*

Key Recommendation 1e: To revise EOP-011-2, R8, to require Generator Owners and Generator Operators to conduct annual unit-specific cold weather preparedness plan training.

Project 2019-06 Cold Weather established the requirement that the Generator Owner, in conjunction with its Generator Operator, would provide generating unit-specific training for its personnel responsible for implementing cold weather preparedness plan(s) for its generating units. The Joint Inquiry Report recommended that EOP-011-2 R8 be revised to require the generating unit-specific training be provided on an "annual" basis. The report explains "Responses from the GOs/GOPs involved in the Event show that annual training is not yet universal in the Event Area." To address this recommendation, the SDT has utilized the existing language in EOP-011-2 and added the word "annual" to require the training on an annual basis. The requirement is deleted from EOP-011-3, and will be placed as a requirement in a new EOP Reliability Standard dedicated solely to extreme cold weather preparedness.

Requirement R6

R6. *Each Generator Owner that owns a generating unit that experiences an event resulting in a derate of more than 10% of the total capacity of the unit for longer than four hours in duration, a start-up failure where the unit fails to synchronize within a specified start-up time, or a Forced Outage for which (i) the apparent cause(s) of the event is due to freezing of the Generator Owner's equipment within the Generator Owner's control, and (ii) the ambient conditions at the site at the time of the event are at or above the temperature documented in Part 3.4.2 shall: [Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

- **6.1.** *No later than 150 days subsequent to the event or by July 1 that follows the event, whichever is earlier, develop a CAP.*
- **6.2.** *The CAP shall contain at a minimum:*
  - **6.2.1.** *A summary of the identified cause(s) for the equipment freezing event where applicable and any relevant associated data;*
  - **6.2.2.** *A review of applicability to similar equipment at other generating units owned by the Generator Owner;*
  - **6.2.3.** *An identification of corrective action(s) for the affected unit(s) and identified similar units, including any necessary modifications to the Generator Owner's cold weather preparedness plan(s);*
  - **6.2.4.** *A timetable for implementing the identified corrective action(s) from Part 6.2.3 which considers any technical, commercial, or operational constraints as defined by the Generator Owner;*
  - **6.2.5.** *An identification of any temporary operating limitations that would apply until execution of the corrective action(s) identified in the CAP; and*

6.2.6. *A declaration, where deemed appropriate by the Generator Owner based on the review of Parts 6.2.1 through 6.2.5 that no revisions to the cold weather preparedness plan are required and that no further corrective actions will be taken. The Generator Owner shall document technical, commercial, or operational constraints as defined by the Generator Owner as support for such declaration.*

Key Recommendation 1d: *To require Generator Owners that experience outages, failures to start, or derates due to freezing to review the generating unit's outage, failure to start, or derate and develop and implement a corrective action plan (CAP) for the identified equipment, and evaluate whether the CAP applies to similar equipment for its other generating units. Based on the evaluation, the Generator Owner will either revise its cold weather preparedness plan to apply the CAP to the similar equipment, or explain in a declaration (a) why no revisions to the cold weather preparedness plan are appropriate, and (b) that no further corrective actions will be taken. The standard drafting team should specify the specific timing for the CAP to be developed and implemented after the outage, derate, or failure to start, but the CAP should be developed as quickly as possible, and be completed by no later than the beginning of the next winter season.*

The key recommendation from the report recommends requiring generator owners to develop a CAP for generators that experience outages, failures to starts, or derates due to freezing. The 2021-07 SDT developed language that defines the circumstances for which a CAP is required, as those when a freezing event effects the equipment within the control of the Generator Owner. The Report identifies that most of the outages and derates in the February 2021 event were due to freezing of instrumentation, transmitters, sensing lines, or wind turbine blades (p 166 in report). As such, the team followed the Report recommendation to require a CAP when the apparent cause of the event is freezing.

The CAP requirement applies to any forced outage due to freezing, regardless of duration. Derates, which are short-lived or of small capacity impact, are excluded from the CAP requirement, although nothing in this standard prevents a GO from taking its own corrective actions resulting from such events. Startup failures are defined using the GADS definition with the removal of "following an outage or reserve shutdown", since the definition of Reserve shutdown is different in GADS than it is in some of the RTO's.

R6 requires the GO to act within 150 days or by July 1 to develop the CAP or document that no corrective action is appropriate. This timeframe was chosen to allow GO's to review multiple events holistically following a winter season, and create one CAP for equipment with common failure causes. Requirement R6.2 define the requirements for a CAP and the requirements for a declaration when technical, commercial, or operational constraints are present.

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UPDATED
Standards Announcement

Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination

Formal Comment Period, Initial Ballots and Non-binding Polls Extended, Now Open through June 21, 2022

Now Available

NERC has been made aware that question 8 of the comment form is missing in SBS. Please submit the response to question 8 with the response to question 10 in SBS. Due to this and the upcoming holiday weekend, the formal Comment Period, initial ballots and non-binding polls for the associated Violation Risk Factors and Violation Severity Levels have been extended, and are now open through **8 p.m. Eastern, Tuesday, June 21, 2022** for the following standards and implementation plan:

- EOP-012-1 – Extreme Cold Weather Preparedness and Operations
- EOP-011-3 – Emergency Preparedness and Operations
- Implementation Plan

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

For more information or assistance, contact Senior Standards Developer, Alison Oswald (via email) or at 404-446-9668. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination” 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

Standards Announcement

Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination

Formal Comment Period Open through June 17, 2022
Ballot Pools Forming through June 2, 2022

Now Available

A formal comment period for **Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination**, is open through **8 p.m. Eastern, Friday, June 17, 2022** for the following standards and implementation plan:

- EOP-012-1 – Extreme Cold Weather Preparedness and Operations
- EOP-011-3 – Emergency Preparedness and Operations
- Implementation Plan

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.

Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Thursday, June 2, 2022.** 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 standards and implementation plan, as well as non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **June 8 – 17, 2022**.

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

For more information or assistance, contact Senior Standards Developer, Alison Oswald (via email) or at 404-446-9668. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination” 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

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/247)
Ballot Name: 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination EOP-011-3 IN 1 ST
Voting Start Date: 6/8/2022 12:01:00 AM
Voting End Date: 6/21/2022 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 297
Total Ballot Pool: 314
Quorum: 94.59
Quorum Established Date: 6/20/2022 2:33:21 PM
Weighted Segment Value: 69.66

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	61	0.763	19	0.238	0	6	3
Segment: 2	7	0.7	1	0.1	6	0.6	0	0	0
Segment: 3	68	1	51	0.823	11	0.177	0	1	5
Segment: 4	19	1	10	0.714	4	0.286	0	2	3
Segment: 5	75	1	48	0.716	19	0.284	0	6	2
Segment: 6	49	1	33	0.733	12	0.267	0	2	2
Segment: 7	1	0	0	0	0	0	0	0	1
Segment: 8	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: 9	0	0	0	0	0	0	0	0	0
Segment: 10	6	0.4	4	0.4	0	0	0	1	1
Totals:	314	6.1	208	4.249	71	1.851	0	18	17

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	Ameren - Ameren Services	Tamara Evey		Negative	Comments Submitted
1	American Transmission Company, LLC	LaTroy Brumfield		Negative	Comments Submitted
1	APS - Arizona Public Service Co.	Daniela Atanasovski	Brandon Smith	Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Arkansas Electric Cooperative Corporation	Jennifer Loiacano		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Avista - Avista Corporation	Mike Magruder		Negative	Comments Submitted
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Micah Runner	Jennifer Malon	Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Negative	Third-Party Comments
1	Dairyland Power Cooperative	Steve Ritscher		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Affirmative	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
1	Edison International - Southern California Edison Company	Jose Avendano Mora		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Allen Klassen	Alan Kloster	Affirmative	N/A
1	Eversource Energy	Quintin Lee		Negative	Comments Submitted
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Gainesville Regional Utilities	David Owens	LaKenya VanNorman	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Sheraz Majid		Negative	Third-Party Comments
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		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	Abstain	N/A
1	JEA	Joe McClung		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Negative	Third-Party Comments
1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	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	Nurul Abser		Abstain	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Negative	Comments Submitted
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Ohio Valley Electric Corporation	Scott Cunningham		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer	Gul Khan	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Negative	Comments Submitted
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle Longo		Negative	Third-Party Comments
1	PSEG - Public Service Electric and Gas Co.	Kyle Down		Negative	Third-Party Comments
1	Public Utility District No. 1 of Chelan County	Diane Landry		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		None	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Chris Hofmann		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seattle City Light	Michael Jang		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Taunton Municipal Lighting Plant	Devon Tremont		Negative	Comments Submitted
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	Comments Submitted
1	VELCO -Vermont Electric Power Company, Inc.	Randy Buswell		Negative	Comments Submitted
1	Western Area Power Administration	sean erickson	Kimberly Bentley	Affirmative	N/A
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
2	California ISO	Darcy O'Connell		Negative	Third-Party Comments
2	Independent Electricity System Operator	Leonard Kula		Negative	Comments Submitted
2	ISO New England, Inc.	John Pearson	Keith Jonassen	Negative	Comments Submitted
2	Midcontinent ISO, Inc.	Bobbi Welch		Negative	Third-Party Comments
2	New York Independent System Operator	Gregory Campoli		Negative	Third-Party Comments
2	PJM Interconnection, L.L.C.	Tom Foster	Elizabeth Davis	Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	AEP	Kent Feliks		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Michael Dieringer		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Negative	Comments Submitted
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs	Jennifer Malon	Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Negative	Comments Submitted
3	CPS Energy	Glenn Pressler		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Dominion - Dominion Resources, Inc.	Connie Schroeder		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Negative	Comments Submitted
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		None	N/A
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Alan Kloster	Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Florida Municipal Power Agency	Carl Turner	LaKenya VanNorman	Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Imperial Irrigation District	Glen Allegranza	Denise Sanchez	Affirmative	N/A
3	JEA	Marilyn Williams		None	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Steve Marshall		None	N/A
3	Lincoln Electric System	Angelica Valencia		Affirmative	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		None	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Ronald Bauer		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney		Negative	Comments Submitted
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	LaKenya VanNorman	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	William Berry		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Negative	Comments Submitted
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	PSEG - Public Service Electric and Gas Co.	maria pardo		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	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		None	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Abshier		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Negative	Comments Submitted
3	WEC Energy Group, Inc.	Christine Kane		Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	American Public Power Association	John McCaffrey		Abstain	N/A
4	Austin Energy	Jun Hua		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
4	DTE Energy	patricia ireland		None	N/A
4	Electricities of North Carolina	Marcus Freeman		None	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Florida Municipal Power Agency	Dan O'Hagan	LaKenya VanNorman	Affirmative	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain	N/A
4	Indiana Municipal Power Agency	Jack Alvey	Scott Berry	Negative	Third-Party Comments
4	MGE Energy - Madison Gas and Electric Co.	Adam Lee		Affirmative	N/A
4	Northern California Power Agency	Marty Hostler		Negative	Comments Submitted
4	Oklahoma Municipal Power Authority	Michael Watt		Negative	Comments Submitted
4	Public Utility District No. 1 of Snohomish County	John Martinsen		None	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Negative	Comments Submitted
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	Acciona Energy North America	George Brown		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Comments Submitted
5	APS - Arizona Public Service Co.	Michelle Amarantos		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	Basin Electric Power Cooperative	Amanda Wangler		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	Derek Silbaugh	Jennifer Malon	Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Negative	Comments Submitted
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Cogentrix Energy Power Management, LLC	Gerry Adamski		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Haizhen Wang		Affirmative	N/A
5	Constellation	Alison Mackellar		Negative	Comments Submitted
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	CPS Energy	Robert Stevens		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Decatur Energy Center LLC	Shannon Ferdinand		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		Negative	Comments Submitted
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Enel Green Power	Natalie Johnson		Abstain	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	LaKenya VanNorman	Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	Greybeard Compliance Services, LLC	Michael Gabriel		Abstain	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	Invenergy LLC	Rhonda Jones		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Jason Fortik		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		None	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	LS Power Development, LLC	Mark Spencer		Abstain	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
5	NB Power Corporation	David Melanson		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	NextEra Energy	Summer Esquerre		Negative	Comments Submitted
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Northern California Power Agency	Jeremy Lawson		Negative	Comments Submitted
5	NRG - NRG Energy, Inc.	Patricia Lynch		Negative	Comments Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Third-Party Comments
5	OTP - Otter Tail Power Company	Tammy Kubela		Affirmative	N/A
5	Pacific Gas and Electric Company	Frank Lee	Michael Johnson	Negative	Comments Submitted
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Negative	Third-Party Comments
5	PSEG - PSEG Fossil LLC	Tim Kucey		Negative	Third-Party Comments
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		Affirmative	N/A
5	Sacramento Municipal Utility District	Nicole Goi	Tim Kelley	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Marty Watson		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Abstain	N/A
5	Southern Company - Southern Company Generation	James Howell		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	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	Tennessee Valley Authority	M Lee Thomas		None	N/A
5	TransAlta Corporation	Ashley Scheelar		Negative	Comments Submitted
5	Tri-State G and T Association, Inc.	Ryan Walter		Negative	Comments Submitted
5	U.S. Bureau of Reclamation	Wendy Kalidass		Negative	Comments Submitted
5	WEC Energy Group, Inc.	Clarice Zellmer		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Xcel Energy, Inc.	Gerry Huitt	Amy Casuscelli	Affirmative	N/A
6	AEP	JT Kuehne		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Lisa Martin		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Abstain	N/A
6	Black Hills Corporation	Claudine Bates		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Negative	Comments Submitted
6	Cleco Corporation	Robert Hirchak		Negative	Third-Party Comments
6	Con Ed - Consolidated Edison Co. of New York	Michael Foley		Affirmative	N/A
6	Constellation	Kimberly Turco		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Jennifer Flandermeyer	Alan Kloster	Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Tricia Bynum		Negative	Comments Submitted
6	Florida Municipal Power Agency	Jade Bulitta	LaKenya VanNorman	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Florida Municipal Power Pool	Aaron Casto	LaKenya VanNorman	Affirmative	N/A
6	Great River Energy	Donna Stephenson		Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Invenergy LLC	Colin Chilcoat		Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Negative	Third-Party Comments
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Manitoba Hydro	Simon Tanapat-Andre		Affirmative	N/A
6	Muscatine Power and Water	Nick Burns		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Negative	Comments Submitted
6	NRG - NRG Energy, Inc.	Martin Sidor		Negative	Comments Submitted
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	Powerex Corporation	Raj Hundal		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia		Negative	Third-Party Comments
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Pam Syrjala		Affirmative	N/A
6	Santee Cooper	Glenda Horne		Affirmative	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.	Erin Spence		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	Tennessee Valley Authority	Armando Rodriguez		Affirmative	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
7	Oxy - Occidental Chemical	Venona Greaff		None	N/A
10	Midwest Reliability Organization	William Steiner		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		None	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	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		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

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Showing 1 to 314 of 314 entries

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/247)
Ballot Name: 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination EOP-012-1 IN 1 ST
Voting Start Date: 6/8/2022 12:01:00 AM
Voting End Date: 6/21/2022 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 296
Total Ballot Pool: 314
Quorum: 94.27
Quorum Established Date: 6/20/2022 2:03:38 PM
Weighted Segment Value: 21.94

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	87	1	14	0.187	61	0.813	0	8	4
Segment: 2	7	0.7	1	0.1	6	0.6	0	0	0
Segment: 3	68	1	11	0.177	51	0.823	0	1	5
Segment: 4	19	1	1	0.071	13	0.929	0	2	3
Segment: 5	77	1	13	0.181	59	0.819	1	2	2
Segment: 6	49	1	10	0.222	35	0.778	1	1	2
Segment: 7	1	0	0	0	0	0	0	0	1
Segment: 8	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: 9	0	0	0	0	0	0	0	0	0
Segment: 10	6	0.4	4	0.4	0	0	0	1	1
Totals:	314	6.1	54	1.338	225	4.762	2	15	18

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
1	Ameren - Ameren Services	Tamara Evey		Negative	Comments Submitted
1	American Transmission Company, LLC	LaTroy Brumfield		Negative	Comments Submitted
1	APS - Arizona Public Service Co.	Daniela Atanasovski	Brandon Smith	Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
1	Arkansas Electric Cooperative Corporation	Jennifer Loiacano		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Negative	Comments Submitted
1	Austin Energy	Thomas Standifur		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Avista - Avista Corporation	Mike Magruder		Negative	Comments Submitted
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Negative	Comments Submitted
1	Basin Electric Power Cooperative	David Rudolph		Negative	Third-Party Comments
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Black Hills Corporation	Micah Runner	Jennifer Malon	Negative	Comments Submitted
1	Bonneville Power Administration	Kammy 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	Colorado Springs Utilities	Mike Braunstein		Negative	Comments Submitted
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Negative	Third-Party Comments
1	Dairyland Power Cooperative	Steve Ritscher		Negative	Third-Party Comments
1	Dominion - Dominion Virginia Power	Candace Marshall		Negative	Comments Submitted
1	Duke Energy	Laura Lee		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Edison International - Southern California Edison Company	Jose Avendano Mora		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Allen Klassen	Alan Kloster	Negative	Third-Party Comments
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Negative	Comments Submitted
1	Gainesville Regional Utilities	David Owens	LaKenya VanNorman	Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis		Negative	Third-Party Comments
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
1	Great River Energy	Gordon Pietsch		Negative	Third-Party Comments
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Negative	Comments Submitted
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Negative	Comments Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Joe 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		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Lower Colorado River Authority	James Baldwin		Negative	Comments Submitted
1	M and A Electric Power Cooperative	William Price		Negative	Third-Party Comments
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		Negative	Third-Party Comments
1	Muscatine Power and Water	Andy 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	Nurul Abser		Abstain	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
1	New York Power Authority	Salvatore Spagnolo		Negative	Third-Party Comments
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Negative	Comments Submitted
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		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		Affirmative	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		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	Lee Maurer	Gul Khan	Abstain	N/A
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	Michael Johnson	Negative	Comments Submitted
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		Abstain	N/A
1	Platte River Power Authority	Matt Thompson		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		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle Longo		Negative	Third-Party Comments
1	PSEG - Public Service Electric and Gas Co.	Kyle Down		Negative	Third-Party Comments
1	Public Utility District No. 1 of Chelan County	Diane Landry		Negative	Comments Submitted
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		None	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	Comments Submitted
1	Salt River Project	Chris Hofmann		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	Seattle City Light	Michael Jang		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Abstain	N/A
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	Negative	Comments Submitted
1	Taunton Municipal Lighting Plant	Devon Tremont		Negative	Comments Submitted
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	Comments Submitted
1	VELCO -Vermont Electric Power Company, Inc.	Randy Buswell		None	N/A
1	Western Area Power Administration	sean erickson	Kimberly Bentley	Negative	Comments Submitted
1	Xcel Energy, Inc.	Eric Barry		Negative	Comments Submitted
2	California ISO	Darcy O'Connell		Negative	Third-Party Comments
2	Independent Electricity System Operator	Leonard Kula		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	Third-Party Comments
2	New York Independent System Operator	Gregory Campoli		Negative	Third-Party Comments
2	PJM Interconnection, L.L.C.	Tom Foster	Elizabeth Davis	Negative	Third-Party Comments
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	AEP	Kent Feliks		Negative	Comments Submitted
3	Ameren - Ameren Services	David Jendras		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
3	Austin Energy	Michael Dieringer		Negative	Comments Submitted
3	Avista - Avista Corporation	Scott Kinney		Negative	Comments Submitted
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs	Jennifer Malon	Negative	Comments Submitted
3	Bonneville Power Administration	Ken Lanehome		Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Third-Party Comments
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Negative	Third-Party Comments
3	Colorado Springs Utilities	Hillary Dobson		Negative	Comments Submitted
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Negative	Comments Submitted
3	CPS Energy	Glenn Pressler		Negative	Comments Submitted
3	Dominion - Dominion Resources, Inc.	Connie Schroeder		Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Karie Barczak		Negative	Comments Submitted
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		None	N/A
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Alan Kloster	Negative	Comments Submitted
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Florida Municipal Power Agency	Carl Turner	LaKenya VanNorman	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	Glen Allegranza	Denise Sanchez	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	JEA	Marilyn Williams		None	N/A
3	KAMO Electric Cooperative	Tony Gott		Negative	Third-Party Comments
3	Lakeland Electric	Steve Marshall		None	N/A
3	Lincoln Electric System	Angelica Valencia		Negative	Comments Submitted
3	Los Angeles Department of Water and Power	Tony Skourtas		None	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Negative	Third-Party Comments
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Ronald Bauer		Negative	Third-Party Comments
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	David Rivera		Negative	Third-Party Comments
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney		Negative	Comments Submitted
3	NW Electric Power Cooperative, Inc.	John Stickley		Negative	Third-Party Comments
3	Ocala Utility Services	Neville Bowen	LaKenya VanNorman	Negative	Comments Submitted
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	Third-Party Comments
3	Orlando Utilities Commission	Ballard Mutters		Negative	Third-Party Comments
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party Comments
3	Owensboro Municipal Utilities	William Berry		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Negative	Comments Submitted
3	Platte River Power Authority	Wade Kiess		Negative	Third-Party Comments
3	PPL - Louisville Gas and Electric Co.	James Frank		Negative	Third-Party Comments
3	PSEG - Public Service Electric and Gas Co.	maria pardo		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	Zack Heim		Negative	Third-Party Comments
3	Santee Cooper	James Poston		Negative	Comments Submitted
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Negative	Third-Party Comments
3	Snohomish County PUD No. 1	Holly Chaney		None	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 Abshier		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Negative	Comments Submitted
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
3	Xcel Energy, Inc.	Nicholas Friebel		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Comments Submitted
4	American Public Power Association	John McCaffrey		Abstain	N/A
4	Austin Energy	Jun Hua		Negative	Comments Submitted
4	CMS Energy - Consumers Energy Company	Aric Root		Negative	Third-Party Comments
4	DTE Energy	patricia ireland		None	N/A
4	Electricities of North Carolina	Marcus Freeman		None	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
4	Florida Municipal Power Agency	Dan O'Hagan	LaKenya VanNorman	Negative	Comments Submitted
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain	N/A
4	Indiana Municipal Power Agency	Jack Alvey	Scott Berry	Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	MGE Energy - Madison Gas and Electric Co.	Adam Lee		Negative	Third-Party Comments
4	Northern California Power Agency	Marty Hostler		Negative	Comments Submitted
4	Oklahoma Municipal Power Authority	Michael Watt		Negative	Comments Submitted
4	Public Utility District No. 1 of Snohomish County	John Martinsen		None	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Comments Submitted
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Negative	Comments Submitted
4	Utility Services, Inc.	Brian Evans-Mongeon		Negative	Comments Submitted
4	WEC Energy Group, Inc.	Matthew Beilfuss		Negative	Comments Submitted
5	Acciona Energy North America	George Brown		Negative	Comments Submitted
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Comments Submitted
5	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Chuck Booth		Negative	Comments Submitted
5	Austin Energy	Michael Dillard		Negative	Comments Submitted
5	Avista - Avista Corporation	Glen Farmer		Negative	Comments Submitted
5	Basin Electric Power Cooperative	Amanda Wangler		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	Derek Silbaugh	Jennifer Malon	Negative	Comments Submitted
5	Bonneville Power Administration	Scott Winner		Negative	Comments Submitted
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Third-Party Comments
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Negative	Third-Party Comments
5	Cogentrix Energy Power Management, LLC	Gerry Adamski		Negative	Comments Submitted
5	Colorado Springs Utilities	Jeff Icke		Negative	Comments Submitted
5	Con Ed - Consolidated Edison Co. of New York	Haizhen Wang		Affirmative	N/A
5	Constellation	Alison Mackellar		Negative	Comments Submitted
5	Cowlitz County PUD	Deanna Carlson		Negative	Comments Submitted
5	CPS Energy	Robert Stevens		Negative	Comments Submitted
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Decatur Energy Center LLC	Shannon Ferdinand		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Adrian Raducea		Negative	Comments Submitted

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		Affirmative	N/A
5	Enel Green Power	Natalie Johnson		Negative	Comments Submitted
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Robert Loy		Negative	Comments Submitted
5	Florida Municipal Power Agency	Chris Gowder	LaKenya VanNorman	Negative	Third-Party Comments
5	Great River Energy	Jacalynn Bentz		Negative	Third-Party Comments
5	Greybeard Compliance Services, LLC	Michael Gabriel		Negative	Third-Party Comments
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Negative	Comments Submitted
5	Invenergy LLC	Rhonda Jones		Negative	Comments Submitted
5	JEA	John Babik		Negative	Comments Submitted
5	Lincoln Electric System	Jason Fortik		Negative	Comments Submitted
5	Los Angeles Department of Water and Power	Glenn Barry		None	N/A
5	Lower Colorado River Authority	Teresa Krabe		Negative	Comments Submitted
5	LS Power Development, LLC	Mark Spencer		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	National Grid USA	Elizabeth Spivak		Negative	Comments Submitted
5	NB Power Corporation	David Melanson		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender		Negative	Third-Party Comments
5	New York Power Authority	Zahid Qayyum		Negative	Third-Party Comments
5	NextEra Energy	Summer Esquerre		Negative	Comments Submitted
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Northern California Power Agency	Jeremy Lawson		Negative	Comments Submitted
5	NRG - NRG Energy, Inc.	Patricia Lynch		Negative	Comments Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Negative	Comments Submitted
5	Omaha Public Power District	Mahmood Safi		Negative	Third-Party Comments
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Third-Party Comments
5	OTP - Otter Tail Power Company	Tammy Kubela		Negative	No Comment Submitted
5	Pacific Gas and Electric Company	Frank Lee	Michael Johnson	Negative	Comments Submitted
5	Platte River Power Authority	Jon Osell		Negative	Third-Party Comments
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Negative	Third-Party Comments
5	PSEG - PSEG Fossil LLC	Tim Kucey		Negative	Third-Party Comments
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Negative	Comments Submitted
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		Affirmative	N/A
5	Sacramento Municipal Utility District	Nicole Goi	Tim Kelley	Negative	Comments Submitted
5	Salt River Project	Kevin Nielsen		Negative	Third-Party Comments
5	Santee Cooper	Marty Watson		Negative	Comments Submitted
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Abstain	N/A
5	Southern Company - Southern Company Generation	James Howell		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Negative	Comments Submitted
5	Talen Generation, LLC	Donald Lock		Negative	Third-Party Comments
5	Tenaska, Inc.	Mark Young		Negative	Comments Submitted
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
5	TransAlta Corporation	Ashley Scheelar		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Tri-State G and T Association, Inc.	Ryan Walter		Negative	Comments Submitted
5	U.S. Bureau of Reclamation	Wendy Kalidass		Negative	Comments Submitted
5	Vistra Energy	Dan Roethemeyer		Negative	Comments Submitted
5	WEC Energy Group, Inc.	Clarice Zellmer		Negative	Comments Submitted
5	Xcel Energy, Inc.	Gerry Huitt	Amy Casuscelli	Negative	Comments Submitted
6	AEP	JT Kuehne		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Comments Submitted
6	Austin Energy	Lisa Martin		Negative	Comments Submitted
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Negative	Comments Submitted
6	Black Hills Corporation	Claudine Bates		Negative	Comments Submitted
6	Bonneville Power Administration	Andrew Meyers		Negative	Comments Submitted
6	Cleco Corporation	Robert Hirchak		Negative	Third-Party Comments
6	Con Ed - Consolidated Edison Co. of New York	Michael Foley		Affirmative	N/A
6	Constellation	Kimberly Turco		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Jennifer Flandermeyer	Alan Kloster	Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Tricia Bynum		Negative	Comments Submitted
6	Florida Municipal Power Agency	Jade Bulitta	LaKenya VanNorman	Negative	Comments Submitted
6	Florida Municipal Power Pool	Aaron Casto	LaKenya VanNorman	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson		Negative	Third-Party Comments
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Negative	Comments Submitted
6	Invenergy LLC	Colin Chilcoat		Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		Negative	Third-Party Comments
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Manitoba Hydro	Simon Tanapat-Andre		Affirmative	N/A
6	Muscatine Power and Water	Nick Burns		Negative	Third-Party Comments
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Northern California Power Agency	Dennis Sismaet		Negative	Comments Submitted
6	NRG - NRG Energy, Inc.	Martin Sidor		Negative	Comments Submitted
6	Omaha Public Power District	Shonda McCain		Negative	No Comment Submitted
6	Platte River Power Authority	Sabrina Martz		Negative	Third-Party Comments
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	Powerex Corporation	Raj Hundal		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Third-Party Comments
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia		Negative	Third-Party Comments
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Negative	Comments Submitted
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	Comments Submitted
6	Salt River Project	Pam Syrjala		Negative	Comments Submitted
6	Santee Cooper	Glenda Horne		Negative	Comments Submitted
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.	Erin Spence		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Negative	Comments Submitted
6	Tennessee Valley Authority	Armando Rodriguez		Affirmative	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
6	Xcel Energy, Inc.	Carrie Dixon		Negative	Comments Submitted
7	Oxy - Occidental Chemical	Venona Greaff		None	N/A
10	Midwest Reliability Organization	William Steiner		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		None	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	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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Showing 1 to 314 of 314 entries

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/247)
Ballot Name: 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination Implementation Plan IN 1 OT
Voting Start Date: 6/8/2022 12:01:00 AM
Voting End Date: 6/21/2022 8:00:00 PM
Ballot Type: OT
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 291
Total Ballot Pool: 312
Quorum: 93.27
Quorum Established Date: 6/20/2022 3:10:40 PM
Weighted Segment Value: 57.74

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	86	1	45	0.682	21	0.318	0	12	8
Segment: 2	7	0.7	1	0.1	6	0.6	0	0	0
Segment: 3	68	1	38	0.655	20	0.345	1	4	5
Segment: 4	18	1	7	0.583	5	0.417	0	4	2
Segment: 5	77	1	34	0.493	35	0.507	0	6	2
Segment: 6	49	1	28	0.651	15	0.349	0	4	2
Segment: 7	1	0	0	0	0	0	0	0	1
Segment: 8	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: 9	0	0	0	0	0	0	0	0	0
Segment: 10	6	0.3	3	0.3	0	0	0	2	1
Totals:	312	6	156	3.464	102	2.536	1	32	21

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	Ameren - Ameren Services	Tamara Evey		Negative	Comments Submitted
1	American Transmission Company, LLC	LaTroy Brumfield		Abstain	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski	Brandon Smith	Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Arkansas Electric Cooperative Corporation	Jennifer Loiacano		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Avista - Avista Corporation	Mike Magruder		Negative	Comments Submitted
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Negative	Third-Party Comments
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Micah Runner	Jennifer Malon	Negative	Comments Submitted
1	Bonneville Power Administration	Kammy Rogers-Holliday		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Negative	Third-Party Comments
1	Dairyland Power Cooperative	Steve Ritscher		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		None	N/A
1	Duke Energy	Laura Lee		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Edison International - Southern California Edison Company	Jose Avendano Mora		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Allen Klassen	Alan Kloster	Affirmative	N/A
1	Eversource Energy	Quintin Lee		Abstain	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Negative	Comments Submitted
1	Gainesville Regional Utilities	David Owens	LaKenya VanNorman	Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis		Negative	Third-Party Comments
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
1	Great River Energy	Gordon Pietsch		None	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		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	Abstain	N/A
1	JEA	Joe McClung		None	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Negative	Third-Party Comments
1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Lower Colorado River Authority	James Baldwin		Negative	Comments Submitted
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		Affirmative	N/A
1	Muscatine Power and Water	Andy 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	Nurul Abser		Abstain	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
1	New York Power Authority	Salvatore Spagnolo		Negative	Third-Party Comments
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Ohio Valley Electric Corporation	Scott Cunningham		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
1	Oncor Electric Delivery	Lee Maurer	Gul Khan	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Negative	Comments Submitted
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle Longo		Negative	Third-Party Comments
1	PSEG - Public Service Electric and Gas Co.	Kyle Down		Abstain	N/A
1	Public Utility District No. 1 of Chelan County	Diane Landry		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		None	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Chris Hofmann		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Negative	Comments Submitted
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Affirmative	N/A
1	Taunton Municipal Lighting Plant	Devon Tremont		Abstain	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	Comments Submitted
1	VELCO -Vermont Electric Power Company, Inc.	Randy Buswell		None	N/A
1	Western Area Power Administration	sean erickson	Kimberly Bentley	Affirmative	N/A
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
2	California ISO	Darcy O'Connell		Negative	Third-Party Comments
2	Independent Electricity System Operator	Leonard Kula		Negative	Comments Submitted
2	ISO New England, Inc.	John Pearson	Keith Jonassen	Negative	Comments Submitted
2	Midcontinent ISO, Inc.	Bobbi Welch		Negative	Third-Party Comments
2	New York Independent System Operator	Gregory Campoli		Negative	Third-Party Comments
2	PJM Interconnection, L.L.C.	Tom Foster	Elizabeth Davis	Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	AEP	Kent Feliks		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Michael Dieringer		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Negative	Comments Submitted
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs	Jennifer Malon	Negative	Comments Submitted
3	Bonneville Power Administration	Ken Lanehome		Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Negative	Third-Party Comments
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	CPS Energy	Glenn Pressler		Negative	Comments Submitted
3	Dominion - Dominion Resources, Inc.	Connie Schroeder		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Negative	Comments Submitted
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		None	N/A
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Alan Kloster	Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Florida Municipal Power Agency	Carl Turner	LaKenya VanNorman	Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Negative	Third-Party Comments
3	Imperial Irrigation District	Glen Allegranza	Denise Sanchez	Affirmative	N/A
3	JEA	Marilyn Williams		None	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Steve Marshall		None	N/A
3	Lincoln Electric System	Angelica Valencia		Affirmative	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		None	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Ronald Bauer		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
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	David Rivera		Negative	Third-Party Comments
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney		Negative	Comments Submitted
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	LaKenya VanNorman	Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Abstain	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	William Berry		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Negative	Third-Party Comments
3	PSEG - Public Service Electric and Gas Co.	maria pardo		Negative	No Comment Submitted
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	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Negative	Comments Submitted
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		None	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Abshier		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	American Public Power Association	John McCaffrey		Abstain	N/A
4	Austin Energy	Jun Hua		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Negative	Third-Party Comments
4	DTE Energy	patricia ireland		None	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
4	Florida Municipal Power Agency	Dan O'Hagan	LaKenya VanNorman	Negative	Comments Submitted
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain	N/A
4	Indiana Municipal Power Agency	Jack Alvey	Scott Berry	Negative	Third-Party Comments
4	MGE Energy - Madison Gas and Electric Co.	Adam Lee		Affirmative	N/A
4	Northern California Power Agency	Marty Hostler		Negative	Comments Submitted
4	Oklahoma Municipal Power Authority	Michael Watt		Abstain	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		None	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	Acciona Energy North America	George Brown		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Comments Submitted
5	APS - Arizona Public Service Co.	Michelle Amarantos		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	Basin Electric Power Cooperative	Amanda Wangler		Negative	Third-Party Comments
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	Derek Silbaugh	Jennifer Malon	Negative	Comments Submitted
5	Bonneville Power Administration	Scott Winner		Negative	Comments Submitted
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Abstain	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Negative	Third-Party Comments
5	Cogentrix Energy Power Management, LLC	Gerry Adamski		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Negative	Comments Submitted
5	Con Ed - Consolidated Edison Co. of New York	Haizhen Wang		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Constellation	Alison Mackellar		Negative	Comments Submitted
5	Cowlitz County PUD	Deanna Carlson		Negative	Comments Submitted
5	CPS Energy	Robert Stevens		Negative	Comments Submitted
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Decatur Energy Center LLC	Shannon Ferdinand		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		Negative	Comments Submitted
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Enel Green Power	Natalie Johnson		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Robert Loy		Negative	Comments Submitted
5	Florida Municipal Power Agency	Chris Gowder	LaKenya VanNorman	Negative	Comments Submitted
5	Great River Energy	Jacalynn Bentz		Negative	Third-Party Comments
5	Greybeard Compliance Services, LLC	Michael Gabriel		Negative	Third-Party Comments
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	Invenergy LLC	Rhonda Jones		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	JEA	John Babik		Negative	Comments Submitted
5	Lincoln Electric System	Jason Fortik		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		None	N/A
5	Lower Colorado River Authority	Teresa Krabe		Negative	Comments Submitted
5	LS Power Development, LLC	Mark Spencer		Abstain	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
5	NB Power Corporation	David Melanson		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender		Negative	Third-Party Comments
5	New York Power Authority	Zahid Qayyum		Negative	Third-Party Comments
5	NextEra Energy	Summer Esquerre		Negative	Comments Submitted
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Northern California Power Agency	Jeremy Lawson		Negative	Comments Submitted
5	NRG - NRG Energy, Inc.	Patricia Lynch		Negative	Comments Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	OTP - Otter Tail Power Company	Tammy Kubela		Affirmative	N/A
5	Pacific Gas and Electric Company	Frank Lee	Michael Johnson	Negative	Comments Submitted
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Negative	Third-Party Comments
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Negative	Comments Submitted
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		Affirmative	N/A
5	Sacramento Municipal Utility District	Nicole Goi	Tim Kelley	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Marty Watson		Negative	Comments Submitted
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Abstain	N/A
5	Southern Company - Southern Company Generation	James Howell		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Talen Generation, LLC	Donald Lock		Negative	Third-Party Comments
5	Tenaska, Inc.	Mark Young		Negative	Comments Submitted
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
5	TransAlta Corporation	Ashley Scheelar		Negative	Comments Submitted
5	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Negative	Comments Submitted
5	Vistra Energy	Dan Roethemeyer		Negative	Comments Submitted
5	WEC Energy Group, Inc.	Clarice Zellmer		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt	Amy Casuscelli	Affirmative	N/A
6	AEP	JT Kuehne		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Lisa Martin		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
6	Black Hills Corporation	Claudine Bates		Negative	Comments Submitted
6	Bonneville Power Administration	Andrew Meyers		Negative	Comments Submitted
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Michael Foley		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Constellation	Kimberly Turco		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Jennifer Flandermeyer	Alan Kloster	Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Tricia Bynum		Negative	Comments Submitted
6	Florida Municipal Power Agency	Jade Bulitta	LaKenya VanNorman	Negative	Comments Submitted
6	Florida Municipal Power Pool	Aaron Casto	LaKenya VanNorman	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson		Negative	Third-Party Comments
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Invenergy LLC	Colin Chilcoat		Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Negative	Third-Party Comments
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Manitoba Hydro	Simon Tanapat-Andre		Affirmative	N/A
6	Muscatine Power and Water	Nick Burns		Abstain	N/A
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.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Negative	Comments Submitted
6	NRG - NRG Energy, Inc.	Martin Sidor		Negative	Comments Submitted
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Third-Party Comments
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Pam Syrjala		Affirmative	N/A
6	Santee Cooper	Glenda Horne		Negative	Comments Submitted
6	Snohomish County PUD No. 1	John Liang		None	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Southern Indiana Gas and Electric Co.	Erin Spence		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	Tennessee Valley Authority	Armando Rodriguez		Affirmative	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
7	Oxy - Occidental Chemical	Venona Greaff		None	N/A
10	Midwest Reliability Organization	William Steiner		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		None	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	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 312 of 312 entries

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/247)
Ballot Name: 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination EOP-011-3 | Non-binding Poll IN 1 NB
Voting Start Date: 6/8/2022 12:01:00 AM
Voting End Date: 6/21/2022 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 266
Total Ballot Pool: 299
Quorum: 88.96
Quorum Established Date: 6/20/2022 9:40:11 PM
Weighted Segment Value: 78.82

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	83	1	48	0.842	9	0.158	20	6
Segment: 2	7	0.3	0	0	3	0.3	3	1
Segment: 3	64	1	40	0.851	7	0.149	10	7
Segment: 4	17	1	9	0.818	2	0.182	3	3
Segment: 5	74	1	35	0.729	13	0.271	17	9
Segment: 6	47	1	25	0.735	9	0.265	8	5
Segment: 7	1	0	0	0	0	0	0	1
Segment: 8	0	0	0	0	0	0	0	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	0.3	3	0.3	0	0	2	1
Totals:	299	5.6	160	4.276	43	1.324	63	33

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Ameren - Ameren Services	Tamara Evey		Abstain	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski	Brandon Smith	Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Arkansas Electric Cooperative Corporation	Jennifer Loiacano		None	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		Negative	Comments Submitted
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		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		Affirmative	N/A
1	Black Hills Corporation	Micah Runner	Jennifer Malon	Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Negative	Comments Submitted
1	Dairyland Power Cooperative	Steve Ritscher		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Affirmative	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
1	Edison International - Southern California Edison Company	Jose Avendano Mora		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Allen Klassen	Alan Kloster	Affirmative	N/A
1	Eversource Energy	Quintin Lee		Abstain	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Gainesville Regional Utilities	David Owens	LaKenya VanNorman	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Abstain	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Sheraz Majid		Negative	Comments Submitted
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		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	Abstain	N/A
1	JEA	Joe McClung		None	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Negative	Comments Submitted
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Lower Colorado River Authority	James Baldwin		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Muscatine Power and Water	Andy Kurriger		Affirmative	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	Nurul Abser		Abstain	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Ohio Valley Electric Corporation	Scott Cunningham		Abstain	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Negative	Comments Submitted
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Portland General Electric Co.	Brooke Jockin		Abstain	N/A
1	PPL Electric Utilities Corporation	Michelle Longo		None	N/A
1	PSEG - Public Service Electric and Gas Co.	Kyle Down		Abstain	N/A
1	Public Utility District No. 1 of Chelan County	Diane Landry		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		None	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Chris Hofmann		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seattle City Light	Michael Jang		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Abstain	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Taunton Municipal Lighting Plant	Devon Tremont		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Abstain	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		Negative	Comments Submitted
1	VELCO -Vermont Electric Power Company, Inc.	Randy Buswell		None	N/A
1	Western Area Power Administration	sean erickson	Kimberly Bentley	Affirmative	N/A
2	California ISO	Darcy O'Connell		None	N/A
2	Independent Electricity System Operator	Leonard Kula		Negative	Comments Submitted
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.	Tom Foster	Elizabeth Davis	Abstain	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
3	AEP	Kent Feliks		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Michael Dieringer		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Abstain	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	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	Jennifer Malon	Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Negative	Comments Submitted
3	CPS Energy	Glenn Pressler		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Schroeder		Abstain	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Negative	Comments Submitted
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		None	N/A
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Alan Kloster	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	Florida Municipal Power Agency	Carl Turner	LaKenya VanNorman	Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Imperial Irrigation District	Glen Allegranza	Denise Sanchez	Affirmative	N/A
3	JEA	Marilyn Williams		None	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Steve Marshall		None	N/A
3	Lincoln Electric System	Angelica Valencia		Abstain	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		None	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	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	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney		Negative	Comments Submitted
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	LaKenya VanNorman	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	William Berry		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Negative	Comments Submitted
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	PSEG - Public Service Electric and Gas Co.	maria pardo		Negative	Comments Submitted
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	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		None	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Abshier		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	American Public Power Association	John McCaffrey		Abstain	N/A
4	Austin Energy	Jun Hua		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
4	DTE Energy	patricia ireland		None	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Florida Municipal Power Agency	Dan O'Hagan	LaKenya VanNorman	Affirmative	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain	N/A
4	Indiana Municipal Power Agency	Jack Alvey	Scott Berry	Negative	Comments Submitted
4	Northern California Power Agency	Marty Hostler		Negative	Comments Submitted
4	Oklahoma Municipal Power Authority	Michael Watt		None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		None	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.	Jonathan Robbins		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Abstain	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	Acciona Energy North America	George Brown		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Chuck Booth		None	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Negative	Comments Submitted
5	Basin Electric Power Cooperative	Amanda Wangler		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	Derek Silbaugh	Jennifer Malon	Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Negative	Comments Submitted
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Cogentrix Energy Power Management, LLC	Gerry Adamski		Abstain	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Haizhen Wang		Affirmative	N/A
5	Constellation	Alison Mackellar		Negative	Comments Submitted
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	CPS Energy	Robert Stevens		None	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Decatur Energy Center LLC	Shannon Ferdinand		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		Negative	Comments Submitted
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Enel Green Power	Natalie Johnson		Abstain	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	LaKenya VanNorman	Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	Greybeard Compliance Services, LLC	Michael Gabriel		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Herb Schrayshuen	Herb Schrayshuen		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	Jason Fortik		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		None	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
5	LS Power Development, LLC	Mark Spencer		Abstain	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
5	NB Power Corporation	David Melanson		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender		Abstain	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	NextEra Energy	Summer Esquerre		Negative	Comments Submitted
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Northern California Power Agency	Jeremy Lawson		Negative	Comments Submitted
5	NRG - NRG Energy, Inc.	Patricia Lynch		Negative	Comments Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
5	OTP - Otter Tail Power Company	Tammy Kubela		None	N/A
5	Pacific Gas and Electric Company	Frank Lee	Michael Johnson	Negative	Comments Submitted
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Abstain	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		Affirmative	N/A
5	Sacramento Municipal Utility District	Nicole Goi	Tim Kelley	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Marty Watson		Abstain	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Abstain	N/A
5	Southern Company - Southern Company Generation	James Howell		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
5	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Negative	Comments Submitted
5	WEC Energy Group, Inc.	Clarice Zellmer		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt	Amy Casuscelli	None	N/A
6	AEP	JT Kuehne		Abstain	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	Lisa Martin		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Abstain	N/A
6	Black Hills Corporation	Claudine Bates		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Negative	Comments Submitted
6	Cleco Corporation	Robert Hirchak		Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Michael Foley		Affirmative	N/A
6	Constellation	Kimberly Turco		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Jennifer Flandermeyer	Alan Kloster	Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Tricia Bynum		Affirmative	N/A
6	Florida Municipal Power Agency	Jade Bulitta	LaKenya VanNorman	Affirmative	N/A
6	Florida Municipal Power Pool	Aaron Casto	LaKenya VanNorman	Affirmative	N/A
6	Great River Energy	Donna Stephenson		Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Invenergy LLC	Colin Chilcoat		None	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	Nick Burns		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Negative	Comments Submitted
6	NRG - NRG Energy, Inc.	Martin Sidor		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		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	Joseph Neglia		Negative	Comments Submitted
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Pam Syrjala		Affirmative	N/A
6	Santee Cooper	Glenda Horne		Abstain	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.	Erin Spence		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	Tennessee Valley Authority	Armando Rodriguez		None	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
7	Oxy - Occidental Chemical	Venona Greaff		None	N/A
10	Midwest Reliability Organization	William Steiner		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		None	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	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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Showing 1 to 299 of 299 entries

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/247)
Ballot Name: 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination EOP-012-1 | Non-binding Poll IN 1 NB
Voting Start Date: 6/8/2022 12:01:00 AM
Voting End Date: 6/21/2022 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 269
Total Ballot Pool: 300
Quorum: 89.67
Quorum Established Date: 6/20/2022 4:32:47 PM
Weighted Segment Value: 19.52

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	82	1	12	0.218	43	0.782	21	6
Segment: 2	7	0.3	0	0	3	0.3	3	1
Segment: 3	64	1	9	0.188	39	0.813	9	7
Segment: 4	17	1	1	0.091	10	0.909	3	3
Segment: 5	76	1	11	0.196	45	0.804	13	7
Segment: 6	47	1	5	0.147	29	0.853	8	5
Segment: 7	1	0	0	0	0	0	0	1
Segment: 8	0	0	0	0	0	0	0	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	0.3	3	0.3	0	0	2	1
Totals:	300	5.6	41	1.14	169	4.46	59	31

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Ameren - Ameren Services	Tamara Evey		Abstain	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski	Brandon Smith	Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
1	Arkansas Electric Cooperative Corporation	Jennifer Loiacano		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Negative	Comments Submitted
1	Austin Energy	Thomas Standifur		Negative	Comments Submitted
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	Basin Electric Power Cooperative	David Rudolph		Negative	Comments Submitted
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	Micah Runner	Jennifer Malon	Negative	Comments Submitted
1	Bonneville Power Administration	Kammy 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	Colorado Springs Utilities	Mike Braunstein		Negative	Comments Submitted
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Negative	Comments Submitted
1	Dairyland Power Cooperative	Steve Ritscher		Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Candace Marshall		Negative	Comments Submitted
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Jose Avendano Mora		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Evergy	Allen Klassen	Alan Kloster	Negative	Comments Submitted
1	Eversource Energy	Quintin Lee		Abstain	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Negative	Comments Submitted
1	Gainesville Regional Utilities	David Owens	LaKenya VanNorman	Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis		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-Qu?bec TransEnergie	Nicolas Turcotte		Negative	Comments Submitted
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Negative	Comments Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Joe McClung		None	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Negative	Comments Submitted
1	Lakeland Electric	Larry Watt		Negative	Comments Submitted
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Lower Colorado River Authority	James Baldwin		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	M and A Electric Power Cooperative	William Price		Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard		Negative	Comments Submitted
1	Muscatine Power and Water	Andy 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	Nurul Abser		Abstain	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Negative	Comments Submitted
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Negative	Comments Submitted
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Abstain	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	Comments Submitted
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		Abstain	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 Longo		None	N/A
1	PSEG - Public Service Electric and Gas Co.	Kyle Down		Abstain	N/A
1	Public Utility District No. 1 of Chelan County	Diane Landry		Negative	Comments Submitted
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		None	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	Comments Submitted
1	Salt River Project	Chris Hofmann		Negative	Comments Submitted
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seattle City Light	Michael Jang		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Abstain	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Taunton Municipal Lighting Plant	Devon Tremont		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Abstain	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	Comments Submitted
1	VELCO -Vermont Electric Power Company, Inc.	Randy Buswell		None	N/A
1	Western Area Power Administration	sean erickson	Kimberly Bentley	Negative	Comments Submitted
2	California ISO	Darcy O'Connell		None	N/A
2	Independent Electricity System Operator	Leonard Kula		Negative	Comments Submitted
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.	Tom Foster	Elizabeth Davis	Abstain	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
3	AEP	Kent Feliks		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Austin Energy	Michael Dieringer		Negative	Comments Submitted
3	Avista - Avista Corporation	Scott Kinney		Negative	Comments Submitted
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs	Jennifer Malon	Negative	Comments Submitted
3	Bonneville Power Administration	Ken Lanehome		Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Comments Submitted
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
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	Cowlitz County PUD	Russell Noble		Negative	Comments Submitted
3	CPS Energy	Glenn Pressler		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Schroeder		Abstain	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Negative	Comments Submitted
3	Duke Energy	Lee Schuster		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Edison International - Southern California Edison Company	Romel Aquino		None	N/A
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Alan Kloster	Negative	Comments Submitted
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Florida Municipal Power Agency	Carl Turner	LaKenya VanNorman	Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		Negative	Comments Submitted
3	Great River Energy	Michael Brytowski		Negative	Comments Submitted
3	Imperial Irrigation District	Glen Allegranza	Denise Sanchez	Negative	Comments Submitted
3	JEA	Marilyn Williams		None	N/A
3	KAMO Electric Cooperative	Tony Gott		Negative	Comments Submitted
3	Lakeland Electric	Steve Marshall		None	N/A
3	Lincoln Electric System	Angelica Valencia		Abstain	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		None	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	New York Power Authority	David Rivera		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney		Negative	Comments Submitted
3	NW Electric Power Cooperative, Inc.	John Stickley		Negative	Comments Submitted
3	Ocala Utility Services	Neville Bowen	LaKenya VanNorman	Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Negative	Comments Submitted
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Comments Submitted
3	Owensboro Municipal Utilities	William Berry		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Negative	Comments Submitted
3	Platte River Power Authority	Wade Kiess		Negative	Comments Submitted
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	PSEG - Public Service Electric and Gas Co.	maria pardo		Negative	Comments Submitted
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	Zack Heim		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Santee Cooper	James Poston		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Negative	Comments Submitted
3	Snohomish County PUD No. 1	Holly Chaney		None	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Abshier		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Comments Submitted
4	American Public Power Association	John McCaffrey		Abstain	N/A
4	Austin Energy	Jun Hua		Negative	Comments Submitted
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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Florida Municipal Power Agency	Dan O'Hagan	LaKenya VanNorman	Negative	Comments Submitted
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain	N/A
4	Indiana Municipal Power Agency	Jack Alvey	Scott Berry	Negative	Comments Submitted
4	Northern California Power Agency	Marty Hostler		Negative	Comments Submitted
4	Oklahoma Municipal Power Authority	Michael Watt		None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		None	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Comments Submitted
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Negative	Comments Submitted
4	Utility Services, Inc.	Brian Evans-Mongeon		Abstain	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Negative	Comments Submitted
5	Acciona Energy North America	George Brown		Negative	Comments Submitted
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Chuck Booth		Abstain	N/A
5	Austin Energy	Michael Dillard		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Avista - Avista Corporation	Glen Farmer		Negative	Comments Submitted
5	Basin Electric Power Cooperative	Amanda Wangler		Negative	Comments Submitted
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Black Hills Corporation	Derek Silbaugh	Jennifer Malon	Negative	Comments Submitted
5	Bonneville Power Administration	Scott Winner		Negative	Comments Submitted
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Comments Submitted
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Negative	Comments Submitted
5	Cogentrix Energy Power Management, LLC	Gerry Adamski		Abstain	N/A
5	Colorado Springs Utilities	Jeff Icke		Negative	Comments Submitted
5	Con Ed - Consolidated Edison Co. of New York	Haizhen Wang		Affirmative	N/A
5	Constellation	Alison Mackellar		Negative	Comments Submitted
5	Cowlitz County PUD	Deanna Carlson		Negative	Comments Submitted
5	CPS Energy	Robert Stevens		None	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Decatur Energy Center LLC	Shannon Ferdinand		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	DTE Energy - Detroit Edison Company	Adrian Raducea		Negative	Comments Submitted
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Enel Green Power	Natalie Johnson		Negative	Comments Submitted
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Robert Loy		Negative	Comments Submitted
5	Florida Municipal Power Agency	Chris Gowder	LaKenya VanNorman	Negative	Comments Submitted
5	Great River Energy	Jacalynn Bentz		Negative	Comments Submitted
5	Greybeard Compliance Services, LLC	Michael Gabriel		Negative	Third-Party Comments
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Negative	Comments Submitted
5	Invenergy LLC	Rhonda Jones		None	N/A
5	JEA	John Babik		Negative	Comments Submitted
5	Lincoln Electric System	Jason Fortik		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		None	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
5	LS Power Development, LLC	Mark Spencer		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	National Grid USA	Elizabeth Spivak		Negative	Comments Submitted
5	NB Power Corporation	David Melanson		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender		Abstain	N/A
5	New York Power Authority	Zahid Qayyum		Negative	Comments Submitted
5	NextEra Energy	Summer Esquerre		Negative	Comments Submitted
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Northern California Power Agency	Jeremy Lawson		Negative	Comments Submitted
5	NRG - NRG Energy, Inc.	Patricia Lynch		Negative	Comments Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Negative	Comments Submitted
5	Omaha Public Power District	Mahmood Safi		Negative	Comments Submitted
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
5	OTP - Otter Tail Power Company	Tammy Kubela		None	N/A
5	Pacific Gas and Electric Company	Frank Lee	Michael Johnson	Negative	Comments Submitted
5	Platte River Power Authority	Jon Osell		Negative	Comments Submitted
5	Portland General Electric Co.	Ryan Olson		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Negative	Comments Submitted
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		Affirmative	N/A
5	Sacramento Municipal Utility District	Nicole Goi	Tim Kelley	Negative	Comments Submitted
5	Salt River Project	Kevin Nielsen		Negative	Comments Submitted
5	Santee Cooper	Marty Watson		Abstain	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Abstain	N/A
5	Southern Company - Southern Company Generation	James Howell		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	Negative	Comments Submitted
5	Talen Generation, LLC	Donald Lock		Negative	Comments Submitted
5	Tenaska, Inc.	Mark Young		Negative	Comments Submitted
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
5	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	U.S. Bureau of Reclamation	Wendy Kalidass		Negative	Comments Submitted
5	Vistra Energy	Dan Roethemeyer		Negative	Comments Submitted
5	WEC Energy Group, Inc.	Clarice Zellmer		Negative	Comments Submitted
5	Xcel Energy, Inc.	Gerry Huitt	Amy Casuscelli	None	N/A
6	AEP	JT Kuehne		Abstain	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		Negative	Comments Submitted
6	Austin Energy	Lisa Martin		Negative	Comments Submitted
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Negative	Comments Submitted
6	Black Hills Corporation	Claudine Bates		Negative	Comments Submitted
6	Bonneville Power Administration	Andrew Meyers		Negative	Comments Submitted
6	Cleco Corporation	Robert Hirchak		Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Michael Foley		Affirmative	N/A
6	Constellation	Kimberly Turco		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	Greg Cecil		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Jennifer Flandermeyer	Alan Kloster	Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Tricia Bynum		Negative	Comments Submitted
6	Florida Municipal Power Agency	Jade Bulitta	LaKenya VanNorman	Negative	Comments Submitted
6	Florida Municipal Power Pool	Aaron Casto	LaKenya VanNorman	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson		Negative	Comments Submitted
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Negative	Comments Submitted
6	Invenergy LLC	Colin Chilcoat		None	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	Nick Burns		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Negative	Comments Submitted
6	NRG - NRG Energy, Inc.	Martin Sidor		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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.	Daniel Mason		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	Joseph Neglia		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Negative	Comments Submitted
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	Comments Submitted
6	Salt River Project	Pam Syrjala		Negative	Comments Submitted
6	Santee Cooper	Glenda Horne		Abstain	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.	Erin Spence		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Negative	Comments Submitted
6	Tennessee Valley Authority	Armando Rodriguez		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
7	Oxy - Occidental Chemical	Venona Greaff		None	N/A
10	Midwest Reliability Organization	William Steiner		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		None	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	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

Previous 1 Next

Showing 1 to 300 of 300 entries

Comment Report

Project Name:	2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Draft 1
Comment Period Start Date:	5/19/2022
Comment Period End Date:	6/21/2022
Associated Ballots:	2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination EOP-011-3 | Non-binding Poll IN 1 NB 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination EOP-011-3 IN 1 ST 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination EOP-012-1 | Non-binding Poll IN 1 NB 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination EOP-012-1 IN 1 ST 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination Implementation Plan IN 1 OT

There were 108 sets of responses, including comments from approximately 249 different people from approximately 162 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. The SDT revised EOP-011-3 requirements R1 and R2 for the TOP to minimize the overlap of UFLS and UVLS circuits from those used for manual load shed or those that serve critical loads. Should PRC-006-5 Requirement R7 and PRC-010-2 Requirement R8 also be modified to include a Requirement that Planning Coordinators shall provide UFLS and/or UVLS (as applicable) program database data to Transmission Operator's upon request, in order to ensure that all TOPs have the necessary data to minimize the overlap of circuits as required in the newly proposed EOP-011-3 Requirement R1.2.5.3? Please provide any explanation with your response.

2. Should the BA be the entity to determine the "winter season", which is used to define applicable generating units in proposed EOP-012-1 Section 4.2 Facilities? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

3. The SDT proposes to include as applicable Facilities in EOP-012-1 only those generating units that operate during the winter weather season, while exempting those units utilized for summer peaking purposes only (and without penalizing such units that may be called upon by the BA during winter weather in response to energy emergencies). Do you agree with the applicability of EOP-012-1 as drafted? If you do not agree, please provide recommended language for how to address from the standard's applicability consistent with the recommendations of The Report.

4. Does the proposed language in EOP-012-1 requirement R1 that require existing units to implement new freeze protection measures or modification of existing freeze protection measures, raise any stakeholder concerns? If so, please provide details of the concern, suggestions to the proposed language that addresses the risk presented in recommendation 1f, and if appropriate, technical or procedural justification.

5. The SDT has proposed that owners of new generation that determine that they are not able to implement freeze protection measures due to technical, commercial, or operational constraints review their determination every five years for EOP-012-1 Requirement R2. Is this separate requirement for "new" generation necessary, given that proposed Requirement R4 provides for Generator Owners to perform a similar review every five years to address the ongoing need to review freeze protection measures and historical cold weather temperatures? Please provide any explanation with your response.

6. The Standard, as proposed, would require Generator Owners to develop plans for modifying generating units to operate to the minimum hourly temperature over the next five years after Commission approval. While Generator Owners identify those generating units that need modifications, develop corrective action plans, and implement modifications, it is important for the ERO Enterprise to have aggregated data about the status of Generation Owners' extreme cold weather preparedness for its generating units for use in its reliability oversight activities.

The SDT believes that there is benefit to having the ERO Enterprise collect information on progress of Generator Owner plans for modifying generating units. The information could be collected through reporting under mandatory Reliability Standard requirements, through a Periodic Data Submittal under Section 400 of the Rules of Procedure (which may or may not be specified in the Compliance section of the standard), or through a request for data under Section 1600 of the Rules of Procedure. Which of these options do you believe is the best procedural option for collecting this information?

7. The drafting team has developed a proposed data collection framework which could form the basis for a periodic data submittal. If you have any comments or edits to the suggested language, please propose an alternative to address the identified risk during the phased-in compliance period.

Collection framework:

- **The Generator Owner will submit an annual summary table by October 1 of each year to its Regional Entity regarding the status of its generating units (as that term is used in EOP-012-1 4.2 Facilities) having freeze protection measures in accordance with Requirements R1 and R2, along with a nine-year projection of status based on the timetables it has determined for Requirement R1. All projections will be based on the Generator Owner's timetables under Requirement R1.4.2; if timetables are not complete for all units, some MW can be designated as "to be determined." The summary table shall contain:**
  - **Status year (for current year, and future years 1-9);**
  - **Sum of capacities (in MW) of all generating units applicable under Facilities, section 4.2;**
  - **Sum of capacities (MW) of generating units meeting (for current year) and projected to meet (for each of the future years 1-9) the criteria of Requirement R1.1;**
  - **Sum of capacities (MW) of generating units not meeting (for current year) and projected to not meet (for each of the future years 1-9) the criteria of Requirement R1.1;**
  - **Sum of the capacities (MW) of existing generating units declared for no action under Requirement R1 (for current year, and projected for future years 1-9);**
  - **Sum of the capacities (MW) of new generating units identified for no action under Requirement R2 (for current year, and projected for future years 1-9).**

9. The SDT is proposing an 18-month implementation time frame for all revised and new requirements except EOP-012-1 Requirements R1 and R2 which have a 5-year implementation time frame. Do you agree with this implementation time frame? If you think an alternate timeframe is needed, please propose an alternate implementation plan and time period, and provide a detailed explanation of actions planned to meet the implementation deadline.

10. 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
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
DTE Energy - Detroit Edison Company	Adrian Raducea	5		DTE Energy - DTE Electric	Karie Barczak	DTE Energy - Detroit Edison Company	3	RF
					Adrian Raducea	DTE Energy - Detroit Edison	5	RF
					patricia ireland	DTE Energy	4	RF
Portland General Electric Co.	Daniel Mason	6		PGE FCD	Ryan Olson	Portland General Electric Co.	5	WECC
					Brooke Jockin	Portland General Electric Co.	1	WECC
					Daniel Mason	Portland General Electric	6	WECC
Elizabeth Davis	Elizabeth Davis		RF,SERC	ISO/RTO Council (IRC) Standards Review Committee (SRC)	Mike Del Viscio	PJM	2	RF
					Becky Davis	PJM	2	RF
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Charles Yeung	Southwest Power Pool, Inc. (RTO)	2	MRO
					Helen Lainis	IESO	2	NPCC
					Bobbi Welch	Midcontinent ISO, Inc.	2	RF
					Al Miremadi	CAISO	2	WECC
					Dana Showalter	Electric Reliability	2	Texas RE

						Council of Texas, Inc.		
					Kathleen Goodman	ISO-NE	2	NPCC
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
					Marc Donaldson	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
PPL - Louisville Gas and Electric Co.	Jennifer Blair	1,3,5,6	SERC	PPL NERC Registered Affiliates	James Frank	PPL - Louisville Gas and Electric Co.	3	SERC
					JULIE HOSTRANDER	PPL - Louisville Gas and Electric Co.	5	SERC
					Linn Oelker	PPL - Louisville Gas and Electric Co.	6	SERC
					Michelle Longo	PPL Electric Utilities Corporation	1	RF
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,NA - Not Applicable,RF,SERC,Texas RE,WECC	ACES Standard Collaborations	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	SERC
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO

					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					Susan Sosbe	Wabash Valley Power Association	3	RF
					Nick Fogleman	Prairie Power, Inc.	1	SERC
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Todd Bennett	Associated Electric Cooperative, Inc.	3	SERC
					Patti Metro	National Rural Electric Cooperative Association	3	NA - Not Applicable
Entergy	Julie Hall	6		Entergy	Oliver Burke	Entergy - Entergy Services, Inc.	1	SERC
					Jamie Prater	Entergy	5	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
					LaTroy Brumfield	American Transmission	1	MRO

						Company, LLC		
					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
					David Heins	Omaha Public Power District	1,3,5,6	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
Duke Energy	Kim Thomas	1,3,5,6	FRCC,RF,SERC,Texas RE	Duke Energy	Laura Lee	Duke Energy	1	SERC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
LaKenya VanNorman	LaKenya VanNorman		SERC	FMPA and Members	Chris Gowder	Florida Municipal Power Agency	5	SERC
					Dan O'Hagan	Florida Municipal Power Agency	4	SERC
					Carl Turner	Florida Municipal Power Agency	3	SERC
					Jade Bulitta	Florida Municipal Power Agency	6	SERC
					Don Cuevas	Beaches Energy Services	1	SERC

					Carolyn Woodard	Beaches Energy Services	3	SERC
					Aaron Casto	Florida Municipal Power Pool	6	SERC
					Jakub Pajak	Fort Pierce Utilities Authority	3	SERC
					Nick Batty	Keys Energy Services	4	SERC
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
					Tricia Bynum	FirstEnergy - FirstEnergy Corporation	6	RF
					Mark Garza	FirstEnergy-FirstEnergy	4	RF
Northern California Power Agency	Marty Hostler	4		NCPA	Michael Whitney	Northern California Power Agency	3	WECC
					Scott Tomashefsky	Northern California Power Agency	4	WECC
					Dennis Sismaet	Northern California Power Agency	6	WECC
					Marty	Northern California Power Agen	5	WECC
Santee Cooper	Marty Watson	5		Santee Cooper	Robert Rhett	Santee Cooper	1,3,5,6	SERC
					Paul Camilletti	Santee Cooper	1,3,5,6	SERC
					Rene' Free	Santee Cooper	1,3,5,6	SERC
					Domenic Ciccolella	Santee Cooper	1,3,5,6	SERC

					Carl Price	Santee Cooper	1,3,5,6	SERC
					Todd Thomas	Santee Cooper	1,3,5,6	SERC
					Ged Moree	Santee Cooper	1,3,5,6	SERC
					Darby Gallagher	Santee Cooper	1,3,5,6	SERC
					William Stevick	Santee Cooper	1,3,5,6	SERC
					Jeffrey Zeigler	Santee Cooper	1,3,5,6	SERC
					Robert Long	Santee Cooper	1,3,5,6	SERC
Public Utility District No. 1 of Chelan County	Meaghan Connell	5		PUD No. 1 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
					Glen Pruitt	Public Utility District No. 1 of Chelan County	6	WECC
					Meaghan Connell	Public Utility District No. 1 Chelan County	5	WECC
Michael Johnson	Michael Johnson		WECC	PG&E All Segments	Marco Rios	Pacific Gas and Electric Company	1	WECC
					Sandra Ellis	Pacific Gas and Electric Company	3	WECC
					James Mearns	Pacific Gas and Electric Company	5	WECC
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
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
					Jim Howell	Southern Company - Southern Company Services, Inc. - Gen	5	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC Regional Standards Committee	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Harish Vijay Kumar	IESO	2	NPCC
					David Kiguel	Independent	7	NPCC
					Nick Kowalczyk	Orange and Rockland	1	NPCC
					Joel Charlebois	AESI - Acumen	5	NPCC

						Engineered Solutions International Inc.		
					Mike Cooke	Ontario Power Generation, Inc.	4	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Shivaz Chopra	New York Power Authority	5	NPCC
					Deidre Altobell	Con Ed - Consolidated Edison	4	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Cristhian Godoy	Con Ed - Consolidated Edison Co. of New York	6	NPCC
					Nurul Abser	NB Power Corporation	1	NPCC
					Randy MacDonald	NB Power Corporation	2	NPCC
					Michael Ridolfino	Central Hudson Gas and Electric	1	NPCC
					Vijay Puran	NYSPS	6	NPCC
					ALAN ADAMSON	New York State Reliability Council	10	NPCC
					Sean Cavote	PSEG - Public Service Electric and Gas Co.	1	NPCC
					Brian Robinson	Utility Services	5	NPCC

					Quintin Lee	Eversource Energy	1	NPCC
					John Pearson	ISONE	2	NPCC
					Nicolas Turcotte	Hydro-Qu?bec TransEnergie	1	NPCC
					Chantal Mazza	Hydro-Quebec	2	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	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
Western Electricity Coordinating Council	Steven Rueckert	10		WECC Entity Monitoring	Steve Rueckert	WECC	10	WECC
					Phil O'Donnell	WECC	10	WECC
OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle	1		OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle	OGE Energy - Oklahoma Gas and Electric Co	1	MRO
					Donald Hargrove	OGE Energy - Oklahoma Gas and Electric Co.	3	MRO
					Patrick Wells	OGE Energy - Oklahoma Gas and Electric Co.	5	MRO
Tim Kelley	Tim Kelley		WECC	LPPC	Holly Chaney	Snohomish County PUD No. 1	3	WECC

					Joe McClung	JEA	1	SERC
					Nicole Looney	Sacramento Municipal Utility District	3	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
					Stephen Pogue	M and A Electric Power Cooperative	3	SERC
					William Price	M and A Electric Power Cooperative	1	SERC
					Peter Dawson	Sho-Me Power Electric Cooperative	1	SERC
					Mark Ramsey	N.W. Electric Power Cooperative, Inc.	1	NPCC
					John Stickley	NW Electric Power Cooperative, Inc.	3	SERC
					Tony Gott	KAMO Electric Cooperative	3	SERC
					Micah Breedlove	KAMO Electric Cooperative	1	SERC
					Kevin White	Northeast Missouri Electric Power Cooperative	1	SERC
					Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	3	SERC
					Ryan Ziegler	Associated Electric Cooperative, Inc.	1	SERC

					Brian Ackermann	Associated Electric Cooperative, Inc.	6	SERC
					Brad Haralson	Associated Electric Cooperative, Inc.	5	SERC

1. The SDT revised EOP-011-3 requirements R1 and R2 for the TOP to minimize the overlap of UFLS and UVLS circuits from those used for manual load shed or those that serve critical loads. Should PRC-006-5 Requirement R7 and PRC-010-2 Requirement R8 also be modified to include a Requirement that Planning Coordinators shall provide UFLS and/or UVLS (as applicable) program database data to Transmission Operator's upon request, in order to ensure that all TOPs have the necessary data to minimize the overlap of circuits as required in the newly proposed EOP-011-3 Requirement R1.2.5.3? Please provide any explanation with your response.

Gul Khan - Gul Khan On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Gul Khan

Answer	No
Document Name	

Comment

No. Revisions to PRC-006 and PRC-010 are not necessary. The proposed revisions to EOP-011 are sufficient to address the related recommendation from The Report and obligate the Transmission Operator to have provisions in their Operating Plan to address these requirements. The Transmission Operator must determine how these provisions are handled for entities and load they may represent.

Likes 0	
Dislikes 0	

Response

Glen Farmer - Avista - Avista Corporation - 5

Answer	No
Document Name	

Comment

Avista presently avoids critical loads with its UFLS plan. The Manual Load Shedding is may contain some critical loads. There is extremely wide overlap between the UFLS and Manual Load Shedding. Given the nature of Avista's system, the amount of load available for Manual Load Shedding will be greatly reduced under this standard. I recommend a NO vote with the following comment. "UFLS schemes are designed to address a multiple contingeny resource loss in real-time. They are not designed to be used during an Energy Emergency where there is no sudden frequency change. The UFLS loads are carefully chosen to avoid critical and sensitive loads. In many cases, the UFLS loads are also used for a manual load shed event, which by definition is slower, and not a frequency sensitive event. Manual Load Shedding is not occurring during a sudden frequency excursion. By limiting the overlap of the two load shedding schemes, flexibility of the BA/TOP to manage load resource balance in an EEA is severely compromised, and the amount of Manual Load Shedding available is greatly reduced. This will likely result in the interruption of critical loads during an EEA as the situation deteriorates and the System Operator is left with very limited options during an EEA."

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

We do not have UVLS and we believe that PRC-006 and PRC-012 should NOT be modified.

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	No
Document Name	

Comment

The IESO is assuming the following:
1. TOP is responsible for establishing and implementating the Operating Plan.
2. TOP orders the maual load shed if and when required.
3. UFLS and UVLS load shedding entities make the arming selections (make the circuits available) for shedding.

The IESO strongly believes that the most effective means to ensure minimization of the overlap of circuits as required by the newly proposed EOP-011-3 is to add the UFLS and UVLS Load Shedding Entities as applicable functional entities. Since UFLS and UVLS load shedding entities are responsible for the arming selections, they are the ones that implement the corrective load shedding circuit requirements.

As such, the IESO requests that UFLS and UVLS load shedding entities be added as applicable functional entities in the newly revised EOP-011-3.

In addition, a new requirement should be added to the newly revised EOP-011-3 that requires the UFLS and UVLS Load Shedding Entities to meet the provisions included in the TOP Operating Plan for operator-controlled manual Load shedding during an Emergency that include:
1. Manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency
2. Minimizing the overlap of circuits that are designated for manual Load shed and circuits that serve designated critical loads
3. Minimizing the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS
4. Limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions.

Likes 0	
Dislikes 0	

Response

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	

Comment

Having multiple Requirements with the same intent will introduce risk of double (non-compliance) jeopardy. PRC-010-2 R8 already states that the UVLS database be made available to TPs. Likewise, PCR-006-5 R14 states that the PC shall respond to written comments from applicable entities that want this data.	
Likes 2	Corn Belt Power Cooperative, 1, brusseau larry; Lincoln Electric System, 1, Johnson Josh
Dislikes 0	
Response	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
DTE Electric supports NAGF 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	
ISO-NE does not support an additional requirement on the Planning Coordinator (PC) to provide data to the Transmission Operator (TOP). The TOP is responsible for providing the PC with the relevant UFLS/UVLS circuit information as currently written. This would only serve to place an additional administrative burden on the PC. The SDT should consider adding the UFLS/UVLS Distribution Providers to the Applicable Facilities for these requirements.	
Likes 0	
Dislikes 0	
Response	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	No
Document Name	

Comment	
Alliant Energy supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation observes that coordination and planning information exchange is already covered in other standards. The addition of new requirements to these standards is unnecessary and would likely cause confusion.	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	No
Document Name	
Comment	
Pacific Gas & Electric (PG&E) supports the comments provided by the North American Generators Forum (NAGF).	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 4, Group Name NCPA	
Answer	No
Document Name	
Comment	

NCPA agrees with the comments of IESO.

Likes 0	
Dislikes 0	

Response

Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	

Comment

Changes to Cold Weather Reliability Standards should not be applicable continent-wide. Standards should not be modified or implemented prior to Market Rule Modifications. See prior NERC Project 2019-06 ballot and commenting by Marty Hostler

Market Rule modifications have not yet been made to mitigate potential Cold Weather Events grid issues. Per FERC/NERC's recommendation, Market Rule modifications should be made prior to, or concurrent with, development of new Standards. To date, no known Market Rule Modification project has been initiated.

On page 86 of FERC/NERC's joint Report The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018 (ferc.gov) the following recommendations where made.

Recommendation 1: The Team recommends a three-pronged approach to ensure Generator Owners/Generator Operators, Reliability Coordinators and Balancing Authorities prepare for cold weather conditions: 1) development or enhancement of one or more NERC Reliability Standards, 2) enhanced outreach to Generator Owners/Generator Operators, and 3) market (Independent System Operators/Regional Transmission Organizations) rules where appropriate. This three-pronged approach should be used to address the following needs: • The need for Generator Owners/Generator Operators to perform winterization activities on generating units to prepare for adverse cold weather, in order to maximize generator output and availability for BES reliability during these conditions. These preparations for cold weather should include Generator Owners/Generator Operators:

While any one of the three approaches may provide significant benefits in solving this problem, the Team does not view any one of the three as the only solution. The Team envisions that a successful resolution of the problem will likely involve concurrent use of all three.

Likes 0	
Dislikes 0	

Response

Jeremy Lawson - Northern California Power Agency - 5	
Answer	No
Document Name	

Comment

NCPA agrees with the comments of IESO.

Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
UFLS schemes are designed to address a multiple contingeny resource loss in real-time. They are not designed to be used during an Energy Emergency where there is no sudden frequency change. The UFLS loads are carefully chosen to avoid critical and sensitive loads. In many cases, the UFLS loads are also used for a manual load shed event, which by definition is slower, and not a frequency sensitive event. Manual Load Shedding is not occurring during a sudden frequency excursion. By limiting the overlap of the two load shedding schemes, flexibility of the BA/TOP to manage load resource balance in an EEA is severely compromised, and the amount of Manual Load Shedding available is greatly reduced. This will likely result in the interruption of critical loads during an EEA as the situation deteriorates and the System Operator is left with very limited options during an EEA.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
AEP does not see a reliability benefit in requiring that program database data be provided to the Transmission Operator’s upon request, and does not recommend revising PRC-006-5 Requirement R7 and PRC-010-2 Requirement R8.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	

Ameren agrees with the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Glenn Pressler - CPS Energy - 3	
Answer	No
Document Name	
Comment	
No. Revisions to PRC-006 and PRC-010 are not necessary. The proposed revisions to EOP-011 are sufficient to address the related concerns.	
Likes 0	
Dislikes 0	
Response	
Robert Stevens - CPS Energy - 5	
Answer	No
Document Name	
Comment	
No. Revisions to PRC-006 and PRC-010 are not necessary. The proposed revisions to EOP-011 are sufficient to address the related concerns.	
Likes 0	
Dislikes 0	
Response	
Michael Dillard - Austin Energy - 5	
Answer	No
Document Name	
Comment	
AE does not feel strongly that there is a need to modify PRC-006-5 R7 or PRC-010-2 R8. As a TOP, AE is able to comply with the requirements without receiving the UFLS/UVLS program database data from the Planning Coordinator.	

Likes 0	
Dislikes 0	
Response	

LaKenya VanNorman - LaKenya VanNorman On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name FMPA and Members

Answer	No
Document Name	
Comment	

The Planning Coordinator's program typically only identifies percentages of load for a given frequency and time "step". The actual specific feeders that are part of a UFLS program of UVLS program are determined by the "UFLS Entities" under the PRC-006 standard / the "UVLS Entites" under PRC-010. The TOP needs to know the specific feeders, and so the UFLS /UVLS entities would be the ones that need to provide that data to the TOP. This information is already shared between UFLS/UVLS Entities as their operations staff today, but not in a formal requirement.

Likes 0	
Dislikes 0	
Response	

Kimberly Bentley - Kimberly Bentley On Behalf of: sean erickson, Western Area Power Administration, 1, 6; - Kimberly Bentley

Answer	No
Document Name	
Comment	

Having multiple Requirements with the same intent introduces confusion and the risk of double jeopardy for non-compliance. Coordination and planning information exchange is already covered in other standards. The addition or change of requirements is unnecessary.

Likes 0	
Dislikes 0	
Response	

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring

Answer	No
Document Name	
Comment	

WECC supports this project and all comments provided by WECC are for drafting team consideration in an attempt to provide clarity or improvement. It may not be necessary to modify PRC-006-5, R7, or PRC-010-2, R8, because TOPs should be able to obtain the required data from entities within their footprint via their Data Specification process required in TOP-003. However, if the drafting team believes it may be beneficial for reliability to specifically require this information from the PC, rather than leaving it up to the TOP to include it in their Data Specification process, WECC is not opposed to adding this requirement to the two Reliability Standards.	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	No
Document Name	
Comment	
Acciona Energy supports Midwest Reliability Organization’s (MRO) NERC Standards Review Forum’s (NSRF) comments on this question.	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - 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	
Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	No
Document Name	
Comment	

Capital Power believes that improvements in industry communication should be facilitated consistently across all regions through a centralized portal (i.e. Align) rather than through the addition of administrative compliance requirements.

Likes 0	
Dislikes 0	

Response

Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3

Answer	No
Document Name	

Comment

MidAmerican supports MRO NSRF's comments. Having multiple Requirements with the same intent will introduce risk of double (non-compliance) jeopardy. PRC-010-2 R8 already states that the UVLS data base be made available to TPs. Likewise, PCR-006-5 R14 states that the PC shall respond to written comments from applicable entities that want this data.

Likes 0	
Dislikes 0	

Response

Russell Noble - Cowlitz County PUD - 3

Answer	No
Document Name	

Comment

PRC-006-5 mandates UFLS entities to "*provide automatic tripping of Load in accordance with the UFLS program design*" as provided by the Planning Coordinator (PC). Therefore, the PC does not necessarily identify specific circuits for load shed action. Further, PRC-010-2 follows the same pattern of PRC-006-5. Typically, the PC communicates to the UFLS/UVLS entities the amount of load shed needed. It is then up to the UFLS/UVLS entity, the Transmission Owner (TO) and/or Distribution Provider (DP), to identify specific circuits for installation of necessary equipment. Of these two functional registrations, it is the DP who has intimate knowledge of the existence of critical loads, such as flood control pumping stations, police and fire dispatch offices, hospitals, etc. The TOP typically does not have the ability to perform manual load shed action which can avoid critical loads. This must be done in the distribution level or in coordination with the DP who is able to identify which transmission circuits can be tripped that will avoid critical load loss. It is better to require the TOP to coordinate a manual load shed plan with the TO and DP within the EOP standards. The TO and DP have the UFLS/UVLS program implementation and critical load data needed to develop a manual load shed plan which would respect the automatic load shed blocks; the PC is not originator of any of the required data. PRC-006 and PRC-010 should not be mixed in with manual load shed planning. Further, developing UFLS and UVLS designated areas where critical loads are not impacted is challenging. Therefore, endeavoring to identify other loads for manual load shed not overlapping UFLS and UVLS may prove to be a compliance burden more devoted to documenting why overlapping is unavoidable.

Likes 0	

Dislikes 0	
Response	
Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLS believes that PRC-006-5 Requirement R7 and PRC-010-2 Requirement R8 should not be modified to include a Requirement that Planning Coordinators shall provide UFLS and/or UVLS (as applicable) program database data to Transmission Operator's. As in current practice, UFLS and/or UVLS program database data is coordinated at the Distribution/Transmission level for each applicable entity where loads and assessment of overlap of loads that serve critical loads are identified. This data is then provided to the Planning Coordinator to be implemented as part of the Planning Coordinator's UFLS Program design. The proposed revisions to EOP-011-3 address the recommendations reported and require TOPs to incorporate the new criteria in their deployment and coordination of loads between manual load shed and UFLS/UVLS events.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)	
Answer	No
Document Name	
Comment	
The SRC does not support the addition of a new administrative requirement on the Planning Coordinator to provide UFLS/UVLS circuit information back to the Transmission Operator but rather mirror the applicability sections of the PRC Standards within the applicability section of EOP-011-3 and requests that EOP-011-3 be modified to ensure the applicable functional entities are identified and responsible for the Load shedding requirements of manual/automatic and UFLS/UVLS circuits. This addition aligns with other NERC Standards where a subset of Distribution Providers and Transmission Owners are responsible for the ownership, operation, or control of the Load shedding circuits (one example is in the applicability section of PRC-010-2 where the functional entities are defined in detail to meet the applicable requirements.) *Proposed language for EOP-011-3* *Applicability:* *Transmission Owners* *Distribution Providers* *UFLS-Only Distribution Providers* *UVLS-Only Distribution Providers*	

R2. *Each applicable Transmission Owner and Distribution Provider responsible for the ownership, operation, or control of manual Load shedding; and UFLS-Only Distribution Providers and UVLS-Only Distribution Providers shall meet the provisions included in the Transmission Operating Plan for operator-controlled manual Load shedding during an Emergency that include:*

R2.1 *Manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;*

R2.2 *Minimizing the overlap of circuits that are designated for manual Load shed and circuits that serve designated critical loads;*

R2.3 *Minimizing the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS*

R2.4 *Limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions.*

M2. *Each Transmission Owner and Distribution Provider responsible for the ownership, operation, or control of manual Load shedding; and UFLS-Only Distribution Providers and UVLS-Only Distribution Providers shall provide evidence of meeting its Transmission Operator's Operating Plan(s) regarding provisions for operator-controlled manual Load shedding during an Emergency.*

Per the Extreme Cold Weather Grid Operations, Preparedness, and Coordination SAR Phase 1, the need to include Transmission Owners (TOs) and Distribution Providers (DPs) is listed within the SAR: "4. In minimizing the overlap of manual and automatic load shed, the load shed procedures of Transmission Operators, Transmission Owners (TOs) and Distribution Providers (DPs) should separate the circuits that will be used for manual load shed from circuits used for underfrequency load shed (UFLS)/undervoltage load shed (UVLS) or serving critical load. UFLS/UVLS circuits should only be used for manual load shed as a last resort and should start with the final stage (lowest frequency). (Report Key Recommendation 1j)" Manual and automatic load shed entities include applicable TOPS, TOs, and DPs and the addition to the Applicability section of EOP-011-3 is needed to support the expanded TOP Load shed provisions.

In the Joint Inquiry Report, under Section 2d. Preparedness for Emergency Operations; i. Manual and Automatic Load Shed Plans; reports "Distribution Providers (DP) have the responsibility for determining exactly which circuits are to be disconnected during a load shed event." The proposed revisions in EOP-011-3 will require the recognition of designated critical loads and minimizing any overlap of the circuits designated for manual Load shed. This section of the Report also highlights DPs as being required to determine underfrequency relay locations in order to minimize the geographical area of underfrequency events. Having the TO/DP added for UFLS (and UVLS) will ensure the correct circuits are used in minimizing the overlap between manual Load shed and UFLS/UVLS circuits.

Recommendation 10 includes Transmission Owners and Distribution Providers in coordinating Load shed plans. This further justifies the need to include TOs and DPs in EOP-011-3 to require this coordination in both planning and real-time operations.

Likes 0	
Dislikes 0	

Response

Nazra Gladu - Manitoba Hydro - 1

Answer	Yes
Document Name	

Comment

Manitoba Hydro believes that without the loads earmarked for UFLS and UVLS known, and considered in the planning stage, entities may not be able to provide sufficient load shed to weather sudden and long term system events.

Likes 0	
Dislikes 0	

Response

LaTroy Brumfield - American Transmission Company, LLC - 1

Answer	Yes
Document Name	

Comment

If the new overlap language in the requirements will be retained, then TOPs will need access to this information. However, manual load shed at the transmission level will invariably impact distribution UFLS or UVLS as well as loads deemed critical by some entity. Reliability may be better served by requiring the Distribution Provider to know which distribution loads are critical or involve feeders involved in UFLS or UVLS, and require the Distribution Provider to manually shed load in response to an Operating Instruction from a Transmission Operator or Balancing Authority. When the Transmission Operator has to perform load shed at the transmission level, time is of the essence since there is no time to issue an Operating Instruction and load should be shed in the most efficient manner, which may mean taking some critical load and/or some load also involved in UFLS or UVLS.

Likes 0	
Dislikes 0	

Response

Kristine Ward - Seminole Electric Cooperative, Inc. - 1

Answer	Yes
Document Name	

Comment

To ensure that all TOPs have the necessary data to minimize the overlap of circuits as required in the newly proposed EOP-011-3 R1.2.5.3, a review of PRC-006-5 R7 should be performed to minimize the redundancy between the PRC-006-5 and ECOP-011-4 standards.

Likes 0	
Dislikes 0	

Response

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF

Answer	Yes

Document Name	
Comment	

In many cases, UFLS and UVLS are implemented on the distribution system, and thus the TOP may not have available detailed information to reflect these in their manual load shedding operations.

Likes 0	
Dislikes 0	
Response	

Randy Buswell - VELCO -Vermont Electric Power Company, Inc. - 1

Answer	Yes
Document Name	
Comment	

In addition to revising PRC-006 and PRC-010, VELCO requests that the Standard Drafting Team revise EOP-011 with due consideration to areas of the ERO Enterprise for which the Transmission Operator does not serve as a Distribution Provider nor UFLS-Only Distribution Provider. For example, in Vermont, VELCO is a transmission-only TOP registered entity. VELCO serves DP and UFLS-Only DP registered entities, which have operational responsibility for both the sub-transmission and distribution system.

As defined in the Joint Inquiry Report (and is the practice in Vermont), “Load Shed” is “the reduction of electrical system load or demand by interrupting the load flow to major customers and/or **distribution circuits**, normally in response to system or area capacity shortages or voltage control considerations” (emphasis added).

Thus, in the event of an Emergency, VELCO would rely upon DP and UFLS-Only DP entities to (1) implement manual Load shedding in a timeframe adequate for mitigating the Emergency, (2) minimize the overlap of circuits that are designated for manual Load shed and circuits that serve designated critical loads, (3) minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for underfrequency load shed (UFLS) or undervoltage load shed (UVLS), and (4) limit the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions.

As written, however, EOP-011 has the unintended consequence of requiring VELCO and other transmission-only entities to implement provisions that, in fact, Distribution Providers and UFLS-Only Distribution Providers are required to perform in order to mitigate operating Emergencies in Vermont’s Transmission Operator Area. A targeted approach to allow TOPs to identify, as necessary, DP and UFLS-Only DP entities that are required to mitigate operating Emergencies in a TOP’s Transmission Operator Area is therefore warranted. For the SDT’s reference, NERC Standard EOP-005-3 provides an illustrative example of a targeted approach for TOPs to both identify DPs and assign responsibilities to DPs based on need.

Given the reasons stated, VELCO requests the following three (3) modifications to EOP-011:

1. Add Distribution Provider and UFLS-Only Distribution Provider to the applicability section:

a. "**4.1.4.** Distribution Provider identified in the Transmission Operators Operating Plan to mitigate operating Emergencies"

b. "**4.1.5.** UFLS-Only Distribution Provider identified in the Transmission Operators Operating Plan to mitigate operating Emergencies"

2. Add Requirement R1.2.5.5., stating:

a. "**R1.2.5.5.** Provisions for identifying Distribution Providers and UFLS-Only Distribution Providers required to mitigate operating Emergencies in its Transmission Operator Area."

3. Add a new Requirement R6, stating:

R6. Each Distribution Provider and UFLS-Only Distribution Provider identified in the Transmission Operators Operating Plan(s) as required to mitigate operating Emergencies in its Transmission Operator Area shall implement the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations]

6.1. Operator-controlled manual load shedding during an Emergency that accounts for each of the following:

6.1.1. Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;

6.1.2. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that serve designated critical loads;

6.1.3. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for underfrequency load shed (UFLS) or undervoltage load shed (UVLS); and

6.1.4. Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions.

Likes 0	
Dislikes 0	

Response

Patricia Lynch - NRG - NRG Energy, Inc. - 5

Answer	Yes
Document Name	

Comment

This will require periodic updates to ensure that UFLS and UVLS circuit data is accurate.

Likes 0	

Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

IF EOP-011-3 is approved as is, BPA supports revising PRC-006 and PRC-010, and is not opposed to sharing its database data with adjacent TOPs, upon request.

Currently, and as written, BPA does not support the EOP-011-3 revisions. Please see BPA's comments to this posting and, its reiterated SAR comments below.

From BPA's perspective, BPA directs entities to perform Manual Load Shed but it does not prescribe where and how to complete the task. BPA has no voice in how entites determine critical loads. BPA does not have distribution level diagrams for customer load within load centers (Citites, counties, etc.). It's difficult to avoid overlap between Manual Load Shed and those that are armed for UFLS/UVLS. Some overlap is inherent. PRC-006 NWPP Plans require a minimum 34.5% of BPA's load to be armed for BPA's UFLS. To allow for margin, and to maintain compliance, BPA actually has 38-40% armed for UFLS. BPA's Manual Load Shed plan is for 38% of BPA's load. This leads to the amount of breakers that can be opened. There's only so many breakers that meet the requirements to be used in load shed.

BPA's comments submitted to the SAR (Dec. 2021)

BPA's UFLS plans avoid Natural Gas and other critical loads. If BPA issues a Manual Load Shed directive, it is up to the recipient of that directive to make an informed decision regarding which loads to shed within their distribution area. BPA prescribes a certain amount of MW load, within a certain amount of time, in the Manual Load Shed plan. Then, the recipient of the directive (Public Utility, etc.) decides which loads to shed. In order for BPA to meet the minimum requirements, for both Manual and Automatic Load Shed, it would equate to roughly ¾ of the load in BPA's Balancing Authority Area. BPA believes it is not practical or feasible to completely minimize overlap between the Manual and Automatic Load Shed plans. BPA disagrees with the report's recommendation pertaining to this issue, thus, does not recommend modifying any current Reliability Standards (PRC-006, PRC-010, etc.) at this time.

Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	Yes
Document Name	
Comment	

This will require periodic updates to ensure that UFLS and UVLS circuit data is accurate.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	Yes
Document Name	

Comment

FirstEnergy agrees with EEI's comments.

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	Yes
Document Name	

Comment

Dominion Energy supports the EEI comments and agrees that for Transmission Operators to ensure they are meeting the intent of EOP-011, Requirement R1 subparts 1.2.5.2, 1.2.5.3 and 1.2.5.4, they will need the same database lists that are provided by the UFLS and UVLS entities to the responsible Planning Coordinator. To ensure this is done and the required information is shared, PRC-006-5 Requirement R7 and PRC-010-2 Requirement R8 should be modified to include sharing with the affected Transmission Operator. Additionally, this information/database should be circulated/shared whenever the PC receives an updated version, not just upon request by the TOP.

Likes 0	
Dislikes 0	

Response

Brian Evans-Mongeon - Utility Services, Inc. - 4

Answer	Yes
Document Name	

Comment

All TOPs may not have the information needed to 'minimize the overlap of circuits'. Planning Coordinators gather the UFLS and UVLS data as part of their program design, so this modification to the Standards would ensure TOPs would be provided this information upon request	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	
we support the RSC comments.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	
YES, by not requiring the option of the data to be shared, there is a good chance, a feeder could be used in both plans.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3	
Answer	Yes
Document Name	
Comment	
WEC Energy Group supports EEIs comments.	

Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Texas RE agrees there should be a Requirement that Planning Coordinators shall provide UFLS and/or UVLS (as applicable) program database data to Transmission Operator's upon request, in order to ensure that all TOPs have the necessary data to minimize the overlap of circuits as required in the newly proposed EOP-011-3 Requirement R1.2.5.3. The System Operators will be more prepared with more information. Texas RE recommends capitalizing "load" in 1.2.5 as it is a defined term in the NERC Glossary.	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
AEPCO signed on to ACES comments below: We support a review of PRC-006-5 R7 and PRC-010-2 R8 standards during the next logical review cycle of those Standards but do not believe the suggested modifications is a high priority. We understand the importance of providing clarity on managing the data collection requirements associated with UFLS and UVLS programs.	
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	
Southern Company supports the EEI comments and would add language to the end of PRC-006-5 R7 and PRC-010-2 R8 stating, "… and to the affected Transmission Operators within 90 days of receiving an updated version of the database."	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
NAGF Comments: Industry communication should be improved. To the extent that a registered entity needs information from another entity or part of their own entity, that information should be provided. This type of communication should not need a requirement to address communications between the two entities.	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
AZPS supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes

Document Name	
Comment	

For Transmission Operators to ensure they are meeting the intent of EOP-011, Requirement R1 subparts 1.2.5.2, 1.2.5.3 and 1.2.5.4, they will need the same database lists that are provided by the UFLS and UVLS entities to the responsible Planning Coordinator. To ensure this is done and the required information is shared, PRC-006-5 Requirement R7 and PRC-010-2 Requirement R8 should be modified to include sharing with the affected Transmission Operator. Additionally, this information/database should be circulated/shared whenever the PC receives an updated version, not just upon request by the TOP.

Likes 0	
Dislikes 0	
Response	

Gerry Adamski - Cogentrix Energy Power Management, LLC - 5

Answer	Yes
Document Name	
Comment	

Does not apply to us as GO/GOP. Selected because N/A was not an option.

Likes 0	
Dislikes 0	
Response	

Diana Torres - Imperial Irrigation District - 6

Answer	Yes
Document Name	
Comment	

This will minimize the overlap of circuits. This is a current business practice within our entity to avoid any overlap with the manual load shedding plan.

Likes 0	
Dislikes 0	
Response	

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	Yes

Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Gerry Huitt, Xcel Energy, Inc., 5, 3, 1; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Xcel Energy supports the comments of the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - Casey Perry On Behalf of: Lynn Goldstein, PNM Resources - Public Service Company of New Mexico, 1, 3; - PNM Resources - Public Service Company of New Mexico - 3 - WECC	
Answer	Yes
Document Name	
Comment	
PNM supports aligning revised EOP-011-3 with existing PRC-006-5 R7 and PRC-010-2 R8.	
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 Regional Standards Committee	
Answer	Yes
Document Name	
Comment	

In addition to revising PRC-006 and PRC-010, RSC requests that the Standard Drafting Team revise EOP-011 with due consideration to areas of the ERO Enterprise for which the Transmission Operator does not serve as a Distribution Provider nor UFLS-Only Distribution Provider. For example, in NPCC, there are transmission-only TOP registered entities. These TOPs serve DP and UFLS-Only DP registered entities, which have operational responsibility for both the sub-transmission and distribution system.

As defined in the Joint Inquiry Report (and is the practice in some parts of NPCC), “Load Shed” is “the reduction of electrical system load or demand by interrupting the load flow to major customers and/or **distribution circuits**, normally in response to system or area capacity shortages or voltage control considerations” (emphasis added).

Thus, in the event of an Emergency, transmission-only TOPs would rely upon DP and UFLS-Only DP entities to (1) implement manual Load shedding in a timeframe adequate for mitigating the Emergency, (2) minimize the overlap of circuits that are designated for manual Load shed and circuits that serve designated critical loads, (3) minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for underfrequency load shed (UFLS) or undervoltage load shed (UVLS), and (4) limit the utilization of UFLS or UVLS circuits for manual Load shed to situations were warranted by system conditions.

As written, however, EOP-011 has the unintended consequence of requiring transmission-only TOPs to implement provisions that, in fact, Distribution Providers and UFLS-Only Distribution Providers are required to perform in order to mitigate operating Emergencies. A targeted approach to allow TOPs to identify, as necessary, DP and UFLS-Only DP entities that are required to mitigate operating Emergencies in a TOP’s Transmission Operator Area is therefore warranted. For the SDT’s reference, NERC Standard EOP-005-3 provides an illustrative example of a targeted approach for TOPs to both identify DPs and assign responsibilities to DPs based on need.

Given the reasons stated, RSC requests the following three (3) modifications to EOP-011:

{C}1. Add Distribution Provider and UFLS-Only Distribution Provider to the applicability section:

{C}a. “**4.1.4.** Distribution Provider identified in the Transmission Operators Operating Plan to mitigate operating Emergencies”

{C}b. “**4.1.5.** UFLS-Only Distribution Provider identified in the Transmission Operators Operating Plan to mitigate operating Emergencies”

{C}2. Add Requirement R1.2.5.5., stating:

{C}a. “**R1.2.5.5.** Provisions for identifying Distribution Providers and UFLS-Only Distribution Providers required to mitigate operating Emergencies in its Transmission Operator Area.”

{C}3. Add a new Requirement R6, stating:

R6. Each Distribution Provider and UFLS-Only Distribution Provider identified in the Transmission Operators Operating Plan(s) as required to mitigate operating Emergencies in its Transmission Operator Area shall implement the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations]

{C}**6.1.** Operator-controlled manual load shedding during an Emergency that accounts for each of the following:

6.1.1. Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;

{C}**6.1.2.** Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that serve designated critical loads;

{C}**6.1.3.** {C}Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for underfrequency load shed (UFLS) or undervoltage load shed (UVLS); and

Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations were warranted by system conditions.

Additional information is required for a better assessment:

add clarification regarding overlap – physical versus frequency domain action overlap

Additional clarification is required regarding when manual load shedding is permitted for the load connected to a feeder part of the UFLS program (extra load margin required with respect to the minimum amount of load accounted for in the UFLS program)

Manual load shedding shall only be allowed to disconnect the critical load for a period of time that is less than the critical load outage withstand time, without having a negative impact.

Similar to the UFLS program it is the time to have a dynamic approach to the critical loads; they should be treated differently based on the assigned priority and the specifics of the load shedding event in terms of extent, duration, and weather condition/season.

Likes 0	
Dislikes 0	

Response

Donna Johnson - Oglethorpe Power Corporation - 5

Answer	Yes
Document Name	

Comment

OPC supports ACES comments: We support a review of PRC-006-5 R7 and PRC-010-2 R8 standards during the next logical review cycle of those Standards but do not believe the suggested modifications is a high priority. We understand the importance of providing clarity on managing the data collection requirements associated with UFLS and UVLS programs.

Likes 0	
Dislikes 0	

Response

Alan Kloster - Alan Kloster On Behalf of: Allen Klassen, Evergy, 1, 3, 5, 6; Jennifer Flandermeyer, Evergy, 1, 3, 5, 6; Marcus Moor, Evergy, 1, 3, 5, 6; - Alan Kloster	
Answer	Yes
Document Name	
Comment	
Evergy supports and includes by reference the comments of the Edison Electric Institute (EEI) for question #1.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon concurs with the comments submitted by the EEI. Submitted on behalf of Exelon (Segments 1 & 3)	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
We support a review of PRC-006-5 R7 and PRC-010-2 R8 standards during the next logical review cycle of those Standards but do not believe the suggested modifications is a high priority. We understand the importance of providing clarity on managing the data collection requirements associated with UFLS and UVLS programs.	
Likes 0	
Dislikes 0	

Response	
Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1, Group Name OGE Energy - Oklahoma Gas and Electric Co.	
Answer	Yes
Document Name	
Comment	
Oklahoma Gas and Electric agrees with and endorses comments as submitted by EEI Reliability Technical Committee (RTC)	
Likes 0	
Dislikes 0	
Response	
Jennifer Blair - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	
PPL NERC Registered Affiliates support EEI comments on Question 1.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
The TOP will need the data from UFLS and UVLS applications to determine if overlap exists with manual load shed expectations. This data will also identify if any additional MWs can be shed manually at these locations once the automatic process has been completed.	
Likes 0	
Dislikes 0	
Response	

Hillary Dobson - Colorado Springs Utilities - 3	
Answer	Yes
Document Name	
Comment	

CSU supports LPPC's comments.

Likes 0	
Dislikes 0	
Response	

Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	

Additionally, we request that Distribution Provider (DP) and UFLS-Only Distribution Provider be added to the applicability section of EOP-011-3 as well as making the followtwng addtions to the Requirements:

Add Requirement **R1.2.5.5**. as follows:
R1.2.5.5. Provisions for identifying Distribution Providers and UFLS-Only Distribution Providers required to mitigate operating Emergencies in its Transmission Operator Area."

Add a new Requirement **R6**, as follows:
R6. Each Distribution Provider and UFLS-Only Distribution Provider identified in the Transmission Operators Operating Plan(s) as required to mitigate operating Emergencies in its Transmission Operator Area shall implement the following, as applicable:

6.1. Operator-controlled manual load shedding during an Emergency that accounts for each of the following:
6.1.1. Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;
6.1.2. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that serve designated critical loads;
6.1.3. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for underfrequency load shed (UFLS) or undervoltage load shed (UVLS); and Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions.

Likes 0	
Dislikes 0	
Response	

Carl Pineault - Hydro-Qu?bec Production - 1,5

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merrell, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; - 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	

Sean Steffensen - IDACORP - Idaho Power Company - 1

Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tony Skourtas - Los Angeles Department of Water and Power - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tom Vinson - American Clean Power Association - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Foung Mua, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Wei Shao, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; - Tim Kelley, Group Name LPPC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Braunstein - Colorado Springs Utilities - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Watt - Oklahoma Municipal Power Authority - 4	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Joe McClung - JEA - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County	
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	

Dwanique Spiller - Dwanique Spiller On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Dwanique Spiller	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Mason - Portland General Electric Co. - 6, Group Name PGE FCD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sam Nietfeld - Public Utility District No. 1 of Snohomish County - 5	
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

James Baldwin - Lower Colorado River Authority - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

John Babik - JEA - 5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer	
Document Name	

Comment

AECI and its members support comments provided by ACES.

Likes 0	
Dislikes 0	

Response

Mark Young - Tenaska, Inc. - 5	
Answer	
Document Name	
Comment	
Tenaska is a generator owner and has no comment on this standard.	
Likes 0	
Dislikes 0	
Response	
Colin Chilcoat - Invenergy LLC - 6	
Answer	
Document Name	
Comment	
N/A – Invenergy is not a Transmission Operator and has no comment on these proposed modifications.	
Likes 0	
Dislikes 0	
Response	
Lisa Martin - Austin Energy - 6	
Answer	
Document Name	
Comment	
I support comments made by Michael Dillard, Austin Energy, Segment 5.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	

Answer	
Document Name	

Comment

Constellation has no comments

Kimberly Turco on behalf of Constellation Energy Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Rick Stadtlander - NEI - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Alison Mackellar - Constellation - 5

Answer	
Document Name	

Comment

Constellation has no comments

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Dan Roethemeyer - Vistra Energy - 5	
Answer	
Document Name	
Comment	
No comment	
Likes 0	
Dislikes 0	
Response	
Mark Spencer - LS Power Development, LLC - 5	
Answer	
Document Name	
Comment	
No comment	
Likes 0	
Dislikes 0	
Response	
Michele Richmond - Texas Competitive Power Advocates - NA - Not Applicable - Texas RE	
Answer	
Document Name	
Comment	
TCPA is an organization with generators as members so we have no input on this question.	
Likes 0	
Dislikes 0	
Response	
Jun Hua - Austin Energy - 4	

Answer	
Document Name	
Comment	
I support comments made by Michael Dillard, Austin Energy, Segment 5	
Likes 0	
Dislikes 0	
Response	
Whitney Wallace - Calpine Corporation - 5 - WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
No comment, as Calpine Corporationis a Generation Owner and/or Operator.	
Likes 0	
Dislikes 0	
Response	
Dana Showalter - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	
Q1. ERCOT supports the SRC comments and the addition of the proposed language to expand applicability and to establish a new requirement for applicable TOs, DPs, and DPs with UVLS and UFLS circuits. As the SRC noted, the FERC/NERC Report on the February 2021 Cold Weather Outages under Section II.C.2.d, Manual and Automatic Load Shed Plans, states: “Transmission Service Providers and Distribution Providers (DP) have the responsibility for determining exactly which circuits are to be disconnected during a load shed event.” Additionally, in Recommendation 10, the FERC/NERC Report highlights the importance of coordination between Transmission Owners with Distribution Providers in coordinating Load shed plans. There is limited value added by placing the responsibility on the PC within this standard. If the provision of the database to others is determined to be necessary, the requirement should be included within the PRC standard.	
Likes 0	
Dislikes 0	
Response	

Ashley Scheelar - TransAlta Corporation - 5	
Answer	
Document Name	
Comment	
No comment.	
Likes 0	
Dislikes 0	
Response	

2. Should the BA be the entity to determine the "winter season", which is used to define applicable generating units in proposed EOP-012-1 Section 4.2 Facilities? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Ashley Scheelar - TransAlta Corporation - 5	
Answer	No
Document Name	
Comment	
Thank you for the opportunity to present our position regarding these proposed standards. A consistent theme that is presented in our responses is that many generators in the North, particularly Canada, successfully operate in extreme cold year after year. In addition, many generators operate in regions that do not have the type of reliability risk being addressed by this standard. Therefore, there should be no need for a definition of "winter season" for all regions of North America. However, if an entity is required to define it, TransAlta agrees with the comments provided by NRG Energy.	
Likes 0	
Dislikes 0	
Response	

John Babik - JEA - 5	
Answer	No
Document Name	
Comment	
We Support LPPC's Comments	
Likes 0	
Dislikes 0	
Response	

Sam Nietfeld - Public Utility District No. 1 of Snohomish County - 5	
Answer	No
Document Name	
Comment	
SNPD supports comments submitted by LPPC and Tacoma Power	
Likes 0	
Dislikes 0	

Response	
Dana Showalter - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
Q2. ERCOT supports the SRC proposed language that proposes a default winter period, but agrees that BA discretion to identify a different definition of winter is appropriate.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)	
Answer	No
Document Name	
Comment	
The SRC proposes the following language change: The winter season is defined as December through February unless the applicable Balancing Authority decides otherwise.	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	No
Document Name	
Comment	
The burden should be on the GO to identify the "winter season," or better, the yearly time span of heightened cold weather risk to the affected Balancing Authority (BA) entities. Further, the GOP can communicate real time heightened risk to the affected BAs to allow for contingency planning. As far as defining applicable generating units in proposed EOP-012-1 Section 4.2 Facilities, it is better to first assume all BES generation is applicable, then define a list of exclusions. Certain generation units are highly unlikely to be directly impacted by cold weather and can demonstrate this via historical	

data extending back 60 years. Reliability efforts should not be incumbered with compliance and monitoring activity with little to no return in benefit to BES stability.	
Likes 0	
Dislikes 0	
Response	
Hillary Dobson - Colorado Springs Utilities - 3	
Answer	No
Document Name	
Comment	
CSU supports LPPC's comments.	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	No
Document Name	
Comment	
We request that the SDT provide justification for selecting the BA as the entity rather than the RC. In addition, whichever entity is ultimately selected, we feel it would be beneficial to include this determination as it's own requirement rather than leaving it in the Facilities definition section. In taking this approach, the entity would be identified as an "Applicable Entity" in section 4.1 Functional Entities of the standard.	
Likes 0	
Dislikes 0	
Response	
Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County	
Answer	No
Document Name	
Comment	

CHPD agrees with LPPC's comments.	
Likes 0	
Dislikes 0	
Response	
Donna Johnson - Oglethorpe Power Corporation - 5	
Answer	No
Document Name	
Comment	
OPC supports ACES comments: We request that the SDT provide justification for selecting the BA as the entity rather than the RC. In addition, whichever entity is ultimately selected, BA of RC, we feel it would be beneficial to include either this determination as it's own requirement rather than leaving it in the Facilities definition section. In taking this approach, the entity would be identified as an "Applicable Entity" in the standard.	
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 Regional Standards Committee	
Answer	No
Document Name	
Comment	
How is the BA held responsible for determining what is considered the "winter season"? EOP-012-1 section 4.2 lacks clarity and there are no requirements concerning this responsibility, nor is it mentioned in the TR. Local BA to provide the "winter season" It is not the winter season that determines the applicability to Facilities (generating units), but rather the potential for localized extreme weather conditions.	
Likes 0	
Dislikes 0	
Response	

Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	No
Document Name	
Comment	
Captial Power believes that focus should be on operation capability during certain weather / temperatureconditions rather than arbitrarily chosen seasons. Capital Power supports the NAGF revisions which eliminate the need for the definition of this term.	
Likes 0	
Dislikes 0	
Response	

Marty Watson - Santee Cooper - 5, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
Determining the winter season should be applicable to GOs. GO actions within the requirements should have deadlines set by the GO. The BA could be located in a different weather zone than the GO's Facilities and therefore not familiar enough with the details to choose a date range that matches local conditions. The BA is not listed under Applicability/Functional Entity.	
Likes 0	
Dislikes 0	
Response	

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Section 4.2 - Facilities states "The winter season will be determined by the generating unit's applicable Balancing Authority." Duke Energy suggest this sentence be removed. Additionally, per the NAGF, "there is not a requirement that addresses anything being done during the winter period. All requirements address cold weather issues. For this reason, it is recommended that this sentence be struck from the applicability." If the current language is not removed: (a) Balancing Authorities (BA) as a Function Entity should be added to Section 4.1 – Functional Entities to ensure BA's have a compliance obligation to provide "winter season" information to generating unit's , and	

(b) The SDT should add appropriate BA submittal language to a new or existing Requirement to ensure the action is enforceable and “winter season” information is submitted by the BA.	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 6	
Answer	No
Document Name	
Comment	
As proposed, EOP-012-1 does not include the BA as an applicable functional entity. IID recommends that if the BA is required to perform a regulatory required function, such as defining “winter season”, then the BA should be listed as a responsible functional entity in the Applicability section, along with the GO and GOP. Additionally, a Requirement should be included in EOP-012-1 that specifies the BA’s responsibility of working with the GO and GOP to define “winter season” and identify units that will or will not be available for that season. The BA needs input from the GOP and GO to understand the temperature and seasonal limitations for each unit to define the “winter season” and which units are summer peaking only. In addition, further guidance is needed on the exclusion of generators but which could be called upon by the BA (specifically since the BA is not listed as a functional entity).	
Likes 0	
Dislikes 0	
Response	
Mike Braunstein - Colorado Springs Utilities - 1	
Answer	No
Document Name	
Comment	
Colorado Springs Utilities agrees with comments endorsed by LPPC	
Likes 0	
Dislikes 0	
Response	
Alison Mackellar - Constellation - 5	

Answer	No
Document Name	

Comment

Constellation Energy Generation (CEG) does not agree the BA should be the authority on determining cold weather, rather the GO/GOP is in the best position to make the determination of defining the winter season based on regional climate differences. Also, the BA is not included in the standard as an applicable entity and therefore should not have the ability to make this determination. Constellation suggests also that "winter season" should not be defined in the standard based on these regional variances. The current title of the draft EOP-012 is "Extreme Cold Weather", not "Winter". Removing the limitation of a defined "winter" season helps ensure generator availability for any cold weather period.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Rick Stadtlander - NEI - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment

Agree with NAGF comments

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	No
Document Name	

Comment

Constellation Energy Generation (CEG) does not agree the BA should be the authority on determining cold weather, rather the GO/GOP is in the best position to make the determination of defining the winter season based on regional climate differences. Also, the BA is not included in the standard as an applicable entity and therefore should not have the ability to make this determination. Constellation suggests also that "winter season" should not be defined in the standard based on these regional variances. The current title of the draft EOP-012 is "Extreme Cold Weather", not "Winter". Removing the limitation of a defined "winter" season helps ensure generator availability for any cold weather period.

Kimberly Turco on behalf of Constellation Energy Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Foung Mua, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Wei Shao, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; - Tim Kelley, Group Name LPPC	
Answer	No
Document Name	
Comment	
As proposed, EOP-012-1 does not include the BA as an applicable functional entity. LPPC recommends that if the BA is required to perform a regulatory required function, like defining “winter season”, then the BA should be listed as a responsible Functional Entity in the Applicability section, along with the GO and GOP. Additionally, a Requirement should be included in EOP-012-1 that specifies the BA’s responsibility of working with the GO and GOP to define “winter season” and identify units that will or will not be available for that season. The BA needs input from the GO and GOP to understand the temperature and seasonal limitations for each unit to define the “winter season” and which units are summer peaking only. These comments have been endorsed by LPPC.	
Likes 2	Colorado Springs Utilities, 1, Braunstein Mike; Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merre
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	NAGF EOP-012-1 06152022 final.pdf
Comment	
NAGF Comments: The NAGF believes there is no need to define the winter season. The NAGF proposed revisions to EOP-012-1 eliminate the need for such a definition.	
Likes 1	Greybeard Compliance Services, LLC, 5, Gabriel Michael
Dislikes 0	

Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
This should be left up to the entity, there is no good one size fits all solution here. We believe that the GO or GOP could be responsible for this notification, in addition to notifications of projected cold weather events that could be handled by the GO and GOP for some entities.	
Likes 0	
Dislikes 0	
Response	
Jeremy Lawson - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
NCPA agrees with the comments of Tri-State G and T Association, Inc.	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
Changes to Cold Weather Reliability Standards should not be applicable continent-wide. Standards should not be modified or implemented prior to Market Rule Modifications. See prior NERC Project 2019-06 ballot and commenting by Marty Hostler Market Rule modifications have not yet been made to mitigate potential Cold Weather Events grid issues. Per FERC/NERC's recommendation, Market Rule modifications should be made prior to, or concurrent with, development of new Standards. To date, no known Market Rule Modification project has been initiated.	

On page 86 of FERC/NERC's joint Report The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018 (ferc.gov) the following recommendations where made.

Recommendation 1: The Team recommends a three-pronged approach to ensure Generator Owners/Generator Operators, Reliability Coordinators and Balancing Authorities prepare for cold weather conditions: 1) development or enhancement of one or more NERC Reliability Standards, 2) enhanced outreach to Generator Owners/Generator Operators, and 3) market (Independent System Operators/Regional Transmission Organizations) rules where appropriate. This three-pronged approach should be used to address the following needs: • The need for Generator Owners/Generator Operators to perform winterization activities on generating units to prepare for adverse cold weather, in order to maximize generator output and availability for BES reliability during these conditions. These preparations for cold weather should include Generator Owners/Generator Operators:

While any one of the three approaches may provide significant benefits in solving this problem, the Team does not view any one of the three as the only solution. The Team envisions that a successful resolution of the problem will likely involve concurrent use of all three.

Likes 0	
Dislikes 0	

Response

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1

Answer	No
Document Name	

Comment

AEPCO signed on to ACES comments below:

We request that the SDT provide justification for selecting the BA as the entity rather than the RC. In addition, whichever entity is ultimately selected, we feel it would be beneficial to include this determination as it’s own requirement rather than leaving it in the Facilities definition section. In taking this approach, the entity would be identified as an “Applicable Entity” in section 4.1 Functional Entities of the standard.

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 4, Group Name NCPA

Answer	No
Document Name	

Comment

NCPA agrees with the comments of Tri-State G and T Association, Inc.

Likes 0	
Dislikes 0	

Response	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	No
Document Name	
Comment	
PG&E recommends that the individual GO's and GOP's determine their own respective "winter seasons". The BA may not have the capability and resources to determine unique winter season dates across a large and diverse region. For example, in California, PG&E has cold weather in the Sierra foothills and at the same time, we have very moderate temperatures at our facilities located on the Pacific Ocean or the Central Valley for the "winter seasons".	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
Recommend RC to be the entity to determine the “winter season” to minimize potential for different winter seasons defined by multiple BAs for a single registered entity.	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation observes that different definitions of the same term are likely to cause confusion, especially in areas where a single entity has facilities under the jurisdiction of multiple BAs. Reclamation recommends instead of defining “winter season” as a time period, the standard should direct entities	

to begin cold weather preparations when temperatures decrease toward 40 degrees and to implement preparations as temperatures decrease toward 30 degrees. Alternatively, Reclamation recommends a universal "winter season" be defined as October through April.

Likes 0	
Dislikes 0	

Response

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1

Answer	No
Document Name	

Comment

we support the RSC comments. Additionally,

How is the BA held responsible for determining what is considered the "winter season"? EOP-012-1 section 4.2 lacks clarity and there are no requirements concerning this responsibility, nor is it mentioned in the TR.

Local BA to provide the "winter season". It is not the winter season that determines the applicability to Facilities (generating units), rather the potential for localized extreme weather condition.

Likes 0	
Dislikes 0	

Response

Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric

Answer	No
Document Name	

Comment

DTE Electric supports NAGF comments.

Likes 0	
Dislikes 0	

Response

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment	
If it is deceided that a requirement to declare a 'winter season' becomes applicable to BAs, BPA believes it's more clear for BAs base the 'winter season' on a date range (such as October-April).	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
BA's can have a large geographical footprint making it inappropriate to establish a winter season criteria, which varies by site. An additional complication is some generating stations have multiple BA's. The GO or its TOP should be the one to determine the winter seasons. If the SDT elects to utilize the TOP, the TOP should establish a "winter season" on a Facility by Facility basis, much like they do with Voltage Schedules for VAR-001. If the SDT elects to have the GO establish its own "winter season" there should be a requirement regarding the establishment of that season, and the justification for when it occurs.	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
As written, EOP-012-1 does not include BA as an applicable functional entity. SRP recommends that if the BA is required to perform a regulatory required function, like defining "winter season", then the BA should be listed as a responsible functional entity in the Applicability section, along with the GO and GOP. Consider including a requirement in EOP-012-1 that specifies the BA's responsibility of working with the GO and GOP to define "winter season" and identify units that will or will not be available for that season. The BA needs input from the GOP and GO to understand the temperature and seasonal limitations for each unit to define the "winter season" and which units are summer peaking only.	
Likes 0	
Dislikes 0	
Response	

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merrell, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; - Jennie Wike, Group Name Tacoma Power

Answer	No
Document Name	

Comment

As proposed, EOP-012-1 does not include the BA as an applicable functional entity. Tacoma Power recommends that if the BA is required to perform a regulatory required function, like defining "winter season", then the BA should be listed as a responsible functional entity in the Applicability section, along with the GO and GOP.

Additionally, a Requirement should be included in EOP-012-1 that specifies the BA's responsibility of working with the GO and GOP to define "winter season" and identify units that will or will not be available for that season. The BA needs input from the GOP and GO to understand the temperature and seasonal limitations for each unit to define the "winter season" and which units are summer peaking only.

Likes 0	
Dislikes 0	

Response

Glen Farmer - Avista - Avista Corporation - 5

Answer	No
Document Name	

Comment

This should be left up to the entity, there is no good one size fits all solution here. We believe that the GO or GOP could be responsible for this notification, in addition to notifications of projected cold weather events could be handled by the GO and GOP for some entities.

Likes 0	
Dislikes 0	

Response

Carl Pineault - Hydro-Qu?bec Production - 1,5

Answer	No
Document Name	

Comment

We don't think the BA should be held responsible for determining what is considered the “winter season”. EOP-012-1 section 4.2 lacks clarity and there are no requirements concerning this responsibility, nor is it mentioned in the TR!

Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
The Reliability Coordinator should make this determination for consistency across the RC footprint.	
Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
If there is a requirement for defining the winter season, LCRA agrees the BA is the best entity that can define this for their respective region.	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
If there is a requirement for defining the winter season, LCRA agrees the BA is the best entity that can define this for their respective region.	

Likes 0	
Dislikes 0	

Response

Rebecca Baldwin - Transmission Access Policy Study Group - NA - Not Applicable - NA - Not Applicable

Answer	Yes
Document Name	TAPS proposed language Q2.docx

Comment

BA Requirement to determine and communicate definition of winter season
The BA is the appropriate entity to determine the “winter season” for purposes of defining applicable generating units in proposed EOP-012-1. Because applicability of EOP-012 hinges on the BA’s determination, the SDT should consider a Requirement, possibly in EOP-011, for the BA to make the determination and communicate it to the GOs in its footprint. Proposed requirement language: “The Balancing Authority shall determine the winter season for its footprint, and shall inform each GO in its footprint of its determination, by [date] of each year for the winter season commencing in that calendar year.”

Communication of plan to operate
In addition, to avoid the potential for disagreements over what constitutes a “plan” to operate, EOP-012-1 Section 4.2 could be revised to include communication of the GO’s plan to its BA.

Proposed language is attached in redline and clean format.

Likes 0	
Dislikes 0	

Response

Natalie Johnson - Enel Green Power - 5

Answer	Yes
Document Name	

Comment

The BA is in the best position to determine the “winter season” as they have the first hand knowledge of their planning area and the visibility of entire system as a whole. This also ensures consistency throughout the region.

Likes 0	
Dislikes 0	

Response

Whitney Wallace - Calpine Corporation - 5 - WECC,Texas RE,NPCC,SERC,RF

Answer	Yes
Document Name	
Comment	

Yes, the BA (or the agency with regulatory oversite of the Balancing Authority) should be the entity to determine the "winter season." This approach accounts for variability in temperature as relates to geographical location. For example, in the Texas RE region, the BA defines the "winter season" as December through February , excluding March, as March is usually a month that experiences milder temperatures in that region. Additionally, the BA (or equivalent entity) is most well-suited to account for climate variability within the sub-regions of the BA itself. Additionally, Calpine proposes that stakeholder input should be allowed and considered in determining the "winter season."

Likes 0	
Dislikes 0	
Response	

Jennifer Blair - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC, Group Name PPL NERC Registered Affiliates

Answer	Yes
Document Name	
Comment	

PPL NERC Registered Affiliates support EEI comments on Question 2.

Likes 0	
Dislikes 0	
Response	

Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1, Group Name OGE Energy - Oklahoma Gas and Electric Co.

Answer	Yes
Document Name	
Comment	

Oklahoma Gas and Electric agrees with and endorses comments as submitted by EEI Reliability Technical Committee (RTC)

Likes 0	
Dislikes 0	
Response	

Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF

Answer	Yes
Document Name	
Comment	

Southern Indiana Gas & Electric Company (SIGE) supports EEI's comment. SIGE supports the BA as the entity to determine the "winter season"; however, EOP-012 does not specifically set a requirement for the BA to define the winter season. The SDT should consider adding the BA requirement to either the Standard language or the Applicability section.

Additionally, in some BA regions the area may be very large, and the BA may need to define winter seasons differently across the area. To address this concern, language should be added to a requirement that obligates the BA to both define the "winter season" and to work with their respective GOs and GOPs to ensure the "winter season" is appropriately defined throughout their area of responsibility.

Likes 0	
Dislikes 0	
Response	

Daniel Gacek - Exelon - 1

Answer	Yes
Document Name	
Comment	

Exelon concurs with the comments submitted by the EEI.

Submitted on behalf of Exelon (Segments 1 & 3)

Likes 0	
Dislikes 0	
Response	

Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3

Answer	Yes
Document Name	
Comment	

MidAmerican supports EEI comments. MidAmerican supports the BA as the entity to determine the "winter season", however, EOP-012 does not specifically set a requirement for the BA to define the winter season. In EOP-012, the Applicability Section is the only place where this is mentioned. Additionally, in some BA regions the area may be very large, and the BA may need to define winter seasons differently across the area. To address this concern, language should be added to a requirement that obligates the BA to both define the "winter season" and to work with their respective GOs and GOPs to ensure the "winter season" is appropriately defined throughout their area of responsibility.

Likes 0	
Dislikes 0	

Response

Alan Kloster - Alan Kloster On Behalf of: Allen Klassen, Evergy, 1, 3, 5, 6; Jennifer Flandermeyer, Evergy, 1, 3, 5, 6; Marcus Moor, Evergy, 1, 3, 5, 6; - Alan Kloster

Answer	Yes
Document Name	

Comment

Evergy supports and includes by reference the comments of the Edison Electric Institute (EEI) for question #2.

Likes 0	
Dislikes 0	

Response

Michele Richmond - Texas Competitive Power Advocates - NA - Not Applicable - Texas RE

Answer	Yes
Document Name	

Comment

It should either be the BA or the agency with regulatory oversite of the Balancing Authority. Within a large BA, there may be wide variability in temperature gradients across the BA's footprint and that variability should be accounted for. Regardless, stakeholder input should be allowed in determining the winter season.

Likes 0	
Dislikes 0	

Response

Mark Spencer - LS Power Development, LLC - 5

Answer	Yes
Document Name	

Comment

The BAs are best positioned to determine their winter season based on region-specific characteristics, their own analysis, and their own stakeholder input.

Likes 0	
Dislikes 0	

Response

Casey Perry - Casey Perry On Behalf of: Lynn Goldstein, PNM Resources - Public Service Company of New Mexico, 1, 3; - PNM Resources - Public Service Company of New Mexico - 3 - WECC

Answer	Yes
Document Name	

Comment

PNM supports comments submitted by EEI.

Likes 0	
Dislikes 0	

Response

Joe McClung - JEA - 1

Answer	Yes
Document Name	

Comment

We support LPPC's comments.

Likes 0	
Dislikes 0	

Response

Devon Tremont - Taunton Municipal Lighting Plant - 1

Answer	Yes
Document Name	

Comment

TMLP echoes the comments submitted by TAPS Group:

BA Requirement to determine and communicate definition of winter season

The BA is the appropriate entity to determine the “winter season” for purposes of defining applicable generating units in proposed EOP-012-1. Because applicability of EOP-012 hinges on the BA’s determination, the SDT should consider a Requirement, possibly in EOP-011, for the BA to make the determination and communicate it to the GOs in its footprint. Proposed requirement language: “The Balancing Authority shall determine the winter season for its footprint, and shall inform each GO in its footprint of its determination, by [date] of each year for the winter season commencing in that calendar year.”

Communication of plan to operate

In addition, to avoid the potential for disagreements over what constitutes a “plan” to operate, EOP-012-1 Section 4.2 could be revised to include communication of the GO’s plan to its BA.

Proposed language (clean)

For purposes of this standard, the term “generating unit” means each Bulk Electric System generator that has informed its Balancing Authority that it plans to operate during the upcoming winter season that has been determined by the generating unit’s applicable Balancing Authority pursuant to EOP-011-3 Requirement R***. The term excludes those generators that do not operate during the winter season except when called upon by the Balancing Authority to be available during Capacity Emergencies or Energy Emergencies.

Likes 0	
Dislikes 0	

Response

Amy Casuscelli - Amy Casuscelli On Behalf of: Gerry Huitt, Xcel Energy, Inc., 5, 3, 1; - Amy Casuscelli

Answer	Yes
Document Name	

Comment

We support the comments of EEI; it is appropriate that the BA determines the "winter season"

Likes 0	
Dislikes 0	

Response

Michael Watt - Oklahoma Municipal Power Authority - 4

Answer	Yes
Document Name	

Comment

I agree with TAPs comments, pasted below:

BA Requirement to determine and communicate definition of winter season

The BA is the appropriate entity to determine the "winter season" for purposes of defining applicable generating units in proposed EOP-012-1. Because applicability of EOP-012 hinges on the BA's determination, the SDT should consider a Requirement, possibly in EOP-011, for the BA to make the determination and communicate it to the GOs in its footprint. Proposed requirement language: "The Balancing Authority shall determine the winter season for its footprint, and shall inform each GO in its footprint of its determination, by [date] of each year for the winter season commencing in that calendar year."

Communication of plan to operate

In addition, to avoid the potential for disagreements over what constitutes a "plan" to operate, EOP-012-1 Section 4.2 could be revised to include communication of the GO's plan to its BA.

Proposed language (clean)

For purposes of this standard, the term "generating unit" means each Bulk Electric System generator that has informed its Balancing Authority that it plans to operate during the upcoming winter season that has been determined by the generating unit's applicable Balancing Authority pursuant to EOP-011-3 Requirement R***. The term excludes those generators that do not operate during the winter season except when called upon by the Balancing Authority to be available during Capacity Emergencies or Energy Emergencies.

Likes 0	
Dislikes 0	

Response

Gerry Adamski - Cogentrix Energy Power Management, LLC - 5

Answer	Yes
Document Name	

Comment

Irrelevant who determines "winter season". Practical outcome is that generating facilities need to prepare no matter who selects the "winter season." Selected because N/A was not an option.

Likes 0	
Dislikes 0	

Response

George Brown - Acciona Energy North America - 5

Answer	Yes
Document Name	

Comment

Acciona Energy supports Midwest Reliability Organization’s (MRO) NERC Standards Review Forum’s (NSRF) comments on this question.	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Entergy agrees but would like clarity on consistency of the winter season from year to year and north vs south.	
Likes 0	
Dislikes 0	
Response	
Dan Roethemeyer - Vistra Energy - 5	
Answer	Yes
Document Name	
Comment	
The SDT appropriately proposes for the applicable Balancing Authority (BA) to define "winter season." This approach recognizes the impact of geographical location on the timing of the winter season. For example, in the Texas Reliability Entity, Inc. (Texas RE) region, the BA (the Electric Reliability Council of Texas, Inc. (ERCOT)) defines "winter season" as December through February, rather than including any portion of March, which typically has milder temperatures in Texas.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	

EEI supports the BA as the entity to determine the “winter season”, however, EOP-012 does not specifically set a requirement for the BA to define the winter season. In EOP-012, the Applicability Section is the only place where this is mentioned. Additionally, in some BA regions the area may be very large, and the BA may need to define winter seasons differently across the area. To address this concern, language should be added to a requirement that obligates the BA to both define the “winter season” and to work with their respective GOs and GOPs to ensure the “winter season” is appropriately defined throughout their area of responsibility.

Likes 0	
Dislikes 0	

Response

Michelle Amarantos - APS - Arizona Public Service Co. - 5

Answer	Yes
Document Name	

Comment

AZPS supports EEI’s comments.

Likes 0	
Dislikes 0	

Response

Tom Vinson - American Clean Power Association - 5

Answer	Yes
Document Name	

Comment

ACP supports the BA determining the winter season. It makes sense to determine the winter season in a way that accounts for regional/geographic differences in weather. And, having the BA determine the winter season rather than individual generator owners will provide uniformity in approach for a given area, which is helpful in ensuring generators are subject to the same requirements.

Likes 0	
Dislikes 0	

Response

Michael Dillard - Austin Energy - 5

Answer	Yes
Document Name	

Comment	
AE recommends adding the BA as a functional entity under the applicability section and have the requirement of defining the winter season clearly stated as a responsibility of BA with input from GO & GOP.	
Likes 0	
Dislikes 0	
Response	
Robert Stevens - CPS Energy - 5	
Answer	Yes
Document Name	
Comment	
The Standard as currently drafted does not require the BA to determine the winter season. There should be a requirement the BA define and coordinate the seasons with the GOs in its footprint. Add something like: "BA shall determine the winter season for its footprint and shall inform each GO in its footprint of its determination, by x-date of each year for the ahead winter season."	
Likes 0	
Dislikes 0	
Response	
Colin Chilcoat - Invenergy LLC - 6	
Answer	Yes
Document Name	
Comment	
Invenergy agrees that the BA is the appropriate entity to determine the winter season. Invenergy suggests that the BA be added as an applicable functional entity in EOP-012-1, and that a separate Requirement be added, which details the method(s) by which the BA will notify subject Generator Owners of their determination.	
Likes 0	
Dislikes 0	
Response	
Rhonda Jones - Invenergy LLC - 5	
Answer	Yes

Document Name	
Comment	
Invenergy agrees that the BA is the appropriate entity to determine the winter season. Invenergy suggests that the BA be added as an applicable functional entity in EOP-012-1, and that a separate Requirement be added, which details the method(s) by which the BA will notify subject Generator Owners of their determination.	
Likes 0	
Dislikes 0	
Response	
Glenn Pressler - CPS Energy - 3	
Answer	Yes
Document Name	
Comment	
The Standard as currently drafted does not require the BA to determine the winter season. There should be a requirement the BA define and coordinate the seasons with the GOs in its footprint. Add something like: “BA shall determine the winter season for its footprint and shall inform each GO in its footprint of its determination, by x-date of each year for the ahead winter season.”	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Ameren agrees with the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes

Document Name	
Comment	
AEP supports the BA being the entity to determine the “winter season” in their region. However, in some BA regions the area may be very large, and the BA may need to define winter seasons differently in certain parts of their footprint. To address this concern, we suggest language be added to require the BA to work with their respective GOs and GOPs to ensure the “winter season” is appropriately defined throughout their area of responsibility.	
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	
Southern Company supports the EEI comments and supports the BA as the entity to determine the “winter season” so long as this determination is applied only to exempt summer peaking generators from the requirements of EOP-12-1 but does NOT determine the timing of when a generating plant should implement its Cold Weather Preparedness Plan each year.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Texas RE agrees the BA is the appropriate entity to determine the “winter season”. Texas RE recommends the BA coordinate with its RC and the PA/PC so the RC and PA/PC understand when the winter season is determined.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3	

Answer	Yes
Document Name	

Comment

WEC Energy Group supports EEIs comments.

Likes 0	
Dislikes 0	

Response

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4

Answer	Yes
Document Name	

Comment

Alliant Energy supports the comments submitted by the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Brian Evans-Mongeon - Utility Services, Inc. - 4

Answer	Yes
Document Name	

Comment

BAs should also be obligated to inform GO/GOPs of their defined “winter season”.

The BA is the appropriate entity to determine the “winter season” for purposes of defining applicable generating units in proposed EOP-012-1. Because applicability of EOP-012 hinges on the BA’s determination, the SDT should consider a Requirement, possibly in EOP-011, for the BA to make the determination and communicate it to the GOs in its footprint. Proposed requirement language: “The Balancing Authority shall determine the winter season for its footprint, and shall inform each GO in its footprint of its determination, by [date] of each year for the winter season commencing in that calendar year.”

Likes 0	
Dislikes 0	

Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Dominion Energy supports the EEI comments that the BA is the entity to determine the “winter season.” However, in some BA regions the area may be very large, and the BA may need to define winter seasons differently in certain parts of their area. To address this concern, we suggest language be added to require the BA to work with their respective GOs and GOPs to ensure the “winter season” is appropriately defined throughout their area of responsibility.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy agrees with EEI’s comments.	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	Yes
Document Name	
Comment	
If there is a requirement for defining the winter season, NRG agrees the BA is the best entity that can define this for their respective region. However, it must be understood that within a large BA, there may be wide variability in temperature gradients across the BA’s footprint and that variability should be accounted for.	
Likes 0	

Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
The Balancing Authority (BA) is the best entity to determine what their "winter season" is. The MRO NSRF recommends the SDT review NERC Reliability Standards to verify if a requirement(s) exists for the BA to actually determine a "winter season".	
Likes 2	Corn Belt Power Cooperative, 1, brusseau larry; Lincoln Electric System, 1, Johnson Josh
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
We find the criterion for freeze protection measures is clear (i.e., "capable of continuous operations at the documented minimum hourly temperature experienced at location since 1/1/1975…") and it is just about determining the generating units it applies to, as long as the dates for the winter season are clear, and that it starts before the first freeze and ends after the last.	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
If there is a requirement for defining the winter season, NRG agrees the BA is the best entity that can define this for their respective region. However, it must be understood that within a large BA, there may be wide variability in temperature gradients across the BA's footprint and that variability should be accounted for.	

Likes 0	
Dislikes 0	

Response

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF

Answer	Yes
Document Name	

Comment

The Standard does not currently require the BA to determine the winter season. A new requirement should be added to ensure the BA provides the seasons to the GOs in its footprint.

Suggested language for the Requirement: "The Balancing Authority shall determine the winter season for its footprint and shall inform each GO in its footprint of its determination, by [date] of each year for the ahead winter season commencing in that calendar year."

Likes 0	
Dislikes 0	

Response

Nazra Gladu - Manitoba Hydro - 1

Answer	Yes
Document Name	

Comment

Yes, but the SDT should consider that the utilities in a BA need to have the changeover between Summer to Winter limits coordintated, where a BA extends into differening climates, this presents a problem. For example, Lousiana Power's summertime may begin earlier than Manitoba Hydro's summer limits conditions. This may be less of an issue when Dynamic limits come into effect in a few years.

Likes 0	
Dislikes 0	

Response

Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	
Response	
Daniel Mason - Portland General Electric Co. - 6, Group Name PGE FCD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Dwanique Spiller On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Dwanique Spiller	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kimberly Bentley - Kimberly Bentley On Behalf of: sean erickson, Western Area Power Administration, 1, 6; - Kimberly Bentley	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LaKenya VanNorman - LaKenya VanNorman On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name FMPA and Members	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tony Skourtas - Los Angeles Department of Water and Power - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Randy Buswell - VELCO -Vermont Electric Power Company, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Gul Khan - Gul Khan On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Gul Khan	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jun Hua - Austin Energy - 4	
Answer	
Document Name	
Comment	
I support comments made by Michael Dillard, Austin Energy, Segment 5	
Likes 0	
Dislikes 0	
Response	

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	
Comment	

WECC is not opposed to this but offers the following options. The terminology for winter season is widely used for Facility Ratings, System Operating Limits, and Planning purposes. To avoid possible confusion, some consideration might be given to allowing the PC or RC to make this determination. This could allow for consistent terminology between cold weather operations and planning activities. Another consideration is whether it is appropriate to allow a Generator Only BA to establish the winter season for the benefit of its own generation (see suggested language in response to question 3). Another alternative or additional language might include a requirement that the BA determine and identify the "winter season" criteria, make formal declarations of the seasonal status, and communicate those to the GO/GOP.

Likes 0	
Dislikes 0	

Response

Lisa Martin - Austin Energy - 6

Answer	
Document Name	

Comment

I support comments made by Michael Dillard, Austin Energy, Segment 5.

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

ISO-NE agrees with the SRC comment and suggested language:

The winter season is defined as a minimum of December through February unless the applicable Balancing Authority decide otherwise.

Likes 0	
Dislikes 0	

Response

Mark Young - Tenaska, Inc. - 5	
Answer	
Document Name	
Comment	
Regardless of official entity that makes the determination, stakeholder input should be considered.	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	
AECI and its members support comments provided by ACES.	
Likes 0	
Dislikes 0	
Response	

3. The SDT proposes to include as applicable Facilities in EOP-012-1 only those generating units that operate during the winter weather season, while exempting those units utilized for summer peaking purposes only (and without penalizing such units that may be called upon by the BA during winter weather in response to energy emergencies). Do you agree with the applicability of EOP-012-1 as drafted? If you do not agree, please provide recommended language for how to address from the standard's applicability consistent with the recommendations of The Report.

Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
Capacity emergencies occur in a variety of seasons. This exemption for peaking units will continue the trend of units not being weatherized and fall short of the overall goal, which is to prevent a repeat of the February, 2021 severe winter storm events in Texas. Listing specific criteria for the exemptions in the standard is preferred.	
Likes 0	
Dislikes 0	
Response	

LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
With the changing generation mix on the electric grid and projected capacity and energy shortfalls by various reliability entities, no BES unit should be exempt from EOP-012 since all may be called on in an extreme cold weather event when other units are unable to start or operate.	
Likes 0	
Dislikes 0	
Response	

Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

We believe that it is more appropriate to have the meaning of “generating unit” or the exclusion of those generators that do not operate during the winter season, except for as called upon by the BA, in the standard requirement rather than in the Applicability.

Likes 0	
Dislikes 0	

Response

Randy Buswell - VELCO -Vermont Electric Power Company, Inc. - 1

Answer	No
Document Name	

Comment

VELCO requests that the SDT consider Emergencies in the summer weather season that may warrant protections.

Likes 0	
Dislikes 0	

Response

Donna Wood - Tri-State G and T Association, Inc. - 1

Answer	No
Document Name	

Comment

If there is any chance of the plant operating during any cold weather energy emergency then the standard should apply. Some of the primary issues in past cold weather events have been tied to units that were not expecting to operate at the time. Tri-State does not believe any exemption would be in the best interest of the BES.

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	No
Document Name	

Comment

The IESO strongly believes that the standard should apply to all the generating units whose capacity is being counted on, including those providing sufficient reserve to withstand a cold weather event.

Likes 0	
Dislikes 0	

Response

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

BPA supports the comments submitted by the US Bureau of Reclamation.

Likes 0	
Dislikes 0	

Response

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	

Comment

The proposed changes are subjective and allow for the exclusion of the very units this project should be attempting to make more reliable and resilient, which is those called upon by the Balancing Authority to be available during Capacity Emergencies or Energy Emergencies. The exclusion of these generators could be detrimental to the reliability and resilience of the BES. The inability of such generators to operate in extreme conditions could manifest as a false sense of security and ultimately contribute to the emergency rather than help alleviate it. Further, if the language were to remain as proposed, there is no explanation or definition on determining units as “plan to operate” or “do not operate” during the winter season.

The MRO NSRF suggests that all BES generators should be included in proposed section 4.2 and therefore the language should remain unchanged from EOP-011-2, section 4.2 Facilities. BES generators such as summer peaking units or those that do not plan to operate in the winter season would have the opportunity to declare exemption through R1.4.4.

Likes 2	Corn Belt Power Cooperative, 1, brusseau larry; Lincoln Electric System, 1, Johnson Josh
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Dominion Energy supports the NAGF comments and agrees that since existing plants should not be required to retrofit and only provide their operational constraints a winter season is not necessary.	
Likes 0	
Dislikes 0	
Response	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
DTE Electric supports NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	No
Document Name	
Comment	
HQ experiences winter peaking months	
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	

Note: BES generating units only; NERC rules do not extend to all Market Participants

Problematic phrasing?

4.2. Facilities: For purposes of this standard, the term “generating unit” means those Bulk Electric System generators that plan to operate during the winter season. The winter season will be determined by the generating unit’s applicable Balancing Authority. The definition excludes those generators that do not operate during the winter season except and are not otherwise required by the BA to be available during Capacity Emergencies or Energy Emergencies.

ISO-NE agrees with the SRC Comments for the proposed Applicable Facilities language and reiterates the concern; Can units operate during one winter season and not the next or vice versa? If so, how will this be treated under the standard since the implementation period is longer than one year? The SRC views this as problematic as units could opt in and out of operating during the “winter season” to avoid the regulation, thereby negating the intended benefits of this standard.

Likes 0	
Dislikes 0	
Response	

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4

Answer	No
Document Name	
Comment	

Alliant Energy supports the comments submitted by the MRO NSRF.

Likes 0	
Dislikes 0	
Response	

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer	No
Document Name	
Comment	

The information in the Facilities section is unclear. The phrase “BES generators that plan to operate during the winter season” is unclear and confusing. Equipment does not plan anything. Is the language referring to Generator Owners or Generator Operators that plan to operate generating units during

the winter? It is unclear if the exclusion of “generators that do not operate during the winter season” refers to Generator Owners, Generator Operators, or generating units. It is unclear why generating units that would be called upon during certain Emergencies would be exempt from requirements that arose out of equipment failures to perform during emergency situations.	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	No
Document Name	
Comment	
PG&E supports the comments provided by the North American Generators Forum (NAGF).	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 4, Group Name NCPA	
Answer	No
Document Name	
Comment	
NCPA agrees with the comments of MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	

AEPCO signed on to ACES comments below:

In regards to the proposed Section 4.2 Facilities definition: In order to ensure a reliable response from generators that may be called upon by the Balancing Authorities during Capacity and Energy Emergencies, we recommend eliminating the exception for generators that do not operate during the winter season except when called upon by the Balancing Authority to be available during Capacity Emergencies or Energy Emergencies. Our recommended change to the language would be “The term excludes those generators that are not expected to operate during the winter season under normal and/or emergency conditions.”

Likes 0	
Dislikes 0	

Response

Dennis Sismaet - Northern California Power Agency - 6

Answer	No
Document Name	

Comment

Changes to Cold Weather Reliability Standards should not be applicable continent-wide. Standards should not be modified or implemented prior to Market Rule Modifications. See prior NERC Project 2019-06 ballot and commenting by Marty Hostler

Market Rule modifications have not yet been made to mitigate potential Cold Weather Events grid issues. Per FERC/NERC's recommendation, Market Rule modifications should be made prior to, or concurrent with, development of new Standards.   To date, no known Market Rule Modification project has been initiated.

On page 86 of FERC/NERC's joint Report The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018 (ferc.gov) the following recommendations where made.

Recommendation 1: The Team recommends a three-pronged approach to ensure Generator Owners/Generator Operators, Reliability Coordinators and Balancing Authorities prepare for cold weather conditions: 1) development or enhancement of one or more NERC Reliability Standards, 2) enhanced outreach to Generator Owners/Generator Operators, and 3) market (Independent System Operators/Regional Transmission Organizations) rules where appropriate. This three-pronged approach should be used to address the following needs: • The need for Generator Owners/Generator Operators to perform winterization activities on generating units to prepare for adverse cold weather, in order to maximize generator output and availability for BES reliability during these conditions. These preparations for cold weather should include Generator Owners/Generator Operators:

While any one of the three approaches may provide significant benefits in solving this problem, the Team does not view any one of the three as the only solution. The Team envisions that a successful resolution of the problem will likely involve concurrent use of all three.

Likes 0	
Dislikes 0	

Response

Jeremy Lawson - Northern California Power Agency - 5

Answer	No

Document Name	
Comment	
NCPA agrees with the comments of MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren agrees with the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Glenn Pressler - CPS Energy - 3	
Answer	No
Document Name	
Comment	
No; capacity emergencies occur in all seasons, especially winter. An exemption for generation unit(s) will continue the trend of units not being weatherized and fall short of the overall goal, which is to prevent a repeat of the February 2021 severe winter storm event. Any specific criteria for any such exemption(s) should be included in the actual requirement wording. We do have a concern that some generators will just say they do not operate during the winter and thus create further winter capacity issues.	
Likes 0	
Dislikes 0	
Response	
Robert Stevens - CPS Energy - 5	
Answer	No

Document Name	
Comment	
No; capacity emergencies occur in all seasons, especially winter. An exemption for generation unit(s) will continue the trend of units not being weatherized and fall short of the overall goal, which is to prevent a repeat of the February 2021 severe winter storm event. Any specific criteria for any such exemption(s) should be included in the actual requirement wording. We do have a concern that some generators will just say they do not operate during the winter and thus create further winter capacity issues.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	
CEG suggests eliminating reference to winter and refer only to “intend to operate in cold weather”, the subject of the Standard. Kimberly Turco on behalf of Constellation Energy Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Rick Stadtlander - NEI - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
Agree with NAGF comments	
Likes 0	
Dislikes 0	
Response	

Kimberly Bentley - Kimberly Bentley On Behalf of: sean erickson, Western Area Power Administration, 1, 6; - Kimberly Bentley	
Answer	No
Document Name	
Comment	
The language used, such as "do not operate" or "plan to operate" is unclear and confusing and could potentially exclude those very generating units that would be called upon during certain Emergency situations.	
Likes 0	
Dislikes 0	
Response	
Alison Mackellar - Constellation - 5	
Answer	No
Document Name	
Comment	
CEG suggests eliminating reference to winter and refer only to “intend to operate in cold weather”, the subject of the Standard. 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 Entity Monitoring	
Answer	No
Document Name	
Comment	
WECC agrees with the concept, but the proposed wording appears to allow each individual GO to determine if it plans to operate during a winter period. Ambiguity could be reduced (and a more consistent use of the term “winter season” could be achieved) by modifying Applicability Section 4.2 to read: “For purposes of this standard, the term “generating unit” means those Bulk Electric System generators that have been studied as “in operation” during winter seasonal studies and base cases performed by the PC or TP where the unit is located. Nothing in this standard is intended to prevent requesting the operation of any generating unit by a Balancing Authority during Capacity Emergencies or Energy Emergencies.” An alternative option may be to include language such as “entities that offer generation day-ahead during the winter season” or “entities whose generation is picked up in the day-ahead market.”	

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

A winter exemption creates potential BES reliability challenges from a resource planning, reserve margin, forecasted load, etc. perspective. Duke Energy does not agree with the proposed winter weather season unit exemption unless meaningful, enforceable, defined, and vetted exemption criteria are developed and incorporated into the proposed Standard.

Likes 0	
Dislikes 0	

Response

Marty Watson - Santee Cooper - 5, Group Name Santee Cooper

Answer	No
Document Name	

Comment

The phrase “do not operate during the winter season except when called upon by the BA needs a standalone definition. Most entities have units that are only called upon during extreme weather events.

Likes 0	
Dislikes 0	

Response

Joe McClung - JEA - 1

Answer	No
Document Name	

Comment

We may be in agreement with the intention, but the language needs revision. All generators not planned to run during the winter should be excluded. Is this the intention? If so, the last sentence in 4.2 Facilities should read, “The term excludes those generators that are not included in the winter season

plan." As mentioned in LPPC comments, a separate Requirement should be included in EOP-012-1 which defines "winter season" AND identifies the units. If this were the case, no mention of emergency is needed.	
Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merre
Dislikes 0	
Response	
Jamie Monette - 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	
Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	No
Document Name	
Comment	
As drafted the applicability of the standard may create adverse impacts on competitive electricity markets in that it may disincentify Market Participants from operation during winter months due to a higher burden of compliance. Capital Power encourages the SDT to ensure the applicability of the standard considers NERC's Market Principles and all types of Market Partipants, including those that may not be unable to recover costs by passing them through to end users (ie. Independent Power Producers). In general, Capital Power supports the NAGF comments on this question.	
Likes 0	
Dislikes 0	
Response	
Mark Spencer - LS Power Development, LLC - 5	
Answer	No
Document Name	
Comment	

In lieu of R1 of EOP-012-01 we recommend that R2 of EOP-011-03 be enhanced to require each BA to quantify the amount of reliable generation it needs to meet extreme cold weather conditions and place the requirement on the BA to identify the specific generators that are designated to provide the service under the BA's specified ambient conditions. This also has the benefit of ensuring that the amount of reliable generation and the degree to which the generation is reliable, including attributes besides freeze protection, is matched closely with the BA's mitigating requirements of R2. This proposal would achieve similar or better reliability benefits at less cost than the current proposal. The BA would also be able to match the weatherization requirements with their regional fuel needs; it is unnecessary and inefficient to require generators that likely may not be able to operate for reasons other than freeze protection (e.g., fuel unavailability, environmental limitations, cooling water supply issues, etc.) to winterize to such an extreme requirement. The BA may also be able to include financial incentives and penalties for absolute performance (i.e., no excuses) in its tariff design that cannot be replicated in a Reliability Standard; we foresee circumstances where generators may make made good faith efforts, comply with the Reliability Standards, but ultimately fail to perform during extreme cold weather events.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

In regards to the proposed Section 4.2 Facilities definition: In order to ensure a reliable response from generators that may be called upon by the Balancing Authorities during Capacity and Energy Emergencies, we recommend eliminating the exception for generators that do not operate during the winter season except when called upon by the Balancing Authority to be available during Capacity Emergencies or Energy Emergencies. Our recommended change to the language would be "The term excludes those generators that are not expected to operate during the winter season under normal and/or emergency conditions."

Likes 0	
Dislikes 0	

Response

Natalie Johnson - Enel Green Power - 5

Answer	No
Document Name	

Comment

Although EGP agrees with the applicability of EOP-012-1, the language in the draft should be clarified. The term "generating unit" in section 4.2 and throughout the draft standard causes confusion in how the standard applies to renewable resources. Although an attempt to clarify is provided, the term generating unit refers to each and every individual turbine or invertor. It is recommended to use the term "generating resource." The term "generating resource" was adopted during the development of PRC-024 to resolve the same issue.

Likes 0	
Dislikes 0	

Response

Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)

Answer	No
Document Name	

Comment

The SRC does not agree with the applicability of EOP-012 as drafted as NERC standards do not obligate a unit to declare their intent to operate by season. In addition, the Implementation Plan for this project provides anywhere from 18 months to 60 months (18 + 42 months) to comply with various requirements under the standard. The ability for a Generator Owner to alter its operability status during the "winter season" on an annual basis has the potential to negate the anticipated improvements that would be realized under this standard. Flexibility associated with applicability of the standard has the potential to reset the clock such that the improvements may never be realized. The SRC proposes the *following language* in replacement of the SDT proposed EOP-012-1 4.2 **Facilities section:**

For purposes of this standard, the term "generating unit" means those Bulk Electric System generators that plan or otherwise are obligated to be available to operate during the winter season, including Blackstart Resources, as determined by the Balancing Authority. The winter season is defined as December through February unless the applicable Balancing Authority decides otherwise. Each Generator Owner shall notify its applicable Balancing Authority if meeting the exemption to this section.

(Please note: ERCOT supports the SRC comments to Question #3 but does not agree with the proposed language in its entirety. ERCOT will provide separate comments to address this discrepancy.)

The SRC proposes this change since a number of RTOs/ISOs have obligated units which are deemed capacity resources to be available when called upon in emergencies irrespective of the particular season. The language as originally drafted would inadvertently tend to create unnecessary ambiguity as to those obligations by not requiring such units to be available if they don't 'plan to operate in the winter season' (NOTE: Use exact language of original proposal). Section 215 (d)(6)of the Federal Power Act and FERC's implementing rules note the need for harmonization of NERC Standards with RTO/ISO market rules and not work against RTO/ISO market rules. The concern with the current proposed EOP-012-1 Applicability section: 4.2 Facilities is the exemption of certain units from having to winterize even if they have been designated as capacity resources to be called upon to operate to meet capacity emergencies. The proposed language would fix this problem without changing the overall approach proposed by the authors.

From the Joint Inquiry Report:

There are multiple references within "the Report" for BAs and RCs to be aware of specific generating unit limitations, such as ambient temperatures or fuel supply." The recently approved NERC Standards require the RC (IRO-010-4) and TOP and BA (TOP-003-5) to have provisions for notification from BES generating unit(s) to TOP and BA during local forecasted cold weather to include: Operating limitations based on: capability and availability; fuel supply and inventory concerns; fuel switching capabilities; and environmental constraints; and generating unit(s) minimum: design temperature; or historical operating temperature; or current cold weather performance temperature determined by an engineering analysis. This GO cold weather data criteria was included in EOP-011-2, R7 and is now moved to EOP-013-1, R3 and is where GO cold weather preparedness plans now reside (per Project 2021-07). However, the facility section of EOP-011-2 used the term "generating unit" to mean all BES generators and does not apply a generating unit exclusion as currently proposed in EOP-012-1. Any generating unit taking the exclusion under the Facilities section of EOP-012-1 will not be subject to EOP-012-1 Requirements. While the TOP may still request cold weather data (i.e. generating unit minimum operating temperature) per TOP-003-4 or TOP-003-5, the determination and evaluation by the generating unit may not serve as a basis to predict whether or not the unit will be able to perform during predicted cold weather if the unit is not performing the operating temperature limit analyses as well as related limitations, as defined in the EOP-012-1 Requirements. Per 'The Report', "The Event demonstrated that ambient temperatures alone do not serve as a basis to predict whether a generating unit can perform during predicted cold weather. For 81 percent of the generating units outaged, at the time the outage occurred, ambient temperatures were above the generating unit's stated design criteria." The concern is the information communicated from the GO to the BA / TOP may be limited and unreliable if units are set to different methods of criteria in determining unit limitations.

Per the Report: "TOP-003-5 R1 and R2 (effective April 1, 2023) will require TOPs and BAs, respectively, to include in their data specifications, to the GO, requests for information "during local forecasted cold weather" about generating units' operating limits, including "capability and availability; fuel supply and inventory concerns; fuel switching capabilities; and environmental constraints," as well as minimum temperature, based on one of three options. A related requirement, EOP-011-2 R7.3 (also effective April 1, 2023), will require GOs to develop cold weather preparedness plans which include, at a minimum, their generating unit(s)' cold weather data such as the aforesaid capability, fuel supply concerns, environmental constraints, etc. The intent behind requiring GOs to identify and share with the BAs and TOPs the expected limitations of their generating units "during local forecasted cold weather, is to prevent grid operators from being surprised when large numbers of generating units that had committed to run are unable to do so during cold weather events." This exchange of accurate generator unit operating limitations will be limited by those generating units no longer subject to a cold weather preparedness and may result in TOPs and BAs not being provided the correct operating limits in performing Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. By removing the unit exemption in EOP-012-1, the unit will perform the operating limitation analysis that meets the current Standard (EOP-011-2, effective April 2023 and newly proposed EOP-012-1) and allows for accurate TOP/BA assessments in preparing and operating in cold weather conditions.

Likes 0	
Dislikes 0	

Response

John Babik - JEA - 5

Answer	No
Document Name	

Comment

We may be in agreement with the intention, but the language needs revision. All generators not planned to run during the winter should be excluded. Is this the intention? If so, the last sentence in 4.2 Facilities should read, "The term excludes those generators that are not included in the winter season plan." As mentioned in LPPC comments, a separate Requirement should be included in EOP-012-1 which defines "winter season" AND identifies the units. If this were the case, no mention of emergency is needed

Likes 0	
Dislikes 0	

Response

Ashley Scheelar - TransAlta Corporation - 5

Answer	No
Document Name	

Comment

TransAlta agrees with exempting the facilities identified. Many generators in the North, particularly Canada, successfully operates in extreme cold year after year. In addition, many facilities operate in regions that do not have the type of reliability risk being addressed by this standard. For those entities, this standard is creating a significant administrative burden. Therefore, there should be further language that exempts those generators in regions where there is little or no reliability risk.

Likes 0	
Dislikes 0	

Response

Patricia Lynch - NRG - NRG Energy, Inc. - 5

Answer	Yes
Document Name	

Comment

NRG generally agrees with the concept on exemptions for summer run only units. Typically penalization of unit operation is related to market rules. Therefore penalties should not be considered under NERC jurisdiction. However, if this becomes a NERC requirement, this could unfairly subject an entity to double jeopardy.

Likes 0	
Dislikes 0	

Response

Martin Sidor - NRG - NRG Energy, Inc. - 6

Answer	Yes
Document Name	

Comment

NRG generally agrees with the concept on exemptions for summer run only units. Typically, penalization of unit operation is related to market rules. Therefore, penalties should not be considered under NERC jurisdiction. However, if this becomes a NERC requirement, this could unfairly subject an entity to double jeopardy.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	Yes

Document Name	
Comment	
FirstEnergy agrees with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
BC Hydro appreciates the opportunity to comment and has the following comment seeking additional clarification on the assessment of the freeze protection measures, specifically for generating facilities that are not directly exposed to extreme cold, i.e. located at least partially indoors. BC Hydro's understanding is that the required assessment will be on facility-by-facility basis (or type of facilities), and will need to account for all equipment that would be exposed to extreme cold temperatures. Please confirm whether our understanding is accurate.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	
This is already an industry standard/best practice.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3	
Answer	Yes

Document Name	
Comment	

WEC Energy Group supports EEIs 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	

Southern Company supports the EEI comments. In addition, Southern would like more claiity on the definition of "non-winter units" and what criteria would deem a unit to be exempt from the requirements of EOP-012-1.

We also suggest defining what advance notice is required when detemiming and communicating which units are exempt from EOP-012.

We suggest modifying the wording in 4.2 from *"For purposes of this standard, the term "generating unit" means those Bulk Electric System generators that plan to operate during the winter season."* to *"For purposes of this standard, the term "generating unit" means those Bulk Electric System generators that* ***are expected*** *to operate during the winter season by their applicable BA."*

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	Yes
Document Name	
Comment	

AEP supports the exclusion of units designated for summer peaking-only from the requirements of EOP-012-1, and supports the comments of EEI in that regard.

AEP recommends that 4.2 (Facilities) be revised to state "… the term excludes those generators, *as defined by the Balancing Authority*, that do not operate…"

Likes 0	
Dislikes 0	
Response	
Colin Chilcoat - Invenergy LLC - 6	
Answer	Yes
Document Name	
Comment	
Invenergy agrees with the applicability of EOP-012-1 as drafted.	
Likes 0	
Dislikes 0	
Response	
LaKenya VanNorman - LaKenya VanNorman On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name FMPA and Members	
Answer	Yes
Document Name	
Comment	
While we agree with having the BA determine, there needs to be a requirement for coordination amongst adjacent BAs. They don’t have to have matching definitions but they need to understand the implications of having one BA with a dramatically different definition than its neighbor.	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	

AZPS supports the SDT's approach to exempt generating units that do not operate during the winter season. As noted by EEI, the term 'peaking' is not used in the Reliability Standard.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the SDT's approach, which exempts units utilized for all periods except for the winter season, noting that the term "peaking" is not used in the Reliability Standard.	
Likes 0	
Dislikes 0	
Response	
Dan Roethemeyer - Vistra Energy - 5	
Answer	Yes
Document Name	
Comment	
The SDT appropriately focuses the draft standard on winterization measures, as emergency grid conditions tend to occur more frequently in the winter than in the summer season. The draft standard also appropriately limits those winterization requirements to resources that operate in winter, as there is no need for a resource that does not operate in the winter to establish or maintain winterization measures.	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	Yes
Document Name	
Comment	

No comments.	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 6	
Answer	Yes
Document Name	
Comment	
An exemption for units only operated in the summer months would be welcome.	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Gerry Huitt, Xcel Energy, Inc., 5, 3, 1; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Xcel Energy supports the comments submitted by EEI and the NAGF.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - Casey Perry On Behalf of: Lynn Goldstein, PNM Resources - Public Service Company of New Mexico, 1, 3; - PNM Resources - Public Service Company of New Mexico - 3 - WECC	
Answer	Yes
Document Name	
Comment	
No additional 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 Regional Standards Committee	
Answer	Yes
Document Name	
Comment	
RSC requests that the SDT consider Emergencies in the summer weather season that may warrant protection.	
Likes 0	
Dislikes 0	
Response	
Michele Richmond - Texas Competitive Power Advocates - NA - Not Applicable - Texas RE	
Answer	Yes
Document Name	
Comment	
EOP-012-1 should only be applied to units that participate in the market during the winter season. Note that the potential cost implications of R1 which can be millions if not tens of millions of dollars, which may result in generators either retiring or opting out of the winter season. Unfunded mandates such as R1 that have such a high material economic impact may ultimately reduce winter season reliability due to reduced generation available for dispatch.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Allen Klassen, Evergy, 1, 3, 5, 6; Jennifer Flandermeyer, Evergy, 1, 3, 5, 6; Marcus Moor, Evergy, 1, 3, 5, 6; - Alan Kloster	
Answer	Yes
Document Name	
Comment	
Evergy supports and includes by reference the comments of the Edison Electric Institute (EEI) for question #3.	

Likes 0	
Dislikes 0	
Response	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	Yes
Document Name	
Comment	
MidAmerican supports EEI's comments and supports the SDT's approach, which exempts units utilized for all periods except for the winter season, noting that the term "peaking" is not used in the Reliability Standard.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon concurs with the comments submitted by the EEI. Submitted on behalf of Exelon (Segments 1 & 3)	
Likes 0	
Dislikes 0	
Response	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
SIGE is responding with "Yes"; however, SIGE does not currently have units identified for summer peaking purposes only.	

Likes 0	
Dislikes 0	
Response	
Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1, Group Name OGE Energy - Oklahoma Gas and Electric Co.	
Answer	Yes
Document Name	
Comment	
Oklahoma Gas and Electric agrees with and endorses comments as submitted by EEI Reliability Technical Committee (RTC)	
Likes 0	
Dislikes 0	
Response	
Jennifer Blair - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	
PPL NERC Registered Affiliates support EEI comments on Question 3.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Dwanique Spiller On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Dwanique Spiller	
Answer	Yes
Document Name	
Comment	
Nv Energy supports EEI’s comments and supports the SDT’s approach, which exempts units utilized for all periods except for the winter season, noting that the term “peaking” is not used in the Reliability Standard.	
Likes 0	
Dislikes 0	

Response	
Hillary Dobson - Colorado Springs Utilities - 3	
Answer	Yes
Document Name	
Comment	
CSU supports LPPC's comments.	
Likes 0	
Dislikes 0	
Response	
Daniel Mason - Portland General Electric Co. - 6, Group Name PGE FCD	
Answer	Yes
Document Name	
Comment	
Portland General Electric Company supports the survey response provided by EEI.	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	
Please see answer to question 2. If the GO can demonstrate via historical data or technical justification that it does not or can't operate during a heightened cold weather event, some form of exemption should be available to avoid required must run mandate during cold weather-related energy emergencies. The standard must avoid forcing the closure of generation units from untenable compliance requirements. However, this should not relieve such Facility from winterizing plans to assure the generation units will not suffer damage rendering them unavailable upon return to warm weather conditions. Example: Generation unit is inaccessible during snow season road closure.	
Likes 0	
Dislikes 0	

Response	
Whitney Wallace - Calpine Corporation - 5 - WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
Calpine agrees that EOP-012-1 should only be applied to units that participate in the market during the winter season. This will limit costly winterization requirements to those resources that actually operate in the winter, alleviating any need for a resource that does not operate in the winter from undertaking costly measures that will not provide real benefits. Additionally, imposition of expensive winterization measures for resources that do not operate in the winter season could result in generators either retiring or opting out of the winter season entirely, potentially impacting reliability.	
Likes 0	
Dislikes 0	
Response	
Dana Showalter - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Q3. ERCOT suggests the applicability language for facilities in Section 4.1.2 be revised as shown below. "Plan to operate" is not sufficiently clear, as neither the Regional Entity nor the BA, RC, or PC can know the GO's subjective intentions. Accordingly, the BA should decide not only how winter should be defined for the BA Area, but also whether a generating unit is obligated to be available under the relevant rules. To the extent the SDT determines that the BA's responsibility to identify units that are covered by the standard should be stated more explicitly within the requirements, ERCOT would support that change. **ALTERNATE LANGUAGE PROPOSED:** *For purposes of this standard, the term "generating unit" means those Bulk Electric System generators that plan, or otherwise are obligated, to be available to operate during the winter season, including Blackstart Resources, as determined by the Balancing Authority. The winter season is defined as December through February unless the applicable Balancing Authority decides otherwise. A list of those units exempt from this standard for a given winter season shall be maintained by the Balancing Authority.*	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes

Document Name	
Comment	
LCRA generally agrees with the concept on exemptions for summer run only units. Typically, penalization of unit operation is related to market rules. Therefore, penalties should not be considered under NERC jurisdiction. However, if this becomes a NERC requirement, this could unfairly subject an entity to double jeopardy.	
Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
LCRA generally agrees with the concept on exemptions for summer run only units. Typically, penalization of unit operation is related to market rules. Therefore, penalties should not be considered under NERC jurisdiction. However, if this becomes a NERC requirement, this could unfairly subject an entity to double jeopardy.	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Gul Khan On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Gul Khan	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
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	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Tony Skourtas - Los Angeles Department of Water and Power - 3	
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	
Rhonda Jones - Invenergy LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tom Vinson - American Clean Power Association - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Rebecca Baldwin - Transmission Access Policy Study Group - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Foung Mua, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Wei Shao, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; - Tim Kelley, Group Name LPPC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Braunstein - Colorado Springs Utilities - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Watt - Oklahoma Municipal Power Authority - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Johnson - Oglethorpe Power Corporation - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sam Nietfeld - Public Utility District No. 1 of Snohomish County - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	
AECI and its members support comments provided by ACES.	
Likes 0	
Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	
N/A- SEC does not operate under winter weather conditions as much of the United States does, therefore, SEC has no opinion.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE agrees with and supports proposed Reliability Standard EOP-012-1. Texas RE is concerned, however, with section A. 4.2. The Facilities language does not indicate that it is exempting those units utilized for summer peaking purposes only as this question states. Texas RE recommends clarifying that any generating unit that could be called upon by the BA be included in the applicability of EOP-012-1. Those entities who are needed at during Capacity Emergencies and Energy Emergencies need to be appropriately prepared for extreme weather.	
Likes 0	
Dislikes 0	
Response	

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	NAGF EOP-012-1 06152022 final.pdf
Comment	

NAGF Comments: As drafted, the applicability section is likely to drive rational Generator Owners from the winter period due to the uncertainty of what may be required to meet the obligations in the EOP-012-1 requirements. Additionally, it appears that the Balancing Authority could call upon a generator to run during a period that is not considered a Capacity or Energy Emergency and thereby cause the generator to be subject to the standard. As worded, it is unclear if the Balancing Authority can only call upon the generators once an emergency has been declared by the Reliability Coordinator or if the Balancing Authority is anticipating an emergency. Each of these issues would need to be addressed to ensure the potential for unintended consequences is reduced.

The NAGF is providing a revised OP-012-1 standard for consideration that addresses these issues in a holistic manner.

Generators should not be placed in a position that by running they become subject to a standard ***unless they have contracted/agreed*** with an entity, to provide that service, similar to EOP-005. Under EOP-005, all generators capable of providing blackstart service are not required to comply; compliance is mandatory only for those generators that have contracted for blackstart service. EOP-012 should only apply to those generators that have agreed to be available to provide service under all conditions, not just by operating during specific months or time periods during the year.

Likes 0	
Dislikes 0	
Response	

Michael Dillard - Austin Energy - 5	
Answer	
Document Name	
Comment	

N/A

Likes 0	
Dislikes 0	
Response	

Lisa Martin - Austin Energy - 6	
Answer	
Document Name	
Comment	

I support comments made by Michael Dillard, Austin Energy, Segment 5.

Likes 0	
Dislikes 0	

Response

Julie Hall - Entergy - 6, Group Name Entergy

Answer	
Document Name	

Comment

At this current time, this is not applicable to Entergy.

Likes 0	
Dislikes 0	

Response

Jun Hua - Austin Energy - 4

Answer	
Document Name	

Comment

I support comments made by Michael Dillard, Austin Energy, Segment 5

Likes 0	
Dislikes 0	

Response

Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	
Document Name	

Comment

CenterPoint Energy Houston Electric, LLC is not a registered Generator Owner or Generator Operator.

Likes 0	
Dislikes 0	
Response	

4. Does the proposed language in EOP-012-1 requirement R1 that require existing units to implement new freeze protection measures or modification of existing freeze protection measures, raise any stakeholder concerns? If so, please provide details of the concern, suggestions to the proposed language that addresses the risk presented in recommendation 1f, and if appropriate, technical or procedural justification.

John Babik - JEA - 5	
Answer	No
Document Name	
Comment	

JEA believes that continuous operations at a single recorded temperature will be a significant undertaking (cost, manpower, active maintenance & associated risks) without much benefit in Jacksonville, FL. Our lowest temperature was in 1985 at 7 degrees F for two hours, but our mean low for December, January, and February is 28, 25, and 28 degrees F. To operate for 7 degrees F continually even during the winter season will place a strain on resources, requiring heat tape where insulation would be sufficient (based upon a conservative forecast).

Some exclusion for regions that experience minimal freezes should be considered. For example, "If hourly temperature data shows that the entity experienced less than 10 five-hour freezes in the past five years, continuous operation at the minimum temperature is not required." This is a suggestion, but a suitable expert could be consulted to suggest a time element (X-hour freezes) with a suitable number of cases (Y instances) over a recent time period (past Z years).

Likes 0	
Dislikes 0	
Response	

Dana Showalter - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	

Q4. The proposed language in EOP-012-1 R1 causes concerns for ERCOT. ERCOT generally supports the SRC comments provided; however, the SRC comments do not encompass all of ERCOT's concerns. These concerns are explicitly identified below and are followed by proposed language. For clarity, ERCOT also addresses its concerns with the CAP and declaration/exemption in this response, as those issues are interrelated.

- R1, in general: should identify the Generator Owner as the entity taking action, not the generating unit.
- R1.1: The use of the word "designed" may imply that existing generators should be redesigned to comply with the defined temperature standard. It is more accurate and more straightforward to phrase this as a capability requirement rather than a design requirement.
- R1.1: Should require the GOs to use an objective source of historical temperature data to be implemented consistently across regions.
- R1.2 and R1.3: Should be more explicitly tied to R1.1 and the ability to be capable of continuous operations. The FERC/NERC Report on the February 2021 Cold Weather Outages states that GOs should "understand how precipitation and the accelerated cooling effect of wind limit their generating unit's performance." The Report further states that the February cold weather event demonstrated that ambient temperatures alone do not serve as a basis to predict whether a generating unit can perform during predicted cold weather. Also, ERCOT urges the SDT to adopt a clear metric for wind speed and precipitation. ERCOT is not presently proposing specific metrics. If the SDT's preference is to address this in Phase 2, ERCOT is comfortable with that.

- R1.2 and R1.3: Similar to comment for R1.1, should not reference unit design.
- R1.4: The meaning of "existing" will change over time. If purpose is to limit this provision to those in existence at the time this rule goes into effect, as distinct from "new" generating units, which presumably enter operations at some later date, the language should say that.
- R1.4: Propose to remove CAP details from R1 and move to a standalone requirement, presented here as R7. It is more concise to have one CAP section since the need for a CAP could be triggered by several requirements.
- R1.4: The CAP requirement should apply to all GOs, since any GO can discover an inability to comply at some point (even outside of the review required by R4 or the circumstances identified in R6). The modifications proposed also require the CAP to be implemented as soon as practicable with a reasonable window for actions with long lead times.
- R1.4.2 (relocated to ERCOT proposed R7.2): Each timetable needs to identify the measures that will be implemented by each winter season.
- R1.4.4: ERCOT provides language to replace the declaration language with explicit exemption language in a new R8. If this is intended to operate as an exemption, that needs to be said explicitly, and it needs to be subject to some reasonable constraint. Recommendation 1f in the FERC/NERC Report does not contemplate any sort of broad exception; however, ERCOT agrees that a narrow exception to avoid retirements is helpful. ERCOT believes that the exemption language provided in R8 better achieves the purpose of the declaration while also improving on the concept by ensuring periodic reviews to ensure the constraint is still valid.

As noted, the revisions to the CAP and exemption language would also apply to R4 and R6. The comments and proposed language revisions to these requirements are as follows:

- R4.1 and R4.2: Clarify that revisions to cold weather preparedness plan need to be made as necessary.
- R4.3: Require a CAP using language similar to that used in R1.4. This addresses a potential gap of modifying the freeze protection measures to updated temperatures.
- R6: Remove "within the Generation Owner's control." All GO equipment should be understood to be within the GO's control, as ownership should determine ultimate legal control. Otherwise, this would create a gap in the standards. If another party owns equipment at the site that could cause a failure, the GO can assign that party responsibility through contract.
- R6: Remove CAP details here in favor of general CAP provision in R7. Add similar CAP introduction language as seen in R1.4 and R4.3.
- R6: Include subparts 6.1 and "similar" language from subpart 6.2.3 from the SDT proposed standard language in the main requirement to avoid the need to put the language in the CAP section (R7).
- R6: This should reference the min hourly temp since 1/1/75, not the min capable operating temp in 3.4.2.

ALTERNATE LANGUAGE PROPOSED (REDLINE VERSION ATTACHED TO QUESTION 10)

R1. Each Generator Owner shall implement freeze protection measures that ensure each of its generating units meet the following minimum criteria:

1.1. Each generating unit shall be capable of continuous operation at the minimum hourly temperature recorded by the National Oceanic and Atmospheric Association or Environment and Climate Change Canada since January 1975 at the weather station nearest to the generator's location;

1.2. For purposes of identifying freeze protection measures needed to comply with Part 1.1, the Generator Operator shall account for the cooling effect of wind at XX mph;

1.3. For purposes of identifying freeze protection measures needed to comply with Part 1.1, the Generator Operator shall account for the impacts of YY precipitation (e.g., sleet, snow, ice, and freezing rain); and

1.4. If a Generator Owner determines that a generating unit requires either new freeze protection measures or modification of existing freeze protection measures to meet the standard established in Part 1.1, the Generator Owner shall develop a Corrective Action Plan (CAP) in accordance with Requirement R7. The CAP shall be developed within 150 days of identifying the need for new or modified freeze protection measures and shall be implemented as soon as practicable but no later than three years from the date the deficiency was identified.

R4. Once every five calendar year, each Generator Owner shall:

4.1. Review the documented minimum hourly temperature developed pursuant to Part 3.1, and, if that temperature is no longer accurate, update the cold weather preparedness plan with the lowest temperature and make any necessary revisions to the plan based on that lower temperature;

4.2. Review its documented cold weather minimum temperature contained within its cold weather preparedness plan(s) for its generating units, pursuant to Part 3.4.2, and update that value as necessary; and

4.3. Review whether its generating units have the freeze protection measures required to comply with Requirement R1 and, if not, develop a CAP in accordance with R7 and implement the CAP as soon as practicable but no later than three years after identifying the need for new or modified freeze protection measures.

R6. Each Generator Owner that owns a generating unit that experiences an event resulting in a derate of more than 10% of the total capacity of the unit for longer than four hours in duration, a start-up failure where the unit fails to synchronize within a specified start-up time, or a Forced Outage for which (i) the apparent cause(s) of the event is due to freezing of the Generator Owner's equipment, and (ii) the ambient conditions at the site at the time of the event are at or above the temperature described in Part 1.1 shall develop a CAP, in accordance with R7, for each generating unit that experiences such a failure and for any other of the Generator Owner's generating units that uses similar equipment that could reasonably be susceptible to a similar failure. The CAP shall be developed within 150 days of the event or by the following July 1, whichever is earlier, and shall be implemented as soon as practicable but no later than three years from the date the CAP is developed.

R7. A Corrective Action Plan (CAP) required by this standard shall include at least the following:

7.1 An identification of corrective actions needed for the affected unit to comply with Requirement R1, including any necessary modifications to the Generator Owner's cold weather preparedness plan;

7.2 A timetable for implementing the corrective actions from Part 1.4.1, Part 7.1, or Requirement R6, as applicable, which shall identify the measures that can reasonably be achieved before each successive winter season and the timetable for implementing each such measure, and documentation of the commercial, technical, or other reasons for the timetable provided;

7.3 An identification of any temporary operating limitations that would apply until execution of the corrective actions identified in the CAP;

7.4 Explanation of, and documentation for, any exemption claimed pursuant to Requirement R8; and

7.5 For any CAP required by Requirement R6, a summary of the identified cause(s) for the equipment freezing event, where applicable, and any relevant associated data.

R8. Notwithstanding any other requirement in this standard, if a generating unit identified in Part 8.1 or 8.2 cannot comply with Requirement R1 due to a technical, commercial, or operational limitation, the generating unit shall be exempt from compliance with R1 to the extent of that limitation if the Generator Owner can provide documentation sufficient to demonstrate that limitation. In the case of a commercial limitation, the Generator Owner shall provide documentation sufficient to demonstrate that the generating unit would reasonably be expected to operate at a financial loss on an annual basis if it were required to comply with the standard. In each case, the Generator Owner shall ensure that the unit complies with Requirement R1 to the greatest extent of its capability. This exemption applies only to the following generating units:

8.1 Any generating unit that began operating before the compliance date for Requirement R1, or

8.2 Any generating unit that began operating on or after the compliance date for Requirement R1, if the asserted technical, commercial, or operational limitation is attributable to either a lower minimum temperature experienced after the unit became operational or some other condition not reasonably foreseeable at the time the unit began operations.

Likes 0	
Dislikes 0	

Response

Natalie Johnson - Enel Green Power - 5

Answer	No

Document Name	
Comment	

R1.4.4 is a critical requirement that recognizes the technical, commercial and operational constraints when implementing modifications to existing freeze protection measures. Support for R1 is contingent on the retention of this specific requirement, as without it, Generators could face unreasonable commercial, technical or operational obstacles to maintaining compliance.

Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	No
Document Name	
Comment	

The requirement has the following problems which should be addressed:

1) “Generating unit” defined simply as “Bulk Electric System Generator that… operate[s] during the winter season” needs further defining limitation. Should this only encompass the generator and its supporting structure? For example, is the powerhouse enclosing hydro units the boundary? Is the switchyard associated with a distributed generation aggregation point excluded? If the ERO later defines “generating unit” also includes all facilities the GO owns, such as the generation transmission interconnection line, is this intended by the SDT?

2) Hourly temperature may be a challenge to attain back to 1975. Suggest allowance of daily minimums and highs for historical records before the standard effective date since this data is more easily obtained and require hourly after the standard is implemented. The NOAA maintains numerous weather data collection sites and the GO should be able to utilize the nearest NOAA site to the generating unit location. This can be included within Measure M1. If the objective for hourly data is merly to document time spans temperatures are below freezing, state this and allow other forms of documentation. Retention of hourly data outside the area of concern adds unnecessary compliance burden.

3) Allow exemption for generation units that can demonstrate continuous operations through 5 days (not necessarily contiguous) where recorded temperature in Celsius was between -10 and 0 degrees or lower.

4) Stating “generation unit design” could create subjective audit interpretation as being from the generator manufacturer. Such data is not likely available for older units. Suggest revising requirement R1 to state “Each Generator Owner… implement mitigation measures at each generating unit for freeze protection based on the following minimum criteria.” Further, remove “generator unit design” from the subsections to clarify “design” refers to the mitigating measure. For example: “design to enable continuous operations…” and “design shall account for…” This will allow for both generator modifications to its manufacturer design and measures to mitigate around manufacturer design parameters that can’t be changed.

5) Assure that failure of a mitigating measure is not a compliance violation. Please consider revising section 1.4 to make this clear, such as “should protective mitigating measures prove inadequate…”

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 Regional Standards Committee	
Answer	No
Document Name	
Comment	
For some Canadian entities, units already operate in cold weather annually from November to March. These requirements represent an added administrative burden. The new reliability standards requirement should be part of a regional variance for the regions where winterization programs are not in place. Canadian entity generators already operate successfully in cold climates with extreme conditions. For such entities, this is an additional compliance burden, with no additional benefit to grid reliability	
Likes 0	
Dislikes 0	
Response	
Jeremy Lawson - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
NCPA agrees with the comments of NRG Energy, Inc.	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
Changes to Cold Weather Reliability Standards should not be applicable continent-wide. Standards should not be modified or implemented prior to Market Rule Modifications. See prior NERC Project 2019-06 ballot and commenting by Marty Hostler	

Market Rule modifications have not yet been made to mitigate potential Cold Weather Events grid issues. Per FERC/NERC's recommendation, Market Rule modifications should be made prior to, or concurrent with, development of new Standards. To date, no known Market Rule Modification project has been initiated.

On page 86 of FERC/NERC's joint Report The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018 (ferc.gov) the following recommendations where made.

Recommendation 1: The Team recommends a three-pronged approach to ensure Generator Owners/Generator Operators, Reliability Coordinators and Balancing Authorities prepare for cold weather conditions: 1) development or enhancement of one or more NERC Reliability Standards, 2) enhanced outreach to Generator Owners/Generator Operators, and 3) market (Independent System Operators/Regional Transmission Organizations) rules where appropriate. This three-pronged approach should be used to address the following needs: • The need for Generator Owners/Generator Operators to perform winterization activities on generating units to prepare for adverse cold weather, in order to maximize generator output and availability for BES reliability during these conditions. These preparations for cold weather should include Generator Owners/Generator Operators:

While any one of the three approaches may provide significant benefits in solving this problem, the Team does not view any one of the three as the only solution. The Team envisions that a successful resolution of the problem will likely involve concurrent use of all three.

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 4, Group Name NCPA

Answer	No
Document Name	

Comment

NCPA agrees with the comments of NRG Energy, Inc.

Likes 0	
Dislikes 0	

Response

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1

Answer	No
Document Name	

Comment

we support the RSC comments.

For some Canadian entites, units already operate in cold weather annually from November to March. These requirements represent an added administrative burden.

The new reliability standards requirement should be part of a regional variance for the regions where winterization programs are not in place. Canadian entities generators already operate successfully in cold climate with extreme conditions. For such entities this is an additional compliance burden, with no additional benefit to grid reliability.

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 opportunity to comment and has the following comment seeking to confirm our understanding against the intent of Requirement R1 of proposed EOP-012-1 (Draft 1) as follows. Following an assessment of the existing generating units' freeze protection, if determined that the freeze protection measure are adequate and meet the criteria set out in Requirement R1 of proposed EOP-012-1, then there would be no need to "implement new freeze protection measures or modification of existing freeze protection measures", i.e. no Corrective Action Plan will be required per Requirement R1 Part 1.4.

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	No
Document Name	

Comment

The IESO requests removing the 'commercial' reference in Requirements 1.4.2 and 1.4.4 as this language is vague, creates an ambiguity as to the obligation otherwise provided for in the standard, and a review of commercial issues is not within NERC's domain and expertise.

1.4.2. A timetable for implementing the corrective action(s) from Part 1.4.1 which considers any technical or operational constraints, as defined by the Generator Owner;

1.4.3. An identification of any temporary operating limitations that would apply until execution of the corrective action(s) identified in the CAP; and

1.4.4. A declaration, where deemed appropriate by the Generator Owner based on the review of Parts 1.4.1 through 1.4.3, that no revisions to the cold weather preparedness plan(s) are required and that no further corrective actions will be taken. The Generator Owner shall document technical or operational constraints as defined by the Generator Owner as support for such declaration.

Likes 0	
Dislikes 0	

Response

Sean Steffensen - IDACORP - Idaho Power Company - 1

Answer	No
Document Name	

Comment

Idaho Power is proposing the following language modification due to the fact that manufacturers do not provide design data. Propose in R1.1-1.3: Each generating unit shall be capable of continuous operations either by design data or by operational data documented minimum hourly temperature.

Likes 0	
Dislikes 0	

Response

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merrell, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; - Jennie Wike, Group Name Tacoma Power

Answer	No
Document Name	

Comment

Tacoma Power is concerned that the proposed language in EOP-012-1 R1, as well as Parts 3.1 and 4.1, places significant administrative and analytical burden on entities, and potentially complicates the assessment of design capabilities. Tacoma Power is concerned that collecting and maintaining hourly temperature data would amount to finding a needle in a haystack (over 400,000 data points in a 50 year time period). Instead, Tacoma Power recommends utilizing annual temperature data to identify the lowest temperature recorded for the year. This approach results in a smaller set of data to maintain and is easier for entities to identify the lowest temperature needed for freeze protection. Additionally, analyzing hourly data from summer periods is not beneficial, so a lowest recorded temperature for the year is more appropriate.

Tacoma Power recommends modifying Part 1.1, Part 3.1 and Part 4.1 to remove the Requirement for a specific interval, and only require documentation of the lowest recorded temperature since 1975, as follows. This change allows an entity to determine whether hourly, daily or annual is the most appropriate for their assessments.

Recommended changes to Parts 1.1, 3.1 and 4.1:

- Part 1.1: “Each generating unit shall be designed and maintained to be capable of continuous operations at the **lowest recorded ambient** temperature experienced at its location since 1/1/1975 or a lesser period if reliable data is not available to 1975.”
- Part 3.1: “**Lowest recorded ambient** temperature experienced at its location since 1/1/1975 or a lesser period if reliable data is not available to 1975;”
- Part 4.1: “Review the **lowest recorded ambient** temperature developed pursuant to Part 3.1, and update the cold weather preparedness plan with the lowest temperature as necessary.”

Likes 0	
Dislikes 0	

Response

Carl Pineault - Hydro-Qu?bec Production - 1,5

Answer	No
Document Name	

Comment

For some Canadian entites, units already operate in cold weather annually from November to March. These requirements represent an added administrative burden.

Likes 0	
Dislikes 0	

Response

Nazra Gladu - Manitoba Hydro - 1

Answer	No
Document Name	

Comment

No issues with the requirements.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Randy Buswell - VELCO -Vermont Electric Power Company, Inc. - 1	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	

Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ashley Scheelar - TransAlta Corporation - 5	
Answer	Yes
Document Name	
Comment	
TransAlta understands the challenges the STD has associated with developing appropriate risk based standards to deal with the effects of extreme weather on the grid. TransAlta respectfully provides the following feedback: The proposed language in EOP-012-1 requirement R1 does raise significant concerns. Facilities in particularly cold climates, such as Canada, would have significant freeze protection measures in place which means they do successfully operate in extremely cold conditions year after year. This standard presents us with the administrative burden of documenting and maintaining that documentation to describe basic facts about our facility as it relates to freeze protection measures with no benefit to the reliability of the grid in those regions. TransAlta also supports comments made by NRG Energy and NPCC Regional Standards Committee with regard to this question.	
Likes 0	
Dislikes 0	
Response	

James Baldwin - Lower Colorado River Authority - 1	
Answer	Yes

Document Name	
Comment	
LCRA agrees with Lthe North American Generator Forum comments and NRG Energy Inc. comments submitted 6/15/2022.	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
LCRA agrees with Lthe North American Generator Forum comments and NRG Energy Inc. comments submitted 6/15/2022.	
Likes 0	
Dislikes 0	
Response	
Sam Nietfeld - Public Utility District No. 1 of Snohomish County - 5	
Answer	Yes
Document Name	
Comment	
SNPD supports comments submitted by LPPC and Tacoma Power	
Likes 0	
Dislikes 0	
Response	
Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)	
Answer	Yes
Document Name	
Comment	

The SRC finds certain aspects of the proposed language as too vague and invites a lack of consistency among generators even those geographically close to each other. In terms of documentation of temperatures, we suggest that the standard be revised to propose the use of NOAA data as the default in determining the minimum hourly temperature, otherwise, provide supporting documentation of data used in determining the minimum hourly temperature. “At its location” may be too ambiguous and doesn’t represent enough specificity to accurately define weather conditions.

The SRC proposes the following EOP-012-1 R1.1 language *changes*:

R1.1. Each generating unit shall be designed and maintained to be capable of continuous operations at the documented minimum hourly temperature experienced at its *nearest National Oceanic and Atmospheric Administration (NOAA) or its Environment and Climate Change (for generating units located in Canada)* location since 1/1/1975 or a lesser period if reliable data is not available to 1975, *should the generating unit wish to utilize a different source of weather information it shall provide documentation as to whether its source is equivalent or superior to the NOAA data as support for using this alternative data source, which documentation of temperature value shall be audited;*

In addition, the SRC requests removing the ‘commercial’ reference in Requirements 1.4.2 and 1.4.4 as this language is vague, creates an ambiguity as to the obligation otherwise provided for in the standard, and a review of commercial issues is not within NERC’s domain and expertise.

R1.4.2. A timetable for implementing the corrective action(s) from Part 1.4.1 which considers any technical, or operational constraints, as defined by the Generator Owner;

R1.4.3. An identification of any temporary operating limitations that would apply until execution of the corrective action(s) identified in the CAP; and

R1.4.4. A declaration, where deemed appropriate by the Generator Owner based on the review of Parts 1.4.1 through 1.4.3, that ***certain*** revisions to the cold weather preparedness plan(s) are ***not*** required and that ***certain*** corrective actions will ***not*** be taken. The Generator Owner shall document technical, or operational constraints as defined by the Generator Owner as support for such declaration.

Likes 0	
Dislikes 0	

Response

Rebecca Baldwin - Transmission Access Policy Study Group - NA - Not Applicable - NA - Not Applicable

Answer	Yes
Document Name	TAPS proposed language Q4.docx

Comment

We have a number of concerns related to clarity and consistency both within R1, and between R1 and other draft requirements.

“Designed and maintained to be capable of continuous operations”
Our most significant concern is the proposed language in R1.1: “Each generating unit shall be designed and maintained to be capable of continuous operations….” This language is significantly more specific, as well as narrower, than Recommendation 1f, and could result in a GO being found noncompliant with R1 based on an R6 Forced Outage, on the theory that if a unit is “designed and maintained to be capable of continuous operation” at the minimum hourly temperature, then a Forced Outage meeting the criteria of R6 should be impossible. We do not believe that to be the SDT’s (or FERC’s) intent; R1.1-R1.3 should require GOs to implement freeze protection measures that they reasonably believe will be adequate, which they will supplement and improve pursuant to R6 and R1.4 if an event reveals a shortcoming. We suggest that R1.1 be revised as follows, which parallels the wording of R1.2 and R1.3 but uses the words “based on” to reflect the common understanding of “design basis”: “The generating unit design shall be based on the documented minimum hourly temperature experienced at its location since 1/1/1975 or a lesser period if reliable data is not available to

1975." If the SDT does not accept this proposed revision, it should at minimum (1) insert language clarifying that experiencing an R6 event is not evidence that a GO is in violation of R1, and (2) delete the words "and maintain" from R1.1, because maintenance of freeze protection measures is already required by R3.3.

Exceptions from R1.1-R1.3
We believe that the SDT intends that if an existing generator is developing and implementing a CAP pursuant to R1.4, or if an existing or new generator has determined (pursuant to R1.4.4 or R2, respectively) that technical, commercial, or operational constraints prevent it from meeting the criteria in R1.1-R1.3, then the GO will not be found noncompliant with R1.1-R1.3 on the basis of the issue(s) that are being addressed through the CAP or that are prevented by the constraint. But that intention is not expressed in the standard: R1 mandates "freeze protection measures based on" R1.1, R1.2, R1.3, and R1.4 as "minimum criteria," in all circumstances. And R1 does not even mention the possibility of new generators being unable to meet the criteria, as contemplated by R2. As currently written, a generator availing itself of R1.4 or R2 would be in violation of R1.1-R1.3. We have proposed language below clarifying that applicable generating units must meet the criteria in R1.1-R1.3 except to the extent that the GO is developing and implementing a CAP, or has documented technical, commercial, or operational constraints.

New vs. existing generators; combining R2 with R1.4.4
If the standard is to distinguish between "new" and "existing" generators—which we do not believe is necessary—then those terms must be defined for the purpose of this standard. In particular, the SDT would need to clarify two issues: (1) whether a generator's status as "new" or "existing" is fixed permanently based on some set date tied to the effectiveness of the standard (e.g. all generators in service on the state the standard becomes effective are "existing," and all that come online after that point are "new generators" throughout their lifespans), or whether the generator's status is instead determined at the time the standard is being applied (e.g. a generator that discovers the need for additional freeze control measures the day before it is to come online is a "new" generator, and thus must comply with R1.1-R1.3 immediately unless, per R2, a "technical, commercial, or operational constraint" prevents it from doing so, while a generator that makes the same discovery the day after beginning operations is "existing" and must develop and implement a CAP pursuant to R1.4). And (2) for a unit that is under development on the effective date of the standard (or other relevant date), or at the time it discovers the need for additional freeze control measures, at what point in the process of design, permitting, construction, and testing does a generator become "existing" rather than "new"?

It seems that the key difference in the treatment of "new" and "existing" generators in the draft standard is that "existing" generators develop a CAP if their freeze protection measures do not meet the criteria in R1.1-R1.3, and implement the CAP unless prevented by a technical commercial, or operational constraint, while "new" generators must meet the criteria in R1.1-R1.3 unless prevented by a constraint—in short, "new" generators skip the CAP step. This is not, in our view, a distinction that requires the definition of separate classes of generators. A simpler approach would be to revise R1 and merge it with R2 to provide three options for compliance for all generators: (1) if possible, have freeze control measures consistent with R1.1-R1.3; (2) if a generator's freeze control measures are not consistent with R1.1-R1.3, but it is feasible to supplement or modify them to make them consistent, develop and implement a CAP to do so; and (3) if freeze control measures consistent with R1.1-R1.3 are not feasible due to a technical, commercial, or operational constraints, document the constraint and review every five years. Please note that our proposed R1.5 below is based on the text of R2 and R2.1, not R1.4.4; as noted in response to Question 5 below, we suggest that R2.2's five-year review requirement be moved to R4, and thus have not included that subrequirement in our proposed redline of R1.

Lack of deadline in R1.4
Requirement R1.4 requires GOs to develop CAPs in some situations, but provides no deadline by which they must do so. The absence of a deadline places registered entities in the untenable position of having to guess, on a case-by-case basis, how long they have to develop a CAP before they would be deemed noncompliant. The standard should also specify which events trigger the need to develop a CAP pursuant to R1.4, i.e. under which circumstances a generator could need new or modified freeze protection measures. We believe that there are three situations with clear "trigger dates" in which a CAP could be required by R1.4: (1) implementation of this standard, where a generator's existing freeze protection measures do not meet the new criteria; (2) an R6 event, and (3) discovery of the need for changes to freeze protection measures through some other means, including an R4 review that results in either an updated minimum hourly temperature necessitating changes to freeze protection measures, or removal of a previously-documented technical, commercial, or operational constraint. (As explained below, we are suggesting that the CAP elements of R6 be moved to R1.4, leaving only the identification and analysis of the event in R6.) We suggest that CAPs developed when this standard first becomes effective, and in response to an R6 event, use the same deadline as currently proposed in R6: "150 days subsequent to the [event/effective date of this Requirement] or by July 1 that follows the [event/effective date of this Requirement], whichever is earlier." CAPs developed in response to some other means of discovery of the need for changes, including R4 updates, should be developed by July 1 of the year following the calendar year in which the review or other means of discovery takes place. This last class of CAPs should not use the same "by July 1 that follows the [completion of the review]" language as other CAPs, because doing so would force a GO that happened to complete a review or discover an issue in June to develop a CAP in less than a month. And development of such CAPs should have only a date deadline, not an alternative number of days; otherwise, a GO conducting numerous R4

reviews in a calendar year would have an incentive to delay completion of any reviews it thinks likely to result in the need for a CAP, in order to avoid having to develop CAPs at the same time it is continuing its review of other units).

Overlap between R1, R4, and R6

R1, R4, and R6 contain overlapping requirements; for the sake of clarity, and to avoid duplicative noncompliance situations, these overlaps should be eliminated and the relationships between the requirements clarified.

As currently drafted, R1 requires a CAP where a generator “requires either new freeze protection measures or modification of existing freeze protection measures.” R4.3 requires each GO to “[r]eview whether its generating units have the freeze protection measures required to operate at the lowest temperature established pursuant to Requirement R1 and, if not, implement appropriate modifications per the requirements of Part 1.4.” A GO that fails to “implement appropriate modifications per the requirements of Part 1.4” would thus be noncompliant with both R4.3 and R1.4. This issue could be remedied with a minor edit to R4.3: replace “and if not, implement appropriate modifications per the requirements of R1.4” with “If freeze protection measures must be supplemented or modified as a result of the updated lowest temperature, the requirements of Part 1.4 apply.”

There is a similar overlap between R1.4 and R6, although R6 does not mention R1.4. R6 requires a GO that has experienced a qualifying event to develop a CAP meeting requirements essentially identical to those of R1.4, with the addition of two analysis requirements (“[a] summary of the identified cause(s) for the equipment freezing event where applicable and any relevant associated data” and “[a] review of applicability to similar equipment at other generating units owned by the Generator Owner”). As drafted, an R6 event would trigger the requirements to develop a CAP pursuant to both R6 and R1.4, unless the R6 analysis identified no need for changes to freeze protection measures. As with the overlap between R1.4 and R4, a failure to develop a CAP would result in an entity being noncompliant with two essentially identical requirements. We suggest replacing R6.2.3 through R6.2.6 with a statement that “Corrective actions in response to an analysis required by R6, including new or modified freeze protection measures, are subject to the requirements of Part 1.4.” Language should be added to R1.4 to indicate that it applies to the incorporation of lessons learned pursuant to R6; and the R6.2.3 requirement to identify corrective actions for “identified similar units” can be added to R1.4.1, e.g. “and, if applicable, any similar units identified pursuant to R6.2.2.”

Proposed language is attached in redline and clean format.

Likes 0	
Dislikes 0	

Response

Whitney Wallace - Calpine Corporation - 5 - WECC,Texas RE,NPCC,SERC,RF

Answer	Yes
Document Name	

Comment

Calpine has concerns with imposition of the R1 requirements, without Key Recommendation #2 in the November 2021 FERC/NERC, report being addressed. This requirement to implement new or modified freeze protection measures without a cost recovery mechanism proposes a significant economic burden on generators, and will result in reduced generation available the winter season; it could even result in permanent retirement due to the significant cost of compliance. These outcomes will reduce grid reliability by decreasing the amount of available generation to the grid. Calpine proposes that the SDT instead focus on Freeze protection measures rather than full retrofits/redesigns of existing units (which may or may not be feasible depending on unit age, design, technical, commercial or operational constraints). Additionally, the SDT requirement should address only those critical components that could potentially trip offline or derate a generation unit due to sustained conditions. Root cause analyses of previous freeze-related outages have not revealed concerns for auxiliary systems that support operations, but are considered part of balance-of-plant equipment. Therefore, the focus should be on freeze protection of critical components only. These can be addressed through industry standard operational practices prior to freeze events. In summary, retrofits of existing units should not include all operating systems and should not be required without some cost recovery realized. Calpine agrees with Texas Competitive Power Advocates (TCPA) in proposing that the SDT should consider ASHRE, a statistically-based standard which uses daily average temperatures, which has been accepted and used by industry for many years. Finally, particularly in the Texas RE region, or other regions susceptible to severe hot weather peaks, overdesigned cold weather protection will reduce hot weather reliability when the grid is most likely to experience peak demand. Without practical limit to winter preparation, summer reliability may be substantially reduced.

Likes 0	
Dislikes 0	

Response

Daniel Mason - Portland General Electric Co. - 6, Group Name PGE FCD

Answer	Yes
Document Name	

Comment

Portland General Electric Company supports the survey response provided by EEI.

Likes 0	
Dislikes 0	

Response

Hillary Dobson - Colorado Springs Utilities - 3

Answer	Yes
Document Name	

Comment

CSU supports LPPC's comments.

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	Yes
Document Name	

Comment

Requirement R1 would require the GO to implement new freeze protection measures or modify existing freeze protection measures if minimum criteria (part 1.1 through 1.3) are not met. Is there a definition or parameters for what the extent of that protection boundary will be? Will this apply to all climates or can GOs take graded approaches to the protective measures depending on the average temperature data?

We recommend splitting R1 into two parts:

Rephrase R1 to “Each Generator Owner shall document an evaluation of freeze protection measures for their applicable generating units taking the following into account:

1.1. The documented minimum hourly temperature experienced at each generating unit’s location since 1/1/1975 (or a lesser period if reliable data is not available to 1975);

1.2. The cooling effect of wind based on each generating unit’s design; and

1.3. The impact on each generating unit’s operations due to precipitation (e.g.,sleet, snow, ice, and freezing rain).”

Make the actions described in R1, part 1.4 a separate Requirement (new R2). Possible wording:

“R2 Based on the evaluation of freeze protection measures performed under Requirement R1, each Generator Owner shall:

2.1 Determine if a generating unit requires new or modified freeze protection measures, and if so develop and implement a Corrective Action Plan (CAP) which includes the following at a minimum:

2.1.1. An identification of corrective action (s) for the affected unit(s), including any necessary modifications to the Generator Owner’s cold weather preparedness plan(s);

2.1.2 A timetable for implementing the corrective action(s) from Part 2.1.1 which considers any technical, commercial, or operational constraints, as defined by the Generator Owner;

2.1.3. An identification of any temporary operating limitations that would apply until execution of the corrective action(s) identified in the CAP; and

2.1.4. A declaration, where deemed appropriate by the Generator Owner based on the review of Parts 2.1.1 through 2.1.3, that no revisions to the cold weather preparedness plan(s) are required and that no further corrective actions will be taken. The Generator Owner shall document technical, commercial, or operational constraints as defined by the Generator Owner as support for such declaration.”

Likes 0	
Dislikes 0	

Response

Jennifer Blair - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC, Group Name PPL NERC Registered Affiliates

Answer	Yes
Document Name	

Comment

PPL NERC Registered Affiliates generally support EEI comments on Question 4, including the proposed language for R1 in the EEI comments. In addition, PPL and LG&E and KU believe both proposed EOP-012-1 R1 language and alternative R1 proposed by EEI could be more clear on how the GO would demonstrate that units comply with the requirements for freeze protection measures with respect to the cooling effect of wind and impacts of precipitation, particularly for existing units (see question 5 for new units). PPL and LG&E and KU recommend the wind and precipitation component of R1 be either removed (suggested language below) or the wind and precipitation criteria be more clearly defined.

1.1 Each generating unit shall be capable of continuous operations at the documented minimum hourly temperature experienced at its location since 1/1/1975, or a lesser period if reliable data is not available to 1975;

1.2 For each existing generating unit that requires either new freeze protection measures or modification of existing freeze protection measures, the Generator Owner shall develop and implement a Corrective Action Plan (CAP) which includes the following at a minimum:

1.2.1 An identification of corrective action (s) for the affected unit(s), including any necessary modifications to the Generator Owner's cold weather preparedness plan(s);

1.2.2 A timetable for implementing the corrective action(s) from Part **1.2.1** which considers any technical, commercial, or operational constraints, as defined by the Generator Owner;

1.2.3 An identification of any temporary operating limitations that would apply until execution of the corrective action(s) identified in the CAP; and

1.2.4 In the event a GO is unable to fully mitigate their generating unit to have the continuous operating capability as defined under R1, a determination shall be made, where deemed appropriate by the Generator Owner based on **their** review of Parts **1.2.1** through **1.2.3**, that no **additional** revisions to the cold weather preparedness plan(s) **will be made** and that no further corrective actions will be taken. The Generator Owner shall document **the** technical, commercial, or operational constraints as defined by the Generator owner as support for such **determination**.

Likes 0	
Dislikes 0	

Response

Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1, Group Name OGE Energy - Oklahoma Gas and Electric Co.

Answer	Yes
Document Name	

Comment

Oklahoma Gas and Electric agrees with and endorses comments as submitted by EEI Reliability Technical Committee (RTC)

Likes 0	
Dislikes 0	

Response

Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF

Answer	Yes
Document Name	

Comment

While SIGE supports efforts to ensure that existing generating units have the ability to continuously operating within their designed operating specifications in extreme temperatures (cold or hot); SIGE does not agree that generating units should be required to make modifications to meet certain freeze protection requirements beyone the expected designed operating specifications.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon concurs with the comments submitted by the EEI. Submitted on behalf of Exelon (Segments 1 & 3)	
Likes 0	
Dislikes 0	
Response	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	Yes
Document Name	
Comment	
MidAmerican supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Allen Klassen, Evergy, 1, 3, 5, 6; Jennifer Flandermeyer, Evergy, 1, 3, 5, 6; Marcus Moor, Evergy, 1, 3, 5, 6; - Alan Kloster	
Answer	Yes
Document Name	

Comment	
Evergy supports and includes by reference the comments of the Edison Electric Institute (EEI) for question #4.	
Likes 0	
Dislikes 0	
Response	
Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County	
Answer	Yes
Document Name	
Comment	
CHPD agrees with LPPC's comments.	
Likes 0	
Dislikes 0	
Response	
Donna Johnson - Oglethorpe Power Corporation - 5	
Answer	Yes
Document Name	
Comment	
In R1.1 it states "each generating unit shall be designed and maintained using the minimum hourly temperature since 1975…" Concern is that expenditures will be required for a temperature that may occurs once in decades or is an anomaly. Perhaps a solution would be to determine the frequency of minimum hourly temperatures that occur in the time period. The standard could read: "if an area has experienced at least 10 (or 5, or 8 or whatever) minimum hourly temperatures within a 10 degree range, ie (-10 to -20) (0 to -10), since 1975, the entity will use the lowest recorded hourly temperature that occurred within that range". This could also eliminate the need for Requirments R4.1 and R4.3, since the probability of hitting lower temperatures using the 10 degree range method in a 5 year period would be minimized. Also R1.1 and R3.1 are redundant in wording….would flow better if the requirements are re-arranged, see comments for #10.	
Likes 0	
Dislikes 0	
Response	

Michele Richmond - Texas Competitive Power Advocates - NA - Not Applicable - Texas RE	
Answer	Yes
Document Name	
Comment	

The requirements of R1, without addressing Key Recommendation #2 in the November 2021 FERC/NERC report is the most significant concern of the Texas generators. Unfunded mandates of this economic magnitude that do not have proposed cost recovery will result in reduced generation available the winter season, at the least, and permanent retirement, at the worst. Neither of these outcomes will enhance grid reliability. Quite the opposite, this requirement will very likely reduce grid reliability by reducing available generation to the grid. Focus should be on Freeze protection measures, not full retrofits/redesign, and should address only those critical components that could potentially trip/derate the unit. Root cause analysis of previous freeze-related outages have not revealed concerns for auxiliary systems that support operation but are considered part of balance-of-plant. These can be addressed through sound operational practices and startup prior to freeze events. In summary, retrofits of existing units should not include all operating systems and should not be required without some cost recovery realized.The SDT should consider ASHRE, a statistically-based standard which uses daily average temperatures, which has been accepted and used by industry for many years. Finally, overdesigned cold weather protection will reduce hot weather reliability. Without practical limit to winter preparation, summer reliability may subsequently be reduced.

Likes 0	
Dislikes 0	
Response	

Mark Spencer - LS Power Development, LLC - 5	
Answer	Yes
Document Name	
Comment	

As an initial matter, we are concerned that the phrase “technical, commercial, or operational constraints” is not sufficiently specific and cannot be interpreted precisely enough to yield incremental reliability benefits. As a generator owner, our view is that all cold weather technical and operational constraints distill down to economic choices. Few, if any, generators are incapable of meeting the proposed standard for technological or operational reasons. The level of investment may vary by technology, and in some cases be significant, but technical and operational constraints can be overcome.   Given the significant investment required to ensure a resource can meet the proposed Standards, we would expect a significant number of generators to self-determine that they are exempt from meeting the Standards. As currently worded, compliance with the Standards appear optional. Fundamentally, a Reliability Standard that is supposed to enhance reliability and can be met in almost all cases through investment should not be discriminatory - e.g. old or new resource, class of resource, or optional.   This vaguely defined exclusion does not appear to meet this standard.   The exemption will also create a patchwork of varying degrees of reliability from generator-to-generator that will make it more difficult for the BAs to manage their grids in extreme conditions.

Additionally, the language in §1.4.2 as drafted is unclear as to whether existing generators that have “technical, commercial, or operational constraints” are exempted from the strict requirement of complying with the standard. Specifically, it is unclear whether the “constraints” determination applies to the “timetable” or whether the determination applies to the absolute performance requirement. This language is contrasted with R2 that applies to new generators and is unequivocal in its meaning:

"Each Generator Owner that is **not able** to implement freeze protection measures for new generating unit(s) as required by Requirement R1 **due to** technical, commercial, or operational constraints as defined by the Generator Owner shall" (emphasis added)

Finally, we think the perceived need for the new generator exemptions belies the overly onerous standard and may be intended for the benefit of a specific resource class. The fact that the drafting team is contemplating an exemption for new generators should provide NERC and stakeholders pause on the reasonableness of the proposed Standards and what exactly the new generator exemption is intending to address.

Likes 0	
Dislikes 0	

Response

Shannon Ferdinand - Decatur Energy Center LLC - 5

Answer	Yes
Document Name	

Comment

Capital Power supports the NAGF comments / concerns / suggested revisions in relation to this question.

Likes 0	
Dislikes 0	

Response

Jamie Monette - Allete - Minnesota Power, Inc. - 1

Answer	Yes
Document Name	

Comment

Minnesota Power does not believe that freeze protection measures need to be adjusted for its units based on its reliability in past extreme temperatures, however Minnesota Power believes that having an engineering design rated for a 50-year minimum hourly temperature is not feasible, could be extraordinarily costly, and would not improve reliability. It would be difficult to impossible to find an engineer willing to guarantee that these units could operate in -59 Fahrenheit degree temperatures for extended periods of time. Minnesota Power also agrees with NSRF comments recommending to implement a statistical approach similar to NERC to have a more realistic method than identifying the lowest value seen since 1975.

Likes 0	
Dislikes 0	

Response

Casey Perry - Casey Perry On Behalf of: Lynn Goldstein, PNM Resources - Public Service Company of New Mexico, 1, 3; - PNM Resources - Public Service Company of New Mexico - 3 - WECC	
Answer	Yes
Document Name	
Comment	
PNM supports EOP-012-1 R1 as long as the language in R1.1 concerning if reliable data is not available back to 1975 an acceptable lesser period is allowed.	
Likes 0	
Dislikes 0	
Response	

Joe McClung - JEA - 1	
Answer	Yes
Document Name	
Comment	
JEA believes that continuous operations at a single recorded temperature will be a significant undertaking (cost, manpower, active maintenance & associated risks) without much benefit in Jacksonville, FL. Our lowest temperature was in 1985 at 7 degrees F for two hours, but our mean low for December, January, and February is 28, 25, and 28 degrees F. To operate for 7 degrees F continually even during the winter season will place a strain on resources, requiring heat tape where insulation would be sufficient (based upon a conservative forecast). Some exclusion for regions that experience minimal freezes should be considered. For example, “If hourly temperature data shows that the entity experienced less than 10 five-hour freezes in the past five years, continuous operation at the minimum temperature is not required.” This is a suggestion, but a suitable expert could be consulted to suggest a time element (X-hour freezes) with a suitable number of cases (Y instances) over a recent time period (past Z years).	
Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merre
Dislikes 0	
Response	

Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	Yes
Document Name	
Comment	
TMLP echoes the comments submitted by the Rebecca Baldwin on behalf of TAPS Group for Question 4.	

Likes 0	
Dislikes 0	

Response

Marty Watson - Santee Cooper - 5, Group Name Santee Cooper

Answer	Yes
Document Name	

Comment

First of all upgrading freeze protection design will take several years or more for each unit not currently meeting the Standard. This time period will have to include budgeting for the cost, evaluation by design engineers who may not be available during the implementation period, supply chain issues with everyone in the country buying heat trace hardware and insulating material all at the same time. The second concern is that the cost per Facility could exceed several million dollars. More for large coal units. Third, the design temperature, wind speed and precipitation criteria can't be functionally tested until the weather meets the parameters specified by the design and stays there for an extended period. Untested it could be argued that the unit was in violation of R1 if it has issues at the specified design parameters. Upgrading the design of a Facility to operate continuously at a temperature that may have been reached only one time in fifty years is not acting as a good steward with the money our customers pay for reliable electricity service. We recommend that the implementation plan allow 10 years for compliance with R1.

Likes 0	
Dislikes 0	

Response

Amy Casuscelli - Amy Casuscelli On Behalf of: Gerry Huitt, Xcel Energy, Inc., 5, 3, 1; - Amy Casuscelli

Answer	Yes
Document Name	

Comment

Xcel Energy has significant concerns with the language in the draft EOP-012 R1 and supports the comments of EEI.

Likes 0	
Dislikes 0	

Response

Michael Watt - Oklahoma Municipal Power Authority - 4

Answer	Yes
Document Name	

Comment

I agree with TAPs comments, pasted below:

We have a number of concerns related to clarity and consistency both within R1, and between R1 and other draft requirements.

"Designed and maintained to be capable of continuous operations"

Our most significant concern is the proposed language in R1.1: "Each generating unit shall be designed and maintained to be capable of continuous operations…." This language is significantly more specific, as well as narrower, than Recommendation 1f, and could result in a GO being found noncompliant with R1 based on an R6 Forced Outage, on the theory that if a unit is "designed and maintained to be capable of continuous operation" at the minimum hourly temperature, then a Forced Outage meeting the criteria of R6 should be impossible. We do not believe that to be the SDT's (or FERC's) intent; R1.1-R1.3 should require GOs to implement freeze protection measures that they reasonably believe will be adequate, which they will supplement and improve pursuant to R6 and R1.4 if an event reveals a shortcoming. We suggest that R1.1 be revised as follows, which parallels the wording of R1.2 and R1.3 but uses the words "based on" to reflect the common understanding of "design basis": "The generating unit design shall be based on the documented minimum hourly temperature experienced at its location since 1/1/1975 or a lesser period if reliable data is not available to 1975." If the SDT does not accept this proposed revision, it should at minimum (1) insert language clarifying that experiencing an R6 event is not evidence that a GO is in violation of R1, and (2) delete the words "and maintain" from R1.1, because maintenance of freeze protection measures is already required by R3.3.

Exceptions from R1.1-R1.3

We believe that the SDT intends that if an existing generator is developing and implementing a CAP pursuant to R1.4, or if an existing or new generator has determined (pursuant to R1.4.4 or R2, respectively) that technical, commercial, or operational constraints prevent it from meeting the criteria in R1.1-R1.3, then the GO will not be found noncompliant with R1.1-R1.3 on the basis of the issue(s) that are being addressed through the CAP or that are prevented by the constraint. But that intention is not expressed in the standard: R1 mandates "freeze protection measures based on" R1.1, R1.2, R1.3, *and* R1.4 as "minimum criteria," in all circumstances. And R1 does not even mention the possibility of *new* generators being unable to meet the criteria, as contemplated by R2. As currently written, a generator availing itself of R1.4 or R2 would be in violation of R1.1-R1.3. We have proposed language below clarifying that applicable generating units must meet the criteria in R1.1-R1.3 *except to the extent that* the GO is developing and implementing a CAP, or has documented technical, commercial, or operational constraints.

New vs. existing generators; combining R2 with R1.4.4

If the standard is to distinguish between "new" and "existing" generators—which we do not believe is necessary—then those terms must be defined for the purpose of this standard. In particular, the SDT would need to clarify two issues: (1) whether a generator's status as "new" or "existing" is fixed permanently based on some set date tied to the effectiveness of the standard (e.g. all generators in service on the state the standard becomes effective are "existing," and all that come online after that point are "new generators" throughout their lifespans), or whether the generator's status is instead determined at the time the standard is being applied (e.g. a generator that discovers the need for additional freeze control measures the day before it is to come online is a "new" generator, and thus must comply with R1.1-R1.3 immediately unless, per R2, a "technical, commercial, or operational constraint" prevents it from doing so, while a generator that makes the same discovery the day after beginning operations is "existing" and must develop and implement a CAP pursuant to R1.4). And (2) for a unit that is under development on the effective date of the standard (or other relevant date), or at the time it discovers the need for additional freeze control measures, at what point in the process of design, permitting, construction, and testing does a generator become "existing" rather than "new"?

It seems that the key difference in the treatment of "new" and "existing" generators in the draft standard is that "existing" generators develop a CAP if their freeze protection measures do not meet the criteria in R1.1-R1.3, and implement the CAP unless prevented by a technical commercial, or operational constraint, while "new" generators must meet the criteria in R1.1-R1.3 unless prevented by a constraint—in short, "new" generators skip the CAP step. This is not, in our view, a distinction that requires the definition of separate classes of generators. A simpler approach would be to revise R1 and merge it with R2 to provide three options for compliance for all generators: (1) if possible, have freeze control measures consistent with R1.1-R1.3; (2) if a generator's freeze control measures are not consistent with R1.1-R1.3, but it is feasible to supplement or modify them to make them consistent, develop and implement a CAP to do so; and (3) if freeze control measures consistent with R1.1-R1.3 are not feasible due to a technical, commercial, or operational constraints, document the constraint and review every five years. Please note that our proposed R1.5 below is based on the text of R2 and R2.1, not R1.4.4; as noted in response to Question 5 below, we suggest that R2.2's five-year review requirement be moved to R4, and thus have not included that subrequirement in our proposed redline of R1.

Lack of deadline in R1.4

Requirement R1.4 requires GOs to develop CAPs in some situations, but provides no deadline by which they must do so. The absence of a deadline places registered entities in the untenable position of having to guess, on a case-by-case basis, how long they have to develop a CAP before they would be deemed noncompliant. The standard should also specify which events trigger the need to develop a CAP pursuant to R1.4, i.e. under which circumstances a generator could need new or modified freeze protection measures. We believe that there are three situations with clear "trigger dates" in which a CAP could be required by R1.4: (1) implementation of this standard, where a generator's existing freeze protection measures do not meet the new criteria; (2) an R6 event, and (3) discovery of the need for changes to freeze protection measures through some other means, including an R4 review that results in either an updated minimum hourly temperature necessitating changes to freeze protection measures, or removal of a previously-documented technical, commercial, or operational constraint. (As explained below, we are suggesting that the CAP elements of R6 be moved to R1.4, leaving only the identification and analysis of the event in R6.) We suggest that CAPs developed when this standard first becomes effective, and in response to an R6 event, use the same deadline as currently proposed in R6: "150 days subsequent to the [event/effective date of this Requirement] or by July 1 that follows the [event/effective date of this Requirement], whichever is earlier." CAPs developed in response to some other means of discovery of the need for changes, including R4 updates, should be developed by July 1 of the year following the calendar year in which the review or other means of discovery takes place. This last class of CAPs should not use the same "by July 1 that follows the [completion of the review]" language as other CAPs, because doing so would force a GO that happened to complete a review or discover an issue in June to develop a CAP in less than a month. And development of such CAPs should have only a date deadline, not an alternative number of days; otherwise, a GO conducting numerous R4 reviews in a calendar year would have an incentive to delay completion of any reviews it thinks likely to result in the need for a CAP, in order to avoid having to develop CAPs at the same time it is continuing its review of other units).

Overlap between R1, R4, and R6

R1, R4, and R6 contain overlapping requirements; for the sake of clarity, and to avoid duplicative noncompliance situations, these overlaps should be eliminated and the relationships between the requirements clarified.

As currently drafted, R1 requires a CAP where a generator "requires either new freeze protection measures or modification of existing freeze protection measures." R4.3 requires each GO to "[r]eview whether its generating units have the freeze protection measures required to operate at the lowest temperature established pursuant to Requirement R1 and, if not, *implement appropriate modifications per the requirements of Part 1.4*." A GO that fails to "implement appropriate modifications per the requirements of Part 1.4" would thus be noncompliant with both R4.3 and R1.4. This issue could be remedied with a minor edit to R4.3: replace "and if not, implement appropriate modifications per the requirements of R1.4" with "If freeze protection measures must be supplemented or modified as a result of the updated lowest temperature, the requirements of Part 1.4 apply."

There is a similar overlap between R1.4 and R6, although R6 does not mention R1.4. R6 requires a GO that has experienced a qualifying event to develop a CAP meeting requirements essentially identical to those of R1.4, with the addition of two analysis requirements ("[a] summary of the identified cause(s) for the equipment freezing event where applicable and any relevant associated data" and "[a] review of applicability to similar equipment at other generating units owned by the Generator Owner"). As drafted, an R6 event would trigger the requirements to develop a CAP pursuant to both R6 and R1.4, unless the R6 analysis identified no need for changes to freeze protection measures. As with the overlap between R1.4 and R4, a failure to develop a CAP would result in an entity being noncompliant with two essentially identical requirements. We suggest replacing R6.2.3 through R6.2.6 with a statement that "Corrective actions in response to an analysis required by R6, including new or modified freeze protection measures, are subject to the requirements of Part 1.4." Language should be added to R1.4 to indicate that it applies to the incorporation of lessons learned pursuant to R6; and the R6.2.3 requirement to identify corrective actions for "identified similar units" can be added to R1.4.1, e.g. "and, if applicable, any similar units identified pursuant to R6.2.2."

Proposed language for R1

Proposed language (clean)

R1. Each Generator Owner shall implement freeze protection measures for each applicable generating unit based on the minimum criteria set forth in R1.1 through R1.3, except to the extent that (i) it is developing and implementing a Corrective Action Plan (CAP) pursuant to R1.4 to enable a unit to meet the criteria set forth in R1.1 through R1.3, or (ii) it has determined, pursuant to R1.5, it is not able to implement freeze protection measures consistent with R1.1 through R1.3 or a CAP developed pursuant to R1.4 due to technical, commercial, or operational constraints: [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning, Operations Planning*]

1.1. The generating unit design shall be based on the documented minimum hourly temperature experienced at its location since 1/1/1975 or a lesser period if reliable data is not available to 1975;

1.2. The generating unit design shall account for the cooling effect of wind; and

1.3. {C}The generating unit design shall account for the impacts on operations due to precipitation (e.g., sleet, snow, ice, and freezing rain); or

1.4. {C}For each generating unit whose freeze protection measures require supplementation and/or modification in order to meet the criteria in R1.1 through R1.3, or based on lessons learned pursuant to R6, the Generator Owner shall develop a Corrective Action Plan (CAP) by the deadline determined pursuant to R1.4.2.

1.4.1. The CAP shall include the following at a minimum:

1.4.1.1. An identification of corrective action(s) for the affected unit(s) (and, if applicable, any similar units identified pursuant to R6.1.2), including any necessary modifications to the Generator Owner's cold weather preparedness plan(s);

1.4.1.2. A timetable for implementing the corrective action(s) from Part 1.4.1 which considers any technical, commercial, or operational constraints, as defined by the Generator Owner; and

1.4.1.3. An identification of any temporary operating limitations that would apply until execution of the corrective action(s) identified in the CAP; and

1.4.2. The Generator Owner shall develop the CAP according to the applicable deadline from the following:

1.4.2.1. A Generator Owner that determines prior to the effective date of this Requirement that its existing freeze protection measures do not meet the criteria set out in R1.1 through R1.3 shall develop a CAP by no later than 150 days following the effective date of this Requirement, or the July 1 that follows the effective date of this Requirement, whichever is earlier.

1.4.2.2. A Generator Owner that has experienced an event meeting the criteria in R6 shall develop a CAP by no later than 150 days subsequent to the event or by July 1 that follows the event, whichever is earlier.

1.4.2.3. A Generator Owner that has determined in circumstances other than those described in R1.4.2.1 and R1.4.2.2 that its freeze protection measures require supplementation or modification, including but not necessarily limited to in response to an updated minimum hourly temperature pursuant to Requirement R4.3 or the removal of a technical, commercial, or operational constraint based on a review pursuant to Requirement R4.4, shall develop a CAP by no later than July 1 of the calendar year following the calendar year in which the Requirement R4 review was conducted or the need for the supplementation or modification was otherwise discovered, as applicable.

1.4.3. The Generator Owner shall implement the CAP according to the timetable established pursuant to R1.4.1.2, except to the extent that it is unable to implement the CAP due to a technical, commercial, or operational constraint documented per R1.5.

1.5. Each Generator Owner that is not able to implement (i) freeze protection measures consistent with R1.1 through R1.3 or (ii) a CAP developed pursuant to R1.4 for a generating unit(s) due to technical, commercial, or operational constraints as defined by the Generator Owner shall document its determination and the constraints on implementation.

Alternative Suggestions

Alternative Revisions to R1.4

If the SDT retains R1.4.4 as a subrequirement under R1.4, it should revise R1.4 to state that the CAP must include "the following at a minimum R1.4.1-R1.4.3." R1.4.4 is required only where a GO cannot implement identified corrective actions; it is not a minimum requirement of every CAP.

Alternative Revisions to R1.4.4

If the SDT does not consolidate R2 with R1.4.4 as suggested above, or if it retains the language of R1.4.4 rather than that of R2, it should at minimum eliminate unnecessary inconsistencies between the two requirements, and should delete from R1.4.4 (and from R6.2.6, if that separate subrequirement is retained) the words “that no revisions to the cold weather preparedness plan(s) are required,” which are unnecessary and give the erroneous impression that R1.4.4 applies to situations where no changes are *needed*, as opposed to where changes cannot be made due to constraints. Our suggested revisions to the language of R1.4.4, to the extent that language is retained:

Where deemed appropriate by the Generator Owner, documentation that the Generator Owner is not able to implement some or all of the corrective actions identified pursuant to Parts 1.4.1-1.4.3 due to technical, commercial, or operational constraints as defined by the Generator Owner.

Alternative elimination of duplication between R6 and R1.4

Finally, as also noted in response to Question 10 below, if the SDT retains a separate CAP requirement in R6, it must clarify in R1.4 that corrective actions in response to an R6 event are subject only to R6, not R1.4. Proposed language:

For each generating unit whose freeze protection measures require supplementation and/or modification in order to meet the criteria in R1.1 through R1.3 (except when such supplementation or modification of freeze protection measures is undertaken in response to an R6 event, in which case the CAP requirements of R6 apply)…

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	Yes
Document Name	

Comment

R1.4.2 establishes a timetable for implementing corrective freeze protection measures actions but the proposed Standard does not establish a implementation period/deadline for the the corrective actions. Recommend that R1.4.2 language be modified to require a reasonable time period/deadline for implementing corrective freeze protection measures.

Likes 0	
Dislikes 0	

Response

Diana Torres - Imperial Irrigation District - 6

Answer	Yes
Document Name	

Comment

EOP-012-1 R1 should be modified to allow for an Engineering Analysis to see if units are subjected to potential freezing, with the possibility of eliminating all requirements of the Standard. Temperature alone is not a true indication of freezing, a time component is also necessary to understand the heat losses. Setting design requirements based on the lowest hourly temperature data places an unecessary burden on southwestern desert facilities that return to above freezing temperatures in a matter of hours. In reviewing the five lowest recorded temperatures since 1975 for IID units, the temperature always returned above freezing the same day. It did not last multiple days or weeks, as in the ERCOT region.

Likes 0	
Dislikes 0	

Response

Gerry Adamski - Cogentrix Energy Power Management, LLC - 5

Answer	Yes
Document Name	

Comment

To retrofit existing units to a historical low temperture below the design temperature should be accompanied with clear cut requirements for an entity to regain the necessary expense for each unit. An IPP does not have the resources vertically integrated utilities have to recoup the required costs or to even front the costs until recovery can be realized.   The commercial component of these activities must occur concurrent with the reliability aspects; Heretofore, only the reliability aspects have been identified.

Likes 0	
Dislikes 0	

Response

George Brown - Acciona Energy North America - 5

Answer	Yes
Document Name	

Comment

Acciona Energy supports Midwest Reliability Organization’s (MRO) NERC Standards Review Forum’s (NSRF) comments on this question.

Likes 0	
Dislikes 0	

Response

Julie Hall - Entergy - 6, Group Name Entergy

Answer	Yes
Document Name	

Comment

Entergy requests clarity around expectation from R1.3.

Likes 0	
Dislikes 0	

Response

Dan Roethemeyer - Vistra Energy - 5	
Answer	Yes
Document Name	
Comment	

The proposal to require the implementation of new or modified freeze protection measures, as currently drafted, is not sufficiently defined or limited in scope and would propose unreasonable and costly compliance burdens on Generator Owners.

First, the standard should better define "temperature" as used in R1.1--e.g., dry bulb/ambient, wet bulb, dew point, etc.--as well as specify the location at which temperature is to be measured--e.g., plant site versus nearest weather station. Luminant does not have a particular preference on the definition, so long as it is clear what is meant by "temperature."

Second, a more reasonable duration requirement should be set than the proposed single lowest hourly temperature ever recorded since January 1, 1975. The proposed single hour standard does not adequately account for nuances in how resources are impacted by temperature and thus is overly rigid, without a clear reliability benefit. For example, a particular resource may not be impacted by a few minutes or even an hour at a given low temperature, but may face operational issues at a slightly higher temperature for prolonged periods of time (e.g., two or three days of extended low temperatures). For purposes of reliability, extended periods of cold, rather than a few minutes or even an hour at an extreme low temperature, are more concerning and are the circumstances for which Generator Owners should be reasonably prepared. In addition, the proposed single hour standard would impose an unreasonably burdensome, costly, and impractical standard on Generator Owners that is unlikely to produce benefits commensurate with the likely compliance costs. Such costs would be significant, given that retrofitting of units would likely be required to "ensure" (which is not even possible) continuous operation of a resource at the coldest temperature ever to occur for one hour in the past nearly 50 years. Such costs would be especially problematic in a region like ERCOT, where competitive generators have no mechanism for cost recovery (unlike in fully regulated utility regimes). Further, even in ISOs with capacity markets, significant winterization costs could cause a unit to not clear the capacity auction, thus potentially resulting in stranded costs. Significant compliance costs related to weather preparedness and freeze protection could force a resource into early retirement.

In contrast, a requirement to reasonably prepare to operate continuously in the face of prolonged, but more likely cold temperatures is more practical and more likely to improve overall reliability of the grid. One option as an alternative to the proposed lowest hourly standard would be to use a percentile standard, such as the one proposed by the Public Utility Commission of Texas (PUCT) in a pending rulemaking proceeding (currently in the comment phase of the rulemaking process). That rule includes a proposal that generators and transmission operators implement weather emergency preparedness measures that are reasonably expected to ensure sustained operation of the resource at the 95th percentile minimum average 72-hour temperature as reported in a historical weather study published by the Balancing Authority (ERCOT) for the weather zone in which the resource operates. The use of a conservative percentile (95th percentile) and a longer duration (72 hours) better captures likely future cold weather outcomes, rather than focusing on the lowest hourly temperature ever recorded in the past nearly 50 years, which does not represent a likely future temperature or one that would likely be experienced in a future winter for any appreciable amount of time. Further, a 95th percentile/72-hour standard, coupled with the qualification that the requirement is one of reasonable preparedness, is one that Generator Owners could more feasibly meet, at a more reasonable compliance cost, than the SDT's proposed lowest hourly temperature standard.

Alternatively, R1 could be written to conform more closely to the preparedness requirements in R3.4.2, which reference the generating unit's minimum design temperature, historical operating temperature, or current cold weather performance temperature determined by an engineering analysis. Those standards recognize the practicality of the design and performance of a particular resource, rather than imposing an impractical standard based on the coldest temperature recorded since January 1, 1975 (which may significantly pre-date the commercial operation date for a given resource).

Either way, the requirement to implement freeze protection measures or preparedness measures to operate to an exact coldest hourly temperature (with "temperature" undefined) dating back to January 1, 1975 is unduly burdensome, impractical, and unreasonable and should not be adopted.

Finally, in R1.4.2, the timetable for corrective action plans should be revised to provide for the development of a plan in five years, rather than specify a timetable for implementation.

Likes 0	
Dislikes 0	

Response

Mike Braunstein - Colorado Springs Utilities - 1

Answer	Yes
Document Name	

Comment

Colorado Springs Utilities agrees with comments endorsed by LPPC

Likes 0	
Dislikes 0	

Response

Alison Mackellar - Constellation - 5

Answer	Yes
Document Name	

Comment

Constellation agrees that generating units need to utilize sound practices for cold weather preparation. Constellation suggests eliminating the wording “shall be designed and maintained to be”. Such wording is too prescriptive in how an entity is to ensure cold weather operation, and implies that a unit needs to be “re-designed”. If the intent is to ensure cold weather capability, suggest staying with “Each generating unit shall be capable of continuous operation....” to allow each generating unit to determine the manner in which the capability is to be achieved, depending on the particular circumstances of design, operation, and location of that unit. Also the re-focus on "capable" allows requirement to include generators both existing and new, without use of wording such as "design", allowing a consolidation of the standard (see comments on R2 following.)

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	

Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	

The Federal Power Act Section 215 definition of "Reliability Standard" states in relevant part that the term includes requirements for "the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation of the bulk power system…." This phrase suggests that reliability standards cannot have requirements that require unplanned modifications to facilities. EEI asks the standard drafting team to request the NERC legal department to provide a legal memorandum on whether Section 215 of the Federal Power Act allows a Reliability Standard to require existing generating units to be redesigned or otherwise modified to meet certain freeze protection requirements beyond their original design as set forth in Requirement R1.

Additionally, consideration should be given to the financial impact of the cold weather modifications to existing generating resource owners (GOs) who must balance the benefits of modifying a resource versus retiring it. For this reason and for the overall reliability of the BES, language for Requirement R1, part 1.4.4 should state that the GO is the authority to make such determinations to prevent early retirement of resources which could result in increased pressures on resource adequacy and BES reliability.

EEI does not agree that R1 should specify that generating units must be redesigned to meet certain freeze protection requirements. Instead R1 should require generating units to have the ability to continuously operate within the specified operating ranges. How this is accomplished should be up to the owner.

The wind and precipitation requirements contained in Requirement R1, subparts 1.2 and 1.3 should be combined into subpart 1.1. because as currently written an entity could be faced with multiple violations as a result of their non-compliance for a wind and precipitation violation while any mitigation to address these two issues would be the same.

To address the above issues, we recommend the following revisions to Requirements R1:

R1. Each Generator Owner shall ensure generating units implement freeze protection measures based on the following minimum criteria: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]

1.1 Each generating unit shall be capable of continuous operations at the documented minimum hourly temperature experienced at its location since 1/1/1975, or a lesser period if reliable data is not available to 1975, **and address the cooling effects of wind and precipitation (e.g., sleet, snow, ice and freezing rain)**.

1.2 For each generating unit**s that do not meet part 1.1 above**, the Generator Owner shall develop and implement a Corrective Action Plan (CAP) which includes the following at a minimum:

1.2.1 An identification of corrective action (s) for the affected unit(s), including any necessary modifications to the Generator Owner's cold weather preparedness plan(s);

1.2.2 A timetable for implementing the corrective action(s) from Part **1.2.1** which considers any technical, commercial, or operational constraints, as defined by the Generator Owner;

1.2.3 An identification of any temporary operating limitations that would apply until execution of the corrective action(s) identified in the CAP; and

1.2.4 **In the event a GO is unable to fully mitigate their generating unit to have the continuous operating capability as defined under R1, a determination shall be made**, where deemed appropriate by the Generator Owner based on **their** review of Parts **1.2.1** through **1.2.3**, that no **additional** revisions to the cold weather preparedness plan(s) **will be made** and that no further corrective actions will be taken. The Generator Owner shall document **the** technical, commercial, or operational constraints as defined by the Generator owner as support for such **determination**.

Likes 0	
Dislikes 0	

Response

Kimberly Bentley - Kimberly Bentley On Behalf of: sean erickson, Western Area Power Administration, 1, 6; - Kimberly Bentley

Answer	Yes
Document Name	

Comment

EOP-012-1 is unclear and confusing because of disorganized language and grammatical errors. For example, generating units do not implement anything. Many pieces of equipment do not "freeze," i.e., solid metal is already "frozen" by definition. Rather, equipment fails due to improper protection from extreme cold. The requirements should be stated so that the registered entity, e.g., the Generator Owner, is the one implementing the action. Distinct obligations should be contained in separate requirements, not combined at the requirement part and sub-part levels.

Likes 0	
Dislikes 0	

Response

Rick Stadtlander - NEI - NA - Not Applicable - NA - Not Applicable

Answer	Yes
Document Name	

Comment

Agree with the NAGF comments, but also want to have the SDT consider the following:

For some nuclear plants the temperature band is built into the design and/or licensing basis of the plant. Changing the analysis is not cost effective nor prudent. NERC required temperature bands in excess of what NRC requires for safety of the plant is prohibitive of economic, cost effective operation. Recommend either a statistical approach be taken similar to the NRC to have more realistic numbers than lowest value seen since 1975 or that nuclear is exempt based on extensive design basis analysis that is already done.

One example of an existing nuclear power plant (NPP):

The Updated Safety Analysis Report (USAR) for the NRC states that the NPP is designed for a low temperature of -5F dry bulb which will only be exceeded 1% of the time during the winter. If -5F is exceed a condition report is generated to allow tracking of amount of time the temperature is exceeded. Per the 1972 ASHRAE Handbook of Fundamentals the winter is considered to be December, January, and February for a total of 2160 hrs each year. The design of -5 was taken from the same 1972 ASHRAE Handbook for the location of the NPP which substantiates the statement in the USAR that the design maximum and minimum temperatures will be exceeded approximately 1% of the time during a normal winter. To verify the NPP maintains within this statement a cumulative percentage has been determined for winter months for the period of July 2004 to March 21, 2022. These results show the design low temperature is exceeded only .49% of the time during the winter.

Based on the extensive design analysis performed at the NPP and ongoing trending that occurs each winter to ensure we are bounded by the analysis, it doesn't seem practical to change the entire design/licensing basis of the plant to match the minimum hourly temperature experienced since 1/1/1975

Likes 0	
Dislikes 0	

Response

Michelle Amarantos - APS - Arizona Public Service Co. - 5

Answer	Yes
Document Name	

Comment

AZPS supports EEI's comments, particularly regarding giving consideration to the financial impact of cold weather modifications vs. retiring a generating unit and that R1 should not specify that generating units must be redesigned to meet certain freeze protection requirements, along with the proposed revisions to R1.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	Yes
Document Name	

Comment

Constellation agrees that generating units need to utilize sound practices for cold weather preparation. Constellation suggests eliminating the wording "shall be designed and maintained to be". Such wording is too prescriptive in how an entity is to ensure cold weather operation, and implies that a unit needs to be "re-designed". If the intent is to ensure cold weather capability, suggest staying with "Each generating unit shall be capable of continuous operation...." to allow each generating unit to determine the manner in which the capability is to be achieved, depending on the particular circumstances of design, operation, and location of that unit. Also the re-focus on "capable" allows requirement to include generators both existing and new, without use of wording such as "design", allowing a consolidation of the standard (see comments on R2 following.)

Kimberly Turco on behalf of Constellation Energy Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Foung Mua, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Wei Shao, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; - Tim Kelley, Group Name LPPC

Answer	Yes
Document Name	

Comment

LPPC is concerned that the proposed language in EOP-012-1 R1, as well as Parts 3.1 and 4.1, places significant administrative and analytical burden on entities, and potentially complicates the assessment of design capabilities. LPPC is concerned that collecting and maintaining hourly temperature data would amount to finding a needle in a haystack (over 400,000 data points in a 50 year time period). Instead, LPPC recommends utilizing annual temperature data to identity the lowest temperature recorded for the year. This approach results in a smaller set of data to maintain and is easier for entities to identify the lowest temperature needed for freeze protection. Additionally, analyzing hourly data from summer periods is not beneficial, so a lowest recorded temperature for the year is more appropriate.

LPPC recommends modifying Part 1.1, Part 3.1, and Part 4.1 to remove the requirement for a specific interval, and only require documentation of the lowest recorded temperature since 1975, as follows. These changes allow an Entity to determine whether hourly, daily, or annual is the most appropriate interval for their assessments.

Recommended changes to Parts 1.1, 3.1, and 4.1:

Part 1.1: “Each generating unit shall be designed and maintained to be capable of continuous operations at the lowest recorded ambient temperature experienced at its location since 1/1/1975 or a lesser period if reliable data is not available to 1975.”

Part 3.1: “Lowest recorded ambient temperature experienced at its location since 1/1/1975 or a lesser period if reliable data is not available to 1975.”

Part 4.1: “Review the lowest recorded ambient temperature developed pursuant to Part 3.1, and update the cold weather preparedness plan with the lowest temperature as necessary.”

These comments have been endorsed by LPPC.

Likes 2	Colorado Springs Utilities, 1, Braunstein Mike; Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merre
Dislikes 0	

Response	
LaKenya VanNorman - LaKenya VanNorman On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name FMPA and Members	
Answer	Yes
Document Name	
Comment	

FMPA does not believe the proposed methodology is an appropriate way to address the the risk presented in recommendation 1f. At heart there are two key issues. First is that while we understand the technical rationale for selecting 1975 as a date to go back to, this is still quite arbitrary and not a very rigorous (statistically) way to ensure we have selected the appropriate level of risk protection. The second issue relates to the first with respect to duration of cold weather. When determining the design requirements for plant equipment to address cold, the temperature, and duration, are equally important. It takes time to freeze. A running plant will withstand most 1hr temperature dips. We do not believe it is appropriate to arbitrarily take the lowest 1 hr (which is really sub-1hr) temperature over the last 47 years and extrapolate that 1 hour duration to “continuous”.

To address both of these issues, a probabilistic-based method should be deployed, which fits the available temperature data to a standard probabilistic distribution and allows the level of extremity of both temperature and duration to be explicitly selected (for example saying the plant must be continuously operable for all temperatures and durations equal to or below “x” standard deviations from the mean). The currently proposed method will result in some areas where plants are weather hardened unnecessarily as well as other areas where the past 47 years of data did not include a temperature as low as, say, the one we get next year. Wind speed should likewise be considered probabilistically. All three of these items should be addressed as part of a methodology that is part of the GO’s cold weather preparedness plan(s). The current proposal implies that plants in south Florida will need to be fully enclosed in a building the way they build plants in North Dakota, because it fails to realize that while South Florida may have seen a brief freezing temperature in the last 47 years, the duration of that freeze is statistically so unlikely to last for 6 hours that modifying plants to address it would be ridiculous.

In addition, this requirement is silent on what data sources will be acceptable (1st order weather station, NOAA, etc) and what constitutes determination that “reliable” data is “not available”. What if no reliable data is available? These issues would need to be resolved when adopting a more rigorous probabilistic methodology.

Likes 0	
Dislikes 0	
Response	
Tom Vinson - American Clean Power Association - 5	
Answer	Yes
Document Name	
Comment	

ACP generally supports R1, but notes this support is conditioned on the retention of the “commercial, technical, or operational constraints” pathway in 1.4.2 and 1.4.4, which constructively addresses a concern ACP raised in comments on the draft standard authorization request (SAR). Without the commercial, technical, or operational constraints pathway, generators could be forced to retire if they do not have a feasible compliance path, which would exacerbate the challenge of generator availability during extreme cold weather. If the commercial, technical, or operational constraints pathway is removed, ACP would oppose R1.

ACP has one concern about this section as currently drafted:

1. In 1.1 the use of the phrase “continuous operations” in the following sentence is problematic for variable energy resources that are dependent on the wind or sun to generate: “Each generating unit shall be designed and maintained to be capable of **continuous** operations at the documented minimum hourly temperature experienced at its location since 1/1/1975 or a lesser period if reliable data is not available to 1975.” (emphasis added)

Put simply, wind and solar generation output is variable, not continuous. Therefore, as drafted, GOs of variable generation resources arguably cannot comply. ACP recommends the following redline be adopted (remove the word "continuous" from the sentence):

Each generating unit shall be designed and maintained to be capable of operations at the documented minimum hourly temperature experienced at its location since 1/1/1975 or a lesser period if reliable data is not available to 1975.

Likes 0	
Dislikes 0	

Response

Michael Dillard - Austin Energy - 5

Answer	Yes
Document Name	

Comment

AE has the following concerns and suggestions:

1. The R1 language may be interpreted as generators having to collect and monitor temperature data within their own premises, as opposed to being allowed to rely on documented temperature data within an identified third party monitored weathter station or recognized weather data source such as NOAA. AE would like to be able to rely on minimum temperature data as recorded from the closet National Weather Service Station (mainly Austin Bergstrom Airport Weather Station). The record minimum temperature data from such NOAA source since 1975 is only available at the daily level. Whether this daily minimum data correlates to hourly minimum temperatures is unknown. In addition, summer temperature data is not necessary and AE’s suggestion would be to only analyse temperature data for the winter months as defined by the BA. In addition, AE would recommend changing the language from hourly minimum temperature to annual minimum temperature in addition to making it clearer that the requirement doesn’t add the burden on entities to collect and monitor hourly temperatures at their own plant facilities and that entities are able to comply by utilizing available third party weather data at a nearby location.
2. R1 and its sub-parts could be read to require continuous operation at the documented minimum hourly temperature, and that if a unit tripped at or above that minimum temperature during an extreme cold weather event, it could be deemed out of compliance. AE believes the SDT’s intent is to require the implementation of freeze protection measures designed with the intent of continuous operation at the documented minimum hourly temperature. R1 states the GO shall ensure generating units implement freeze protection measures, and M1 states each GO will have dated evidence that demonstrates it has freeze protection measures. However, M1 also says “*in accordance with R1*” and R1 part 1.1 says “*Each generating unit shall be designed and maintained to be capable of continuous operations at the documented minimum* ….” AE requests that the SDT clarify the language to ensure the compliance expectation is not continuous operation. No Generator Owner can guarantee its resource will continue to run even if it has implemented the required freeze protection measures.

Likes 0	
Dislikes 0	

Response

Robert Stevens - CPS Energy - 5	
Answer	Yes
Document Name	
Comment	

Yes, we have concern and want to ensure GO requirements will align with the BA. Using coldest data information since 1975 does have concern, as the GO still won't be able to document all applicable temp/wind/moisture/etc. facts that impact reality. The requirement should only specify the minimum hourly temperature at the nearest National Weather Service location that plant has successfully operated.

Existing generating units should only be required to analyze their designed operation parameters using freeze data and any cold weather limitations based on historic operations dating back to 1975, with defined interval(s) of operation.

Likes 0	
Dislikes 0	
Response	

Colin Chilcoat - Invenergy LLC - 6	
Answer	Yes
Document Name	
Comment	

Invenergy has the following concerns and suggestions about the proposed language:

(1)   Invenergy supports the retention of the "commercial, technical, or operational constraints" clause in R1, and would be concerned if it were removed.

(2)   Invenergy is concerned about the temperature criteria used in R1.1, which relies on an arbitrary historical temperature start date of 1/1/1975 along with a single minimum hourly temperature. Together, these two parameters create an arbitrarily stringent standard that could impose more onerous design and maintenance requirements than are necessary to ensure generator availability during the prolonged extreme cold events – occurring over multiple hours or days – that this Standard is intended to address. As but one example, the minimum historical hourly temperature at a given location might be in the middle of the night, but it would not be reasonable to design a solar generator to meet that criterion. Instead, Invenergy suggests the SDT explore alternative methodologies to generate design and maintenance parameters that are targeted to ensuring generator availability during the extreme cold events this Standard seeks to address. For example, and without endorsing the specific parameters used or the resulting proposed requirements, Invenergy notes that the Public Utility Commission of Texas has an open docket (Project No. 53401, Electric Weather Preparedness Standards-Phase II) to set weather preparedness standards. In that proceeding, the Commission Staff proposed (Memorandum and Proposal for Publication dated May 19, 2022), among other items, a standard of "…the lesser of the minimum ambient temperature at which the resource has experience sustained operations or **the 95th percentile minimum average 72-hour temperature** reported in ERCOT's historical weather study…for the weather zone in which the resource is located." (Emphasis added.) The use of a multi-day average temperature with a percentile rather than the single coldest hour better targets the events the Standard is intended to address. The specific parameters (how many hours or days, which percentile, which zones, and other criteria) could be developed as part of the SDT's process.

(3)   Invenergy recommends striking “continuous” from R1.1. to be more inclusive of all generation types, such as wind and solar generation output, which is variable, not continuous.

(4)   Invenergy suggests the following modifications to R1.4 to clarify Generation Owners declaring a commercial, technical, or operational constraint are not required to develop and implement a Corrective Action Plan:

1.4. For each existing generating unit that requires either new freeze protection measures or modification of existing freeze protection measures to meet the requirements of 1.1, 1.2, or 1.3, the Generator Owner shall do one of the following:

1.4.1. Develop and implement a Corrective Action Plan (CAP) that includes the following at a minimum:

1.4.1.1. An identification of corrective action(s) for the affected unit(s), including any necessary modifications to the Generator Owner’s cold weather preparedness plan(s);

1.4.1.2. A timetable for implementing the corrective action(s) from Part 1.4.1 which considers any technical, commercial, or operational constraints, as defined by the Generator Owner;

1.4.1.3. An identification of any temporary operating limitations that would apply until execution of the corrective action(s) identified in the CAP; **OR**

1.4.2. Submit a declaration that the implementation or modification of freeze protection measures for existing generating unit(s) as required by Requirement R1 is not possible due to technical, commercial, or operational constraints as defined by the Generator Owner, and that no further corrective actions will be taken. The Generator Owner shall document technical, commercial, or operational constraints as defined by the Generator Owner as support for such declaration.

Likes 0	
Dislikes 0	

Response

Rhonda Jones - Invenergy LLC - 5

Answer	Yes
Document Name	

Comment

Invenergy has the following concerns and suggestions about the proposed language:

(1) Invenergy supports the retention of the “commercial, technical, or operational constraints” clause in R1, and would be concerned if it were removed.

(2) Invenergy is concerned about the temperature criteria used in R1.1, which relies on an arbitrary historical temperature start date of 1/1/1975 along with a single minimum hourly temperature. Together, these two parameters create an arbitrarily stringent standard that could impose more onerous design and maintenance requirements than are necessary to ensure generator availability during the prolonged extreme cold events – occurring over multiple hours or days – that this Standard is intended to address. As but one example, the minimum historical hourly temperature at a given location might be in the middle of the night, but it would not be reasonable to design a solar generator to meet that criterion. Instead, Invenergy suggests the SDT explore alternative methodologies to generate design and maintenance parameters that are targeted to ensuring generator availability during the extreme cold events this Standard seeks to address. For example, and without endorsing the specific parameters used or the resulting proposed requirements, Invenergy notes that the Public Utility Commission of Texas has an open docket (Project No. 53401, Electric Weather Preparedness Standards-Phase II) to set weather preparedness standards. In that proceeding, the Commission Staff proposed (Memorandum and Proposal for Publication dated May 19, 2022), among other items, a standard of "…the lesser of the minimum ambient temperature at which the resource has experience sustained operations or **the 95th percentile minimum average 72-hour temperature** reported in ERCOT's historical weather study…for the weather zone in which the resource is located." (Emphasis added.) The use of a multi-day average temperature with a percentile rather than the single coldest hour better targets the events the Standard is intended to address. The specific parameters (how many hours or days, which percentile, which zones, and other criteria) could be developed as part of the SDT's process.

(3) Invenergy recommends striking "continuous" from R1.1. to be more inclusive of all generation types, such as wind and solar generation output, which is variable, not continuous.

(4) Invenergy suggests the following modifications to R1.4 to clarify Generation Owners declaring a commercial, technical, or operational constraint are not required to develop and implement a Corrective Action Plan:

1.4. For each existing generating unit that requires either new freeze protection measures or modification of existing freeze protection measures to meet the requirements of 1.1, 1.2, or 1.3, the Generator Owner shall do one of the following:

1.4.1. Develop and implement a Corrective Action Plan (CAP) that includes the following at a minimum:

1.4.1.1. An identification of corrective action(s) for the affected unit(s), including any necessary modifications to the Generator Owner's cold weather preparedness plan(s);

1.4.1.2. A timetable for implementing the corrective action(s) from Part 1.4.1 which considers any technical, commercial, or operational constraints, as defined by the Generator Owner;

1.4.1.3. An identification of any temporary operating limitations that would apply until execution of the corrective action(s) identified in the CAP; **OR**

1.4.2. Submit a declaration that the implementation or modification of freeze protection measures for existing generating unit(s) as required by Requirement R1 is not possible due to technical, commercial, or operational constraints as defined by the Generator Owner, and that no further corrective actions will be taken. The Generator Owner shall document technical, commercial, or operational constraints as defined by the Generator Owner as support for such declaration.

Likes 0	
Dislikes 0	

Response

Glenn Pressler - CPS Energy - 3

Answer	Yes
Document Name	

Comment

Yes, we have concern and want to ensure GO requirements will align with the BA. Using coldest data information since 1975 does have concern, as the GO still won't be able to document all applicable temp/wind/moisture/etc. facts that impact reality. The requirement should only specify the minimum hourly temperature at the nearest National Weather Service location that plant has successfully operated.

Existing generating units should only be required to analyze their designed operation parameters using freeze data and any cold weather limitations based on historic operations dating back to 1975, with defined interval(s) of operation.

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 3

Answer	Yes
Document Name	

Comment

Ameren agrees with the NAGF comments.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	Yes
Document Name	

Comment

AEP does not agree that R1 should specify that generating units must be redesigned to meet freeze protection requirements. Instead, R1 should require generating units to have the *ability* to continuously operate within an identified operating range, with the methods on how this is accomplished determined solely by the owner. Many actions can and have been taken to ensure units operate successfully through the winter that would not impact unit design (such as temporary enclosures and temporary heat sources).

AEP suggests that R1 be revised so that the wind and precipitation requirements contained in subparts 1.2 and R 1.3 are incorporated into subpart 1.1. The considerations for wind versus precipitation are not always unique and are typically all considered at the same time when systems are reviewed for cold weather operability which is required by R 1.1. As a result, separate sections are not warranted in the standard.

Requirement 1.4.4 allows for the Generator Owner to make a declaration of no action due to technical, commercial, or operational constraints, which infers that the Generator Owner is able to establish the criteria regarding the resulting exemption. AEP agrees with this concept, but suggests that the additional clarity be provided within the standard to make it clear that such a declaration, and the decision making which drives it, is solely at the discretion of the Generator Owner.

AEP supports the comments made by EEI in response to this question.

Likes 0	
Dislikes 0	

Response

Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	

R1 – 1.1 appears to require us to monitor the temperature at each of our facilities and to review that data from 1/1/1975 to current. Most of our facilities, especially our hydro facilities do not monitor the air temperature or wind speed at our plants. For compliance with EOP 11-2 we intend to use the national weather service at a nearby airport (Spokane) to represent the temperature of the plants in our region. The farthest plant from this datum is about 120 miles from the Spokane airport NOAA station. We believe that the national weather service is a much more credible source of forecasting and monitoring temperatures in our area than our own gauges would be. Does the NERC assume that to comply with EOP 12-2, R1.1 and R3.1 that all plants will now be required to install temperature monitoring at our sites, perform compliance calibrations and certifications on such temperature monitoring equipment, and use our own temperature monitoring equipment at each site to monitor for compliance notification protocols associated with TOP 3-5 and IRO 10-3 to satisfy this standard? If so, this seems unreasonable. To comply with EOP 11-2 our current draft plans for cold weather notifications for EOP 11-2, TOP 3-5 and IRO 10-3 are to use the regional airport temperature from NOAA as our gauge for weather forecasting for all our plants in the area. We have one system operations office that will among many other things, monitor the temperature in the region (if necessary) and perform appropriate callouts to plants proactively, before the temp gets to or below the extreme historical minimum notifying them of extreme cold weather may be on the way at or before the cold weather is experienced at each plant. We believe if we must monitor multiple temperature monitoring sites across our region (at each site, or at a separate datum like regional airports near each plant) we will burden the operations teams with many more activities and calls during a cold weather event. This could lead to many more latent errors, missed steps, completing too many tasks to accurately monitor the operation of the system during an emergency event, and we believe that this would go beyond the intent of the Cold Weather Standard, and/or the report recommendations. Can you please clarify in EOP 12-1 R1.1 and R3.1 if it is acceptable to monitor a regional third-party temperature sensor (Such as NOAA) for compliance with EOP 12-1 for a group of facilities if the temperature monitoring equipment is within 150 miles of each facility?

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	

Southern Company supports the EEI comments and would add that the declarations of technical, commercial, or operational constraints by the GO that limit operational capability should, at minimum, be communicated to their applicable BA and RC to prevent the creation of an avenue for avoidance of availability that would limit the generation being available to the BA during extreme cold weather events.

Likes 0	
Dislikes 0	
Response	

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	Yes
Document Name	
Comment	
PG&E supports the comments provided by the Edison Electric Institute (EEI) and the North American Generators Forum (NAGF). In addition, PG&E has the following comments: PG&E representatives attended the April 27th and 28th, 2022 FERC\NERC technical conference on cold weather. Listening to all of the testimony from utilities in New Mexico, Texas, and the South and Eastern United States representing GO's and GOP's, ISO's, and Natural Gas Distributors, it became apparent to PG&E that utilities across the USA have taken corrective actions to harden their generating units from cold weather. PG&E contends that EOP-012-1 is not required and believes that utilities that have had historical operating problems during cold weather events have already implemented cold weather plans/checklists and equipment upgrades that follow the FERC recommendations. EOP-012-1 will make warm-weather utilities perform expensive analysis, training, and design changes that are not commensurate with grid reliability and risk reduction. In the PG&E California portfolio, we have numerous plants that historically have never experienced below-freezing temperatures for extended periods. In addition, numerous GO's in the western part of North America have an extremely low probability of experiencing sub-freezing temperatures. With this new standard, GO's are being required to develop a cold weather plan, train the operating staff, and implement design changes that do not benefit operational reliability or grid reliability. PG&E believes the current EOP-011-1 meets the intent of the FERC recommendations. If EOP-012-1 continues to be developed and later approved, PG&E recommends an allowance (exemption) within the Standard that those GO's who can prove their lowest hourly temperature is above freezing, the Standard should clearly state that those GO's are exempted from EOP-012-1.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3	
Answer	Yes
Document Name	
Comment	
WEC Energy Group supports EEIs comments.	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes

Document Name	
Comment	

EOP-012-1 is unclear and confusing because of disorganized language and grammatical errors, some of which have perpetuated from EOP-011-2. For example, generating units do not implement anything. Many pieces of equipment do not “freeze,” i.e., solid metal is already “frozen” by definition. Rather, equipment fails due to improper protection from extreme cold. The requirements should be stated so that the registered entity, e.g., the Generator Owner, is the one implementing the action. Distinct obligations should be contained in separate requirements, not combined at the requirement part and sub-part levels. Reclamation recommends using active voice throughout the standard to clearly state the requirements.

Reclamation recommends rewriting the requirements of EOP-012-1 as follows:

R1. *use existing language from Draft 1 EOP-012-1 R1.1* with the following corrections:

Each Generator Owner shall design new and maintain existing generating units to be capable of continuous operations at the documented minimum hourly temperature experienced at each unit’s location since 1/1/1975 or a lesser period if reliable data is not available to 1975.

R2. *use existing language from Draft 1 EOP-012-1 R1* with the following corrections:

Each Generator Owner shall implement new or modify existing protection based on the documented minimum hourly temperature for its generating units including the following minimum criteria:

R2.1. the cooling effect of wind; and

R2.2. impacts on equipment operation due to precipitation (e.g., sleet, snow, ice, and freezing rain).

R3. *use existing language from Draft 1 EOP-012-1 R1.4* with the following corrections:

For each existing generating unit that requires new or modified protection based on the documented minimum hourly temperature, the Generator Owner shall develop and implement a Corrective Action Plan (CAP) or, where deemed appropriate by the Generator Owner based on the review of parts R3.1.1 through R3.1.3., declare that no corrective actions will be taken.

R3.1. A CAP shall contain the following minimum information:

R3.1.1. Corrective action(s) for the affected unit(s).

R3.1.2. Any temporary operating limitations that would apply until the corrective actions are implemented.

R3.1.3. A schedule for implementing the corrective action(s).

R3.2. A declaration shall document any technical, commercial, or operational constraints of each affected unit, as defined by the Generator Owner, in support of the declaration.

R4. *use existing language from Draft 1 EOP-012-1 R2* with the following corrections:

Each Generator Owner that does not implement new or modify existing protection based on the documented minimum hourly temperature in accordance with R2 due to technical, commercial, or operational constraints, as defined by the Generator Owner, shall:

R4.1. Document its determination and the constraints; and

R4.2. Review its determination every five calendar years to determine whether the constraints remain applicable.

R5. *use existing language from Draft 1 EOP-012-1 R3*

R6. *use existing language from Draft 1 EOP-012-1 R4, update Part numbers as necessary*

R7. *use existing language from Draft 1 EOP-012-1 R5* with the following corrections:

Each Generator Owner, in conjunction with its Generator Operator, shall ensure generating unit-specific cold weather preparedness plan training is provided to its personnel responsible for implementing cold weather preparedness plans.

R7.1. The Generator Owner and Generator Operator shall identify the entity responsible for providing the training.

R7.2. The Generator Owner and Generator Operator shall ensure the training is provided to personnel responsible for implementing cold weather preparedness plans upon entrance on duty and annually thereafter.

R8. *use existing language from Draft 1 EOP-012-1 R6* with the following corrections:

Each Generator Owner that owns a generating unit that experiences an event resulting in a derate of more than 10% of the total capacity of the unit for longer than four hours in duration, a start-up failure where the unit fails to synchronize within a specified start-up time, or a Forced Outage for which (i) the apparent cause(s) of the event is due to extreme cold weather effects within the Generator Owner's control to protect against, and (ii) the ambient conditions at the site at the time of the event are at or above the temperature documented in Part 3.4.2 shall:

R8.1. No later than 150 days subsequent to the event or by July 1 that follows the event, whichever is ***later***, develop a CAP; or

R8.2. Declare, where deemed appropriate by the Generator Owner based on review of Parts 8.3.1. through 8.3.5, that no revisions to the cold weather preparedness plan are required and that no further corrective actions will be taken.

R8.3. At a minimum, a CAP shall contain:

R8.3.1. A summary of the identified cause(s) ***of*** the equipment ***derate, failure to start, or Forced Outage***, and any relevant associated data.

8.3.2 use existing 6.2.1. language

8.3.3. use existing 6.2.2. language

8.3.4. (modified 6.2.3.) Specific corrective action(s) for the affected unit(s) and identified similar units, including:

8.3.4.1. (modified 6.2.3.) any necessary modifications to the Generator Owner's cold weather preparedness plan(s); and

8.3.4.2. (modified 6.2.4.) consideration of any technical, commercial, or operational constraints, as defined by the Generator Owner.

8.3.5. A ***schedule*** for implementing the corrective actions.

R8.4. At a minimum, a declaration shall document technical, commercial, or operational constraints, as defined by the Generator Owner, as support for the declaration.

Reclamation recommends the timeframe for developing a CAP be 150 days subsequent to the event or by July 1 that follows the event, whichever is ***later***. Using whichever is earlier could subject an entity to an unreasonably short deadline depending on when the event occurs.

Reclamation recommends moving the language pertaining to the cold weather preparedness plans from the original R1 to the original R3 (new R5 based on Reclamation's proposed renumbering in the above comments). Modifications to the cold weather preparedness plan should relate back to the CAP, if necessary, not the CAP requirements relating forward to the cold weather preparedness plan.

Reclamation recommends not limiting the training on cold weather preparedness plans to "maintenance or operations" personnel, as other personnel may also be responsible for implementing cold weather preparedness plans and should not be excluded from the training. Reclamation recommends the annual cold weather preparedness plan training be contained in PER-006 instead of EOP-012.

Reclamation supports the retention and reuse of pertinent information from the Draft 1 Measures.

Likes 0	
Dislikes 0	

Response

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	Yes
Document Name	

Comment
Alliant Energy supports the comments submitted by the MRO NSRF.

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

"At it's location" may be too ambiguous and doesn't represent enough specificity to accurately define weather conditions. The FERC report also references the nearest city. What constitutes the nearest city? The nearest city may not be indicative of the local weather.

Suggested Edit:

"A NOAA established location within 25 miles. NOAA data is a default. To use another documented method, justification would need to be provided as to why it is needed or why it is superior to NOAA. Alternative temperature data shall be described in the applicable cold weather preparedness plan."

This could also be more detailed in Requirement 3.1 which defines areas that are covered in the cold weather preparedness plan.

Suggest Revising:

R3.1 Documented minimum hourly temperature experienced at a NOAA or Environment and Climate Change (for generating units located in Canada) established location within 25 miles of its location since 1/1/1975 or a lesser period if data is not available.

R3.1.1 Justification for the use of alternative temperature data if NOAA data is unavailable or another source of temperature data is used to determine the minimum temperature

Other concerns are for Commercial Constraints. Will this be interpreted as “too expensive”? Does this clause render the entire Standard moot for anyone that doesn’t want to spend the money to upgrade the facilities? Are there any other references in the NERC Standards that allow entities to opt out due to commercial constraints? For example: FAC-003 does not allow for skipping tree trimming due to cost. What will the oversight process be for generators that declare they are unable to implement freeze protection? See ISO—NE Concerns in Question 3.

Likes 0	
Dislikes 0	

Response

Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric

Answer	Yes
Document Name	

Comment

DTE Electric supports NAGF comments.Please see NAGF proposed language.

Likes 0	
Dislikes 0	

Response

Brian Evans-Mongeon - Utility Services, Inc. - 4

Answer	Yes
Document Name	

Comment

Concerns include:

1.‘Designed and maintained’ and ‘continuous operation’ are not measurable requirements.

Propose this language for R1.1: The generating unit(s) design shall be based on the documented minimum hourly temperature experienced at its location since 1/1/1975 or a lesser period if reliable data is not available to 1975;

2. R1.4 as written should be separated into multiple Requirements and not part of 1.1 as follows:

2 Each Generator Owner that determines their generating unit(s) require either new freeze protection measures or modification of existing freeze protection measures pursuant to R1, the Generator Owner shall develop and implement a Corrective Action Plan (CAP) which includes the following at a minimum:

2.1 An identification of corrective action (s) for the affected unit(s), including any necessary modifications to the Generator Owner’s cold weather preparedness plan(s);

2.1 A timetable for implementing the corrective action(s) from Part 1.4.1 which considers any technical, commercial, or operational constraints, as defined by the Generator Owner;

2.1 An identification of any temporary operating limitations that would apply until execution of the corrective action(s) identified in the CAP

3. If the Generator Owner determines, that no revisions to the cold weather preparedness plan(s) are required and that no further corrective actions will be taken based on the review of Parts 1.1.1 through 1.1.3, the Generator Owner shall document technical, commercial, or operational constraints as defined by the Generator Owner as support for such determination.

Likes 0	
Dislikes 0	

Response

Tony Skourtas - Los Angeles Department of Water and Power - 3

Answer	Yes
Document Name	

Comment

We suggest for the requirement to include cold weather frequency and duration of the criteria to determine if additional cold weather and freeze protection measures need to be implemented. This would allow for generating units in tropical climates that may rarely experience momentary freezing temperatures to more cost effectively implement the standard.

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	Yes
Document Name	

Comment

Dominion Energy supports continued cold weather measures being taken for existing generators to meet their designed operating specifications in extreme cold weather. Dominion Energy supports both the EEI and NATF comments that both the FPA Section 215 of 2005 and NERC's own market principles preclude a retrofit requirement for existing generators to meet a design specification universally. The Federal Power Act Section 215 definition of "Reliability Standard" states in relevant part that the term includes requirements for "the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation of the bulk power system…." This phrase suggests that reliability standards cannot have requirements that require unplanned modifications. Dominion Energy supports EEI's suggestion that the standard drafting team ask NERC to provide a legal memorandum on whether Section 215 of the Federal Power Act allows a Reliability Standard to require existing generating units to be redesigned or otherwise modified to meet certain freeze protection requirements beyond their original design as set forth in Requirement R1.

Additionally, the requirements to make modifications to existing resources to expand their capability may not be a recoverable expense for generator owners.

Additionally, we support two separate requirements, 1) that addresses new generating resources installed on or after the effective date of the Standard and; 2) those generating units that were installed prior to the effective date of the Standard to proactively maintain existing system to ensure the reliable operation of the BES.

R2 for Existing Generating Units installed prior to the effective date of EOP-012-1:

R2. Each Generator Owner **who owns generating units that were placed into commercial operation prior to the effective date of the Standard shall:that is not able to implement freeze protection measures for new generating unit(s) as required by Requirement R1 due to technical, commercial, or operational constraints as defined by the Generator Owner shall:** *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

{C}**2.1.** {C}**Document its determination and the constraints on implementation; and Identify the operational capability of the generating units and supporting auxiliary systems, within the cold weather criteria identified in Requirement R1, subparts 1.1 and 1.2, through one of the following methods:**

2.1.1 Report the designed operational capability as specified by the OEM within the identified cold whether criteria to their responsible GOP and BA; or

2.1.2 Calculate the expected operational capability through either an engineering analysis of available unit data or an assessment of the unit's performance since its commercial operation date, not exceeding a period of twenty years and report it to their responsible GOP and BA. Review its determination every five calendar years to determine whether the documented constraints on implementation remain applicable.

2.2 Report all generating units that are not designed (2.1.1) or do not have the evaluated capability (2.1.2) to reliably operate at their rated capacity over the full range of the cold weather criteria to their responsible GOP and BA.

{C}**2.3 Report the expected cold weather operating capability of each of its generating units to their responsible GOP and BA.**

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	Yes
Document Name	

Comment

FirstEnergy agrees with EEI's comments.

Likes 0	

Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	Yes
Document Name	
Comment	

NRG has numerous concerns related to this requirement:

A.) NRG agrees with NAGF's comment that the SDT is not following NERC's stated Market Principals, which exist for a reason. NERC needs to address the conflict between the proposed requirement and the Market Principle which states "Standards shall not define an adequate amount of, or require expansion of, bulk power system resources or delivery capability." By requiring generators to improve their capability to withstand extreme weather beyond the current design, they are requiring expansion of the delivery capability. This proposed requirement also appears to conflict with NERC's Market Principal "A reliability standard shall not give any market participant an unfair competitive advantage." As long as some market participants are able to pass the costs associated with retrofitting units through to rate payers and other market participants are not able to pass the costs through to the end users, the proposal to require retrofits will provide some market participants advantages over others. Has the SDT taken this into account and, if so, how are they addressing the concern?

B). NRG also agrees with the NAGF to support the desire to allow the Transmission Planners, Balancing Authorities, Transmission Operators and Reliability Coordinators to better predict the point where extreme weather may cause problems, but this requirement does not do that. Instead, this requirement puts the onus on generators to be able to operate through any cold weather event, regardless of the existing capability or limits, including potentially more restrictive limits on Transmission, Distribution, and fuel delivery.

C.) NRG generally agrees that, ideally, minimum operating temperatures need to include effects of wind chill and precipitation when defining unit limitations. However, NRG does not agree with using the one-hour min historical operating temperature as the criterion for basing all freeze protection measures for all plant systems. The one-hour criterion is much more conservative, and the probability of this occurring is extremely small yet much more costly to implement. This criterion is not practical and not based upon a technically based industry design standard for freeze protection. The SDT should consider ASHRE, a statistically based standard which uses daily average temperatures, which has been accepted and used by industry for many years. The criterion is also not consistent with other regulatory body rulings such as the PUCT draft ruling (which uses the lesser of the min ambient operation at which the resource has experienced sustained operation or the ASHRE 95% min average 72-hour temp reported in the ERCOT historical study). Finally, overdesigned cold weather protection will reduce hot weather reliability. Without practical limits to winter preparation, summer reliability may subsequently be reduced.

D.) NRG also has concerns that retrofitting existing units to the same design standard as new units will also be costly and lengthy to implement. Focus should be on freeze protection measures, not full retrofits/redesign, and should address only those critical components that could potentially trip/derate the unit. Root cause analyses of previous freeze-related outages have not revealed concerns for auxiliary systems that support operation but are considered part of balance-of-plant. These can be addressed through sound operational practices and startup prior to freeze events. In summary, retrofits of existing units should not include all operating systems and should not be required without some cost recovery realized.

E.) NRG agrees with NAGF's comments that most engineering processes do not attempt to create 100 percent reliability, simply because it is impossible to achieve. This is true for generator design to meet expected temperatures. Traditionally, generation was designed to meet some level of expectation below 100 percent.

For these reasons, NRG cannot recommend support for this requirement until the issues identified here are adequately addressed by the SDT.

Likes 0	
Dislikes 0	

Response

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	

Comment

The cold weather preparedness plan(s) required by EOP-012-1 R3.2 include freeze protection measures be taken. The proposed Requirement R1 appears redundant to R3.2 and should be removed from the proposed revision.

The difference between the temperature requirement in R1.1 and that of the stated minimum unit temperature in R3.4.2 has the potential to be significant and working towards operating at the lowest of the two will possibly, in many cases, be too cost prohibitive and therefore will likely cause many entities to claim this declaration under R1.4.4.

For nuclear plants, the temperature band is built into both the design and licensing basis of the plant. Changing the analysis is neither cost effective nor prudent. The NERC required temperature bands in excess of what NRC requires for safety of the plant is prohibitive of economic, cost effective operation.

As an example, the NRC Updated Safety Analysis Report (USAR) for one particular nuclear plant states that the plant is designed for a low temperature of -5° F dry bulb, which will only be exceeded 1% of the time during the winter. If -5° F is exceed a condition report is generated to allow tracking of the amount of time the temperature is exceeded. Per the 1972 ASHRAE Handbook of Fundamentals, the winter is considered to be December, January, and February, which amounts to 2160 hours each year. The design value of -5° F was taken from the same 1972 ASHRAE Handbook for a location geographically close to the plant, which substantiates the statement in the USAR that the design maximum and minimum temperatures will be exceeded approximately 1% of the time during a normal winter. To verify the operating conditions for this plant meet this statement a cumulative percentage was determined for winter months for the period of July 2004 to March 21, 2022. These results show the design low temperature is exceeded only .49% of the time during the winter.

Based on the extensive design analysis performed at nuclear generating facilities and ongoing trending that occurs each winter to ensure they are bounded by the analysis, it doesn’t seem practical to change the entire design/licensing basis of the plants to match the minimum hourly temperature experienced since 1/1/1975. This proposed NERC requirement is in conflict with the NRC Requirement.

Additionally, the design requirements for line and structure strength are based on wind speeds and radial ice formation less than the historical maximums experienced at the line locations. Construction of a power line designed to withstand the conditions experienced in a hurricane or tornado would be unreasonably cost prohibitive.

Consideration of temperature data back to 1/1/1975 seems excessive and does not correlate to NERC compliance history. We recommend the scope of study required by R1.1 and R3.1 be changed from 1/1/1975 to 6/18/2007. NERC requirements cannot create requirements prior to the enforcement date of June 18, 2007 there is no legal authority.

Recommendation:

a) Change the lookback date for coldest temperature to 6/18/07

b) Implement a standardized statistical approach for all BES generators be taken to have a more realistic method than identifying the lowest value seen since the specified lookback date

c) Include an exemption in Section 4.2 Facilities for nuclear generation based on the extensive design basis analysis that has already been completed

d) Change verbiage of Requirement R1. "Each Generator Owner shall plan to implement freeze protection measures on generating units based on the following minimum criteria: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]"

Likes 2	Corn Belt Power Cooperative, 1, brusseau larry; Lincoln Electric System, 1, Johnson Josh
Dislikes 0	

Response

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

BPA supports the comments submitted by the US Bureau of Reclamation.

Likes 0	
Dislikes 0	

Response

Patricia Lynch - NRG - NRG Energy, Inc. - 5

Answer	Yes
Document Name	

Comment

NRG has several concerns related to this requirement:

A) NRG agrees with NAGF's comment that the SDT is not following NERC's stated Market Principals, which exist for a reason. NERC needs to address the conflict between the proposed requirement and the Market Principle which states "Standards shall not define an adequate amount of, or require expansion of, bulk power system resources or delivery capability." By requiring generators to improve their capability to withstand extreme weather beyond the current design, they are requiring expansion of the delivery capability. This proposed requirement also appears to conflict with NERC's Market Principal "A reliability standard shall not give any market participant an unfair competitive advantage." As long as some market participants are able to pass the costs associated with retrofitting units through to rate payers and other market participants are not able to pass the costs through to the end users, the proposal to require retrofits will provide some market participants advantages over others. Has the SDT taken this into account and, if so, how are they addressing the concern?

B) NRG also agrees with the NAGF to support the desire to allow the Transmission Planners, Balancing Authorities, Transmission Operators and Reliability Coordinators to better predict the point where extreme weather may cause problems, but this requirement does not do that. Instead, this requirement puts the onus on generators to be able to operate through any cold weather event, regardless of the existing capability or limits, including potentially more restrictive limits on Transmission, Distribution, and fuel delivery.

C) NRG generally agrees that, ideally, minimum operating temperatures need to include effects of wind chill and precipitation when defining unit limitations. However, NRG does not agree with using the one-hour min historical operating temperature as the criterion for basing all freeze protection measures for all plant systems. The one-hour criterion is much more conservative, and the probability of this occurring is extremely small yet much more costly to implement. This criterion is not practical and not based upon a technically based industry design standard for freeze protection. The SDT should consider ASHRE, a statistically based standard which uses daily average temperatures, which has been accepted and used by industry for many years. It is also not consistent with other regulatory bodies rulings such as the PUCT draft ruling (which uses the lesser of the min ambient operation at which the resource has experienced sustained operation or the ASHRE 95% min average 72-hour temp reported in the ERCOT historical study). Finally, overdesigned cold weather protection will reduce hot weather reliability. Without practical limit to winter preparation, summer reliability may subsequently be reduced.

D) NRG also has concerns that retrofitting existing units to the same design standard as new units will also be costly and lengthy to implement. Focus should be on Freeze protection measures, not full retrofits/redesign, and should address only those critical components that could potentially trip/derate the unit. Root cause analysis of previous freeze-related outages have not revealed concerns for auxiliary systems that support operation but are considered part of balance-of-plant. These can be addressed through sound operational practices and startup prior to freeze events. In summary, retrofits of existing units should not include all operating systems and should not be required without some cost recovery realized.

E) NRG agrees with NAGF's comments that most engineering processes do not attempt to create 100 percent reliability, simply because it is impossible to achieve. This is true for generator design to meet expected temperatures. Traditionally, generation was designed to meet some level of expectation below 100 percent.

For these reasons, NRG cannot recommend support for this requirement until the issues identified here are adequately addressed by the SDT.

Likes 0	
Dislikes 0	

Response

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF

Answer	Yes
Document Name	

Comment	
The year 1975 pre-dates modern weather forecasting and recording capabilities. If desired to extend the monitoring period to that extent, we suggest that the requirement instead specify the minimum hourly temperature at the nearest National Weather Service location. Existing generating units should be required to analyze their designed operation parameters using the freeze protection factors to identify any cold weather limitations based on historic operations dating back to 1975, then develop a time limited Corrective Action Plan. Requirement 1 is an overreach of the Federal Power Act because it requires existing facilities to add equipment or retrofit its facilities.	
Likes 0	
Dislikes 0	
Response	

Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Installing freeze protection is redundant in many cases and in some case may not even be applicable, not to mention the excessive cost to modify or implement new measures.	
Likes 0	
Dislikes 0	
Response	

Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
R1 – 1.1 appears to require us to monitor the temperature at each of our facilities and to review that data from 1/1/1975 to current. Most of our facilities, especially our hydro facilities do not monitor the air temperature or wind speed at our plants. For compliance with EOP 11-2 we intend to use the national weather service at a nearby airport (Spokane) to represent the temperature of the plants in our region. The farthest plant from this datum is about 120 miles from the Spokane airport NOAA station. We believe that the national weather service is a much more credible source of forecasting and monitoring temperatures in our area than our own gauges would be. Does the NERC assume that to comply with EOP 12-2, R1.1 and R3.1 that all plants will now be required to install temperature monitoring at our sites, perform compliance calibrations and certifications on such temperature monitoring equipment, and use our own temperature monitoring equipment at each site to monitor for compliance notification protocols associated with TOP 3-5 and IRO 10-3 to satisfy this standard? If so, this seems unreasonable. To comply with EOP 11-2 our current draft plans for cold weather notifications for EOP 11-2, TOP 3-5 and IRO 10-3 are to use the regional airport temperature from NOAA as our gauge for weather forecasting for all our plants in the area. We have one system operations office that will among many other things, monitor the temperature in the region (if necessary)	

and perform appropriate callouts to plants proactively, before the temp gets to or below the extreme historical minimum notifying them of extreme cold weather may be on the way at or before the cold weather is experienced at each plant. We believe if we must monitor multiple temperature monitoring sites across our region (at each site, or at a separate datum like regional airports near each plant) we will burden the operations teams with many more activities and calls during a cold weather event. This could lead to many more latent errors, missed steps, completing too many tasks to accurately monitor the operation of the system during an emergency event, and we believe that this would go beyond the intent of the Cold Weather Standard, and/or the report recommendations. Can you please clarify in EOP 12-1 R1.1 and R3.1 if it is acceptable to monitor a regional third-party temperature sensor (Such as NOAA) for compliance with EOP 12-1 for a group of facilities if the temperature monitoring equipment is within 150 miles of each facility?	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
The proposed language does not provide a formula for determining minimum hourly temperature. Is this minimum instantaneous temperature or integrated minimum temperature over a period of time? In addition, the new language requires continuous operation but ability to start-up under minimum temperature conditions is left unaddressed or implied. Specific language regarding ability to start-up should be considered for R1.1 in addition to start up failures described in R6.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Dwanique Spiller On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Dwanique Spiller	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Gul Khan On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Gul Khan	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC is not a registered Generator Owner or Generator Operator.	
Likes 0	
Dislikes 0	
Response	
Jun Hua - Austin Energy - 4	
Answer	
Document Name	
Comment	
I support comments made by Michael Dillard, Austin Energy, Segment 5	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	
Comment	

No Comment.

Likes 0	
Dislikes 0	

Response

Lisa Martin - Austin Energy - 6

Answer	
Document Name	

Comment

I support comments made by Michael Dillard, Austin Energy, Segment 5.

Likes 0	
Dislikes 0	

Response

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	
Document Name	NAGF EOP-012-1 06152022 final.pdf

Comment

NAGF Comments: The NAGF has several concerns related to the requirement.

a. First, the process being used is ignoring, and appears to conflict with, NERC's stated Market Principles. This requirement will most likely cause a depression of prices for energy provided while increasing the cost to own and operate generation. Together, this structure will drive investment out of the generation market at a time when multiple areas of the NERC footprint are seeing concerns with the ability for operators to meet expected load during normal and extreme weather. These issues are why NERC needs to address the conflict between the Market Principle which states "Standards shall not define an adequate amount of, or require expansion of, bulk power system resources or delivery capability." and the proposed requirement. By requiring generators to improve their capability to withstand extreme weather beyond the generator's current design, they are requiring expansion of the delivery capability. This is the same as requiring Transmission Owners or Distribution Providers to harden their wires so no customers will lose power due to a hurricane or tornado. This requirement also appears to conflict with NERC's Market Principle "A reliability standard shall not give any market participant an unfair competitive advantage." As long as some market participants are able to pass the costs associated with retrofitting units through to rate payers and other market participants are not able to pass the costs through to the end users, the proposal to require retrofits will provide some market participants advantages over other market participants in that market.

The NAGF does support the desire to allow the Transmission Planners, Balancing Authorities, Transmission Operators and Reliability Coordinators to better predict the point where extreme weather may cause problems but this requirement does not do that. Instead, this requirement puts the onus on generators to be able to operate through any cold weather event, regardless of the existing capability or limits including potentially more restrictive limits on Transmission, Distribution and fuel delivery.

While the NAGF grants that there are exclusions for the Generator Owner to take, these very exclusions cause the requirement to be completely unenforceable. As written, generator investments to improve or maintain generation may be determined to be too costly by the Generator Owner and therefore no effort need be made beyond writing down that the cost is too much for the benefit expected. With the allowed exceptions, it is even more critical that the BAs, TOPs, TPs and RCs understand each generator's capability and ***use that data in their planning processes***.

b. NERC is moving forward with this requirement to retrofit existing generation without any effort to address Recommendation 2 in the report. If these two recommendations are not addressed together, it is extremely likely that Recommendation 2 will not be addressed until such time as investment in generation has suffered a great deal. Since reports, such as MISO's Summer Readiness, are currently showing a significant potential for insufficient generation in the near future, further retirements and reduced investment in new generation could mean serving loads during most periods of the year will be tight if not impossible. As an example, when concerns already exist related to the retirement of generation causing problems for reliable service, NERC is proposing a requirement to raise the cost of continuous operation with no certainty related to the ability to recoup the costs. In fact, economic theory says that this type of requirement will depress market prices for energy during the winter, making even more generators uneconomic. This requirement will raise the cost to continue to operate the existing fleet of traditional generation, which pushes them to retire even faster.

c. While the requirement mentions both the cooling effect of wind and precipitation, the language does not require any specific identification of impacts to the dry bulb temperature for operational purposes due to wind or precipitation. To the extent a Balancing Authority or Transmission Planner is using a dry bulb temperature to determine if a generator is able to maintain service, then failures to accurately and appropriately forecast seasonal capability will continue to occur. The classic example in this respect is the Polar Vortex of 2014, which caused no trouble in the PJM area (at Allentown, Pa) for a brief (1 hour) dip to of -4.0 F with a wind of 4.6 mph (-14.6 F wind chill) on 1/4/2014, but knocked units offline on 1/7/2014 at sustained conditions reaching 0 F with a 21.9 mph wind (-22.8 F wind chill). How could these units be unreliable at 0 F when they proved themselves able to tolerate -4 F just three days earlier? The answer is that the dry bulb temperature is the wrong parameter, and will always yield wrong expectations, regardless of EOP-012. If a unit is heat-traced for 0 F and a 10 mph wind (-16 F wind chill), for example, is it EOP-012 rated for 0 F, -16 F, or (if the max winter storm wind speed is 30 mph) 7 F (7 F and 30 mph yield a wind chill of -16 F)? The first two alternatives fail to predict outages that will be suffered under blizzard conditions, while the last one is unreasonably pessimistic if applied as a general rule and not solely when a severe windstorm is expected.

d. This requirement also makes no mention of a start-up capability, yet the report authors clearly state that failure to start was an issue. With most generators, a minimum operating temperature is very likely to have no bearing on whether a unit can start at that temperature. A unit's ability to operate at a temperature is not the same thing as a unit's ability to start. Until Balancing Authorities, Transmission Planners, and Transmission Operators utilize the correct information to formulate their plans, they will continue to fail to be adequately prepared. By failing to address startup capability in the standard until a Corrective Action Plan is required (which can be completed by stating that the conditions identified are for continuous operation and not related to startups), the standard is failing to address the critical issue: giving the Balancing Authority and other entities important information about the generator that should be used to appropriately plan system operations.

e. Requirement 1 mentions the cooling effects of wind and precipitation. However, Requirements 3 and 4 and 6 look only at temperature and ignore wind and moisture completely. Each of these requirements must be consistent.

f. Generator Owners are being asked to determine design criteria for weather protection systems for which it is likely impossible to calculate the freeze protection measure. It is true that heat trace applications do have a "design temperature" although experience has shown that this may not be accurately applied from one installation to the next, and likely deteriorates over time. Example of issues with this requirement:

i. what is the design temperature of a wind block for wind coming straight at the structure versus 90 degrees to the left or right?

ii. What is the design temperature (with or without wind) for a temporary enclosure with a portable heater? Is there a significant difference if the source of the heat is electric, kerosene or LP gas? Wind can also blow out flames and carry heat away before it raises the temperature of the system the heater is there to protect.

During FERC's April 2022 technical conference, one panelist stated that it may take several years to determine the point at which a temporary device fails. It is not clear under this requirement what is required to show the design capability. Based on these issues, is it technically feasible to have design documentation for a generator that uses any temporary devices, or does the Generator Owner say that it is technically infeasible to having design documentation until such time as the unit successfully (or unsuccessfully) operates through a severe cold weather event?

g.   Most engineering processes do not attempt to create 100 percent reliability. This is true for generator design to meet expected temperatures. Traditionally, generation was designed to meet some level of expectation below 100 percent. Meaning if the expected low temperature was 10 degrees F, the generator design may not have tried to meet that temperature 100 percent of the time. The design would be to have it reliable 97 percent of the time at that point, not have able to operate 100 percent at that point for an undetermined time.

For these reasons, the NAGF cannot recommend support for this requirement until the issues identified here are adequately addressed. The NAGF has provided a revised EOP-012-1 standard for consideration that address these issues in a reasonable manner. Please note that the NAGF cannot recommend its member support a retrofit requirement in any way until such time as the compensation issue is addressed outside of the NERC process as recommended in the report. Until that occurs, the NAGF believe that NERC should focus its efforts on ensuring that ***the planners have and utilize the generator information needed to support improved planning processes***.

Likes 0	
Dislikes 0	
Response	
Mark Young - Tenaska, Inc. - 5	
Answer	
Document Name	EOP-012 Comments - Tenaska Final.docx
Comment	
See comments provided in separate Word documents.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	

Answer	
Document Name	

Comment
AECI and its members support comments provided by ACES.

Likes 0	
Dislikes 0	

Response

5. The SDT has proposed that owners of new generation that determine that they are not able to implement freeze protection measures due to technical, commercial, or operational constraints review their determination every five years for EOP-012-1 Requirement R2. Is this separate requirement for "new" generation necessary, given that proposed Requirement R4 provides for Generator Owners to perform a similar review every five years to address the ongoing need to review freeze protection measures and historical cold weather temperatures? Please provide any explanation with your response.

Gul Khan - Gul Khan On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Gul Khan	
Answer	No
Document Name	
Comment	
While Oncor is not a Generator Operator or Generator Owner, it does appears that R2 is redundant to R4 and therefore is not necessary.	
Likes 0	
Dislikes 0	
Response	

Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	No
Document Name	
Comment	
Requirement R4 appears to already fullfill the requirement of R2. The 2 requirements should be merged into one.	
Likes 0	
Dislikes 0	
Response	

Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
We operate in a cold weather envorpnment, the requirements for our facilities are site specific and are taken into account by the owner. We do not need this language in the standard.	
Likes 0	

Dislikes 0	

Response

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merrell, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; - Jennie Wike, Group Name Tacoma Power

Answer	No
Document Name	

Comment

Requirement 4 provides sufficient coverage for new generation.

Likes 0	
Dislikes 0	

Response

Kristine Ward - Seminole Electric Cooperative, Inc. - 1

Answer	No
Document Name	

Comment

SEC agrees with R2 as written and does not believe that a requirement for “new” generation is required.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

We believe that a review of “every six years” is more appropriate as it would align with our audit cycle or be reviewed every other audit.

Likes 0	
Dislikes 0	

Response

Donna Wood - Tri-State G and T Association, Inc. - 1

Answer	No
Document Name	

Comment

R2 seems unnecessary and redundant. This is covered by R1.4.4 and R4.3

Likes 0	
Dislikes 0	

Response

Patricia Lynch - NRG - NRG Energy, Inc. - 5

Answer	No
Document Name	

Comment

NRG believes that all new units should be subject to Requirement 1.1(based on criterion stated in Response to 4C), 1.2 and 1.3 for entry into the market and not be eligible for R2. This requirement as written should be considered and applied only to the retrofit of existing units as it may not be economically feasible to retrofit these units to meet the requirements in Requirement 1.1, 1.2 and 1.3. Existing units should be eligible for exemptions due to technical and operational constraints. Exemptions due to commercial concerns are unclear in the draft and need to more clearly defined.   The SDT should consider changing exception for commercial reasons to commercial/economic reasons as requirement that would make a unit uneconomic will result in mothball or retirement of the unit. Exceptions for uneconomic is needed to ensure that standards do not result in greater resource adequacy problems.

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	No
Document Name	

Comment

The IESO does not believe a separate requirement is necessary for ‘new generation’, as long as Requirement R4 covers all applicable generating units, and is wide enough in scope and content.

However, Generator Owners should be required to notify the applicable Balancing Authority of any CAP and its details, or its declaration of not taking corrective action and the technical or operational constraints to support such declaration.

Likes 0	
Dislikes 0	

Response

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

BPA supports the comments submitted by the US Bureau of Reclamation.

Likes 0	
Dislikes 0	

Response

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	

Comment

Requirement R2 seems unnecessary when considering Requirements R1.4.4 and R4.3. Neither Requirement R1 nor R4 stipulates the applicable facilities be either new or existing, so any generating plants constructed after the enforcement date of the Standard would be required to comply with R1.4.4 and R4.3. We recommend incorporating Requirement R2 into Requirement R1. Possible solutions are to remove the word, “existing” from the text of R1.4, or to create a new sub-requirement (R1.5.) to account for new generation within the construct of R1.

Likes 2	Corn Belt Power Cooperative, 1, brusseau larry; Lincoln Electric System, 1, Johnson Josh
Dislikes 0	

Response

Martin Sidor - NRG - NRG Energy, Inc. - 6

Answer	No
Document Name	

Comment	
NRG believes that all new units should be subject to Requirement 1.1(based on criterion stated in Response to 4C), 1.2 and 1.3 for entry into the market and not be eligible for R2. This requirement as written should be considered and applied only to the retrofit of existing units as it may not be economically feasible to retrofit these units to meet the requirements in Requirement 1.1, 1.2 and 1.3. Existing units should be eligible for exemptions due to technical and operational constraints. Exemptions due to commercial concerns are unclear in the draft and need to more clearly defined. The SDT should consider changing the exception for commercial reasons to commercial/economic reasons. If left unclear, the commercial exemption may not apply if following the requirement would not make economic sense, resulting in mothball or retirement of the unit. Exemptions for uneconomic reasons are needed to ensure that this standard does not result in greater resource adequacy problems.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FirstEnergy agrees with EEI's comments. FirstEnergy asks for clarification on when "new" generation would fall under the scope of R1.	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Dominion Energy supports the EEI comments and agrees with the SDT that separate requirements are necessary for both new and existing generating units. Dominion Energy is of the opinion that some GOs may not have been sufficiently notified before making commercial commitments for key components, as a result of their approved interconnection agreement, and therefore may not be able to fully comply with the enhanced cold weather requirements similar to GOs with existing generating units. For this reason, we suggest that where GOs who have either begun construction or purchased key components affecting their generating unit's cold weather operational capability and were not properly notified of the enhanced cold weather requirements, should be afforded with a reasonable timeframe (i.e., 5-year reporting cycle) to remediate those issues and in some cases may have long term limitations similar to many existing generating units.	
Likes 0	

Dislikes 0	
Response	
Brian Evans-Mongeon - Utility Services, Inc. - 4	
Answer	No
Document Name	
Comment	
The SDT should clarify when is a generator considered new and when is it considered existing. In the future, once the Extreme Cold Weather Standards are approved and fully implemented, this distinction will be straightforward, but during the Implementation Period, GO/GOPs will be uncertain what category their generating units fall into.	
Likes 1	Los Angeles Department of Water and Power, 3, Skourtas Tony
Dislikes 0	
Response	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
DTE Electric supports NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	No
Document Name	
Comment	
Requirement R4 appears to already fullfill the requirement of R2. The 2 requirements should be merged into one.	
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	
No Additional Comments	
Likes 0	
Dislikes 0	
Response	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	No
Document Name	
Comment	
Alliant Energy supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation recommends each unit that is unable to have freeze protection measures implemented be reviewed every 5 years on a rolling schedule, regardless of the age of the generating unit.	
Likes 0	
Dislikes 0	
Response	

Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
It is felt that this is a duplication of Requirement R2; thus R4 is not needed.	
Likes 0	
Dislikes 0	
Response	

Christine Kane - WEC Energy Group, Inc. - 3	
Answer	No
Document Name	
Comment	
WEC Energy Group supports EEIs comments.	
Likes 0	
Dislikes 0	
Response	

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	No
Document Name	
Comment	
PG&E supports the comments provided by the North American Generators Forum (NAGF).	
Likes 0	
Dislikes 0	
Response	

Marty Hostler - Northern California Power Agency - 4, Group Name NCPA	
Answer	No

Document Name	
Comment	
NCPA agrees with the comments of NRG Energy, Inc.	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
AEPCO signed on to ACES comments below: Our answer is based upon not understanding the reason to carve out “new” generation from existing generation. We likely would be supportive of a separate requirement for “new” generation if appropriate justification for it can be provided by the SDT. If the term “new” generation continues to be utilized, we recommend the SDT develop a formal definition for the term.	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
Changes to Cold Weather Reliability Standards should not be applicable continent-wide. Standards should not be modified or implemented prior to Market Rule Modifications. See prior NERC Project 2019-06 ballot and commenting by Marty Hostler Market Rule modifications have not yet been made to mitigate potential Cold Weather Events grid issues. Per FERC/NERC's recommendation, Market Rule modifications should be made prior to, or concurrent with, development of new Standards. To date, no known Market Rule Modification project has been initiated. On page 86 of FERC/NERC's joint Report The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018 (ferc.gov) the following recommendations where made. Recommendation 1: The Team recommends a three-pronged approach to ensure Generator Owners/Generator Operators, Reliability Coordinators and Balancing Authorities prepare for cold weather conditions: 1) development or enhancement of one or more NERC Reliability Standards, 2) enhanced	

outreach to Generator Owners/Generator Operators, and 3) market (Independent System Operators/Regional Transmission Organizations) rules where appropriate. This three-pronged approach should be used to address the following needs: • The need for Generator Owners/Generator Operators to perform winterization activities on generating units to prepare for adverse cold weather, in order to maximize generator output and availability for BES reliability during these conditions. These preparations for cold weather should include Generator Owners/Generator Operators:

While any one of the three approaches may provide significant benefits in solving this problem, the Team does not view any one of the three as the only solution. The Team envisions that a successful resolution of the problem will likely involve concurrent use of all three.

Likes 0	
Dislikes 0	

Response

Jeremy Lawson - Northern California Power Agency - 5

Answer	No
Document Name	

Comment

NCPA agrees with the comments of NRG Energy, Inc.

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 supports the EEI comments and believes the GO should be the sole entity to determine technical, operational, or operational constraints that would prohibit compliance from new units.

Likes 0	
Dislikes 0	

Response

Mike Magruder - Avista - Avista Corporation - 1

Answer	No
Document Name	

Comment	
We operate in a cold weather envorpnment, the requirements for our facilities are site specific and are taken into account by the owner. We do not need this language in the standard.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
A reference to new generation in this standard will add confusion, because a “new unit” soon becomes “existing generation” after it starts up. In addition, R2 as proposed is duplicative and would be satisfied with minor modifications to consider all units “existing generation.” AEP does not believe this proposed, separate requirement is necessary for “new” generation. In addition, AEP recommends that the five year cycle specified in R2 and R4 be revised to instead be a *maximum* five year cycle, in order to allow the Generator Operator adequate opportunity to align the cycle for all generating assets. AEP supports EEI’s comments in their response to Question #5.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren agrees with the NAGF comments.	
Likes 0	
Dislikes 0	
Response	

Glenn Pressler - CPS Energy - 3	
Answer	No
Document Name	
Comment	
No, an additional Requirement appears to be redundant; all GO's should have this requirement.	
Likes 0	
Dislikes 0	
Response	
Rhonda Jones - Invenergy LLC - 5	
Answer	No
Document Name	
Comment	
Invenergy agrees that R2, as drafted, is redundant given R1 is applicable to all generating units, and R4 provides for a five year review of cold weather temperatures and freeze protection measures.	
Likes 0	
Dislikes 0	
Response	
Colin Chilcoat - Invenergy LLC - 6	
Answer	No
Document Name	
Comment	
Invenergy agrees that R2, as drafted, is redundant given R1 is applicable to all generating units, and R4 provides for a five year review of cold weather temperatures and freeze protection measures.	
Likes 0	
Dislikes 0	
Response	
Robert Stevens - CPS Energy - 5	

Answer	No
Document Name	

Comment

No, an additional Requirement appears to be redundant; all GO's should have this requirement.

Likes 0	
Dislikes 0	

Response

LaKenya VanNorman - LaKenya VanNorman On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name FMPA and Members

Answer	No
Document Name	

Comment

It may be suitable to have parallel requirements for existing and new generators, but the way the draft is written, new generators get a loose, un-enforceable "opt-out" in R2 while existing generators have no such parallel requirement. We see two issues with this. First is that "technical, commercial or operational constraints" is so broad and ambiguous that either no one will have to comply with R1, or everyone will have to, depending on how auditors interpret the requirement. This is unacceptable. Second is that we see no parallel determination of technical, commercial or operational constraints for existing generators (which are far more likely to have these issues than new ones). As far as we can tell in the draft language for existing generators, the only determination is the low one hour temperature experienced at the site since 1975, and whether the unit will run in the "winter season".

As to the question of whether the 5 year review would suffice to cover new generators, we believe any operating generator should have a "determination" on file and the 5 year review is only to re-assess units that already have a determination. So you would need something requiring new units to be evaluated before commercial operation.

Likes 0	
Dislikes 0	

Response

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Foung Mua, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Wei Shao, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; - Tim Kelley, Group Name LPPC

Answer	No
Document Name	

Comment

Requirement 4 provides sufficient coverage for new generation.

These comments have been endorsed by LPPC.

Likes 2	Colorado Springs Utilities, 1, Braunstein Mike; Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merre
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	No
Document Name	

Comment

R2 should be combined with Requirement R1 and extend to any Generator not just new Generators. As written, an entity has to be in violation of R1 to be able to leverage R2 to document its situation. If retained, R2 should be an additional item in R1 where entities either have to meet the specs as set or document the reasons it cannot due to technical, commercial, or operational constraints. R4 should be separately maintained, but should be revised to include periodic review of any determinations that the unit cannot implement the protections due to technical, commercial, or operational constraints.

Kimberly Turco on behalf of Constellation Energy Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Michelle Amarantos - APS - Arizona Public Service Co. - 5

Answer	No
Document Name	

Comment

AZPS supports EEI's comments and proposed revisions to R2.

Likes 0	
Dislikes 0	

Response

Rick Stadtlander - NEI - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
Agree with the NAGF comments.	
Likes 0	
Dislikes 0	
Response	

Kimberly Bentley - Kimberly Bentley On Behalf of: sean erickson, Western Area Power Administration, 1, 6; - Kimberly Bentley	
Answer	No
Document Name	
Comment	
Each unit that is unable to implement protection measures should be reviewed every 5 years, regardless of age or if it is a new or existing resource.	
Likes 0	
Dislikes 0	
Response	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

EEI does not agree that GOs should be given a separate requirement that allows them to, in perpetuity, have the ability to not meet the freeze protection measures set in EOP-012. Accommodations for generating units that were approved for interconnection, or where key components in the design of the resource were already purchased prior the effective date of EOP-012, should be allowed to make a determination similar to what is provided for existing resources. Otherwise, the generating resource should be designed and constructed to meet the cold weather standards set forth in EOP-012. We suggest the following:

R2. Each Generator Owner who owns generating units that were placed into commercial operation on or after the effective date of the Standard shall design those units to have freeze protection measures based on the following minimum criteria set forth in Requirement R1, parts 1.1 & 1.2; except where the cold weather criteria contained in parts 1.1 & 1.2 was not conveyed to the owner as a condition of interconnection. In these cases, 2.1 applies. [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning, Operations Planning*]

2.1 The GO shall either modify their new generating unit in compliance with Requirement R1, parts 1.1 & 1.2, and report on their efforts to remediate all issues on a 5 year cycle, or in cases where the generating unit cannot be modified fully for documented technical, commercial, or operational constraints; the GO shall make a determination per Requirement R1, part 1.4.4.

Likes 0	
Dislikes 0	

Response

Alison Mackellar - Constellation - 5

Answer	No
Document Name	

Comment

R2 should be combined with Requirement R1 and extend to any Generator not just new Generators. As written, an entity has to be in violation of R1 to be able to leverage R2 to document its situation. If retained, R2 should be an additional item in R1 where entities either have to meet the specs as set or document the reasons it cannot due to technical, commercial, or operational constraints. R4 should be separately maintained, but should be revised to include periodic review of any determinations that the unit cannot implement the protections due to technical, commercial, or operational constraints.

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 Entity Monitoring

Answer	No
Document Name	

Comment

In five years' time and in subsequent years, the generator would not be considered new, and Requirement 4 would cover those generators.

Additionally, we believe that allowing an exemption due to commercial constraints as defined by the GO is inconsistent with the concept of mandatory reliability standards. Operational constraints should be supported with a technical basis. All other operational limits are covered in R3. WECC would recommend consideration of replacing "commercial, or operational limitations" with "regulatory constraints." WECC suggests similar wording changes throughout the standard.

Likes 0	
Dislikes 0	
Response	
Mike Braunstein - Colorado Springs Utilities - 1	
Answer	No
Document Name	
Comment	
Colorado Springs Utilities agrees with comments endorsed by LPPC	
Likes 0	
Dislikes 0	
Response	
Dan Roethemeyer - Vistra Energy - 5	
Answer	No
Document Name	
Comment	
No. While R4 should be maintained to clarify the review that is required every 5 years with respect to existing weather preparedness plans and freeze protection measures, there is no basis to exclude existing resources from the exceptions in R2, when existing resources are the ones more likely to encounter technical, commercial, or operational impediments to implementing the required freeze protection measures. Thus, R2 should be modified to include existing resources and allow for such resources to determine that they cannot meet the required cold weather preparedness and freeze protection standards for technical, commercial, or operational reasons and to review that determination every 5 years. This is especially important in regions like ERCOT, which has competitive generators that do not currently get any type of guaranteed cost recovery for implementation of freeze protection or weather preparedness standards. Imposing technically, commercially, or operationally infeasible burdens on such Generator Owners may cause or accelerate retirements of existing resources. Therefore, it is important for the standard to acknowledge that technical, commercial, and operational constraints are valid bases for allowing deviations from the draft standard for existing resources, so long as such constraints are documented and reviewed regularly, as proposed in R2.	
Likes 0	
Dislikes 0	
Response	

Julie Hall - Entergy - 6, Group Name Entergy	
Answer	No
Document Name	
Comment	
Entergy's position is R4 encompasses all generation whether it is new or existing, which makes R2 unnecessary.	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 6	
Answer	No
Document Name	
Comment	
R2 is not necessary. Any new generation is subject to the design requirements of R1 and the review period of R4.	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Gerry Huitt, Xcel Energy, Inc., 5, 3, 1; - Amy Casuscelli	
Answer	No
Document Name	
Comment	
Xcel Energy supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Joe McClung - JEA - 1	

Answer	No
Document Name	
Comment	

We support LPPC's comments.

Likes 0	
Dislikes 0	
Response	

Casey Perry - Casey Perry On Behalf of: Lynn Goldstein, PNM Resources - Public Service Company of New Mexico, 1, 3; - PNM Resources - Public Service Company of New Mexico - 3 - WECC

Answer	No
Document Name	
Comment	

PNM supports having the applicability of EOP-012-1 R4 be applicable to both “new” and “existing” generating units as stated in the comment provided by EEI.

Likes 0	
Dislikes 0	
Response	

Shannon Ferdinand - Decatur Energy Center LLC - 5

Answer	No
Document Name	
Comment	

Capital Power supports the NAGF comments / concerns / suggested revisions related to this question.

Likes 0	
Dislikes 0	
Response	

Mark Spencer - LS Power Development, LLC - 5

Answer	No

Document Name	
Comment	
We do not agree that a new generator exemption is necessary. We offer that generators, including wind turbines, have been effectively operating in the upper Great Plains, Canada, Sweden, and even Antarctica for many years. If the SDT determines that it is necessary to retain the new generator exemption then we ask that they provide detailed justification why it is necessary.	
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 Regional Standards Committee	
Answer	No
Document Name	
Comment	
Requirement R4 appears to already fulfill the requirement of R2. The 2 requirements should be merged into one.	
Likes 0	
Dislikes 0	
Response	
Michele Richmond - Texas Competitive Power Advocates - NA - Not Applicable - Texas RE	
Answer	No
Document Name	
Comment	
Differentiating between new and existing generation in R2 is not necessary. This requirement as written should be considered and applied only to the retrofit of existing units as it may not be economically feasible to retrofit these units to meet the requirements in Requirement 1.1, 1.2 and 1.3. Existing units should be eligible for exemptions due to technical and operational constraints. Exemptions due to commercial concerns are unclear in the draft and need to more clearly defined. The SDT should consider changing exception for commercial reasons to commercial/economic reasons as requirement that would make a unit uneconomic will result in mothball or retirement of the unit. Exceptions for uneconomic is needed to ensure that standards do not result in greater resource adequacy problems.	
Likes 0	
Dislikes 0	
Response	

Donna Johnson - Oglethorpe Power Corporation - 5	
Answer	No
Document Name	
Comment	
Agree with ACES comments: Our answer is based upon not understanding the reason to carve out "new" generation from existing generation. We likely would be supportive of a separate requirement for "new" generation if appropriate justification for it can be provided by the SDT. If the term "new" generation continues to be utilized, we recommend the SDT develop a formal definition for the term.	
Likes 0	
Dislikes 0	
Response	

Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County	
Answer	No
Document Name	
Comment	
CHPD agrees with LPPC's comments.	
Likes 0	
Dislikes 0	
Response	

Alan Kloster - Alan Kloster On Behalf of: Allen Klassen, Evergy, 1, 3, 5, 6; Jennifer Flandermeyer, Evergy, 1, 3, 5, 6; Marcus Moor, Evergy, 1, 3, 5, 6; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy supports and includes by reference the comments of the Edison Electric Institute (EEI) for question #5.	
Likes 0	
Dislikes 0	
Response	

Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	No
Document Name	
Comment	
MidAmerican supports the MRO NSRF's comments. Requirement R2 seems unnecessary when considering Requirements R1.4.4 and R4.3. Neither Requirement R1 nor R4 stipulates the applicable facilities be either new or existing, so any generating plants constructed after the enforcement date of the Standard would be required to comply with R1.4.4 and R4.3. We recommend incorporating Requirement R2 into Requirement R1. Possible solutions are to remove the word, "existing" from the text of R1.4, or to create a new sub-requirement (R1.5.) to account for new generation within the construct of R1.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon concurs with the comments submitted by the EEI. Submitted on behalf of Exelon (Segments 1 & 3)	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	No
Document Name	
Comment	
Our answer is based upon not understanding the reason to carve out "new" generation from existing generation. We likely would be supportive of a separate requirement for "new" generation if appropriate justification for it can be provided by the SDT. If the term "new" generation continues to be utilized, we recommend the SDT develop a formal definition for the term.	
Likes 0	

Dislikes 0	

Response

Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF

Answer	No
Document Name	

Comment

SIGE does not believe separate requirements are necessary for new and existing generating units. If R2 stays as is or 'new' is incorporated into R1, SIGE requests the SDT provide a definition of 'new' generation – is this since the effective date of the Standard or does it only apply for a certain amount of time after a unit is online? The definition may impact whether R2 is necessary or if it can be addressed by R1/R4.

Likes 0	
Dislikes 0	

Response

Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1, Group Name OGE Energy - Oklahoma Gas and Electric Co.

Answer	No
Document Name	

Comment

Oklahoma Gas and Electric agrees with and endorses comments as submitted by EEI Reliability Technical Committee (RTC)

Likes 0	
Dislikes 0	

Response

Jennifer Blair - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC, Group Name PPL NERC Registered Affiliates

Answer	No
Document Name	

Comment

PPL NERC Registered Affiliates generally support EEI comments on Question 5, including proposed language for R1 in the EEI comments. However, consistent with our comments on Question 4, PPL and LG&E and KU offer the following modification to the proposed language for Requirement 2.

R2. Each Generator Owner **who owns generating units that were placed into commercial operation on or after the effective date of the Standard shall design those units to have** freeze protection measures based on the minimum criteria set forth in Requirement R1, **parts 1.1 and 1.2 and including cooling effects of wind and freezing precipitation (e.g., sleet, snow, ice, and freezing rain) according to a relevant design**

standard selected by the GO for the units geographic location except where such cold weather criteria was not conveyed to the owner as a condition of interconnection. In these cases, 2.1 applies.

2.1 **The GO shall either modify their new generating unit in compliance with Requirement R1, parts 1.1 and1.2 and including cooling effects of wind and freezing precipitation (e.g., sleet, snow, ice and freezing rain) according to a relevant design standard selected by the GO for the unit's geographic location, and report on their efforts to remediate all issues on a 5 year cycle, or in cases where the generating unit cannot be modified fully for documented technical, commercial, or operational constraints; the GO shall make a determination per Requirement R1, part 1.2.4.**

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

If R4 applies to all generation, this would include any new generation. Interconnection studies for generation added to the BES should include provisions to meet these standards prior to commercial operations or with detailed schedule for compliance if approved for construction prior to the effective date of these requirements.

Likes 0	
Dislikes 0	

Response

Dwanique Spiller - Dwanique Spiller On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Dwanique Spiller

Answer	No
Document Name	

Comment

NV Energy supports EEIs comments:

EEI does not agree that GOs should be given a separate requirement that allows them to, in perpetuity, have the ability to not meet the freeze protection measures set in EOP-012. Accommodations for generating units that were approved for interconnection, or where key components in the design of the resource were already purchased prior the effective date of EOP-012, should be allowed to make a determination similar to what is provided for existing resources. Otherwise, the generating resource should be designed and constructed to meet the cold weather standards set forth in EOP-012. We suggest the following:

R2. Each Generator Owner who owns generating units that were placed into commercial operation on or after the effective date of the Standard shall design those units to have freeze protection measures based on the following minimum criteria set forth in Requirement R1, parts 1.1, 1.2 & 1.3; except where the cold weather criteria contained in parts 1.1, 1.2 and 1.3 was not conveyed to the owner as a condition of interconnection. In these cases, 2.1 applies. [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning, Operations Planning*]

2.1 The GO shall either modify their new generating unit in compliance with Requirement R1, parts 1.1, 1.2 and 1.3, and report on their efforts to remediate all issues on a 5 year cycle, or in cases where the generating unit cannot be modified fully for documented technical, commercial, or operational constraints; the GO shall make a determination per Requirement R1, part 1.4.4.

Likes 0	
Dislikes 0	

Response

Hillary Dobson - Colorado Springs Utilities - 3

Answer	No
Document Name	

Comment

CSU supports LPPC's comments.

Likes 0	
Dislikes 0	

Response

Russell Noble - Cowlitz County PUD - 3

Answer	No
Document Name	

Comment

Advise combining the two requirements. In addition, should consider exemption for generation that has proven over decades of cold weather events, i.e., normal weather patterns regularly dip into extended freezing temperatures, that operations are minimally impacted. Performing cold weather contraint analysis periodically for generation units proven to have no problems over many years of operation serves no reliability purpose.

Likes 0	
Dislikes 0	

Response

Whitney Wallace - Calpine Corporation - 5 - WECC,Texas RE,NPCC,SERC,RF

Answer	No
Document Name	
Comment	

It is not necessary to differentiate between new and existing generation in R2. Additionally, this requirement should only apply to the retrofit of existing units as it may not be economically feasible to retrofit these units to meet the requirements in Requirement 1.1, 1.2 and 1.3. This is particularly important in regions like ERCOT with competitive generation, where generation owners do not currently have any mechanism for guaranteed cost recovery for implementation of such freeze protection measures. Existing units should also be eligible for exemptions due to technical and operational constraints, as long as these constraints are documented and regularly reviewed. Exemptions due to commercial concerns should be more clearly defined in the draft as they are currently uncelar, though Calpine proposes that the exception for commercial reasons should also be modified to reflect commercial or economic reasons; i.e. a requirement that would make a unit uneconomic such that it will result in mothball or retirement of the unit. Exceptions for economic purposes are needed to ensure that standards do not result in greater resource adequacy problems.

Likes 0	
Dislikes 0	

Response

Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)

Answer	No
Document Name	
Comment	

The SRC's recommendation is to continue a periodicity for "all" generating units to review its ongoing freeze protection measures and historical cold weather temperatures; and to provide a cost analysis of any technology that could be employed. Any GO asserting an inability to implement freeze protection measures should be required to perform a periodic review at least every 5 years to demonstrate the constraint is still valid.

Likes 0	
Dislikes 0	

Response

Sam Nietfeld - Public Utility District No. 1 of Snohomish County - 5

Answer	No
Document Name	
Comment	

SNPD supports comments submitted by LPPC and Tacoma Power

Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	No
Document Name	
Comment	
LCRA believes that all new units should be subject to Requirement 1.1 (based on criterion stated in Response to 4C), 1.2 and 1.3 for entry into the market and not be eligible for R2. This requirement as written should be considered and applied only to the retrofit of existing units as it may not be economically feasible to retrofit these units to meet the requirements in Requirement 1.1, 1.2 and 1.3. Existing units should be eligible for exemptions due to technical and operational constraints. Exemptions due to commercial concerns are unclear in the draft and need to be more clearly defined. The SDT should consider changing the exception for commercial reasons to commercial/economic reasons. If left unclear, the commercial exemption may not apply if following the requirement would not make economic sense, resulting in mothball or retirement of the unit. Exemptions for uneconomic reasons are needed to ensure that this standard does not result in greater resource adequacy problems.	
Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1	
Answer	No
Document Name	
Comment	
LCRA believes that all new units should be subject to Requirement 1.1(based on criterion stated in Response to 4C), 1.2 and 1.3 for entry into the market and not be eligible for R2. This requirement as written should be considered and applied only to the retrofit of existing units as it may not be economically feasible to retrofit these units to meet the requirements in Requirement 1.1, 1.2 and 1.3. Existing units should be eligible for exemptions due to technical and operational constraints. Exemptions due to commercial concerns are unclear in the draft and need to be more clearly defined. The SDT should consider changing the exception for commercial reasons to commercial/economic reasons. If left unclear, the commercial exemption may not apply if following the requirement would not make economic sense, resulting in mothball or retirement of the unit. Exemptions for uneconomic reasons are needed to ensure that this standard does not result in greater resource adequacy problems.	
Likes 0	
Dislikes 0	
Response	
John Babik - JEA - 5	

Answer	No
Document Name	
Comment	
We support LPPC's comments	
Likes 0	
Dislikes 0	
Response	
Ashley Scheelar - TransAlta Corporation - 5	
Answer	No
Document Name	
Comment	
TransAlta supports comments provided by NAGF.	
Likes 0	
Dislikes 0	
Response	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
All exceptions identified by Generator Owners that are submitted to NERC per proposed EOP-012, must be distributed to the applicable BA and TOP. This not only includes the original exception, any subsequent status reports but also the results of the five year reviews. If these units are not expected to be able to generate under specific weather conditions, and the BA and TOP are still expected to provide all necessary electric power, the BA and TOP need to know the status of all resources.	
Likes 0	
Dislikes 0	
Response	
Randy Buswell - VELCO -Vermont Electric Power Company, Inc. - 1	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Mason - Portland General Electric Co. - 6, Group Name PGE FCD	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Redundant information that a 5-year review is acceptable to be included.	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	

Technical reasons may be mitigated over time by development of newer technology or methods. Therefore, a review should occur. The frequency of five years may be too frequent, however. A definition of "new" generation should also be described in R2, and there should be clarification on when R2 does not apply.

Likes 0	
Dislikes 0	

Response

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF

Answer	Yes
Document Name	

Comment

A declaration that the GO cannot meet the constraints is good, but the Requirement does not specify to whom the declaration must be made. Is it simply a compliance document, or should the requirement specify that the impacted BA(s) be notified of the constraint?

Likes 0	
Dislikes 0	

Response

Tony Skourtas - Los Angeles Department of Water and Power - 3

Answer	Yes
Document Name	

Comment

A definition for New Generating Unit should be provided. As written, I would interpret that R2 would apply to new Generating Units in their first year. After the first year of operation, they will be considered existing Generating units, in which case R1.4 will apply.

Likes 0	
Dislikes 0	

Response

Michael Dillard - Austin Energy - 5

Answer	Yes
Document Name	

Comment

Requirement 2 is needed to address the documentation needed to substantiate whether the constraints related to new generating units not able to implement freeze protection measures still exist or apply after a 5 year duration. This particular review of determination is not necessarily addressed in R4.	
Likes 0	
Dislikes 0	
Response	
Rebecca Baldwin - Transmission Access Policy Study Group - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Requirement R4 as currently drafted would not require GOs to review constraints previously documented pursuant to R2 (or R1.4.4 or R6); the separate requirement is therefore necessary. As noted in our response to Question 4, we believe that the distinction between "new" and "existing" generators should be dropped, R1.4.4 deleted, and most of the text of R2 added (with appropriate edits) to R1 as R1.5. R2's five-year review requirement, however, should instead be moved to R4, as R4.4. Doing so would have two benefits: it would consolidate the five-year reviews in a single Requirement for ease of reference, and it would allow GOs to perform all of their five-year reviews on the same cycle, rather than potentially tracking multiple staggered cycles.	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	Yes
Document Name	
Comment	
Acciona Energy supports Midwest Reliability Organization's (MRO) NERC Standards Review Forum's (NSRF) comments on this question.	
Likes 0	
Dislikes 0	
Response	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	Yes

Document Name	
Comment	

R2 should be employeed to capture all “new” generation, however 2.2 can be removed with the utilization of R4. In addition, one needs to be concerned about the inclusion of commercial as a rationale for not completing freeze protection measures for new generators. Does this provide an opportunity on the basis of cost not implement such measures? if so, then the same latitude must be afforded existing units on the basis of cost until such time an adequate FERC compensation strategy is implemented. Therefore, R4 should be further updated to be equivalent to the framework offered by R2.

Likes 0	
Dislikes 0	
Response	

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	Yes
Document Name	
Comment	

Leave R2 as written and add the following to R2: …freeze protection measures for new “ and existing” generating unit(s)…

Likes 0	
Dislikes 0	
Response	

Michael Watt - Oklahoma Municipal Power Authority - 4

Answer	Yes
Document Name	
Comment	

I agree with TAPs comments, pasted below:

Requirement R4 as currently drafted would not require GOs to review constraints previously documented pursuant to R2 (or R1.4.4 or R6); the separate requirement is therefore necessary. As noted in our response to Question 4, we believe that the distinction between “new” and “existing” generators should be dropped, R1.4.4 deleted, and most of the text of R2 added (with appropriate edits) to R1 as R1.5. R2’s five-year review requirement, however, should instead be moved to R4, as R4.4. Doing so would have two benefits: it would consolidate the five-year reviews in a single Requirement for ease of reference, and it would allow GOs to perform all of their five-year reviews on the same cycle, rather than potentially tracking multiple staggered cycles.

Likes 0	
Dislikes 0	

Response	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	Yes
Document Name	
Comment	
Requirement R4 as currently drafted would not require GOs to review constraints previously documented pursuant to R2 (or R1.4.4 or R6); the separate requirement is therefore necessary. As noted in our response to Question 4, we believe that the distinction between "new" and "existing" generators should be dropped, R1.4.4 deleted, and most of the text of R2 added (with appropriate edits) to R1 as R1.5. R2's five-year review requirement, however, should instead be moved to R4, as R4.4. Doing so would have two benefits: it would consolidate the five-year reviews in a single Requirement for ease of reference, and it would allow GOs to perform all of their five-year reviews on the same cycle, rather than potentially tracking multiple staggered cycles.	
Likes 0	
Dislikes 0	
Response	
Natalie Johnson - Enel Green Power - 5	
Answer	Yes
Document Name	
Comment	
A separate requirement that recognizes the technical, commercial and operational constraints when implementing new freeze protection measures for a new site is helpful. The process for implementing new freeze protection measures will be different from the process of modifying existing as there is no baseline to correct if it is a new design. This difference can be addressed as a separate requirement for new and existing or another separate subrequirement under R1. Either option can be used to address the different processes for implementation of freeze protection measures. However it is unclear when a new site becomes an existing site. Will there be a date threshold? For example, sites that come online in 2022 are considered new, however, in 2025 are they still to be considered new or do the existing site requirements (R1.4) apply after a certain time.	
Likes 0	
Dislikes 0	
Response	
Dana Showalter - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	

Q5. ERCOT supports the SRC comments. ERCOT does not believe R2 is necessary because new units would be covered by the general requirement in R1. Also, because developers of units that will come into service after the compliance date of this standard (i.e., 5 years after FERC approval) should have full advance knowledge of the performance requirements, we see no legitimate reason for an exemption from this requirement, unless the impediment arose after the date the generator began operations.

Likes 0	
Dislikes 0	

Response

Sean Steffensen - IDACORP - Idaho Power Company - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Marty Watson - Santee Cooper - 5, Group Name Santee Cooper

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Jamie Monette - Allete - Minnesota Power, Inc. - 1

Answer	Yes
Document Name	

Comment

Likes 0	

Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	
AECI and its members support comments provided by ACES.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not think a separate requirement for new generation is necessary and has not typically been done in the NERC Reliability Standards. New generation should be subject to the same requirements as existing generation in Requirement R4. If Requirement R2 is upheld, the question would be when the new generation is not considered "new" and when the transition from Requirement R2 to Requirement R4 occurs. Texas RE strongly recommends making clear that new generation shall perform EOP-012-1 R4 prior to the commercial operation date (COD) date as defined in the Registration Policy. Texas RE recommends clarifying when a newly registered entity would be subject to compliance if it is registered during the time period after the effective date of the order, but prior to the compliance date for Requirements R1 and R2. Please see Texas RE's comments to question #9 regarding Requirement R4 periodicity.	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	NAGF EOP-012-1 06152022 final.pdf
Comment	

NAGF Comments: The SDT has not identified what determines a new generator versus an existing generator. Therefore, either the SDT must add information to the requirement to identify these units that qualify as new or treat all units the same, regardless of age. The NAGF recommends that all units be subject to the same requirements, so Requirement 2 is not needed.

The NAGF has provided a revised EOP-012-1standard for consideration that address these issues in a reasonable manner. Please review the proposed changes to the standard.

Likes 0	
Dislikes 0	

Response

Tom Vinson - American Clean Power Association - 5

Answer	
Document Name	

Comment

ACP finds it difficult to respond “yes” or “no” to this question. On the one hand, if R2 is removed, the remaining language would seem to suggest that new generation would be subject to doing a Corrective Action Plan under 1.4 as there would be no distinction between “new” and “existing.” On the other hand, it is a bit confusing as originally drafted too in terms of what applies to “new” and what applies to “existing.”

As an alternative, ACP recommends relocating R2 under R1 as a new section 1.5. That clarifies there is a single standard for all generation, but establishes separate compliance pathways for new and existing. The SDT could also consider clarifying what is considered “new” and what is considered “existing.” Perhaps a resource becomes existing upon the initial 5-year review period.

Likes 0	
Dislikes 0	

Response

Lisa Martin - Austin Energy - 6

Answer	
Document Name	

Comment

I support comments made by Michael Dillard, Austin Energy, Segment 5.

Likes 0	
Dislikes 0	

Response

Jun Hua - Austin Energy - 4	
Answer	
Document Name	
Comment	
I support comments made by Michael Dillard, Austin Energy, Segment 5	
Likes 0	
Dislikes 0	
Response	

Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC is not a registered Generator Owner or Generator Operator.	
Likes 0	
Dislikes 0	
Response	

6. The Standard, as proposed, would require Generator Owners to develop plans for modifying generating units to operate to the minimum hourly temperature over the next five years after Commission approval. While Generator Owners identify those generating units that need modifications, develop corrective action plans, and implement modifications, it is important for the ERO Enterprise to have aggregated data about the status of Generation Owners' extreme cold weather preparedness for its generating units for use in its reliability oversight activities.

The SDT believes that there is benefit to having the ERO Enterprise collect information on progress of Generator Owner plans for modifying generating units. The information could be collected through reporting under mandatory Reliability Standard requirements, through a Periodic Data Submittal under Section 400 of the Rules of Procedure (which may or may not be specified in the Compliance section of the standard), or through a request for data under Section 1600 of the Rules of Procedure. Which of these options do you believe is the best procedural option for collecting this information?

Ashley Scheelar - TransAlta Corporation - 5	
Answer	No
Document Name	
Comment	
TransAlta presented in preceding questions that we successfully operate in extreme cold in regions that do not have the type of reliability risk being addressed by this standard. Therefore, there should be no need for data requests. However, if a data request is required it would be best if the entities requesting have the discretion to determine in what regions/generators that information is useful and only request information of those entities. In addition, it is best if a centralized approach is taken as entities like ours operate in many regions and still manage requests and requirements on various platforms and portals which is still very challenging to manage, even with the advent of Align.	
Likes 0	
Dislikes 0	
Response	

John Babik - JEA - 5	
Answer	No
Document Name	
Comment	
We support LPPC's comments	
Likes 0	
Dislikes 0	
Response	

James Baldwin - Lower Colorado River Authority - 1	
Answer	No

Document Name	
Comment	
LCRA suggests GO data is best provided to regional Transmission Planner/Planning Coordinator for aggregation and provided to the ERO who can provide to FERC as desired.	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	No
Document Name	
Comment	
LCRA suggests GO data is best provided to regional Transmission Planner/Planning Coordinator for aggregation and provided to the ERO who can provide to FERC as desired.	
Likes 0	
Dislikes 0	
Response	
Dana Showalter - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
Q6. ERCOT supports the SRC comments.	
Likes 0	
Dislikes 0	
Response	
Whitney Wallace - Calpine Corporation - 5 - WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	

Comment	
Calpine joins the comments of the TCPA and does not have additional comments on this question.	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	No
Document Name	
Comment	
No is selected to indicate the SDT should avoid data collection for the ERO under a standard requirement unless a defined reliability gap is being addressed. If NERC determines a value in tracking progress of generation unit modification efforts, data collection should be under Section 1600 as developed by NERC, not the SDT. This allows the ERO to modify data collection as necessary, including termination without a standard revision. If compliance monitoring is the objective, then Section 400 is appropriate for requirements meeting reliability objectives.	
Likes 0	
Dislikes 0	
Response	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	No
Document Name	
Comment	
MidAmerican supports EEI's comments. Section 1600 cannot be used to collect entity information on their progress to modify affected generating units because the Rules of Procedure are clear that "Section 1600 shall not apply to Requirements contained in any Reliability Standard to provide data or information." CAPs are compliance obligations clearly defined by EOP-012. For this reason, Section 400 of the Rules of Procedure should be used.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Allen Klassen, Evergy, 1, 3, 5, 6; Jennifer Flandermeyer, Evergy, 1, 3, 5, 6; Marcus Moor, Evergy, 1, 3, 5, 6; - Alan Kloster	

Answer	No
Document Name	
Comment	
Evergy supports and includes by reference the comments of the Edison Electric Institute (EEI) for question #6.	
Likes 0	
Dislikes 0	
Response	
Mark Spencer - LS Power Development, LLC - 5	
Answer	No
Document Name	
Comment	
As we discuss in our response to Q3 we believe that it is more important for the BAs to be active participants in defining the specified operating conditions, defining their need in MWs, and managing the data collection to ensure that their Operating Plans are in mesh with generator cold weather preparedness. Reporting should flow through and by the BAs, not around.	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments and would recommend clarification on how this information is going to be used to verify which section of the Rules of Procedure should be referenced.	
Likes 0	
Dislikes 0	
Response	
Joe McClung - JEA - 1	

Answer	No
Document Name	
Comment	
We support LPPC's comments.	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Gerry Huitt, Xcel Energy, Inc., 5, 3, 1; - Amy Casuscelli	
Answer	No
Document Name	
Comment	
Xcel Energy believes Section 400 of the Rules of Procedure is the appropriate avenue to collect this data.	
Likes 0	
Dislikes 0	
Response	
Michael Watt - Oklahoma Municipal Power Authority - 4	
Answer	No
Document Name	
Comment	
I agree with TAPs comments, pasted below: The information should be collected through a Periodic Data Submittal via the Align tool, which is already being used for other Periodic Data Submittals. It should not be a Reliability Standard requirement.	
Likes 0	
Dislikes 0	
Response	
Alison Mackellar - Constellation - 5	

Answer	No
Document Name	
Comment	

No new data collection process needs to be created by the Standard. Processes currently exist to obtain this data, e.g., Section 1600 data requests, which allow pertinent data to be obtained as deemed necessary by the entities needing the data. Without a confirmed need on the part of the proposed recipient of the data, the usefulness of data gathering and reporting is low.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	

Kimberly Bentley - Kimberly Bentley On Behalf of: sean erickson, Western Area Power Administration, 1, 6; - Kimberly Bentley

Answer	No
Document Name	
Comment	

While either of these options are tools at disposal of the ERO entertprise, progress information is not required by any reliability standard. The ERO Enterprise does not collect information on the progress of implementing any other new standards. This type of data collection would be purely administrative and would not improve reliability. Without additional information on how the data would be used beyond an administrative collection tool, it is not clear where the benefit lies.

Likes 0	
Dislikes 0	
Response	

Rick Stadtlander - NEI - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	
Comment	

Agree with the NAGF comments.

Likes 0	
Dislikes 0	

Response	
Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	
No new data collection process needs to be created by the Standard. Processes currently exist to obtain this data, e.g., Section 1600 data requests, which allow pertinent data to be obtained as deemed necessary by the entities needing the data. Without a confirmed need on the part of the proposed recipient of the data, the usefulness of data gathering and reporting is low. Kimberly Turco on behalf of Constellation Energy Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren agrees with the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	

This would not apply, based on our review for compliance with EOP 11-2 our plants have operated to conditions as low as experienced in the region (-22 deg F, -38.5 deg F when considering wind chill during that event) and we believe they could operate if the temperature decreased another 10 or 20 degrees. We are already in compliance with this standard so no data submittal for a compliance plan will be required.

Likes 0	
Dislikes 0	

Response

Jeremy Lawson - Northern California Power Agency - 5

Answer	No
Document Name	

Comment

NCPA does not believe there is reason to implement additional reporting requirements and agrees with the comments of NRG Energy, Inc.

Likes 0	
Dislikes 0	

Response

Dennis Sismaet - Northern California Power Agency - 6

Answer	No
Document Name	

Comment

Changes to Cold Weather Reliability Standards should not be applicable continent-wide. Standards should not be modified or implemented prior to Market Rule Modifications. See prior NERC Project 2019-06 ballot and commenting by Marty Hostler

Market Rule modifications have not yet been made to mitigate potential Cold Weather Events grid issues. Per FERC/NERC's recommendation, Market Rule modifications should be made prior to, or concurrent with, development of new Standards. To date, no known Market Rule Modification project has been initiated.

On page 86 of FERC/NERC's joint Report The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018 (ferc.gov) the following recommendations where made.

Recommendation 1: The Team recommends a three-pronged approach to ensure Generator Owners/Generator Operators, Reliability Coordinators and Balancing Authorities prepare for cold weather conditions: 1) development or enhancement of one or more NERC Reliability Standards, 2) enhanced outreach to Generator Owners/Generator Operators, and 3) market (Independent System Operators/Regional Transmission Organizations) rules where appropriate. This three-pronged approach should be used to address the following needs: • The need for Generator Owners/Generator Operators to perform winterization activities on generating units to prepare for adverse cold weather, in order to maximize generator output and availability for BES reliability during these conditions. These preparations for cold weather should include Generator Owners/Generator Operators:

While any one of the three approaches may provide significant benefits in solving this problem, the Team does not view any one of the three as the only solution. The Team envisions that a successful resolution of the problem will likely involve concurrent use of all three.

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 4, Group Name NCPA

Answer	No
Document Name	

Comment

NCPA does not believe there is reason to implement additional reporting requirements and agrees with the comments of NRG Energy, Inc.

Likes 0	
Dislikes 0	

Response

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments

Answer	No
Document Name	

Comment

PG&E supports the comments by the North American Generators Forum (NAGF) comments.

Likes 0	
Dislikes 0	

Response

Claudine Bates - Black Hills Corporation - 6

Answer	No
Document Name	

Comment

BHP is supportive of Section 400 or 1600 Reporting as opposed to mandatory reporting through a Reliability Standard Requirement.

Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation does not agree there is a benefit to having the ERO Enterprise collect information on progress of Generator Owner plans for modifying generating units. Progress information is not required by any reliability standard. The ERO Enterprise does not collect information on the progress of implementing any other new standards. This type of data collection would be purely administrative and would not improve reliability.	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	No
Document Name	
Comment	
We support the RSC comments.	
Likes 0	
Dislikes 0	
Response	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
DTE Electric supports NAGF comments.	
Likes 0	

Dislikes 0	
Response	
Brian Evans-Mongeon - Utility Services, Inc. - 4	
Answer	No
Document Name	
Comment	
This data collection should not be a mandatory Reliability Standard requirement, and would make more sense as a Periodic Data Submittal	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Dominion Energy supports both EEI and NAGF comments and does not agree that Section 1600 could be used to collect entity information on their progress to modify affected generating units because the Rules of Procedure are clear that "Section 1600 shall not apply to Requirements contained in any Reliability Standard to provide data or information." CAPs are compliance obligations clearly defined by EOP-012. For this reason, Section 400 of the Rules of Procedure should be used if this information is collected at all. Dominion Energy agrees with the NATF comments that this information being provided to NERC does not add a reliability benefit.	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	No
Document Name	
Comment	

NRG agrees with comments made by the NAGF that Generator related capability data based upon progress of modifying units in accordance with implementation plan under Requirement 1.4 would not be as useful for identifying areas of potential concern than data directly from the planning entities, assuming the planning entities are using the information provided by the Generator Owners. This information is best provided by the Generator Owners to the Transmission Planner or Planning Coordinator (who use this info for the necessary planning studies) who can then provide it to the ERO, who can then provide it to FERC as desired. This avoids duplicate and sometimes conflicting information.

Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA supports the comments submitted by the US Bureau of Reclamation.	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	

NRG agrees with comments made by the NAGF that Generator related capability data based upon progress of modifying units in accordance with implementation plan under Requirement 1.4 would not be as useful for identifying areas of potential concern than data directly from the planning entities, assuming the planning entities are using the information provided by the Generator Owners. This information is best provided by the Generator Owners to the Transmission Planner or Planning Coordinator (who use this info for the necessary planning studies) who can then provide it to the ERO, who can then provide it to FERC as desired. This avoids duplicate and sometimes conflicting information.

Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	

Answer	No
Document Name	
Comment	
Section 1600 would be appropriate until ERO could see that CAP efforts are complete.	
Likes 0	
Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
SEC does not believe that data requests are necessary. Has the SDT taken into consideration how many entities need to make modifications and the frequency of modification. The standard indicates entities already must have a plan. This would be a burden on the entity and regulatory board reviewing this. SEC believes that the new standard addresses this concern in the requirements.	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
This would not apply, based on our review for compliance with EOP 11-2 our plants have operated to conditions as low as experienced in the region (-22 deg F, -38.5 deg F when considering wind chill during that event) and we believe they could operate if the temperature decreased another 10 or 20 degrees. We are already in compliance with this standard so no data submittal for a compliance plan will be required.	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 1,5	

Answer	No
Document Name	
Comment	
We are questioning the added value for the specific operating context of some Canadian entities' hydroelectric that have generation units already designed and operated in cold and extreme weather decades ago.	
Likes 0	
Dislikes 0	
Response	
Sam Nietfeld - Public Utility District No. 1 of Snohomish County - 5	
Answer	Yes
Document Name	
Comment	
SNPD supports comments submitted by LPPC and Tacoma Power	
Likes 0	
Dislikes 0	
Response	
Natalie Johnson - Enel Green Power - 5	
Answer	Yes
Document Name	
Comment	
Data requests are the preferred option under Section 1600 Rules of Procedures. Similar to GADS and MIDAS, data submittal dates are scheduled and deadlines are provided to entities in advance and therefore submittal due dates and methods are consistent. In addition, it is important to note that this type of data is not used for compliance evaluation purposes thereby enabling entities to keep their focus on meeting the requirements of the standard.	
Likes 0	
Dislikes 0	
Response	
Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1, Group Name OGE Energy - Oklahoma Gas and Electric Co.	

Answer	Yes
Document Name	
Comment	

Oklahoma Gas and Electric agrees with and endorses comments as submitted by EEI Reliability Technical Committee (RTC)

Likes 0	
Dislikes 0	
Response	

Casey Perry - Casey Perry On Behalf of: Lynn Goldstein, PNM Resources - Public Service Company of New Mexico, 1, 3; - PNM Resources - Public Service Company of New Mexico - 3 - WECC

Answer	Yes
Document Name	
Comment	

Section 400 of the Rules of Procedure

Likes 0	
Dislikes 0	
Response	

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	Yes
Document Name	
Comment	

Duke Energy suggest the aggregated data be collected through NERC Section 1600 — Request for Data or Information.

Likes 0	
Dislikes 0	
Response	

Gerry Adamski - Cogentrix Energy Power Management, LLC - 5

Answer	Yes
Document Name	

Comment	
PDS would be the best process for this status update.	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	Yes
Document Name	
Comment	
Acciona Energy supports Midwest Reliability Organization’s (MRO) NERC Standards Review Forum’s (NSRF) comments on this question.	
Likes 0	
Dislikes 0	
Response	
Robert Stevens - CPS Energy - 5	
Answer	Yes
Document Name	
Comment	
We agree with the collection of data under Section 1600 rather than from a new standard requirement. However, we have some concerns with what is included in the “generating unit” definition, so more clarity is needed to know what is in scope.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3	
Answer	Yes
Document Name	
Comment	

WEC Energy Group supports EEIs comment in favor of Section 400 of the Rules of Procedure.

Likes 0	
Dislikes 0	

Response

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Alliant Energy supports the comments submitted by the MRO NSRF.	
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 has no preference as to the method of reporting, however any Generator cold weather data should be provided to the applicable RCs/BAs/TOPs/PCs/TPs. The EROs already have a method to retrieve periodic data from the BAs under BAL-003. A similar method could be used for the GO cold weather data.	
Likes 0	
Dislikes 0	
Response	

Mark Young - Tenaska, Inc. - 5	
Answer	Yes
Document Name	
Comment	

Periodic Data Submittal is the best method.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	Yes
Document Name	

Comment

FirstEnergy agrees with EEI's comments and agree with the Data Submittal applying to Section 400 of the Rules of Procedure

Likes 0	
Dislikes 0	

Response

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	Yes
Document Name	

Comment

Since both of these rules of procedures are a tool that the ERO can use to see CAP statuses, either is a valuable option for the ERO.

Likes 2	Corn Belt Power Cooperative, 1, brusseau larry; Lincoln Electric System, 1, Johnson Josh
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	Yes
Document Name	

Comment

In addition to the ERO Enterprise collecting information on Generator Owner progress on its plans for modifying generating units, the same information should be provided to their respective Balancing Authorities.

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

We agree with the collection of data under Section 1600 rather than from a standard requirement standpoint. However, we share the same concerns from other entities on the equipment included in the “generating unit” as some of the equipment may be in heated facilities or indoors where they may never see those temperatures. So, more clarity is needed to know what is in scope.

Likes 0	
Dislikes 0	

Response

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merrell, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; - Jennie Wike, Group Name Tacoma Power

Answer	Yes
Document Name	

Comment

Tacoma Power prefers utilizing Section 1600 for data collection, similar to what was implemented for the GMD Standards Project.

Likes 0	
Dislikes 0	

Response

Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)

Answer	
Document Name	

Comment

In addition to the ERO Enterprise collecting information on Generator Owner progress on its plans for modifying generating units, the SRC is requesting this same information be provided to Regional Entities, Reliability Coordinators, Balancing Authorities, Planning Coordinators, Transmission Planners, and Transmission Operators. An additional modification to EOP-012-1, along with a form for Generator Owners to populate, may be used similar to how data is collected in BAL-003-2 Frequency Response and Frequency Bias Setting Attachment A, where the ERO is able to collect data from Balancing Authorities on an established periodic basis.

Likes 0	
Dislikes 0	

Response

Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	
Document Name	

Comment

CenterPoint Energy Houston Electric, LLC is not a registered Generator Owner or Generator Operator.

Likes 0	
Dislikes 0	

Response

Jun Hua - Austin Energy - 4

Answer	
Document Name	

Comment

I support comments made by Michael Dillard, Austin Energy, Segment 5

Likes 0	
Dislikes 0	

Response

Hillary Dobson - Colorado Springs Utilities - 3

Answer	
Document Name	

Comment	
Section 1600. CSU supports LPPC's comments.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Dwanique Spiller On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Dwanique Spiller	
Answer	
Document Name	
Comment	
NV Energy supports EEI's comments. Section 1600 cannot be used to collect entity information on their progress to modify affected generating units because the Rules of Procedure are clear that "Section 1600 shall not apply to Requirements contained in any Reliability Standard to provide data or information." CAPs are compliance obligations clearly defined by EOP-012. For this reason, Section 400 of the Rules of Procedure should be used.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
We prefer a request for data under Section 1600 of the Rules of Procedure.	
Likes 0	
Dislikes 0	
Response	
Jennifer Blair - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC, Group Name PPL NERC Registered Affiliates	
Answer	

Document Name	
Comment	

PPL and LGE and KU support EEI comments on Question 6.

Likes 0	
Dislikes 0	
Response	

Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF

Answer	
Document Name	
Comment	

Similar to other entities; SIGE would like clarity on what is in scope from a ‘generating unit’ standpoint. Additionally, if a ‘data submittal’ is required, the information is better suited for the Planning Coordinators as it may impact their studies. Their resulting studies could then be provided to the ERO.

Likes 0	
Dislikes 0	
Response	

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

Answer	
Document Name	
Comment	

Periodic Data Submital under Section 400 of the Rules of Procedures.

Likes 0	
Dislikes 0	
Response	

Daniel Gacek - Exelon - 1

Answer	
Document Name	
Comment	

Exelon concurs with the comments submitted by the EEI.

Submitted on behalf of Exelon (Segments 1 & 3)

Likes 0	
Dislikes 0	

Response

Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County

Answer	
Document Name	

Comment

CHPD agrees with LPPC's comments.

Likes 0	
Dislikes 0	

Response

Donna Johnson - Oglethorpe Power Corporation - 5

Answer	
Document Name	

Comment

Please explain: Why it is important for the ERO Enterprise to have this information? See additional comments under #7.

Likes 0	
Dislikes 0	

Response

Michele Richmond - Texas Competitive Power Advocates - NA - Not Applicable - Texas RE

Answer	
Document Name	

Comment

NERC does not need detailed information on progress on the CAP's. Ultimately, the requirements of the EOP-012-1 require development of the CAP and implementing the CAP. The generator owners should be required to provide a timeline for units to be compliant with the RS but not periodic progress reports. An annual statement that the generator owner is on schedule with the CAP should be sufficient for NERC.

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 Regional Standards Committee

Answer	
Document Name	

Comment

RSC abstains from commenting on the best procedural option and trusts that the ERO Enterprise is best suited to make such a determination.

Likes 0	
Dislikes 0	

Response

Shannon Ferdinand - Decatur Energy Center LLC - 5

Answer	
Document Name	

Comment

Capital Power supports the NAGF comments / concerns / suggested revisions related to this question. Capital Power encourages NERC to focus on the facilitation of a centralized and consistent data portal for all of the regions (i.e. Align).

Likes 0	
Dislikes 0	

Response

Devon Tremont - Taunton Municipal Lighting Plant - 1

Answer	
Document Name	

Comment

The information should be collected through a Periodic Data Submittal via the Align tool, which is already being used for other Periodic Data Submittals. It should not be a Reliability Standard requirement.

Likes 0	
Dislikes 0	

Response

Marty Watson - Santee Cooper - 5, Group Name Santee Cooper

Answer	
Document Name	

Comment

We believe the report should follow Section 1600.

Likes 0	
Dislikes 0	

Response

Diana Torres - Imperial Irrigation District - 6

Answer	
Document Name	

Comment

IID prefers utilizing Section 1600 for data collection.

Likes 0	
Dislikes 0	

Response

Julie Hall - Entergy - 6, Group Name Entergy

Answer	
Document Name	

Comment

Entergy supports data submittal under Section 1600 of the Rules of Procedure.

Likes 0	
Dislikes 0	

Response

Dan Roethemeyer - Vistra Energy - 5

Answer	
Document Name	

Comment

Luminant joins the comments of the Texas Competitive Power Advocates (TCPA) and does not have any additional comments on this question.

Likes 0	
Dislikes 0	

Response

Mike Braunstein - Colorado Springs Utilities - 1

Answer	
Document Name	

Comment

Colorado Springs Utilities agrees with comments endorsed by LPPC

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

A yes or no response does not conform to the question contained in Question 6, therefore, EEI has not selected either response. Our response regarding a Section 400 vs. a Section 1600 data request is as provided below:

Section 1600 cannot be used to collect entity information on their progress to modify affected generating units because the Rules of Procedure are clear that “Section 1600 shall not apply to Requirements contained in any Reliability Standard to provide data or information.” CAPs are compliance obligations clearly defined by EOP-012. For this reason, Section 400 of the Rules of Procedure should be used.	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 5	
Answer	
Document Name	
Comment	
AZPS supports EEI’s comments that Section 400 of the Rules of Procedure should be used.	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Foung Mua, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Wei Shao, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; - Tim Kelley, Group Name LPPC	
Answer	
Document Name	
Comment	
LPPC prefers utilizing Section 1600 of the Rules of Procedure for data collection, similar to what was implemented with the GMD Standards Project, in which FERC simultaneously approved TPL-007-1 and directed the collection of data by way of Section 1600. These comments have been endorsed by LPPC.	
Likes 2	Colorado Springs Utilities, 1, Braunstein Mike; Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merre
Dislikes 0	
Response	

Lisa Martin - Austin Energy - 6	
Answer	
Document Name	
Comment	
I support comments made by Michael Dillard, Austin Energy, Segment 5.	
Likes 0	
Dislikes 0	
Response	
LaKenya VanNorman - LaKenya VanNorman On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name FMPA and Members	
Answer	
Document Name	
Comment	
FMPA and members support TAPS comments on question 6	
Likes 0	
Dislikes 0	
Response	
Rebecca Baldwin - Transmission Access Policy Study Group - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
The information should be collected through a Periodic Data Submittal via the Align tool, which is already being used for other Periodic Data Submittals. It should not be a Reliability Standard requirement.	
Likes 0	

Dislikes 0	
Response	
Michael Dillard - Austin Energy - 5	
Answer	
Document Name	
Comment	
Section 1600 would be preferable	
Likes 0	
Dislikes 0	
Response	
Colin Chilcoat - Invenergy LLC - 6	
Answer	
Document Name	
Comment	
Invenergy believes that a request for data in the ERO Portal under Section 1600 of the Rules of Procedure is the best procedural option for collecting Generator Owner information regarding the modification of its generating units per EOP-012-1 R1.	
Likes 0	
Dislikes 0	
Response	
Rhonda Jones - Invenergy LLC - 5	
Answer	
Document Name	
Comment	
Invenergy believes that a request for data in the ERO Portal under Section 1600 of the Rules of Procedure is the preferred procedural option for collecting Generator Owner information regarding the modification of its generating units per EOP-012-1 R1.	
Likes 0	
Dislikes 0	

Response	
Glenn Pressler - CPS Energy - 3	
Answer	
Document Name	
Comment	
We agree with the collection of data under Section 1600 rather than from a new standard requirement. However, we have some concerns with what is included in the "generating unit" definition, so more clarity is needed to know what is in scope.	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	NAGF EOP-012-1 06152022 final.pdf
Comment	
NAGF Comments: The NAGF notes that information related to Generator weather capability should be used by the Transmission Planners, Planning Authorities, Balancing Authorities and Transmission Operators. To the extent that NERC and/or FERC wants information related to an area's expected ability to survive an extreme weather event, the Transmission Planner or Planning Coordinator would be the better entity to provide this information to the ERO who can then provide it to FERC as desired. The NAGF notes that if the planners asked for and utilized information from the generators identifying the pertinent data, this information would be available in the processes already in place. Generator Owner level information is not as useful for identifying areas of potential concern than data directly from the planning entities, assuming the planning entities are using the information provided by the Generator Owners. The NAGF has provided a revised EOP-012-1 standard for consideration that address these issues in a reasonable manner. Please review the proposed changes to the standard.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	

AEP believes it would be preferable for this information to be provided outside of NERC data requests, and instead be provided as part of attestations submitted to RTO's in an agreed-upon format and schedule.

If NERC however does choose to make these data requests themselves, we would encourage that those requests not be unduly burdensome on industry in terms of either their detail or frequency. Between the two options suggested, AEP would prefer they be Section 400 requests. In addition, we don't believe Section 1600 data requests would be appropriate in this case, as the ROP states that "the provisions of Section 1600 shall not apply to Requirements contained in any Reliability Standard to provide data or information."

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

Southern Company supports the EEI comments but would like more clarity concerning the proposed methods of submitting information pertaining to EOP-012 and how that data would be collected/reported.

Likes 0	
Dislikes 0	

Response

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1

Answer	
Document Name	

Comment

AEPCO signed on to ACES comments below:

Periodic Data Submital under Section 400 of the Rules of Procedures.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	
Comment	
Texas RE recommends using Section 1600 of the Rules of Procedure, rather than the Periodic Data Submittal process. This would eliminate possible PNCs from occurring due to Generator Owner engagement in PDS process. This would also provide for a review by Reliability personnel, rather than Compliance personnel.	
Likes 0	
Dislikes 0	
Response	
Randy Buswell - VELCO -Vermont Electric Power Company, Inc. - 1	
Answer	
Document Name	
Comment	
VELCO abstains from commenting on the best procedural option, and trusts that the ERO Enterprise is best suited to make such a determination.	
Likes 0	
Dislikes 0	
Response	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	
Document Name	
Comment	
Section 1600	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	

Document Name	
Comment	
AECI and its members support comments provided by ACES.	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Gul Khan On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Gul Khan	
Answer	
Document Name	
Comment	
N/A. Oncor is not registered as a Generator Owner/Operator.	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	
Document Name	
Comment	
NA	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	
Document Name	
Comment	

No comment on what method is more effective.

Likes 0	
Dislikes 0	

Response

7. The drafting team has developed a proposed data collection framework which could form the basis for a periodic data submittal. If you have any comments or edits to the suggested language, please propose an alternative to address the identified risk during the phased-in compliance period.

Collection framework:

- **The Generator Owner will submit an annual summary table by October 1 of each year to its Regional Entity regarding the status of its generating units (as that term is used in EOP-012-1 4.2 Facilities) having freeze protection measures in accordance with Requirements R1 and R2, along with a nine-year projection of status based on the timetables it has determined for Requirement R1. All projections will be based on the Generator Owner's timetables under Requirement R1.4.2; if timetables are not complete for all units, some MW can be designated as "to be determined." The summary table shall contain:**
  - **Status year (for current year, and future years 1-9);**
  - **Sum of capacities (in MW) of all generating units applicable under Facilities, section 4.2;**
  - **Sum of capacities (MW) of generating units meeting (for current year) and projected to meet (for each of the future years 1-9) the criteria of Requirement R1.1;**
  - **Sum of capacities (MW) of generating units not meeting (for current year) and projected to not meet (for each of the future years 1-9) the criteria of Requirement R1.1;**
  - **Sum of the capacities (MW) of existing generating units declared for no action under Requirement R1 (for current year, and projected for future years 1-9);**
  - **Sum of the capacities (MW) of new generating units identified for no action under Requirement R2 (for current year, and projected for future years 1-9).**

Nazra Gladu - Manitoba Hydro - 1	
Answer	
Document Name	
Comment	
The recording of units forced outage status and derates, will steer existing and new generation owners and operators to weatherize their units and auxillary systems, as it's available capacity will affect the profitability to the units. This incentive is the best driver to see the goal of generation reliability improved.	
Likes 0	
Dislikes 0	
Response	

LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	
Document Name	
Comment	
Recommend that this data request cover the listed bullets by primary fuel type to quickly identify trends.	
Likes 0	

Dislikes 0	

Response

Gul Khan - Gul Khan On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Gul Khan

Answer	
Document Name	

Comment

No Comments.

Likes 0	
Dislikes 0	

Response

Carl Pineault - Hydro-Qu?bec Production - 1,5

Answer	
Document Name	

Comment

We are questioning the added value of EOP-012 for the specific operating context of some Canadian entites' hydroelectric generating units.

For Canadian entites, the necessary cold weather practices are already in place. The administrative burden associated to the tasks being required in the standards outweigh the reliability benefits, as we already have a good handle on planning, operations and maintenance activites in cold (and even extreme cold) weather.

Likes 0	
Dislikes 0	

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer	
Document Name	

Comment

AECI and its members support comments provided by ACES.

Likes 0	

Dislikes 0	

Response

Glen Farmer - Avista - Avista Corporation - 5

Answer	
Document Name	

Comment

We are already in compliance with the standard for all of our facilities and will not need to submit a compliance plan.

Likes 0	
Dislikes 0	

Response

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merrell, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; - Jennie Wike, Group Name Tacoma Power

Answer	
Document Name	

Comment

The final guidance for the periodic data submittal should be inclusive of all generation types. For example, hydroelectric unit capacities are dependent on multiple factors and a unit may not operate to its full nameplate capacity. Based on the above, the guidance should specify whether the “sum of capacities” means the nameplate capacity or an estimate of the available capacity for the upcoming season.

Likes 0	
Dislikes 0	

Response

Kristine Ward - Seminole Electric Cooperative, Inc. - 1

Answer	
Document Name	

Comment

This seems duplicative of what entities already send to the RC and regional entity.

Likes 0	

Dislikes 0	
Response	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
Ok with the framework. This may also be added as data collection under Section 1600.	
Likes 0	
Dislikes 0	
Response	
Randy Buswell - VELCO -Vermont Electric Power Company, Inc. - 1	
Answer	
Document Name	
Comment	
VELCO requests that SDT consider whether October 1 provides enough lead time to support the needs of BAs to make necessary preparations for the winter weather season.	
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	

Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	
Document Name	
Comment	
If this is information the Planning Coordinators and Transmission Planners can use, then NRG would rather submit this information to the PC or TP who could then send it to the Regional Entity. Generator Owners sending additional data to the Regional Entities duplicates work and may cause conflicting information.	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	
Document Name	
Comment	
In general, Idaho Power does not believe this level of tracking is needed. Idaho Power proposes an aggregated summary submittal to coincide every five years along with R4. Utilities with prior operating freeze issues should be subject to periodic reporting.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
BPA supports the comments submitted by the US Bureau of Reclamation.	
Likes 0	
Dislikes 0	
Response	

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	
The SDT should not require this granular amount of data and a specific time frame, within this Standard. If this type of information is required, perhaps it can be requested under the construct of question 6. This will allow the RE to determine what highest risk generators that they want to review concerning any CAP progress.	
Likes 2	Corn Belt Power Cooperative, 1, brusseau larry; Lincoln Electric System, 1, Johnson Josh
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	
Document Name	
Comment	
If this is information the Planning Coordinators and Transmission Planners can use, then NRG would rather submit this information to the PC or TP who could then send it to the Regional Entity. Generator Owners sending additional data to the Regional Entities duplicates work and may cause conflicting information.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
FirstEnergy questions why the annual table summary would be to the Regional Entity – in some cases RF- and suggest submitting to **the** BA and not to Regional Entity	
Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	
Document Name	
Comment	
Dominion Energy supports NAGF comments and does not support this reporting requirement.	
Likes 0	
Dislikes 0	
Response	

Mark Young - Tenaska, Inc. - 5	
Answer	
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	

Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	
Document Name	
Comment	
DTE Electric supports NAGF comments.	
Likes 0	
Dislikes 0	
Response	

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	
Document Name	
Comment	
We support the RSC comments. Additionally, We are questioning the added value of EOP-012 for the specific operating context of some Canadian entites' hydroelectric generating units. This is an unnecessary administrative burden for all the generating units, especially Canadian entites' generating units.	
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	
ISO-NE supports the data collection and requests this information be submitted to the following entities: Regional Entities, Reliability Coordinators, Balancing Authorities, Planning Coordinators, Transmission Planners and Transmission Operators	
Likes 0	
Dislikes 0	
Response	

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	
Document Name	
Comment	
Alliant Energy supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	

Response

Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	
Document Name	
Comment	
Reclamation does not support the proposed data collection. First, its purpose is not identified. Second, any reliability benefit it may provide is not identified. Therefore, it appears to be an additional ask of industry with no purpose and no benefit, which will only serve to detract already limited resources from implementing the newly required activities. Reclamation recommends NERC leverage the existing GADS reporting to satisfy this type of data collection.	
Likes 0	
Dislikes 0	
Response	

Claudine Bates - Black Hills Corporation - 6	
Answer	
Document Name	
Comment	
No alternative suggestions. The company would have ‘designed and implemented’ freeze protection measures into new facilities prior to commissioning.	
Likes 0	
Dislikes 0	
Response	

Christine Kane - WEC Energy Group, Inc. - 3	
Answer	
Document Name	
Comment	
WEC Energy Group supports EEIs comments.	
Likes 0	
Dislikes 0	

Response	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	
Document Name	
Comment	
PG&E supports the comments provided by the North American Generators Forum (NAGF).	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE recommends that it would be most useful for the GO to submit its annual summary table to its BA, rather than its Regional Entity since the Regional Entity would not have an action with the data. This would support key recommendation 1g as it would give the BA the status of the generating units and the data could assist with determining the generating unit capacity that can be relied upon forecasted cold weather.	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 4, Group Name NCPA	
Answer	
Document Name	
Comment	
NCPA does not support collection of this data and agrees with the comments of the U.S. Bureau of Reclamation.	
Likes 0	
Dislikes 0	

Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	
No comments at this time.	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	
Document Name	
Comment	

Changes to Cold Weather Reliability Standards should not be applicable continent-wide. Standards should not be modified or implemented prior to Market Rule Modifications. See prior NERC Project 2019-06 ballot and commenting by Marty Hostler

Market Rule modifications have not yet been made to mitigate potential Cold Weather Events grid issues. Per FERC/NERC's recommendation, Market Rule modifications should be made prior to, or concurrent with, development of new Standards. To date, no known Market Rule Modification project has been initiated.

On page 86 of FERC/NERC's joint Report The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018 (ferc.gov) the following recommendations where made.

Recommendation 1: The Team recommends a three-pronged approach to ensure Generator Owners/Generator Operators, Reliability Coordinators and Balancing Authorities prepare for cold weather conditions: 1) development or enhancement of one or more NERC Reliability Standards, 2) enhanced outreach to Generator Owners/Generator Operators, and 3) market (Independent System Operators/Regional Transmission Organizations) rules where appropriate. This three-pronged approach should be used to address the following needs: • The need for Generator Owners/Generator Operators to perform winterization activities on generating units to prepare for adverse cold weather, in order to maximize generator output and availability for BES reliability during these conditions. These preparations for cold weather should include Generator Owners/Generator Operators:

While any one of the three approaches may provide significant benefits in solving this problem, the Team does not view any one of the three as the only solution. The Team envisions that a successful resolution of the problem will likely involve concurrent use of all three.

Likes 0	
Dislikes 0	
Response	

Jeremy Lawson - Northern California Power Agency - 5	
Answer	
Document Name	
Comment	
NCPA does not support collection of this data and agrees with the comments of the U.S. Bureau of Reclaimation.	
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	
Southern Company supports the EEI comments and would include language to share this information with each generator's applicable BA and RC.	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	
Document Name	
Comment	
We are already in compliance with the standard for all of our facilities and will not need to submit a compliance plan.	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	
AEP does not see a need to include the last bullet for “Sum of the capacities (MW) of new generating units identified for no action under Requirement R2 (for current year, and projected for future years 1-9)”, and recommends that it be deleted from the suggested list. We believe it is duplicative of the fourth bullet which states “Sum of capacities (MW) of generating units not meeting (for current year) and projected to not meet (for each of the future years 1-9) the criteria of Requirement R1.1.”	
Likes 0	
Dislikes 0	
Response	

David Jendras - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
Ameren agrees with the NAGF comments.	
Likes 0	
Dislikes 0	
Response	

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
NAGF Comments: Please refer to NAGF’s comments to Questions 3, 4 and 6 above. It is NAGF’s position that this level of information will not be helpful to identify areas of concern for the reasons stated in those responses.	
Likes 0	
Dislikes 0	
Response	

Glenn Pressler - CPS Energy - 3	
Answer	
Document Name	
Comment	
This seems duplicative of what entities already send to the RC/BA, recommend RC/BA be required to send to the regional entity. 9-year requirement is too long and should be reduced to 5-year or less. The entirety of Standard EOP-012-1 should have a 5-year implementation plan. The Generator Owners will need sufficient time to develop compliant procedures and practices. Further, the scheduling and financing of modifications will require greater than 18 months.	
Likes 0	
Dislikes 0	
Response	

Rhonda Jones - Invenergy LLC - 5	
Answer	
Document Name	
Comment	
Invenergy recommends coordinating the scope of the data request with BAs and other regulatory authorities who are making, and have already made, similar requests in order to reduce the administrative burden for Generator Owners.	
Likes 0	
Dislikes 0	
Response	

Colin Chilcoat - Invenergy LLC - 6	
Answer	
Document Name	
Comment	
Invenergy recommends coordinating the scope of the data request with BAs and other regulatory authorities who are making, and have already made, similar requests in order to reduce the administrative burden for Generator Owners.	
Likes 0	

Dislikes 0	

Response

Robert Stevens - CPS Energy - 5

Answer	
Document Name	

Comment

This seems duplicative of what entities already send to the RC/BA, recommend RC/BA be required to send to the regional entity. 9-year requirement is too long and should be reduced to 5-year or less.

The entirety of Standard EOP-012-1 should have a 5-year implementation plan. The Generator Owners will need sufficient time to develop compliant procedures and practices. Further, the scheduling and financing of modifications will require greater than 18 months.

Likes 0	
Dislikes 0	

Response

Michael Dillard - Austin Energy - 5

Answer	
Document Name	

Comment

The guidance should specify whether the “sum of capacities” means the nameplate capacity or an estimate of the available capacity for the upcoming season

Likes 0	
Dislikes 0	

Response

Tom Vinson - American Clean Power Association - 5

Answer	
Document Name	

Comment

ACP does not have an objection to the proposed data collection, however, we note that BAs and other regulatory authorities are requesting similar information. ACP recommends coordination and collaboration happen between BAs, EROs, state PUCs etc. who are making similar requests in order to settle on a single set of data that GOs collect on extreme cold weather performance for submission to the various authorities.	
Likes 0	
Dislikes 0	
Response	
LaKenya VanNorman - LaKenya VanNorman On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name FMPA and Members	
Answer	
Document Name	
Comment	
This seems convoluted. Entities should not be reporting a 9 year projection, as this is an odd number since planning studies go out to ten years. Some of these quantities don't seem logical as a projection beyond year 1- We see no scenario where we would have a new plant in year 8 that we were projecting to not be able to meet freeze protection requirements. There is no language in R1 that discusses "no action", is it the SDT's intent that there is "no change from the prior year's plan"? In general, FMPA supports the concept of reporting status but believe the RE should continue to be responsible for Periodic Data Submittals as they deem appropriate based on their forecasted risks.	
Likes 0	
Dislikes 0	
Response	
Lisa Martin - Austin Energy - 6	
Answer	
Document Name	
Comment	
I support comments made by Michael Dillard, Austin Energy, Segment 5.	
Likes 0	
Dislikes 0	
Response	

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Foung Mua, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Wei Shao, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; - Tim Kelley, Group Name LPPC	
Answer	
Document Name	
Comment	
The final guidance for the data collection (LPPC considers a Section 1600 data request more appropriate), should be inclusive of all generation types. For example, hydroelectric unit capacities are dependent on multiple factors and a unit may not operate to its full nameplate capacity. Based on the above, the guidance should specify whether the “sum of capacities” means the nameplate capacity or an estimate of the available capacity for the upcoming season. These comments have been endorsed by LPPC.	
Likes 2	Colorado Springs Utilities, 1, Braunstein Mike; Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merre
Dislikes 0	
Response	

Kimberly Turco - Constellation - 6	
Answer	
Document Name	
Comment	
CEG is concerned that standard based periodic data requests will be difficult to manage over time. The CEG concerns include: any desired changes would require a new standard development project to accomplish; the proposed data has not been vetted with those who might need the data; the data collection inserts a time-table for completion of actions under the Standard that does not appear in the Standard. CEG would instead urge the drafting team to encompass any data requests and collections under the Section 1600 data request process. The Section 1600 data request process is more flexible to update over time as data points or needs change. Such flexibility would allow planning entities across the ERO to tailor the data request as applicable. The Section 1600 Data Request allows for industry comments. Kimberly Turco on behalf of Constellation Energy Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Michelle Amarantos - APS - Arizona Public Service Co. - 5	
Answer	
Document Name	
Comment	
AZPS supports the reporting proposal.	
Likes 0	
Dislikes 0	
Response	

Rick Stadtlander - NEI - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
Agree with the NAGF comments.	
Likes 0	
Dislikes 0	
Response	

Kimberly Bentley - Kimberly Bentley On Behalf of: sean erickson, Western Area Power Administration, 1, 6; - Kimberly Bentley	
Answer	
Document Name	
Comment	
It remains unclear what the benefit of the proposed PDS would offer. Its purpose is not identified. Any reliability benefit it may provide is not identified. Therefore, it appears to be an additional ask of industry with no purpose and no benefit, which will only serve to detract already limited resources from implementing the newly required activities. Other reporting tools, such as GADS, exist to satisfy this type of data collection.	
Likes 0	
Dislikes 0	
Response	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	

Answer	
Document Name	
Comment	

EEI supports the reporting proposal as submitted.

Likes 0	
Dislikes 0	
Response	

Alison Mackellar - Constellation - 5

Answer	
Document Name	
Comment	

CEG is concerned that standard based periodic data requests will be difficult to manage over time. The CEG concerns include: any desired changes would require a new standard development project to accomplish; the proposed data has not been vetted with those who might need the data; the data collection inserts a time-table for completion of actions under the Standard that does not appear in the Standard. CEG would instead urge the drafting team to encompass any data requests and collections under the Section 1600 data request process. The Section 1600 data request process is more flexible to update over time as data points or needs change. Such flexibility would allow planning entities across the ERO to tailor the data request as applicable. The Section 1600 Data Request allows for industry comments.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	

Mike Braunstein - Colorado Springs Utilities - 1

Answer	
Document Name	
Comment	

Colorado Springs Utilities agrees with comments endorsed by LPPC

Likes 0	
Dislikes 0	

Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	
Comment	
If a timetable is specified in R1, Part 1.4.2, it seems that including the phrase “to be determine” is not necessary. WECC offers the following language as an option for consideration. “All projections will be based on the GO’s timetable under Requirement R1, Part 1.4.2. If timetables are not finalized for all units, the GO may provide an estimate for completion or list the end date of the implementation plan.	
Likes 0	
Dislikes 0	
Response	
Dan Roethemeyer - Vistra Energy - 5	
Answer	
Document Name	
Comment	
Luminant has no comments on this question.	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	
Document Name	
Comment	
Entergy requests clarification on the definition of capacity. Entergy also recommends a 1-5 year future projection as opposed to 1-9 year. Separating new and existing generating units doesn’t add value.	
Likes 0	

Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	
Document Name	
Comment	
Acciona Energy supports Midwest Reliability Organization’s (MRO) NERC Standards Review Forum’s (NSRF) comments on this question.	
Likes 0	
Dislikes 0	
Response	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 6	
Answer	
Document Name	
Comment	
But should not be required if the units are exempt from from EOP-012-1 as IID proposes.	
Likes 0	
Dislikes 0	
Response	

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	

Duke Energy suggest the following modifications:

Add the word “existing” to Bullet #1: …table by October 1 of each year to its Regional Entity regarding the status of its “existing” generating units…

Likes 0	
Dislikes 0	
Response	

Amy Casuscelli - Amy Casuscelli On Behalf of: Gerry Huitt, Xcel Energy, Inc., 5, 3, 1; - Amy Casuscelli	
Answer	
Document Name	
Comment	

Xcel Energy supports this reporting proposal.

Likes 0	
Dislikes 0	
Response	

Marty Watson - Santee Cooper - 5, Group Name Santee Cooper	
Answer	
Document Name	
Comment	

The proposed language is somewhat unclear in its present form. It may be clear enough to comment on if presented in the format of the actual Summary Table.

Likes 0	
Dislikes 0	
Response	

Joe McClung - JEA - 1	
Answer	
Document Name	
Comment	
We support LPPC's comments.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - Casey Perry On Behalf of: Lynn Goldstein, PNM Resources - Public Service Company of New Mexico, 1, 3; - PNM Resources - Public Service Company of New Mexico - 3 - WECC	
Answer	
Document Name	
Comment	
PNM agrees with the proposed data submittal framework.	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
Minnesota Power agrees with NSRF’s comments.	
Likes 0	
Dislikes 0	
Response	
Shannon Ferdinand - Decatur Energy Center LLC - 5	

Answer	
Document Name	
Comment	

Capital Power supports the NAGF comments / concerns / suggested revisions related to this question. Capital Power encourages NERC to focus on the facilitation of a centralized and consistent data portal for all of the regions (i.e. Align).

Likes 0	
Dislikes 0	
Response	

Mark Spencer - LS Power Development, LLC - 5

Answer	
Document Name	
Comment	

Since R7.2.0 of EOP-011-02 already requires generator owners to define the conditions that they are able to operate under, it seems more informative for the generators to provide the quantity of MWs that are not able to comply with R1.1 and the design conditions that they are expected to be able to operate at. It seems more useful from a planning and progress reporting perspective to report on the shape of the MW vs temperature curves by BA.

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 Regional Standards Committee

Answer	
Document Name	
Comment	

We are questioning the added value of EOP-012 for the specific operating context of some Canadian entities' hydroelectric generating units.

RSC requests that SDT consider whether October 1 provides enough lead time to support the needs of BAs to make necessary preparations for the winter weather season.

This is an unnecessary administrative burden for all the generating units, especially Canadian entities generating units.

Likes 0	
Dislikes 0	

Response

Michele Richmond - Texas Competitive Power Advocates - NA - Not Applicable - Texas RE

Answer	
Document Name	

Comment

If this is information the Planning Coordinators and Transmission Planners can use, then TCPA would rather submit this information to the PC or TP who could then send it to the Regional Entity. Generator Owners sending additional data to the Regional Entities duplicates work and may cause conflicting information

Likes 0	
Dislikes 0	

Response

Donna Johnson - Oglethorpe Power Corporation - 5

Answer	
Document Name	

Comment

This submittal does not contribute to the overall reliability of the BES and is an administrative burden on GOs.

Likes 0	
Dislikes 0	

Response

Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County

Answer	
Document Name	

Comment

CHPD agrees with LPPC's comments.

Likes 0	

Dislikes 0	

Response

Alan Kloster - Alan Kloster On Behalf of: Allen Klassen, Evergy, 1, 3, 5, 6; Jennifer Flandermeyer, Evergy, 1, 3, 5, 6; Marcus Moor, Evergy, 1, 3, 5, 6; - Alan Kloster

Answer	
Document Name	

Comment

Evergy supports and includes by reference the comments of the Edison Electric Institute (EEI) for question #7.

Likes 0	
Dislikes 0	

Response

Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3

Answer	
Document Name	

Comment

MidAmerican believes that a 9-year forecast is too uncertain to be useful; a shorter forecast of no more than 2-5 years seems more appropriate.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	
Document Name	

Comment

Exelon concurs with the comments submitted by the EEI.

Submitted on behalf of Exelon (Segments 1 & 3)

Likes 0	
Dislikes 0	

Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	
Document Name	
Comment	
No comments at this time.	
Likes 0	
Dislikes 0	
Response	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	
Document Name	
Comment	
If this information is to be provided, SIGE has the following comments: • SIGE interpreted “Regional Entity” to mean Reliability First (for our area). If that is a correct interpretation, SIGE believes this information should not be provided to the “Regional Entity. • SIGE believes this information is better suited for the Planning Coordinators. • SIGE would like additional clarity on the ‘capacities’ in the framework – is that nameplate or available capacity for winter season?	
Likes 0	
Dislikes 0	
Response	
Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1, Group Name OGE Energy - Oklahoma Gas and Electric Co.	
Answer	
Document Name	
Comment	
Oklahoma Gas and Electric agrees with and endorses comments as submitted by EEI Reliability Technical Committee (RTC)	
Likes 0	
Dislikes 0	

Response

Jennifer Blair - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC, Group Name PPL NERC Registered Affiliates	
Answer	
Document Name	
Comment	
PPL NERC Registered Affiliates support EEI comments on Question 7.	
Likes 0	
Dislikes 0	
Response	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
No Comment.	
Likes 0	
Dislikes 0	
Response	

Dwanique Spiller - Dwanique Spiller On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Dwanique Spiller	
Answer	
Document Name	
Comment	
NV Energy believes that a 9-year forecast is too uncertain to be useful, a shorter forecast of no more than 2-5 years seems more appropriate.	
Likes 0	
Dislikes 0	
Response	

Hillary Dobson - Colorado Springs Utilities - 3	
Answer	
Document Name	
Comment	
CSU supports LPPC's comments.	
Likes 0	
Dislikes 0	
Response	

Russell Noble - Cowlitz County PUD - 3	
Answer	
Document Name	
Comment	
This fails to address a reliability gap. Suggest this be placed under the Section 1600 process as developed by NERC.	
Likes 0	
Dislikes 0	
Response	

Daniel Mason - Portland General Electric Co. - 6, Group Name PGE FCD	
Answer	
Document Name	
Comment	
Portland General Electric Company does not agree with establishing a fixed date for the proposed periodic data submittal. The Regional Entity should retain the flexibility to take of advantage of opportunities to minimize Responsible Entity reporting burdens, through consolidation of this PDS with other existing data requests, such as WECC's annual Loads and Resources data request. Also, the Generator Owner's projection information should also be disseminated to the Generator Owner's BA.	
Likes 0	
Dislikes 0	
Response	

Jun Hua - Austin Energy - 4

Answer	
Document Name	

Comment

I support comments made by Michael Dillard, Austin Energy, Segment 5

Likes 0	
Dislikes 0	

Response

Whitney Wallace - Calpine Corporation - 5 - WECC,Texas RE,NPCC,SERC,RF

Answer	
Document Name	

Comment

The BA (or the agency with regulatory oversite of the Balancing Authority) should be the entity to determine requirement for submission of information and the content of the same. This will avoid potential duplication and conflict between information already collected by the BA (or applicable oversite authorities) and any new standard.

Likes 0	
Dislikes 0	

Response

Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	
Document Name	

Comment

CenterPoint Energy Houston Electric, LLC is not a registered Generator Owner or Generator Operator.

Likes 0	
Dislikes 0	

Response

Natalie Johnson - Enel Green Power - 5

Answer	
Document Name	

Comment

The data collection framework proposed is fair, however, the BAs are also requesting this type of information on a regular basis as well as other regulatory entities. Will there be improved coordination between different regulatory entities all requiring similar information?

Likes 0	
Dislikes 0	

Response

Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)

Answer	
Document Name	

Comment

The SRC supports this data collection and requests this information to be submitted by the Generator Owners to the Regional Entities, Reliability Coordinators, Balancing Authorities, Planning Coordinators, Transmission Planners and Transmission Operators. Per our response to Question 7, the SRC recommends the addition of this data request via an Attachment to EOP-012-1 to allow for a defined periodic data submittal. The SRC requests the following questions be added to this data request:

Sum of capacities (in MW) by each generating unit

o   By units not applicable under Facilities, section 4.2

o   By units applicable under Facilities, section 4.2

Likes 0	
Dislikes 0	

Response

Dana Showalter - Electric Reliability Council of Texas, Inc. - 2

Answer	
Document Name	

Comment

Q7. ERCOT supports the SRC comments. ERCOT encourages a thoughtful and efficient process to achieve this awareness.

Likes 0	
Dislikes 0	

Response

Sam Nietfeld - Public Utility District No. 1 of Snohomish County - 5

Answer	
Document Name	

Comment

SNPD supports comments submitted by LPPC and Tacoma Power

Likes 0	
Dislikes 0	

Response

Teresa Krabe - Lower Colorado River Authority - 5

Answer	
Document Name	

Comment

LCRA suggests this framework is overly burdensome and concerned this type of information is better suited for the regional Transmission Planner/Reliability Coordinator/Balancing Authority. The Regional Entity can inquire with these entities to evaluate risks/issues with implementation on a more global aggregate perspective.

Likes 0	
Dislikes 0	

Response

James Baldwin - Lower Colorado River Authority - 1

Answer	
Document Name	

Comment

LCRA suggests this framework is overly burdensome and concerned this type of information is better suited for the regional Transmission Planner/Reliability Coordinator/Balancing Authority. The Regional Entity can inquire with these entities to evaluate risks/issues with implementation on a more global aggregate perspective.

Likes 0	
Dislikes 0	

Response

John Babik - JEA - 5

Answer	
Document Name	

Comment

We support LPPC's comments

Likes 0	
Dislikes 0	

Response

Ashley Scheelar - TransAlta Corporation - 5

Answer	
Document Name	

Comment

These data requirements add to the administrative burden described in previous responses. There should not be any data requirement in regions where there is no reliability risk. However, if a data request is required, it is best if a centralized approach is taken as entities like ours operate in many regions and still manage requests and requirements on various platforms and portals which is still very challenging to manage, even with the advent of Align.

Likes 0	
Dislikes 0	

Response

9. The SDT is proposing an 18-month implementation time frame for all revised and new requirements except EOP-012-1 Requirements R1 and R2 which have a 5-year implementation time frame. Do you agree with this implementation time frame? If you think an alternate timeframe is needed, please propose an alternate implementation plan and time period, and provide a detailed explanation of actions planned to meet the implementation deadline.

Ashley Scheelar - TransAlta Corporation - 5	
Answer	No
Document Name	
Comment	
TransAlta likely has no need to implement any “new” freeze protection measures due to the fact we operate successfully in extreme cold. However, for generators that have large fleets and many changes to make, this 5-year implementation timeframe is not reasonable for the reasons NAGF and others have raised in their comments.	
Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1	
Answer	No
Document Name	
Comment	
LCRA suggests a 10 year implementation period is more reasonable and in line with other implemenation periods (i.e. – MOD-026 and MOD-027).	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	No
Document Name	
Comment	
LCRA suggests a 10 year implementation period is more reasonable and in line with other implemenation periods (i.e. – MOD-026 and MOD-027).	
Likes 0	

Dislikes 0	
Response	
Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)	
Answer	No
Document Name	
Comment	
The SRC recommends a twelve month implementation time frame for all revised and new requirements; and a three year implementation time frame for EOP-012-1 Requirements R1 and R2 as this seems to be a sufficient amount of time to become compliant given that the new requirements were included in The Joint Inquiry Report published on November 18, 2021, the additional year for standard development and regulatory review requirements. A twelve month implementation would only miss implementation for one winter (2023-2024).	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	No
Document Name	
Comment	
As the standards are drafted, the implementation plan appears very aggressive. This could have the effect of implementing design changes that prove ineffective. Agree with NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Michele Richmond - Texas Competitive Power Advocates - NA - Not Applicable - Texas RE	
Answer	No
Document Name	
Comment	

EOP-011-3 and EOP-012-1 should meet the key recommendations in The Report. Unfortunately, Key Recommendation #2 regarding cost recovery is not addressed. Compliance with EOP-012-1 should be tied to the presence of cost recovery mechanisms in the generator's marketplace. If there is no provision available for cost recovery, compliance with EOP-012-1 should be deferred until a suitable cost recovery mechanism is available to the generator. Further comments on cost recovery from TCPA are contained in our response to Question #10.	
Likes 0	
Dislikes 0	
Response	
Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	No
Document Name	
Comment	
Capital Power supports the NAGF comments / concerns / suggested revisions related to this question.	
Likes 0	
Dislikes 0	
Response	
Marty Watson - Santee Cooper - 5, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
Five year is not enough time to allow for design budgets to be approved, followed by construction budgets and finally implementation of the new designs. Every GO in the nation will be calling on a handful of design engineers, followed by orders for the same heat trace and inulating materials, as well as the limited number of contractors qualified for installation. MOD-026 and MOD-027 were allotted a 10 year implementation period with percentage milestones along the way. Leading up to the first milestone of these Standards there were no conctractors available for more than a year in advance. The same bottleneck will be experienced for EOP-012 but will last longer than a year because multiple disciplines are required during each phase (engineering and construction).. Giving a 10 year implementation will alleviate the bottleneck during subsequent milestones.	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	

Answer	No
Document Name	

Comment

A 36-month implementation time frame is suggested for all revised and new requirements except EOP-012-1 Requirements R1 and R2 which should be assigned a 10-year implementation time frame. The basis for these time frames follow:

Requirement R1 will likely require existing sites to retrofit generating units to meet the minimum hourly temperature experienced at the site since 1/1/1975. Although new standards are often implemented 18 months after being accepted or implemented based on fleet completion percentages over several years, R1 will require a detailed engineering analysis to evaluate site conditions to retrofit equipment at each site.

To determine if a component/system must be retrofitted, current design capabilities must be known. Many older generating sites do not have design basis documentation that provide an in-depth analysis of winter impacts, especially winter impacts for the minimum hourly temperature experienced at the site since 1/1/1975. To implement this requirement, many sites will therefore first have to perform a detailed analysis of all cold weather critical components/systems to determine current winter capability design, followed by an extensive retrofit analysis and implementation. The baseline analysis alone could take several years to perform for older units and likely involve extensive contractor support. As stated, the above descibed work would challenge a site's ability to meet any normal implementation methods commonly used by NERC.

Likes 0	
Dislikes 0	

Response

Alison Mackellar - Constellation - 5

Answer	No
Document Name	

Comment

An 18 month implementation will not allow enough time for a large fleet to ensure all units are compliant, to complete required analysis, design change and schedule vendor/contractor resources. Implementation schedule could reflect fleet size, for example 5 years for a large fleet. For comparison, MOD-026 and MOD-027 had a 10 year implementation period. MOD-025, PRC-019 and PRC-024 all had 5 year implementation periods. The proposed requirement that could require every unit to upgrade their capability will require a great deal more resources and manpower than any of these other standards.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Kimberly Bentley - Kimberly Bentley On Behalf of: sean erickson, Western Area Power Administration, 1, 6; - Kimberly Bentley

Answer	No
Document Name	
Comment	

The implementation period stated in the plan for EOP-012-1 R1-R2 is 42 months, not the above stated 60 months. There should also be consideration that EOP-011-2 is not yet even effective, resulting in ineffective use of resources associated with the planning and adjustments required to satisfy moving compliance requirements.

Likes 0	
Dislikes 0	
Response	

Rick Stadtlander - NEI - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	
Comment	

Agree with the NAGF comments.

Likes 0	
Dislikes 0	
Response	

Kimberly Turco - Constellation - 6

Answer	No
Document Name	
Comment	

An 18 month implementation will not allow enough time for a large fleet to ensure all units are compliant, to complete required analysis, design change and schedule vendor/contractor resources. Implementation schedule could reflect fleet size, for example 5 years for a large fleet. For comparison, MOD-026 and MOD-027 had a 10 year implementation period. MOD-025, PRC-019 and PRC-024 all had 5 year implementation periods. The proposed requirement that could require every unit to upgrade their capability will require a great deal more resources and manpower than any of these other standards.

Kimberly Turco on behalf of Constellation Energy Segments 5 and 6

Likes 0	

Dislikes 0	

Response

LaKenya VanNorman - LaKenya VanNorman On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name FMPA and Members

Answer	No
Document Name	

Comment

FMPA does not believe the time frames to be reasonable based on the unfavorable language and technical basis of the standards as presented.

FMPA and members additionally support TAPS comments on question 9

Likes 0	
Dislikes 0	

Response

Robert Stevens - CPS Energy - 5

Answer	No
Document Name	

Comment

The entirety of Standard EOP-012-1 should have a 5-year implementation plan. The Generator Owners will need sufficient time to develop compliant procedures and practices. GO engineering analysis, development, planning, outage scheduling, etc. require greater than 18 months.

Likes 0	
Dislikes 0	

Response

Glenn Pressler - CPS Energy - 3

Answer	No
Document Name	

Comment

The entirety of Standard EOP-012-1 should have a 5-year implementation plan. The Generator Owners will need sufficient time to develop compliant procedures and practices. GO engineering analysis, development, planning, outage scheduling, etc. require greater than 18 months.

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren agrees with the NAGF comments.	
Likes 0	
Dislikes 0	
Response	

Jeremy Lawson - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
NCPA agrees with the comments of MRO NSRF.	
Likes 0	
Dislikes 0	
Response	

Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	

Changes to Cold Weather Reliability Standards should not be applicable continent-wide. Standards should not be modified or implemented prior to Market Rule Modifications. See prior NERC Project 2019-06 ballot and commenting by Marty Hostler

Market Rule modifications have not yet been made to mitigate potential Cold Weather Events grid issues. Per FERC/NERC's recommendation, Market Rule modifications should be made prior to, or concurrent with, development of new Standards.   To date, no known Market Rule Modification project has been initiated.

On page 86 of FERC/NERC's joint Report The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018 (ferc.gov) the following recommendations where made.

Recommendation 1: The Team recommends a three-pronged approach to ensure Generator Owners/Generator Operators, Reliability Coordinators and Balancing Authorities prepare for cold weather conditions: 1) development or enhancement of one or more NERC Reliability Standards, 2) enhanced outreach to Generator Owners/Generator Operators, and 3) market (Independent System Operators/Regional Transmission Organizations) rules where appropriate. This three-pronged approach should be used to address the following needs: • The need for Generator Owners/Generator Operators to perform winterization activities on generating units to prepare for adverse cold weather, in order to maximize generator output and availability for BES reliability during these conditions. These preparations for cold weather should include Generator Owners/Generator Operators:

While any one of the three approaches may provide significant benefits in solving this problem, the Team does not view any one of the three as the only solution. The Team envisions that a successful resolution of the problem will likely involve concurrent use of all three.

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 4, Group Name NCPA

Answer	No
Document Name	

Comment

NCPA agrees with the comments of the MRO NSRF provided in their extended comments on question 10.

Likes 0	
Dislikes 0	

Response

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments

Answer	No
Document Name	

Comment

PG&E supports the comments provided by the North American Generators Forum (NAGF).	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation recommends a 24-month implementation plan. Once again, modifications are being proposed to standards that are not even effective yet. This environment of constant churn results in ineffective use of resources associated with the planning and adjustments required to satisfy moving compliance requirements. NERC should foster a compliance environment that allows entities to fully implement technical compliance with current standards before moving to subsequent versions.	
Likes 0	
Dislikes 0	
Response	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	No
Document Name	
Comment	
Alliant Energy supports the comments submitted by the MRO NSRF.	
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 prior implementation plan for EOP-011-2 included the passing of 2 winter seasons (2021-2022 and 2022-2023) before becoming effective. Adding another 18 months after approval, which is expected in the fall, could include two additional winters beyond the original effective date.

Likes 0	
Dislikes 0	

Response

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1

Answer	No
Document Name	

Comment

The 5 years implementation timeframe may be arbitrarily chosen; i.e. there is no correlation between the number of the generating units requiring compliance measures implementation and the implementation timeframe. Timeframe for implementation should be subject on the outage coordination process and the negotiation between the GO/GOP and BA and should be mutually agreed by both GO/GOP and BA.

Likes 0	
Dislikes 0	

Response

Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric

Answer	No
Document Name	

Comment

DTE Electric supports NAGF comments.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	No
Document Name	

Comment

FirstEnergy supports the proposed 18 month implementation for all revised and new requirements for EOP-011-3 and EOP-012-1 (except R1 & R2) but disagree with the proposal to only allow 42 months after the implementation of EOP-012-1 for Requirements R1 and R2. Instead, we ask for the full 60 months after the implementation of EOP-012-1 for R1 & R2 in order to ensure fulfillment of the requirements.

Likes 0	
Dislikes 0	

Response

Martin Sidor - NRG - NRG Energy, Inc. - 6

Answer	No
Document Name	

Comment

It is unclear if the implementation plan is for full compliance of R1/R2 requirements or if the 5-year requirements is to develop a CAP and not to retrofit existing units. This needs to be clarified by the SDT. Retrofits of existing units to the proposed standard requirements under R1 and R2 will require considerable time to implement based upon outage and resource constraints to perform freeze protection hardening as well as budgetary considerations. A 5-year horizon is not consistent with other new standards that have allowed for 10 or 12 years to implement, such as MOD-026 and MOD-027 as well as PRC-005, that are tied with outages to schedule and implement. NRG believes that this should be extended to a 10-year window.

Likes 0	
Dislikes 0	

Response

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	

Comment

The Implementation Plan, Effective Date and Phased-in Compliance Dates section, states the implementation period for EOP-012-1 Requirement R1 and R2 is 42 months.

The time required for physical implementation of material modifications to generating plants could be highly variable depending on the extent of the modifications. For example, installation of heat trace on a few components at a small single unit station would likely take significantly less time than more major modifications to a large coal unit, which would ostensibly occur more quickly than changes to a nuclear unit. NSRF recommends at least a 10-year implementation period for these requirements, or consideration of a staggered approach to the implementation period based on the type of plant and required modifications. A staggered approach seems to have the potential to be exceedingly complicated.

Likes 2	Corn Belt Power Cooperative, 1, brusseau larry; Lincoln Electric System, 1, Johnson Josh

Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA supports the comments submitted by the US Bureau of Reclamation.	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	
This is unclear if the implementation plan is for full compliance of R1 /R2 requirements or if the 5-year requirements is to develop a CAP and not to retrofit existing units. This needs to be clarified by the SDT. Retrofits of existing units to the proposed standard requirements under R1 and R2 will require considerable time to implement based upon outage and resource constraints to perform freeze protection hardening as well as budgetary considerations. A 5-year horizon is not consistent with other new standards that have allowed for 10 or 12 years to implement, such as MOD-026 and MOD-027 as well as PRC-005, that are tied with outages to schedule and implement. NRG believes that this should be extended to a 10-year window.	
Likes 0	
Dislikes 0	
Response	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	No
Document Name	
Comment	
The entirety of Standard EOP-012-1 should have a 5 year implementation plan. The Generator Owners will need sufficient time to develop compliant procedures and practices. Further, the scheduling and financing of modifications will require greater than 18 months.	

Likes 0	
Dislikes 0	
Response	
Natalie Johnson - Enel Green Power - 5	
Answer	Yes
Document Name	
Comment	
The implementation timeframe is fair including 5 years for R1 and R2 and 18 months for the other requirements.	
Likes 0	
Dislikes 0	
Response	
Whitney Wallace - Calpine Corporation - 5 - WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
Calpine agrees with a 5-year implementation time frame to develop a corrective action plan under R1 and R2, though the SDT should be clarified to specify whether the proposed timeline is for full compliance of R1 /R2 reqirements or to develop a corrective action plan. Retrofits of existing units to the proposed standard requirements under R1 and R2 will require considerable time to implement based upon outage and resource constraints and based on budgetary considerations; therefore, a 5-year timeline for such implementation is not reasonable and is inconsistent other new standards that have allowed for 10 or 12 years to implement, such as MOD-026 and MOD-027 as well as PRC-005.	
Likes 0	
Dislikes 0	
Response	
Hillary Dobson - Colorado Springs Utilities - 3	
Answer	Yes
Document Name	
Comment	
CSU supports LPPC's comments.	

Likes 0	
Dislikes 0	

Response

Jennifer Blair - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC, Group Name PPL NERC Registered Affiliates

Answer	Yes
Document Name	

Comment

PPL NERC Registered Affiliates support EEI comments on Question 9.

Likes 0	
Dislikes 0	

Response

Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1, Group Name OGE Energy - Oklahoma Gas and Electric Co.

Answer	Yes
Document Name	

Comment

Oklahoma Gas and Electric agrees with and endorses comments as submitted by EEI Reliability Technical Committee (RTC)

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	Yes
Document Name	

Comment

Exelon concurs with the comments submitted by the EEI.

Submitted on behalf of Exelon (Segments 1 & 3)

Likes 0	

Dislikes 0	
Response	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	Yes
Document Name	
Comment	
MidAmerican supports EEI's comments. We support the proposed 18-month implementation for all revised and new requirements for EOP-011-3 and EOP-012-1 (except R1 & R2) but disagree with the proposal to only allow 42 months after the implementation of EOP-012-1 for Requirements R1 and R2. Instead, we ask for the full 60 months after the implementation of EOP-012-1 for R1 & R2.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Allen Klassen, Evergy, 1, 3, 5, 6; Jennifer Flandermeyer, Evergy, 1, 3, 5, 6; Marcus Moor, Evergy, 1, 3, 5, 6; - Alan Kloster	
Answer	Yes
Document Name	
Comment	
Evergy supports and includes by reference the comments of the Edison Electric Institute (EEI) for question #9.	
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 Regional Standards Committee	
Answer	Yes
Document Name	
Comment	
The 5 years implementation timeframe may be arbitrarily chosen; i.e. there is no correlation between the number of the generating units requiring compliance measures implementation and the implementation timeframe. Timeframe for implementation should be subject to the outage coordination process and the negotiation between the GO/GOP and BA and should be mutually agreed upon by both GO/GOP and BA	

Likes 0	
Dislikes 0	

Response

Jamie Monette - Allete - Minnesota Power, Inc. - 1

Answer	Yes
Document Name	

Comment

Minnesota Power agrees with NSRF comments that R1.1 has the potential to cause entities to incur significant costs and therefore allow entities to either declare exemption through R1.4.4 or decommission generating units. Minnesota Power also agrees that the declaration of exemption based on commercial constraints as stated in R1.4.4 would not increase performance, and the decommissioning of units may have the unintended consequence of decreasing the resiliency of the grid by removing sufficient capacity from the market. Minnesota Power believes that the Criteria in R6 is an effective approach to investigate issues experienced during the cold to continuously improve reliability.

Likes 0	
Dislikes 0	

Response

Casey Perry - Casey Perry On Behalf of: Lynn Goldstein, PNM Resources - Public Service Company of New Mexico, 1, 3; - PNM Resources - Public Service Company of New Mexico - 3 - WECC

Answer	Yes
Document Name	

Comment

PNM agrees with the proposed 18-month implementation timeline with exception of EOP-012-1 R1 and R2 which are 5-years.

Likes 0	
Dislikes 0	

Response

Amy Casuscelli - Amy Casuscelli On Behalf of: Gerry Huitt, Xcel Energy, Inc., 5, 3, 1; - Amy Casuscelli

Answer	Yes
Document Name	

Comment

Xcel Energy supports the implementation plan as proposed.	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	Yes
Document Name	
Comment	
No Comments.	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Would like to see flexibility with the 5-year implementation plan. Given the current state of the economy and the supply chain disruptions, industry wide contractor and supply issues could impact a 5-year implementation.	
Likes 0	
Dislikes 0	
Response	
Dan Roethemeyer - Vistra Energy - 5	
Answer	Yes
Document Name	
Comment	

Luminant agrees with the general implementation timeline, but notes that it appears the implementation plan specifies a 42 month implementation plan for EOP-012-1, R1, R2 versus a 5-year (i.e. 60 month) implementation time frame above. The implementation plan document should be changed to 60 months.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	Yes
Document Name	

Comment

EEI supports the implementation plan as proposed.

Likes 0	
Dislikes 0	

Response

Michelle Amarantos - APS - Arizona Public Service Co. - 5

Answer	Yes
Document Name	

Comment

AZPS supports the implementation plan as proposed.

Likes 0	
Dislikes 0	

Response

Tom Vinson - American Clean Power Association - 5

Answer	Yes
Document Name	

Comment

ACP supports the proposed implementation time frames, including five years for R1 and R2 and 18 months for other items.	
Likes 0	
Dislikes 0	
Response	
Colin Chilcoat - Invenergy LLC - 6	
Answer	Yes
Document Name	
Comment	
Invenergy agrees with the proposed implementation time frames.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
While AEP agrees with a 5-year implementation timeframe for EOP-012-1 Requirements R1 and R2 (as suggested by Question #9), we do not believe this is clearly articulated within the proposed Implementation Plan. EOP-012-1 R1 and R2's implementation period start date appears to be the same as the start date for the other requirements rather than being subsequent to them. We believe clarity is needed within the Implementation Plan to make it clear that EOP-012-1 Requirements R1 and R2 indeed has a 5-year implementation time frame.	
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	

Southern Company supports the EEI comments that the timeframes are reasonable.

Likes 0	
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3

Answer	Yes
Document Name	

Comment

WEC Energy Group supports EEIs comments.

Likes 0	
Dislikes 0	

Response

Claudine Bates - Black Hills Corporation - 6

Answer	Yes
Document Name	

Comment

BHP feels the 18 month implementation, baring any supply chain issues for entities; but the 5 years is sufficient.

Likes 0	
Dislikes 0	

Response

Brian Evans-Mongeon - Utility Services, Inc. - 4

Answer	Yes
Document Name	

Comment

Did the SDT intend for R1 and R2 to have a 5-year implementation time frame? In other words, giving GOs up to five years to fully implement a CAP if needed? If so, we agree this is a reasonable time frame considering budget planning for capital expenses and potential supply chain issues.

Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Implemetation timeframes should as short as can be feasibly implemented.	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
The implementation Plan states: “Entities shall not be required to comply with Requirement R1 and R2 until 42 months after the effective date of Reliability Standard EOP-012-1.” This is confusing and should just state 60 months.	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	

Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merrell, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Depending on the final drafting of the Standard and associated guidance for CAPs, Tacoma Power supports an 18-month implementation timeframe.	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Manitoba Hydro sees no issues with these standards, or equipment that is designed for the extremes of our local environment. Any deviation should be addressed in a timely manner.	
Likes 0	
Dislikes 0	
Response	
John Babik - JEA - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sam Nietfeld - Public Utility District No. 1 of Snohomish County - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Mason - Portland General Electric Co. - 6, Group Name PGE FCD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
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	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Donna Johnson - Oglethorpe Power Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Joe McClung - JEA - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michael Watt - Oklahoma Municipal Power Authority - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Diana Torres - Imperial Irrigation District - 6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Braunstein - Colorado Springs Utilities - 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, 5, 6, 4, 1; Foung Mua, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Wei Shao, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; - Tim Kelley, Group Name LPPC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Dillard - Austin Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rhonda Jones - Invenergy 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	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 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	
Tony Skourtas - Los Angeles Department of Water and Power - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Randy Buswell - VELCO -Vermont Electric Power Company, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 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	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Gul Khan On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Gul Khan	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dana Showalter - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	
Q9. ERCOT supports the SRC comments regarding the implementation timing.	
Likes 0	
Dislikes 0	
Response	

Jun Hua - Austin Energy - 4

Answer	
Document Name	
Comment	
I support comments made by Michael Dillard, Austin Energy, Segment 5	
Likes 0	
Dislikes 0	
Response	

Dwanique Spiller - Dwanique Spiller On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Dwanique Spiller

Answer	
Document Name	
Comment	
NV Energy supports EEI's comments. We support the proposed 18-month implementation for all revised and new requirements for EOP-011-3 and EOP-012-1 (except R1 & R2) but disagree with the proposal to only allow 42 months after the implementation of EOP-012-1 for Requirements R1 and R2. Instead, we ask for the full 60 months after the implementation of EOP-012-1 for R1 & R2.	
Likes 0	
Dislikes 0	
Response	

Mark Spencer - LS Power Development, LLC - 5

Answer	
Document Name	
Comment	
As drafted, the proposed standards may require invasive modifications to existing facilities that may only reasonably be performed during a major inspection (for combustion turbines) or major outages (for steam turbine). Our experience is that these outage cycles may be 8 years or longer and require significant pre-planning given that the new systems may need to be designed, equipment procured, and installed. While most facilities may be able to comply with R1 and R2 within the 5 year timeframe, some will not without scheduling a dedicated outage. We suggest that if generators are able to demonstrate that if the obligations cannot be accomplished within a scheduled outage within the 5-year window that they be granted a one-time extension of up to 10 years.	
Likes 0	

Dislikes 0	
Response	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	
Document Name	
Comment	
TMLP echoes the same concerns raised by TAPS Group: TAPS had understood that the intent was for R2 and R4 (not R1) to have 5-year implementation periods, because both involve five-year reviews. If the SDT's intent is to give R1 a 5-year implementation period, and R4 an 18-month period, we would appreciate more information regarding the SDT's reasoning.	
Likes 0	
Dislikes 0	
Response	
Lisa Martin - Austin Energy - 6	
Answer	
Document Name	
Comment	
I support comments made by Michael Dillard, Austin Energy, Segment 5.	
Likes 0	
Dislikes 0	
Response	
Rebecca Baldwin - Transmission Access Policy Study Group - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
TAPS had understood that the intent was for R2 and R4 (not R1) to have 5-year implementation periods, because both involve five-year reviews. If the SDT's intent is to give R1 a 5-year implementation period, and R4 an 18-month period, we would appreciate more information regarding the SDT's reasoning.	

Likes 0	
Dislikes 0	

Response

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	
Document Name	

Comment

NAGF Comments: MOD-026 and MOD-027 had a 10 year implementation period. MOD-025, PRC-019 and PRC-024 all had 5 year implementation periods. The proposed requirement to require every unit to upgrade their capability will require a great deal more resources and manpower than any of these other standards. Additionally, there are a limited number of qualified sources to provide the required Engineering and Design Analysis Services. An implementation time period for Requirement 1 of less than 10 years is unreasonable.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE recommends clarifying the implementation plan. Texas RE strongly recommends including an initial performance date for Requirement R4 in the implementation plan. When there is no initial performance data specified for periodic requirements, it is a challenge to determine when the entity needs to perform the action(s) for the first time. In the past, when there is no initial performance date specified, the entity would not have to be compliant until the effective date plus the amount of the periodicity. In this case, 18 months after first day of first calendar quarter after the effective date of the Order plus five years. Is this the SDT's intent? With regards to Requirement R2, the implementation plan does specify a compliance date. Is that intended to be an initial performance date of R2.2? The terms compliance date and initial performance date should be clarified. Please see Texas RE's comments in question #5 regarding Requirement R2.

Texas RE does think a CAP could be developed in less than 42 months.

Texas RE recommends that entities have a one-year periodicity in Requirement R4, rather than five years. Texas RE is concerned a new issue may arise, such as a new minimum temperature/condition occurs that affects the units, in less than five years.

Texas RE recommends the retention cover the entire period, whether it is five years or one year. The retention period should consistent with the period in the requirement.

Likes 0	
Dislikes 0	

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	
AECI and its members support comments provided by ACES.	
Likes 0	
Dislikes 0	
Response	

LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	
Document Name	
Comment	
NA	
Likes 0	
Dislikes 0	
Response	

10. Provide any additional comments for the standard drafting team to consider, including the provided technical rationale document, if desired.

Nazra Gladu - Manitoba Hydro - 1	
Answer	
Document Name	

Comment

(1) For EPO-012 R1, R3 includes different areas that can cause Generation to be unavailable.

3.4.1.1. Capability and availability;

3.4.1.2. Fuel supply and inventory concerns;

3.4.1.3. Fuel switching capabilities; and

3.4.1.4. Environmental constraints.

Manitoba Hydro suggests that an additional area could be considered which details the switchgear to be rated for the area weather conditions in that area, back to 1975's coldest temperature. The scope of equipment being the GOP's switchgear, from the unit, to where it meets the TOP's switchgear and/or the BES.

Manitoba Hydro regularly operates in extreme cold weather conditions, in addition to cooling water and DIW systems being at risk to extreme cold; Breakers and Disconnects are common points of failure in cold weather conditions.

Proposed addition to 3.4.1 Generating unit(s) operating limitations in cold weather to include:

3.4.1.5. Switchgear connecting the unit to the BES.

(2) Question 8 was not visible in this online comment form. Manitoba Hydro's response is as follows:

Question 8. The SDT proposes that the modifications in EOP-011-3 and the newly drafted EOP-012-1 meet the key recommendations in The Report 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

Comments: Manitoba Hydro agrees, while the scope of cost is not available to the SDT at this time, the improvements being recommended are reasonable.

Likes 0	
Dislikes 0	

Response

LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	

Document Name	
Comment	
NA	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Gul Khan On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Gul Khan	
Answer	
Document Name	
Comment	
Oncor agrees that the proposed modifications to EOP-011-3 meet the applicable key recommendations from the report in a cost effective manner.	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	
Document Name	
Comment	
For Canadian entites, operation of hydroelectric generating units in cold weather condition is part of the normal operating conditions. The design, maintenance and operation of the generating units are done accordingly. For example, the generating units being installed indoor (either in a powerhouse or underground), they do not require specific freezing measure protection. Consider removing the Time Horizon and VRF columns in the EOP-011-3 VSL Table. Requirement R3 in EOP-012-1 reads that “each GO shall implement and maintain one or more cold weather preparedness plans …” where as R5 refers to “implementing cold weather preparedness plans developed pursuant to R3.”. The SDT should consider revising R3 to include “develop, implement and maintain one or more cold weather preparedness plans”.	
Likes 0	

Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	
AECI and its members support comments provided by ACES.	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	
Document Name	
Comment	
Introduction, Section 4.2 - Please modify the definition of "Facilities" to include only "Thermal Generating Facilities - facilities that use a fuel source such as hydrocarbons, human or other derived trash, and/or facilities that use the heating and/or cooling of water to generate electricity". Thermal generating facilities as defined above appear to be the primary intended target of this standard and are the most susceptible facilities for extreme cold weather. The standard specifically calls out things for us to assess for each facility such as "Fuel Switching Capability," "Fuel Supply and Inventory Concerns" and "Environmental Concerns" (i.e., Environmental Permitting Concerns). Preliminary review of this standard in accordance with EOP-11-2 for our Hydro Generating facilities has not identified any significant impact to the operation of our facilities, maintenance practices, or limitations on operation due to temperature. An ongoing review of our hydro facilities every five years for fuel switching capabilities, fuel supply and inventory concerns, and environmental permitting concerns, design temperature concerns, etc. for our hydro facilities will be an ongoing paperwork exercise and does not seem to align with the intent of the cold weather preparedness standard. Nor does it make sense for the system operator to have to call the hydro facilities in accordance with TOP 3-5 or IRO 10-3 if extreme cold weather is going to impact the area. Hydro facilities in general are typically enclosed in a structure to protect them from the elements, they have a well understood source for energy that varies seasonally and are not affected by extreme cold weather in the same way thermal facilities are, and they have been operating for over 100 years in all weather conditions. Alternatively, the exclusion of "Hydro Generating Facilities" from the "Facilities" definition would also be acceptable. R6- reads, "… and (ii) the ambient conditions at the site at the time of the event are at or above the temperature documented in Part 3.4.2 shall…" Should this section read "… and (ii) the ambient conditions at the site at the time of the event are at or ***below*** above the temperature documented in Part 3.4.2 shall…"?	
Likes 0	
Dislikes 0	

Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merrell, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; - Jennie Wike, Group Name Tacoma Power	
Answer	
Document Name	
Comment	
Tacoma Power recommends clarifying the scope of equipment included in the definition of a "generating unit" in the technical rationale for EOP-012-1 R1. For example, the technical rationale should clarify whether the high or low side of the GSU is considered part of the generating unit, whether transmission equipment (e.g. transmission lines above the power station) are included in the assessment, if supporting equipment not directly on-site of the power station is included (e.g. an upstream intake or screen house), and whether equipment housed in a heated building needs to be assessed to extreme cold weather temperatures. Tacoma Power primarily owns hydroelectric generation and most of the important equipment necessary for operations is housed in a heated facility and is not exposed to ambient temperatures. Tacoma Power supports the comments submitted by LPPC.	
Likes 0	
Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	
1. Has question 8 in this document been purposely omitted? 2. Can the SDT distinguish the difference between the below in EOP-012 · Min. hourly Temperature (R1.1) · Historical operating temperature (R3.4) · Cold Weather minimum temperature (R4.2) 3. SEC suggests consistency in language relating to weather temperature in EOP-012. A recommended change would be "minimum recorded temperature" or "sustained lowest temperature". 4. Asking for previous decades of temperatures is burdensome on the entities as public data available is recorded by month or by years, not hours. Please clarify how entities would obtain hourly temperatures.	

5. For EOP-012 R6, SEC recommends “cold weather” be added before “event resulting in a derate of more than 10%....” The term “event” seems vague.

6. EOP-012 R4 seem duplicative. Suggested language “Once every five calendar years, each Generator Owner shall review documented temperature data and updated its cold weather preparedness plan”

Likes 0	
Dislikes 0	

Response

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF

Answer	
Document Name	

Comment

Question 8 reaponse is a negative with the following comments:

The Standard is a gross overreach of Federal power. The costs for implementing the Changes to EOP-011-3 and EOP-012-1 will be mitigated through an extended implementation plan and through the suggested adjustments to the requirements of the Standards.

Question 10:

While the proposed standards provide criteria to guide GO/GOP to implement cold-weather operating capabilities, there is no requirement that the generators actually operate properly during cold weather. Without a results-based requirement that the generators actually operate properly in these conditions (e.g. a compliance violation should they not), the standards fall short.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

None.

Likes 0	

Dislikes 0	
Response	
Scott Kinney - Avista - Avista Corporation - 3	
Answer	
Document Name	
Comment	
See comments provided by Glen Farmer from Avista	
Likes 0	
Dislikes 0	
Response	
Randy Buswell - VELCO -Vermont Electric Power Company, Inc. - 1	
Answer	
Document Name	
Comment	
As proposed, EOP-011 has the unintended consequence of requiring VELCO and other transmission-only entities to implement provisions that, in fact, Distribution Providers and UFLS-Only Distribution Providers are required to perform in order to mitigate operating Emergencies in Vermont's Transmission Operator Area. VELCO requests that the Standard Drafting Team revise EOP-011 and the Technical Rationale with due consideration to areas of the ERO Enterprise for which the Transmission Operator does not serve as a Distribution Provider nor UFLS-Only Distribution Provider.	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
Question 8. was not on the comment form. The SDT proposes that the modifications in EOP-011-3 and the newly drafted EOP-012-1 meet the key recommendations in The Report 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.	

Answer = NO

Using a benchmark of the 1975 lowest temperature criteria seems excessive and not likely achievable for the aging generation plants. Also, over time using the 1975 criteria will muddy or dilute weather data. Rather than looking to a specific date in time, we recommend the drafting team determine a set amount of years back GOs will be required to look. This will help account for changes in local climate, while still accounting for infrequent weather events.

Likes 0	
Dislikes 0	

Response

Patricia Lynch - NRG - NRG Energy, Inc. - 5

Answer	
Document Name	

Comment

NRG appreciates the comprehensive work that the SDT has provided in short order to address the first 4 requirements of the FERC report on Texas Storm Uri. NRG also is appreciative of the opportunity to provide comments for consideration to this team. NRG does believe that additional criteria are required to improve reliability and protect the grid from extreme cold weather conditions to prevent another unexpected event like Uri. NRG would like the SDT to address our concerns on the use of minimum hourly operating temperature requirements extreme costs without cost recovery mechanisms to implement R1 and R2, and the undue burden being placed on the fossil fuel generation sector to protect the grid for extreme weather condition in the near-term. Technical exemptions may give an unfair advantage to exempting many renewable technologies while placing an unfair burden on conventional fossil fuel technologies that already run on slim margins.

NRG is generally supportive of the balance of the standard under R3, R4, and R5 as this would be -considered best practice. One area for a proposed change is rewriting EOP-012-2 R3.4.1.2 to be restated as: “Fuel supply contract details, and onsite fuel inventory concerns”. This NAGF language captures information GOPs can share from the fuel supplier companies.

*****Note that Q8 is not on this comment form. NRG's response to Q8:

No-do not agree.

NRG agrees with NAGF’s position that the proposed EOP-012 has a high cost potential and cannot be reasonably implemented in a cost-effective manner as stated in our responses above. Without cost recovery for required modifications, this places an undue cost of capital burden on the generators that cannot pass along the additional costs, thus impacting markets in different and unintended ways up to and including forced retirement which may exacerbate reliability rather than enhancing it.

Likes 0	
Dislikes 0	

Response

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	

It appears that question 8 *"The SDT proposes that the modifications in EOP-011-3 and the newly drafted EOP-012-1 meet the key recommendations in The Report in a cost effective manner. Do you agree?"* was omitted from the SBS form.

BPA supports the answer and comments submitted by the US Bureau of Reclamation to question 8 below.

Answer = No

Comment:

The proposed modifications are not cost effective because they universally apply a compliance burden to solve a problem that exists only in a limited geographic area and that is limited to certain types of generation facilities. Further, the proposed ability for Generator Owners to limit the scope of their own applicability (i.e., use of “as defined by the Generator Owner”) precludes the implementation of meaningful change.

Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	2021-07_Comment_Form_MRO-NSRF_06-15-2022_Final-V2.docx
Comment	

The practice of designing a system to a temperature that has been experienced for one hour over the past 47 years seems unreasonable. If a minimum design temperature is specified by this project, it seems more reasonable to take a statistical approach, similar to that used by NRC for nuclear generation unit requirements.

For the sub-parts of Requirement R1, we request addition of the term “freeze protection” or “freeze protection measures” to the language. As currently proposed, the sub-parts could, if taken individually, be interpreted as requirements for the plant design, rather than the design of the freeze protection measures.

The MRO NSRF would ask the drafting team to consider careful usage of the words “unit” versus “plants”. Each individual wind turbine or solar inverter is a NERC “unit”. This will drive unintended impacts using NERC zero defect standards. NERC should focus on the loss of the aggregate “plant”, not the individual “unit”.

The MRO NSRF would request clarification on what “hourly” minimums are defined as or what data an entity should be looking for. Typically, NOAA weather stations take hourly observations, the data of which is stored in a database that is available here (https://www.ncdc.noaa.gov/cdo-web/search). The lowest temperature observed on a given day is listed as a daily minimum temperature. Is the SDT asking entities to drill down to what exact time the temperature was recorded? This would require unneeded extra administrative work and possibly interfacing with local National Weather Service forecast offices to further clarify what time the observation was recorded. A somewhat cursory review of the February 2021 FERC/NERC/Regional Entity report shows no mention of this “hourly temperature” specificity, nor does the SAR for this project.

The MRO NSRF would ask for personnel or persons to be removed from the R5 VSL. The MRO NSRF is concerned that personnel or persons will take the emphasis off proper training for the plant or appropriate “units”.

Regarding the timeline requirements of R6.1, NSRF recommends replacement of the text of the requirement with, “Develop a CAP within 150 days after the event”. If the event were to occur during the month of February, development of the CAP would be required before the end of July. This 30-day (20%) deviation from the language proposed by the SDT seems inconsequential, and would greatly simplify tracking and procedure requirements necessary by registered entities.

In regard to clarification of the scope of Requirement R6, we recommend the following text for R6.:

“Each Generator Owner that owns a generating Facility that experiences an event resulting in a total capacity derate of or could have resulted in a total capacity derate of:

• 10% or greater than or equal to 20MVA, whichever is greater, for generating resources identified under Inclusion I2 of the BES definition, or

• 10% or greater than or equal to 75MVA, whichever is greater, for generating resources identified under Inclusion I4 of the BES definition

for longer than four hours in duration, a start-up failure where the unit fails to synchronize within a specified start-up time, or a Forced Outage for which (i) the apparent cause(s) of the event is due to freezing of the Generator Owner’s equipment within the Generator Owner’s control, and (ii) the ambient conditions at the site at the time of the event are at or above the temperature documented in Part 3.4.2 shall:”

The MRO NSRF believes that the proposed language in EOP-012-1 may have the unintended consequence of reducing the available generation during the winter period similar to what occurred with Blackstart Resource(s) due to previous revisions to NERC Standards.

Please note that questions 8 from the unofficial comment form is not available in the SBS, as such the MRO NSRF provides the following response:

8.The SDT proposes that the modifications in EOP-011-3 and the newly drafted EOP-012-1 meet the key recommendations in The Report 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.

Response: NO

Comments:

The lowest temperature since 1975 criteria as stated in R1.1 has the potential to cause entities to incur significant costs and therefore allow entities to either declare exemption through R1.4.4 or decommission generating units. The declaration of exemption based on commercial constraints as stated in R1.4.4 would not increase performance over the current state, and the decommissioning of units would have the unintended consequence of decreasing the resiliency of the grid by removing otherwise sufficient capacity from the market.

A more cost-effective approach would be to remove R1 completely, rely on the CAP criteria of R6 as written to improve existing units reliability in cold weather, and incorporate a statistical approach to low temperature operation for new builds rather than an absolute all-time low.

Likes 2	Corn Belt Power Cooperative, 1, brusseau larry; Lincoln Electric System, 1, Johnson Josh
Dislikes 0	

Response

Martin Sidor - NRG - NRG Energy, Inc. - 6

Answer	
Document Name	

Comment

Response to Q8:

No. NRG agrees with NAGF's position that the proposed EOP-012 has a high cost potential and cannot be reasonably implemented in a cost-effective manner as stated in our responses above. Without cost recovery for required modifications, this places an undue cost of capital burden on the generators that cannot pass along the additional costs, thus impacting markets in different and unintended ways up to and including forced retirement which may exacerbate reliability rather than enhance it.

Response to Q10:

NRG appreciates the comprehensive work that the SDT has provided in short order to address the first 4 requirements of the FERC report on Texas Storm Uri. NRG also is appreciative of the opportunity to provide comments for consideration to this team. NRG does believe that additional criteria are required to improve reliability and protect the grid from extreme cold weather conditions to prevent another unexpected event like Uri. NRG would like the SDT to address our concerns on the use of minimum hourly operating temperature requirements extreme costs without cost recovery mechanisms to implement R1 and R2, and the undue burden being placed on the fossil fuel generation sector to protect the grid for extreme weather condition in the near-term. Technical exemptions may give an unfair advantage to exempting many renewable technologies while placing an unfair burden on conventional fossil fuel technologies that already run on slim margins.

NRG is generally supportive of the balance of the standard under R3, R4, and R5 as this would be -considered best practice. One area for a proposed change is rewriting EOP-012-2 R3.4.1.2 to be restated as: “Fuel supply contract details, and onsite fuel inventory concerns”. This NAGF language captures information GOPs can legally share from the fuel supplier companies.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	
Document Name	

Comment

For Question 8's cost effective approaches -

FE feels these obligations can be fulfilled in a cost effective and timely manner as long as the Implementation Plan maintains its proposed 18-month time frame for EOP-011-3.

FirstEnergy disagrees with the proposal to only allow 42 months after the implementation of EOP-012-1 for Requirements R1 and R2. Instead, we ask for the full 60 months after the implementation of EOP-012-1 for R1 & R2 in order to plan and implement these requirements.

FirstEnergy supports EEI’s additional comments toward clarifying the language of critical loads.

Also, FirstEnergy suggest review of edits for VSL to ensure clarity.

VSL for R1’s Lower should read “…Parts 1.1 – 1.3 for up to 5% **of** its units…” adding the “of” VSL for R2’s Moderate, High and Severe read “The Generator Owner did not document its determination and the constraints described in Requirement R1 Part 2.1 for more…” but should read “The Generator Owner did not document its determination and the constraints described in Requirement **R2** Part 2.1 for more…” changing R1 to R2

VSL’s for R6 would need to be written as number of events not developed rather than by percent. With 6 items listed under 6.2, to be High is stated as more than 10% but less than 15% which we are reading as more than .6 but less than .9 of the events listed.

VSL for R6 should be written similar to R3’s VSL - **The Generator Owner’s cold weather preparedness plan failed to include two of the applicable requirement parts within Requirement R6.**

Likes 0	
Dislikes 0	

Response

Tony Skourtas - Los Angeles Department of Water and Power - 3

Answer	
Document Name	

Comment

Question #8 is missing: Comment for question # 8 is as follows:

We suggest for the requirement to include cold weather frequency and duration of the criteria to determine if additional cold weather and freeze protection measures need to be implemented. This would allow for generating units in tropical climates that may rarely experience momentary freezing temperatures to more cost effectively implement the standard.

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	
Document Name	

Comment

Dominion Energy supports the EEI comments that ask the SDT to provide clearer language stating that the “critical loads” as identified in EOP-011-3 (see Requirement R1, subpart 1.2.5.2) are solely those critical load necessary for the reliable operation of the BES, and should not be confused with the critical loads (e.g., hospitals, police stations, emergency management facilities, etc.) managed by DP under the authority of state and local public service commission rules and outside NERC regulatory authority.

Dominion Energy also seeks clarity on why the title of EOP-011 is being changed to the term preparedness. EOP-011 still contains a preparedness aspect and the planning horizons are still being used in the requirements.

Likes 0	
Dislikes 0	

Response

Brian Evans-Mongeon - Utility Services, Inc. - 4

Answer	
Document Name	

Comment

We believe the following edits be made to R6:

Derate threshold

We have both substantive and clarity/consistency concerns regarding R6. With respect to the substance, the choice of a derate of 10% of the unit’s capacity as the threshold does not seem to be supported by any technical analysis, and would be unreasonable in the case of small generators. If a derate threshold is retained, the SDT should consider making it “the greater of” some percent of the unit’s capacity or a MW value, e.g. “10% of the total capacity of the unit or 10 MW, whichever is greater,” and/or tying it to reserve requirements.

Clarifications

“a specified start-up time”

Failure to synchronize “within a specified start-up time” is vague to the point of unenforceability: it could mean the minimum start-up time that the GO has communicated to its BA (assuming that every GO has done so), but there is nothing in the proposed text preventing an auditor from deciding that some other “specified time” should have been used. We suggest that “minimum start-up time” be added to the cold weather preparedness plan in R3 (possibly under R3.4.1), and then referenced in R6, i.e. “a start-up failure where the unit fails to synchronize within the start-up time specified in the applicable cold weather preparedness plan.”

Other necessary clarifications

The text of R6 is unclear in other ways. In particular, (1) the word “event” is used in different places to mean either (i) a derate, failure to start, or Forced Outage, or (ii) the cause of the derate, failure to start, or Forced Outage; (2) it is syntactically ambiguous whether the two numbered preconditions in R6 (“for which (i) the apparent cause(s) of the event…”) must be met with respect to all three types of issue, or only with respect to Forced Outages; and (3) “freezing of equipment” is vague: does it include icing, or only freezing of the liquid components of generation equipment? We propose edits to address the first two concerns, including making R6 an if-then statement with three preconditions; if all three are satisfied, the subrequirements are applicable. This does not change the meaning of the SDT’s proposed text; it simply clarifies it by making all three preconditions explicit.

Likes 0	
Dislikes 0	

Response

Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric

Answer	
Document Name	

Comment

DTE Electric supports NAGF comments.

Likes 0	
Dislikes 0	

Response

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1

Answer	
Document Name	

Comment	

Response to Question 8

For Canadian entites, the necessary cold weather practices are already in place. The administrative burden associated to the tasks being required in the standards outweigh the reliability benefits, as we already have a good handle on planning, operations and maintenance activites in cold (and even extreme cold) weather.

Question 10

- We support the RSC comments. Additionally,
- For Canadian entites, operation of hydroelectric generating units in cold weather condition is part of the normal operating conditions. The design, maintenance and operation of the generating units are done accordingly. For example, the generating units being installed indoor (either in a powerhouse or underground), they do not require specific freezing measure protection.
- Sub requirement 1.2.5.3 and 1.2.5.4 of Requirement 1.2.5 in EOP-011-3 state:

1.2.5.3. Provisions to minimize the overlap of circuits that are designated for manual Load shed

and circuits that are utilized for underfrequency load shed (UFLS) or undervoltage load shed

(UVLS); and

1.2.5.4. Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions.

If, for certain region, there is no provision to minimize the overlap of circuit because the load is insufficient, how does an entity comply with the requirement?

- Sub requirement 1.2.5.1 of Requirement 1.2.5 in EOP-011-3 states:

1.2.5.1 Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;

What amount of load should be available for operator-controlled manuel load shedding?

- Consider removing the Time Horizon and VRF columns in the EOP-011-3 VSL Table.
- Requirement R3 in EOP-012-1 reads that “each GO shall implement and maintain one or more cold weather preparedness plans …” where as R5 refers to “implementing cold weather preparedness plans developed pursuant to R3.”. The SDT should consider revising R3 to include “develop, implement and maintain one or more cold weather preparedness plans”.

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	

ISO-NE supports migrating all GO/GOP requirements for Cold Weather in EOP-011 to EOP-012. This retains the focus for EOP-011 and provides the dedicated location for GO/GOP Cold Weather requirements under EOP-012.

ISO-NE also supports the comments from the SRC Group.

Question #8 Is not included in the form.

ISO-NE has no Comment on Question #8

Likes 0	
Dislikes 0	

Response

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4

Answer	
Document Name	

Comment

Alliant Energy supports the comments submitted by the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer	
Document Name	

Comment

Reclamation again recommends the standard be limited to generating equipment located outside of temperature-controlled buildings. Reclamation observes that the proposed requirement to identify the coldest hourly temperature experienced at each generating unit since 1975 will result in the expenditure of millions of dollars by entities whose generating units are indoors, only to find that the units successfully operated at historic low temperatures. An exercise to mathematically justify successful operations is not an efficient use of resources and will not improve reliability.

This is the answer to question #8 from the unofficial comment form that does not show up on this Comment Form. The proposed modifications are not cost effective because they universally apply a compliance burden to solve a problem that exists only in a limited geographic area and that is limited to certain types of generation facilities. Further, the proposed ability for Generator Owners to limit the scope of their own applicability (i.e., use of "as defined by the Generator Owner") precludes the implementation of meaningful change.

Likes 0	

Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	
Document Name	
Comment	
Black Hills Corporation would like to ensure that the SDT makes it very clear in what they are trying to mean by "Operating a plant during cold weather". We feel they are trying to mean "generation facilities applicable as defined in EOP-012, R.2. Facilities" - to produce power during the defined cold/extreme weather period, whether the plant is on-line or off-line, despite the conditions. The way the verbiage is in various parts of EOP-012, it is unclear and could very easily be interpreted to mean "Maintain on-line operation". Is the SDT & NERC intending for entities to be able to restore our generators at any time? We would like to see more clarity on what is meant by 'operating during cold weather'.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3	
Answer	
Document Name	
Comment	
WEC Energy Group supports EEIs comments, noting that Question 8 was omitted from the survey.	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	
Document Name	
Comment	
FOR Q10:	

PG&E supports the comments provided by the North American Generators Forum (NAGF) comment related to "equipment freezing"..

FOR Q8 THAT IS MISSING FROM THE SBS INPUT:

Answer is - NO

Comment is -

PGAE supports the North American Generators Forum (NAGF) comments. PG&E also has the following comments:

The Standard as written does not provide a method or means to recoup costs associated with plant design upgrades. The performance of expensive analysis, training and design changes that are not commensurate with grid reliability and risk reduction do not appear to be cost effective.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

In proposed EOP-12-1 Requirement Part 1.1 Texas RE inquires which criteria is used to determine what “reliable data” is or is not. Texas RE recommends this criteria be captured in the GOs’ cold weather preparedness plans.

Texas RE noticed that the definition of Energy Emergency includes LSE, which no longer a registered function.

Texas RE recommends modifying the verbiage in Requirement Parts 1.4.4 and 6.2.6 from “a declaration” to “Documentation, where deemed appropriate by the Generator Owner based on the review of Parts 1.4.1 through 1.4.3, that no revisions to the cold weather preparedness plan(s) are required…”. Texas RE recommends this information be submitted to the BA so the BA is aware of the generating units within its footprint. This supports key recommendation 1g – providing great specificity on the roles of the GO, GOP, and BA in determining generating unit capacity that can be relied upon during forecasted cold weather.

Texas RE is concerned there is no ending timeframe for CAPs in Requirements R1.4 and R6. Additionally, Texas RE recommends CAPs be filed with the BA so the BA understands operating limitations.

Requirement Part 3.4.2 requires three options for temperature to be included in the GO's cold weather preparedness plan. Requirement Part 1.4, however, specifies "each generating unit shall be designed and maintained shall be designed and maintained to be capable of continuous operations at the documented minimum hourly temperature experienced at its location since 1/1/1975 or a lesser period if reliable data is not available to 1975". If the units are required to be designed according to Requirement Part 1.4, what is the purpose of the three options in Requirement Part 3.4.2?

Additionally, Requirement R6 references Requirement Part 3.4.2, which is merely included as part of the cold weather preparedness plan and not necessarily what the generating unit would be designed for in accordance with Requirement Part 1.4.

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 4, Group Name NCPA

Answer	
Document Name	

Comment

Changes to Cold Weather Reliability Standards should not be applicable continent-wide. Standards should not be modified or implemented prior to Market Rule Modifications. See prior NERC Project 2019-06 ballot and commenting by Marty Hostler

Market Rule modifications have not yet been made to mitigate potential Cold Weather Events grid issues. Per FERC/NERC's recommendation, Market Rule modifications should be made prior to, or concurrent with, development of new Standards.   To date, no known Market Rule Modification project has been initiated.

On page 86 of FERC/NERC's joint Report The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018 (ferc.gov) the following recommendations where made.

Additionally, NCPA agrees with the comments provided by Avista Corporation and the MRO NSRF.

Recommendation 1: The Team recommends a three-pronged approach to ensure Generator Owners/Generator Operators, Reliability Coordinators and Balancing Authorities prepare for cold weather conditions: 1) development or enhancement of one or more NERC Reliability Standards, 2) enhanced outreach to Generator Owners/Generator Operators, and 3) market (Independent System Operators/Regional Transmission Organizations) rules where appropriate. This three-pronged approach should be used to address the following needs: • The need for Generator Owners/Generator Operators to perform winterization activities on generating units to prepare for adverse cold weather, in order to maximize generator output and availability for BES reliability during these conditions. These preparations for cold weather should include Generator Owners/Generator Operators:

While any one of the three approaches may provide significant benefits in solving this problem, the Team does not view any one of the three as the only solution. The Team envisions that a successful resolution of the problem will likely involve concurrent use of all three.

Recommendation 1: The Team recommends a three-pronged approach to ensure Generator Owners/Generator Operators, Reliability Coordinators and Balancing Authorities prepare for cold weather conditions: 1) development or enhancement of one or more NERC Reliability Standards, 2) enhanced outreach to Generator Owners/Generator Operators, and 3) market (Independent System Operators/Regional Transmission Organizations) rules where appropriate. This three-pronged approach should be used to address the following needs: • The need for Generator Owners/Generator Operators

to perform winterization activities on generating units to prepare for adverse cold weather, in order to maximize generator output and availability for BES reliability during these conditions. These preparations for cold weather should include Generator Owners/Generator Operators:

While any one of the three approaches may provide significant benefits in solving this problem, the Team does not view any one of the three as the only solution. The Team envisions that a successful resolution of the problem will likely involve concurrent use of all three.

Likes 0	
Dislikes 0	

Response

Michael Whitney - Northern California Power Agency - 3, Group Name NCPA

Answer	
Document Name	

Comment

Changes to Cold Weather Reliability Standards should not be applicable continent-wide. Standards should not be modified or implemented prior to Market Rule Modifications. See prior NERC Project 2019-06 ballot and commenting by Marty Hostler

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While any one of the three approaches may provide significant benefits in solving this problem, the Team does not view any one of the three as the only solution. The Team envisions that a successful resolution of the problem will likely involve concurrent use of all three.

Likes 0	
Dislikes 0	

Response

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1

Answer	
Document Name	

Comment

AEPCO signed on to ACES comments below:

In regards to determining the minimum hourly temperature to which generating units should be designed and maintained to be capable of continuous operations: was there any consideration of utilizing future forecasted minimum temperature data rather than, or in addition to, historical temperature data?

Question number 8 was missing, therfore it has been added here with the comments:

The SDT proposes that the modifications in EOP-011-3 and the newly drafted EOP-012-1 meet the key recommendations in The Report 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.

Answer:

No

Comments:

The SAR does not prescribe the historical minimum hourly temperature threshold as prescribed in EOP-012-1. Rather than imposing additional financial obligations for GOs to implement freeze protection for the worst historical conditions, allow GOs to implement a risk-based freeze protection approach. Allow GOs to protect their systems to a known ambient condition, and communicate this capability to the BA for the development of a winter season dispatch plan.

Likes 0	
Dislikes 0	

Response

Dennis Sismaet - Northern California Power Agency - 6

Answer	
Document Name	

Comment

Changes to Cold Weather Reliability Standards should not be applicable continent-wide. Standards should not be modified or implemented prior to Market Rule Modifications. See prior NERC Project 2019-06 ballot and commenting by Marty Hostler

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While any one of the three approaches may provide significant benefits in solving this problem, the Team does not view any one of the three as the only solution. The Team envisions that a successful resolution of the problem will likely involve concurrent use of all three.

Likes 0	
Dislikes 0	

Response

Jeremy Lawson - Northern California Power Agency - 5

Answer	
Document Name	

Comment

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While any one of the three approaches may provide significant benefits in solving this problem, the Team does not view any one of the three as the only solution. The Team envisions that a successful resolution of the problem will likely involve concurrent use of all three.

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	

Missing Question #8: The SDT proposes that the modifications in EOP-011-3 and the newly drafted EOP-012-1 meet the key recommendations in The Report 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**, Southern Company can agree that the modifications in EOP-012 are cost effective so long as the GO continues to define "cost effective" by declaring what constitutes a technical, commercial, or operational constraint to meeting the stringent criteria for minimum low operating capability as defined in EOP-012-1 Requirement R1.1.

QUESTION #10: Provide any additional comments for the standard drafting team to consider, including the provided technical rationale document, if desired.

- Southern Company supports the EEI comments.

Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	
Document Name	
Comment	

Answer to question 8: No.

Comments: See comment above for question 4 related to temperature monitoring requirements at the plant site. We do not currently monitor the temperature at each facility, adding this requirement for each plant, including the associated calibrations and certifications to ensure the equipment is operating properly to monitor temperature is not cost effective. We believe that monitoring the temperature on public, regional, national weather service sites for a region within 150 miles of the temperature equipment will be much more cost effective and will satisfy the intent of the standard. Whether the temperature at one site is -20 degrees or another is at -22 degrees, we will still be operating during extreme cold weather for the entire region equipment can freeze and likely has been susceptible for freezing all winter prior to the event. Additionally, related notifications for extreme cold weather events should be allowed to be broadcast to a GO or GOP region rather than on a plant-by-plant basis.

Additional General Comments:

Introduction, Section 4.2 - Please modify the definition of "Facilities" to include only "Thermal Generating Facilities - facilities that use a fuel source such as hydrocarbons, human or other derived trash, and/or facilities that use the heating and/or cooling of water to generate electricity". Thermal generating facilities as defined above appear to be the primary intended target of this standard and are the most susceptible facilities for extreme cold weather. The standard specifically calls out things for us to assess for each facility such as "Fuel Switching Capability," "Fuel Supply and Inventory Concerns" and "Environmental Concerns" (i.e., Environmental Permitting Concerns). Preliminary review of this standard in accordance with EOP-11-2 for our Hydro Generating facilities has not identified any significant impact to the operation of our facilities, maintenance practices, or limitations on operation due to temperature. An ongoing review of our hydro facilities every five years for fuel switching capabilities, fuel supply and inventory concerns, and environmental permitting concerns, design temperature concerns, etc. for our hydro facilities will be an ongoing paperwork exercise and does not seem to align with the intent of the cold weather preparedness standard. Nor does it make sense for the system operator to have to call the hydro facilities in accordance with TOP 3-5 or IRO 10-3 if extreme cold weather is going to impact the area. Hydro facilities in general are typically enclosed in a structure to protect them from the elements, they have a well understood source for energy that varies seasonally and are not affected by extreme cold weather in the same way thermal facilities are, and they have been operating for over 100 years in all weather conditions. Alternatively, the exclusion of “Hydro Generating Facilities” from the “Facilities” definition would also be acceptable.

R6- reads, “… and (ii) the ambient conditions at the site at the time of the event are at or above the temperature documented in Part 3.4.2 shall…” Should this section read “… and (ii) the ambient conditions at the site at the time of the event are at or ***below*** above the temperature documented in Part 3.4.2 shall…”?

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	
Document Name	

Comment

Response to Question #8:
Answer: “No”
Comments:
Section R1.1 states that each generating unit “shall be *designed* and maintained capable of continuous operations”, however changing the design of existing facilities is a challenging (and at times, infeasible) endeavor and may not be the most cost effective way to accomplish cold weather hardening for existing units. Many facilities are successfully and economically using temporary enclosures, heaters, insulation blankets etc. which are installed during the winter season and later removed. The word “designed” in the standard does not seem to recognize this current and successful practice as a prudent way to ensure a unit is capable of continuous operation during severe cold winter weather.

Response to Question #10:
Comments:
The proposed revisions for EOP-011 include the term “critical load,” which for purposes of the standard would infer loads critical to the operation of the BES. However, many local jurisdictions also use the term “critical load” to describe loads that are *not* related to the BES. AEP recommends that the SDT look for ways to clearly differentiate that term to avoid confusion.

In addition, AEP supports the comments made by EEI on EOP-012-1 regarding difference in generating units as reflected in the BES definition.

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 3

Answer	
Document Name	
Comment	

Ameren agrees with the NAGF comments.

Likes 0	
Dislikes 0	
Response	

Mark Young - Tenaska, Inc. - 5

Answer	
Document Name	EOP-012 Comments - Tenaska Final.docx
Comment	

See attached Wod document. Also, in regards to question #8 that was removed the original version of this form, we do not agree that the newly drafted EOP-012-1 meets the key recommendations in The Report in a cost effective manner.

Likes 0	
Dislikes 0	
Response	

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	
Document Name	NAGF EOP-012-1 06152022 final.pdf
Comment	

NAGF Comments: The NAGF recognizes that the events of February 2021 were catastrophic. However, the timeline that is being used to rush these proposed standards through the process is causing the SDT to rush the effort with no time to coordinate these efforts with the requirements within this standard, let alone other standards. As an example, Requirement 1 requires units to be designed to meet certain capabilities regarding wind, moisture and temperature, yet R3 asks only about temperature and ignores the wind and precipitation impacts required in R1. Requirement R6 uses the term "equipment freezing" yet does not define what this means. Should industry assume that freezing means water turns to ice, causing a disruption in the generation process? If so, does that mean blade icing is freezing? The report supporting the modifications to the standards uses the term freezing but includes issues unrelated to water turning to ice. The drafting team needs to clarify exactly what events the Generator Owner is expected to protect against as we go forward.

Unfortunately, the rush to complete the standard is pushing industry to approve a disjointed standard that is unlikely to provide much, if any, improvement in generator performance while ignoring the fact that the Balancing Authorities and Transmission Planning functions are not currently asking for or utilizing the information needed to improve system planning. The NAGF believes that rather than rushing to complete a poorly structured standard, NERC would be better served to create a good standard in a reasonable amount of time. The NAGF feels that the proposed standard fails to provide significant value in large part due to the rush to the finish line. As currently structured, it is more likely to cause the creation of numerous of documents that will state that there is a technical, commercial or operational constraint and therefore the generator will make no changes instead of a significant improvement in generator's ability to operate in extreme cold conditions, until such time as it is clear where the compensation for the investment will come from.

The NAGF has provided a revised EOP-12-1 standard for consideration that address the issues identified throughout these comments in a reasonable manner. Please review the proposed requirements and other suggested changes to the standard. The proposed revisions would require verified weather capability information be provided to the BA, RC, TOP and TP while providing the same clarity of what is desired for existing generation and requiring the proposed (or better) weather capability for new generation going forward. Existing generation can determine whether the investment in modifications is worth the potential payback based on the generator's specifics. This provides the same value with much greater clarity as the SDT's proposed requirements.

Thank you for the opportunity to comment. The NAGF looks forward to continuing to work with NERC and FERC to help draft a reasonable standard that addresses improved reliability while waiting for the other recommendations from the report to be addressed.

Question #8: The NAGF does not support that the modifications in EOP-011-3 and the newly drafted EOP-012-1 meet the key recommendations in The Report in a cost-effective manner.

NAGF Comments for Question #8:

As drafted, the requirements in the proposed EOP-012 have an unlimited cost potential and cannot reasonably be implemented in a cost effective manner. Please see the responses provided above for the NAGF's reasoning. The NAGF recommends that the drafting team first address having the Balancing Authorities and Transmission Planners use the information related to expected weather startup and operational capability to determine where units need to improve before creating a blanket requirement for all generators to perform unlimited retrofits without a clear means of compensation. As noted above, without compensation for the required modifications, NERC is putting the Generator Owners at greater financial risk, which will cause increased cost of capital and a needed higher return on equity while driving market prices down. The NAGF has provided a revised EOP-012-1 standard for consideration that address these issues in a reasonable manner. Please review the proposed changes to the standard.

Likes 0	
Dislikes 0	
Response	

Rhonda Jones - Invenergy LLC - 5	
Answer	
Document Name	
Comment	

Response to Q8: No - See Q8 Comments below

For EOP-012-1, Invenergy is unable to quantify the overall costs and benefits to arrive at a definitive conclusion about the cost effectiveness of the current draft.

However, as noted in Invenergy's response to Question 4, the current proposal yields an arbitrarily stringent standard that could impose more onerous requirements than are necessary to ensure generator availability during the prolonged extreme cold events – occurring over multiple hours or days -

that this Standard is intended to address. The alternative approach Invenergy suggests would reasonably be expected to yield a more cost-effective approach to meeting the key recommendations in the Joint Inquiry Report.

Lastly, Invenergy agrees with “Key Recommendation 2” from the Joint Inquiry Report, which directly considers cost:

Generator Owners should have the opportunity to be compensated for the costs of retrofitting their units to operate to a specified ambient temperature and weather conditions (or designing any new units they may build) through markets or through cost recovery approved by state public utility commissions (e.g., as a reliability surcharge) to be included in end users’ service rates. The applicable ISOs/RTOs (market operators) and/or public utility commissions should identify how best to ensure Generator Owners have the opportunity to be compensated for making these infrastructure investments. (Winter 2022-2023)

Comments for Q10

Invenergy recommends replacing the 10% derate performance trigger in R6 with a loss of 75 MVA. This ties the requirement more closely to existing presumptions of what level of loss impacts BES reliability, and provides more balance in the application of the Requirement across generation types and facility size.

Likes 0	
Dislikes 0	

Response

Colin Chilcoat - Invenergy LLC - 6

Answer	
Document Name	

Comment

In response to Question 8, Invenergy votes "No" with the following comments:

For EOP-012-1, Invenergy is unable to quantify the overall costs and benefits to arrive at a definitive conclusion about the cost effectiveness of the current draft.

However, as noted in Invenergy’s response to Question 4, the current proposal yields an arbitrarily stringent standard that could impose more onerous requirements than are necessary to ensure generator availability during the prolonged extreme cold events – occurring over multiple hours or days - that this Standard is intended to address. The alternative approach Invenergy suggests would reasonably be expected to yield a more cost-effective approach to meeting the key recommendations in the Joint Inquiry Report.

Lastly, Invenergy agrees with “Key Recommendation 2” from the Joint Inquiry Report, which directly considers cost:

Generator Owners should have the opportunity to be compensated for the costs of retrofitting their units to operate to a specified ambient temperature and weather conditions (or designing any new units they may build) through markets or through cost recovery approved by state public utility commissions (e.g., as a reliability surcharge) to be included in end users’ service rates. The applicable ISOs/RTOs (market operators)

and/or public utility commissions should identify how best to ensure Generator Owners have the opportunity to be compensated for making these infrastructure investments. (Winter 2022-2023)

In response to Question 10, Invenergy has the following comments:

Invenergy recommends replacing the 10% derate performance trigger in R6 with a loss of 75 MVA. This ties the requirement more closely to existing presumptions of what level of loss impacts BES reliability, and provides more balance in the application of the Requirement across generation types and facility size.

Likes 0	
Dislikes 0	

Response

Michael Dillard - Austin Energy - 5

Answer	
Document Name	

Comment

(**NOTE:** For Question 8, which did not appear in this form, AE comment is "No Opinion".)

Question 10 Response:

AE recommends clarifying the scope of equipment included in the definition of a "generating unit" in the technical rationale for EOP-012-1 R1. For example, the technical rationale should clarify whether the high or low side of the GSU is considered part of the generating unit, whether the transmission equipment (e.g. transmission lines above the power station) are included in the assessment, if supporting equipment not directly on-site of the power station is included (e.g. an upstream intake or screen house), and whether equipment housed in a heated building needs to be assessed to extreme cold weather temperatures.

AE is endorsing an Affirmative vote for EOP-011-3 and a Negative vote for EOP-012-2. The Negative vote for EOP-012-2 is to provide constructive criticism for the creation of a new revision that will:

Include the BA to be included as a responsible functional entity and to include the "winter season" determination as a Requirement
Modify the hourly temperature collection and analysis to more reasonable solution
Refine the scope of "generating unit"
Clearly limit data collection to a Section 1600 Data Request, based upon precedent

Likes 0	
Dislikes 0	

Response

Tom Vinson - American Clean Power Association - 5

Answer	
Document Name	ACP redlines for NERC project 2021-07.docx

Comment

ACP recommends the following revisions to the following sections not specifically teed up in this series of question. Attached are specific redline recommendations.

1. ACP recommends clarifying the “facilities” definition in 4.2 to make it clear that compliance under the proposed standard is facility-wide for dispersed power resources, not unit-by-unit. This is important for wind farms and solar facilities that are made up of several distinct generating units aggregated to the facility level. In other words, for example, a corrective action plan, if needed, should apply at the facility level, not the individual wind turbine level or a subset of solar panels in a facility.

2. In R6, ACP is concerned about the 10% trigger and recommends an alternative methodology tied to the BES definition. As currently drafted, the 10% trigger could impose a significant administrative burden on GOs of dispersed generation resources. In the event of such a derate, staff would have to assess the temperature at which it happened, whether the apparent cause was due to freezing, and whether that cause was within the generator’s control. For dispersed generating resources, this would potentially have to be done on a unit-by-unit basis. One ACP member has calculcated using historical data that for one facility, it would average 2.7 analyses per day with 3 hours per analysis.

In addition, while perhaps such as administrative burden would be justified if reliability impacts were possible from the derate, ACP is concerned the 10% trigger is arbitrary and unrelated to any consideration of BES reliability impacts.

ACP notes NERC Project 2014-01 Standards Applicability for Dispersed Generation Resources for NERC Reliability Standard PRC-004 Protection System Misoperation Identification and Correction takes a different approach. The SDT white paper for that project finds:

- “However, based on the experience of the SDT, there is minimal impact to BPS reliability for analyzing, reporting, and developing Corrective Action Plans for each individual generating unit that trips at a dispersed power producing resource site, as the tripping of one or a small number of these units has no material impact to BPS reliability.” (p. 23)
- “Additionally, reporting of Misoperations on each individual generating unit may result in substantial and unnecessary burdens on both the dispersed generation resource owner and the Regional Entities that review and track the resulting reports and Corrective Action Plan implementations.” (p. 24)

Therefore, ACP recommends the attached redline to tie the trigger to a presumption of impacts to BES reliability.

Should the SDT nonetheless maintain the 10% trigger, ACP recommends attached redlines to clarify how it applies in the case of dispersed generating resources.

First, it is unclear if the 10% trigger applies facility-wide or on an individual unit basis (i.e. wind turbine or PV panel section)? ACP believes it should apply on a facility-wide basis.

Second, it is unclear if it is it based on nameplate capacity or available capacity? ACP believes the lower threshold 10% trigger should be based on available capacity since wind and solar generation are weather dependent and not always generating at nameplate capacity.

ACP proposes the attached redline for consideration.

Likes 0	
Dislikes 0	

Response

LaKenya VanNorman - LaKenya VanNorman On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name FMPA and Members

Answer	

Document Name	
Comment	

Question 8: The SDT proposes that the modifications in EOP-011-3 and the newly drafted EOP-012-1 meet the key recommendations in The Report 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.

Possible Answer: No

Comments: For the reasons discussed above associated with R1 of EOP-012-1, we do not believe this will be cost effective. In fact the cost impacts will be arbitrary -in some areas this will cost substantially more than it should, while in other areas it may cost less (e.g. by requiring less cold weather protection than may actually be warranted). The current language of R1 implicates absolutely massive construction projects for every plant in Florida, which will drive entities to indicate it is not economically feasible (which we wonder, given the current language of the standard, whether that will be allowed or not – seems to be up to the auditors which is not how we want standards to be applied). Whereas if a probabilistic approach is applied, we believe this will allow a more refined determination of what level of cold weather protection is required at each given plant.

In addition to the issues with R1 and R2 of EOP-012, FMPA has the following concerns.

R4 – If an event occurs that is outside the temperature range identified for the plant site, that should trigger a Plan update. Otherwise it would take up to 5 years to recognize the new potential range of temperatures. This has effects on several requirements.

R5 – Requirement is really two requirements that should be parsed and clarified – training of staff on cold weather preparedness plan, and GO/GOP jointly determining who should conduct the training.

R6 - “Apparent cause of the event is freezing” – should say “effects of cold weather, including but not limited to freezing”. This allows for cold weather affects that may not necessarily be freezing to be considered.

R6.1 – A CAP is just a project. The other items in 6.2.1 through 6.2.6 belong in a Root Cause Analysis, the result of which would determine a CAP. We believe a preliminary RCA should be required ot be completed in advance of the July 1st date which would also include an operations plan for the subsequent winter if the CAP cannot be completed in time.

Likes 0	
Dislikes 0	
Response	

Summer Esquerre - NextEra Energy - 5

Answer	
Document Name	
Comment	

NextEra Energy (NEE) supports the weather emergency preparedness objectives and the development of standards and respectfully submits that any weatherization standards adopted through this rulemaking should strike a careful balance of fulfilling the mandates required without discouraging future investment or financially burdening existing generation. NEE recommends that cold-weather weatherization requirements consider Original Equipment Manufacturer (“OEM”) limits and available technologies, and not require weatherization beyond what is commercially available, especially for renewable generating resources. Although other weatherization technologies are still being researched, they are not commercially available today. It is important that generators maintain their generation equipment consistent with the OEM design. Requiring operations or retrofits outside of the manufacturer's parameters or adopting unproven technology can reduce overall reliability. NEE also notes that increased cold-weather weatherization of renewable generating resources, such as wind turbines, carries the unintended consequence of decreasing the OEM high temperature operational limit.

NEE also supports the comments submitted by the Electric Edison Institute.

Likes 0	
Dislikes 0	

Response

Lisa Martin - Austin Energy - 6

Answer	
Document Name	

Comment

I support comments made by Michael Dillard, Austin Energy, Segment 5.

Likes 0	
Dislikes 0	

Response

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Foung Mua, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Wei Shao, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; - Tim Kelley, Group Name LPPC

Answer	
Document Name	

Comment

LPPC recommends clarifying the scope of equipment included in the definition of a "generating unit" in the technical rationale for EOP-012-1 R1. For example, the technical rationale should clarify whether the high or low side of the GSU is considered part of the generating unit, whether the transmission equipment (e.g. transmission lines above the power station) are included in the assessment, if supporting equipment not directly on-site of the power station is included (e.g. an upstream intake or screen house), and whether equipment housed in a heated building needs to be assessed to extreme cold weather temperatures. For those that primarily own hydroelectric generation, most of the equipment necessary for operations is housed in a heated facility and is not exposed to ambient temperatures.

LPPC has endorsed an Affirmative vote for EOP-011-3 and a Negative vote for EOP-012-1. The Negative vote for EOP-012-1 is to provide constructive criticism for the creation of a new revision that will:

1. Include the BA to be included as a responsible Functional entity and to include the "winter season" determination as a Requirement;

2. Modify the hourly temperature collection and analysis to a more reasonable solution;

3. Refine the scope of “generating unit”;

4. Clearly limit data collection to a Section 1600 Data Request, based upon precedent.

Response to Question 8 - YES

These comments have been endorsed by LPPC.

Likes 2	Colorado Springs Utilities, 1, Braunstein Mike; Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merre
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	
Document Name	

Comment

Question 8 Response

As drafted, the requirements in the proposed EOP-012 have an unlimited cost potential and create only an administrative burden on those generators that have a history of reliable operation in extreme cold weather. CEG recommends that the drafting team should first address having the Balancing Authorities and Transmission Planners use the information related to expected weather startup and operational capability to determine where units need to improve before creating a blanket requirement for all generators to perform unlimited retrofits without a clear means of compensation. These concerns could be addressed in Requirement R1.4.4, or in the M1 measures, e.g., "... documentation that no upgrade is required based on information provided by attestation from the BA or TP, or by demonstrated historical operating experience."

Question 10 Response

• CEG considers the Standard as-written too prescriptive and appears to add no value to Generators with a history of successful severe cold weather operation. Suggest the SDT remove prescriptive details of “how” something is to be accomplished and focus instead on the intent to improve cold weather operation. For example, the Standard could simply require that GOPs prepare for cold weather operation without specifying a limiting temperature, demonstrate successful operation, i.e., through measures such as power history or capability curves, and if operation was not successful, development of corrective measures, or justification why none are practical. It would then be up to planning and balancing authorities, market regulators, and market forces, to determine the best mix of additional generation or compensation of existing generation, as part of an integrated BES, to guaranty supply and delivery during cold weather.
• Section 4.2 Applicability. CEG does not think the BA should determine a winter season. CEG would like to suggest the following language as an option. “For purposes of this standard, the term “generating unit” means those Bulk Electric System generators that plan to operate year around. Generators that do not operate during the winter by design are exempt.”

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Michelle Amarantos - APS - Arizona Public Service Co. - 5

Answer	
Document Name	

Comment

Question 8 Response: With the EEI proposed changes to R1 and R2, AZPS agrees that EOP-012-1 meets the key recommendations in The Report in a cost-effective manner.

Likes 0	
Dislikes 0	

Response

Rick Stadtlander - NEI - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

None additional

Likes 0	
Dislikes 0	

Response

Kimberly Bentley - Kimberly Bentley On Behalf of: sean erickson, Western Area Power Administration, 1, 6; - Kimberly Bentley

Answer	
Document Name	

Comment

Within EOP-012-1, recommend clarifying how hourly minimums are defined and determined. Would also recommend limit the standard to equipment located outside of temperature-controlled buildings to avoid needless work and avoid excessive use of resources.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

Question 8: No response

Question 10 Comments:

Additional Comments for EOP-011-3

EEI recommends clarifying the language stating that the “critical loads” as identified in EOP-011-3 (see Requirement R1, subpart 1.2.5.2) are solely those critical load necessary for the reliable operation of the BES, and should not be confused with the critical loads (e.g., hospitals, police stations, emergency management facilities, etc.) managed by a DP under the authority of state and local public service commission rules and outside NERC regulatory authority. We also ask that DP be added to the applicability section of this Standard, given the critical role that DP plan in the implementation and reporting of load shedding programs.

Additional Comments for EOP-012-1

The difference between “generating units” under the BES definition as defined under I2 and aggregated inverter based resources as defined under I4 should be clarified within EOP-012-1 R6. There are technical and scalability issues to monitoring each individual I4 resource which is technically a BES “unit” for a 4-hour weather related 10% derate.

- **Technical Measurement Issues:** At any given time, a 75 MVA or greater aggregate wind or solar unit may have 10% of individual I4 BES generating resources at the aggregate “plant” out-of-service during a rolling 4-hour period for various reasons including mechanical issues, weather issues, or fuel (lack of wind or sun) issues. This will require programming and human oversight issues to separate and identify a “plant” level rolling 4-hour weather related 10% derate without material reliability benefit.
- **Scalability Issues:** Monitoring any large wind / solar farm or farms with 100 – 300 individual I4 BES Inverter-based resources presents a scalability issue. Monitoring and identifying mechanical issues, weather issues, or fuel (lack of wind or sun) issues will require significant programming and human oversight to separate and identify a “plant” level rolling 4-hour weather related 10% derate without material reliability benefit.

To address this concern, the SDT should clarify for purposes of EOP-012, that Requirement R6 applicability should conform to the following requirements:

For EOP-012, Requirement R6 a BES “generating unit” shall be addressed as follows:

- An individual 20 MVA single shaft unit of 20 MVA or larger as defined in I2 of the NERC BES definition.
- For dispersed power producing resources, as defined in I4 of the BES definition and aggregate to 75 MVA or more at a single Point Of Interconnection (POI) connected at 100 kV or greater; the total plant shall be considered as a single “generating unit” under R6

Likes 0	
Dislikes 0	

Response

Alison Mackellar - Constellation - 5	
Answer	
Document Name	

Comment

Question 8 Response

As drafted, the requirements in the proposed EOP-012 have an unlimited cost potential and create only an administrative burden on those generators that have a history of reliable operation in extreme cold weather. CEG recommends that the drafting team should first address having the Balancing Authorities and Transmission Planners use the information related to expected weather startup and operational capability to determine where units need to improve before creating a blanket requirement for all generators to perform unlimited retrofits without a clear means of compensation. These concerns could be addressed in Requirement R1.4.4, or in the M1 measures, e.g., "... documentation that no upgrade is required based on information provided by attestation from the BA or TP, or by demonstrated historical operating experience."

Question 10 Response

• CEG considers the Standard as-written too prescriptive and appears to add no value to Generators with a history of successful severe cold weather operation.   Suggest the SDT remove prescriptive details of “how” something is to be accomplished and focus instead on the intent to improve cold weather operation. For example, the Standard could simply require that GOPs prepare for cold weather operation without specifying a limiting temperature, demonstrate successful operation, i.e., through measures such as power history or capability curves, and if operation was not successful, development of corrective measures, or justification why none are practical. It would then be up to planning and balancing authorities, market regulators, and market forces, to determine the best mix of additional generation or compensation of existing generation, as part of an integrated BES, to guaranty supply and delivery during cold weather.
• Section 4.2 Applicability. CEG does not think the BA should determine a winter season. CEG would like to suggest the following language as an option. “For purposes of this standard, the term “generating unit” means those Bulk Electric System generators that plan to operate year around. Generators that do not operate during the winter by design are exempt.”

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Mike Braunstein - Colorado Springs Utilities - 1	
Answer	
Document Name	

Comment

Colorado Springs Utilities agrees with comments endorsed by LPPC

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring

Answer	
Document Name	

Comment

None of the NO answers above indicate a disagreement or opposition to the proposed standards. They are meant to offer additional suggestions, as requested by the drafting team. In addition to the comment above, WECC offers the following:

EOP-012 R1: This requirement specifically states a generating unit must be capable of “continuous” operations. Some facilities may be capable of operation in severe cold weather if they are already in operation but a start up in cold weather may be more challenging. The drafting team may wish to consider the language in R1 and clarify if cold weather performance is intended to be satisfied only by units that are in service and running or if the freeze protection measures must be adequate for startup during the specified temperatures. The intent to address startup capability is implied in R6 but may be clarified here and not depend on a linkage between the two requirements.

R1 also states that generating “shall be designed….” Most applicable generating units are already designed and in operation. Does this imply or require a re-design? This requirement could be worded in a more results-oriented way and address these issues. (We do understand the word “design” was used in the FERC recommendations but believe the objective could be met without that word)

Many facilities built since 1975 had no climate data at their specific location. How far away would reliable data have to be to satisfy the criteria “at its location.” Our Recommendation is to consider specifying use of the nearest NOAA weather source.

WECC suggests the Drafting Team consider replacing the words “designed and maintained” in R1, Parts 1.1, 1.2, and 1.3, to “capable?” Also, as per the comment above, suggest the drafting team consider a reference to the nearest NOAA weather source.

As per earlier comments, suggest replacement of “commercial, or operations constraints” to “regulatory constraints” in R1, part 1.4.2. and part 1.4.4

EOP-012 R3: Same comment as above. Consider use of the nearest NOAA weather source in part 3.1.

Since R1 already specifies the freeze protection requirements, WECC suggests the Drafting Team consider removing “based on geographical locations and plant configuration” from part 3.2.

EOP-012 R5: With respect to one function performing “in conjunction with” another function, the use of this phrase is not clear with respect to applicability. If it is viewed by the ERO as being only applicable to the first function (Ref: RSAW's for TPL-001 and TPL-007) this phrase creates ambiguity.

Because EOP-012 was expanded beyond what was in EOP-011, R5 should reference what training is being required. Below is recommended wording for consideration:

“Each Generator Owner shall identify either itself or the Generator Operator as the responsible entity for developing and providing generating unit-specific training on its cold weather preparedness plans developed pursuant to R3 to all maintenance and operations personnel responsible for implementing those plans. And the identified responsible entity shall provide the annual training to its maintenance or operations personnel responsible for implementing cold weather preparedness plan(s) developed pursuant to Requirement R3.”

EOP-012 R6, Part 6.2.6: This recommendation would only be appropriate if the recommended language change for R2 and R4.4 were accepted. Suggest replacement of “commercial, or operations constraints” to “regulatory constraints” and removing the words “as defined by the GO.”

WECC has no comment for Question #8.

Thank you for the opportunity to provide suggested clarifying or improved language.

Likes 0	
Dislikes 0	

Response

Dan Roethemeyer - Vistra Energy - 5

Answer	
Document Name	

Comment

Response to Q8 - No:

Luminant agrees that the proposed standards should meet the key recommendations in The Report in a cost effective manner, but it disagrees that the proposed standards do so as currently drafted. Luminant joins the comments of the Texas Competitive Power Advocates (TCPA), which discuss in detail the specific issues relating to cost effectiveness in the ERCOT region. Competitive generators in ERCOT currently do not have any mechanism for cost recovery for weather preparedness or freeze protection measures and are already facing significant costs from implementing phase 1 weather preparedness requirements of the Public Utility Commission of Texas (PUCT) and will face additional compliance costs to implement the soon-to-be adopted phase 2 PUCT weather preparedness requirements. While the PUCT is considering market design reforms, it is uncertain at this time exactly what those reforms will entail, and there has been no suggestion to date that the PUCT will adopt cost recovery mechanisms for weather preparedness compliance. NERC thus should adopt a standard that will not be as likely to impose significant, unrecoverable retrofitting costs on Generator Owners while still providing an objective and meaningful weatherization standard, such as the alternative standards proposed above under Question 4 (e.g., the 95th percentile minimum average temperature over 72 hours). In addition, NERC should focus the standard on weather preparedness, which is something within the control of the Generator Owner, as opposed to requiring definitive continuous operation at a specific temperature, which would more likely require retrofitting of generation resources to meet those weather performance requirements. If NERC were to modify the standard to require preparing resources such that they are "reasonably expected" to operate continuously at a minimum average temperature over a prolonged period (e.g., 95th percentile minimum average temperature over 72 hours),then a meaningful and objective standard would be set, but one that is less likely to require that Generator Owners expend extraordinary sums to retrofit units to meet the standard and in turn less likely to push economically marginal but reliability-critical resources out of service.

Imposing the current proposedweatherization requirement in EOP-012-1 on resources outside of ERCOT similarly would also be unreasonably burdensome, costly, and unnecessary. While resources outside of ERCOT may have the opportunity for some cost recovery (e.g., operated by rate-regulated utilities), that is not the case for all generators, and it is unclear at this time exactly how those costs would be recovered. For example, if weatherization related upgrades cause a unit to not clear a capacity auction, there is no mechanism for that Generator Owner to recover those costs, especially if they are not rate-based companies. Further, in regions outside of ERCOT, reserve margins are already generally higher, and the grid is interconnected across ISOs that have significant geographic diversity. The alternative standard proposed above (e.g., based on the 95th percentile average minimum temperature over a 72-hour period) thus also makes sense for resources operating in other ISOs.

For both ERCOT and non-ERCOT ISOs, the ability to seek an exception under R2 -- modified, as proposed under Question 5, to include existing resources -- for technical, commercial, and operational reasons is an important feature to ensure that the proposed standards are cost effective in their implementation.

Response for Q10:

Luminant incorporates the additional comments of the Texas Competitive Power Advocates. In addition, the proposed requirement to develop a Corrective Action Plan (CAP) by the earlier of July 1 or 150 days subsequent to the event seems unnecessarily constrained for an event that happens toward the end of the winter season (e.g., February 28), and thus for which a CAP would be due in a much shorter period than 150 days (nearly a month sooner) if the standard requires the earlier of July 1 or 150 days. There is no apparent reason to require a CAP to be developed more quickly for events that occur in February than in other winter months. Even with a 150-day standard across the board, CAPs would be in place well in advance of the next winter season. Luminant thus recommends that the standard simply require a CAP to be developed no later than 150 days subsequent to the event.

Likes 0	
Dislikes 0	

Response

Julie Hall - Entergy - 6, Group Name Entergy

Answer	
Document Name	

Comment

Q8. Entergy's response is Yes regarding cost effective. No Comments.

R6.1

The Technical Rationale and Justification for EOP-012-1 states that the intent of R6. is to allow entities to review multiple events holistically following a winter season, and create one CAP for equipment with common failure causes. Entergy's position is that the July 1 deadline supports that intent and 150 days is not necessary.

Likes 0	
Dislikes 0	

Response

George Brown - Acciona Energy North America - 5

Answer	
Document Name	

Comment

Acciona Energy believes that section 4.2 is unnecessary. The intention of the standard is to ensure applicable 'generation Facilities' or 'generation resources' can operate during the winter season. Using either of the two aforementioned terms, ties the applicable equipment back to the NERC Glossary of Terms or the BES definition. Introducing the term "generating unit" causes confusion. Acciona suggests using the term 'generation Facility' because it includes all equipment, BES and non-BES. The standard should only be applicable to the GO and GOP without any further dissection in section 4.

Please note that questions 8 from the unofficial comment form is not available in the SBS, as such the Acciona Energy provides the following response:

8.The SDT proposes that the modifications in EOP-011-3 and the newly drafted EOP-012-1 meet the key recommendations in The Report 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.

Response: NO

Comments:

When considering a threshold to analyze and determine whether or not a derate is caused by cold weather and therefore requires a Corrective Action Plan, the SDT needs to consider the administrative resources required for Generator Owners to complete the analysis. Consider for example a dispersed power producing resources identified under Inclusion I4 of the BES Definition with an installed capacity of 95.325 MW and each individual generating unit is 3.075 MW (31 total individual generating units). The 10% threshold as currently proposed, would equate to four individual generating units offline for four-hours. To determine whether these individual generating units were offline due to the effects of cold weather, administrative personnel would have to analyze the alarm codes and ambient conditions associated with each unavailable individual generating unit. In our analysis of historical data, a winter period for one Generator Owner would average 2.7 analysis per day with 3 hours per analysis.

Acciona Energy would suggest tying the 10% magnitude back to a reliability concept such as the BES Definition: 75MVA/20MVA. The simple reasoning is that for a 100MVA facility, a 10% derate (10MVA) would not constitute a reliability concern as it does not even meet the thresholds to be BES.

Further, Acciona Energy would suggest using the reasoning as develop by Project 2014-01 Standards Applicability for Dispersed Generation Resources for NERC Reliability Standard PRC-004 Protection System Misoperation Identification and Correction. This reasoning is outlined in this team's white paper (https://www.nerc.com/pa/Stand/Pages/Project-2014-01-Standards-Applicability-for-Dispersed-Generation-Resources.aspx). As stated by the 2014-01 SDT:

- However, based on the experience of the SDT, there is minimal impact to BPS reliability for analyzing, reporting, and developing Corrective Action Plans for each individual generating unit that trips at a dispersed power producing resource site, as the tripping of one or a small number of these units has no material impact to BPS reliability.

- Additionally, reporting of Misoperations on each individual generating unit may result in substantial and unnecessary burdens on both the dispersed generation resource owner and the Regional Entities that review and track the resulting reports and Corrective Action Plan implementations.

- The SDT was also concerned with the applicability of events where one or more individual units tripped and the root cause of the operations was identified as a setting error. In this case, the requirements of PRC-004 would be applicable for any individual units where identical settings were applied on the Protection Systems of like individual generation resources identified under Inclusion I4 of the BES definition.

NERC PRC-004 Applicability language

4. Applicability

4.2 Facilities

4.2.1 Protection Systems for BES Elements, with the following exclusions:

4.2.1.5 Protection Systems of individual dispersed power producing resources identified under Inclusion I4 of the BES definition where the Misoperations affected an aggregate nameplate rating of less than or equal to 75 MVA of BES Facilities.

Suggested Requirement Language:

Each Generator Owner that owns a generating Facility that experiences an event resulting in a total capacity derate of or could have resulted in a total capacity derate of:

- 10% or greater than or equal to 20MVA, whichever is greater, for generating resources identified under Inclusion I2 of the BES definition or

- 10% or greater than or equal to 75MVA, whichever is greater, for generating resources identified under Inclusion I4 of the BES definition

for longer than four hours in duration, a start-up failure where the unit fails to synchronize within a specified start-up time, or a Forced Outage for which (i) the apparent cause(s) of the event is due to freezing of the Generator Owner's equipment within the Generator Owner's control, and (ii) the ambient conditions at the site at the time of the event are at or above the temperature documented in Part 3.4.2 shall:

Acciona Energy also does not believe designing or retrofitting generation resources to "the documented minimum hourly temperature experienced at its location since 1/1/1975" is a practical or economical approach without applying a statistical analysis.

Likes 0	
Dislikes 0	

Response

Diana Torres - Imperial Irrigation District - 6

Answer	
Document Name	

Comment

The lowest hourly recorded temperature design criteria does not represent true freezing potential for IID units and is problematic. The EOP-012-1 should be revised to allow for an exemption based on an Engineering Analysis.

The reponse to Comment 8 was "Yes"

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	
Document Name	

Comment

Response #8:

No. Due to the speed at which EOP-011-2 and EOP-012-1 are being implemented, Duke Energy will repeat much of the work performed for EOP-011-2 shortly after it is implemented. From a GO/GOP perspective, it would more cost effective to cancel implementation of EOP-011-2 GO/GOP related Requirements and implement EOP-012-1 when approved.

Response #10:

R1.1: Requirement R1.1 appears to be disproportionate relative to the required minimum hourly temperature data that must be evaluated and retained in perpetuity for each generating unit. For example, assuming an implementation date of 7/1/2024, it is anticipated that Duke Energy will be required to retrieve and maintain in excess of 40 million hourly data records for R1.1 during its initial examination of minimum hourly temperature data. Additionally, the date of 1/1/1975 does not address the accuracy and availability of data or recent documented changes in the climate of North America. The following four primary arguments support modification of the 1/1/1975 date:

(1) R4 as currently written requires that once every five calendar years each GO review its documented minimum hourly temperature developed pursuant to Part 3.1 and “update” its cold weather preparedness plan with the lowest temperature. If a “lower” minimum temperature is experienced after the initial evaluation, R4 will remedy any subsequent need to modify this temperature.

(2) Duke Energy meterologist suggest that the quantity of weather recording sites with reasonably accurate data is much more favorable for the period starting 1991.

(3) A 30 year period for the calculation of climate normals was first adopted by the governing body of international meteorology in the 1930's. The National Weather Service (NWS) continues this practice by using the last 30 years of data to calculate national climate averages. This data can be found in the NWS Climate Normalization Increment Period of 1991-2021.

(4) Climate change data presented by the United States Environmental Protection Agency's website (www.epa.gov), indicates a marked increase in annual average temperatures in the contiguous 48 states beginning around 1990. This would suggest that restricting the historic data to a timeframe of 30 years or less would better reflect climate changes being experienced in North America.

Please consider modifying the R1.1 date of 1/1/1975 date to 1/1/1991.

R1.2: Is the intent of R1.2 to incorporate Newton's Cooling Law in generating unit design freeze protection measures? If no, please define its intent and GO/GOP required actions to achieve compliance.

R1.2/R1.3: Does R1.2 or R1.3 require the collection of meterological data other than ambient dry-bulb temperature (e.g., wind speed/direction and precipitation,)? If yes, please define additional data.

R1.2/R1.3: What methodology(ies), procedures, standards, etc. are suggested to properly evaluate and apply the cooling effects of wind and freezing precipitation? Industry will need assistance from NERC in determining how to perform this analysis given the ambiguous nature of this requirement. Additionally, suggest adding “as necessary” to these phrases.

R1.2/R1.3: Requirements R1.2 and R1.3 use the phrase "generating unit design". Does this phrase imply these requirements only apply to new units during the design process? Since an existing generating unit is based on an existing design, is the intent to include existing units in these Requirements? Additionally, if the intent is to only impact new units in the design phase, consider changing "generating unit design" with "new generation unit design"; if all unit types are included, consider changing the phrase to "new and existing generating unit designs".

R1.3: The R1.3 requirement is nebulous, over-reaching, and not auditable as written (“design shall account for the impacts on operation due to precipitation”). In order to understand the intent and breadth of this Requirement, please consider rewriting this Requirement to state specific and achievable actions. Additionally, is “non-freezing” rain considered precipitation?

R2: Considering the length of time needed to design, construct, and startup “new generating unit(s)”, it may be desirable to clearly define: (a) the compliance phases of a new versus existing generating unit and (b) whether the modification of an existing unit would change its definition and application to a new unit. For example: Utility A is constructing a nuclear unit that has a design phase (which includes “freeze protection measures”) of 2 years and a minimum construction period of 8 years. During its design phase, it is determined that the applicable minimum hourly temperature is -10 F. If a minimum hourly temperature of -20 is experienced during year 7 of its construction period, how would R1.1 and R3.1 apply relative to the “minimum hourly temperature”?

M2: Consider modifying M2 language as follows: …or hardcopy format: Documentation of technical, commercial, or operational constraints”, and” Documentation of five…

R3: It may be desirable to maintain a single Cold Weather Preparedness Plan on a site/plant basis – instead of a unit basis. Consider modifying R3 to read: …for its generating units “or sites”: The cold…

R3.4.2: Does R.3.4.2 Bullet 1 decribe the design temperature based on historical minimum hourly temperature (e.g., 1975 to Implementation Date)? If no, please further define.

R3.4.2: Does R.3.4.2 Bullet 3 describe the design cold weather temperature that exist prior to the implementation of any new freese protection measures? If no, please further define. (Note: Does Requirement R3.4.2 Bullet 3 require an engineering analysis to determine the current design cold weather temperature?)

R4.2: Requirement 3.4.2 list three “Generating unit(s) minimum” temperatures (Design, Historical and Current). Requirement 4.2 reads: Review its documented cold weather minimum temperature contained… Consider adding a “s” to temperature as follows: …minimum temperature”s” contained…

Section R4.2: This Section defines "generating unit" as Bulk Electric System Generators. This definition would exclude solar sites since photovoltaic panels are not generators. Consider replacing the word "generator" in this section with "generation sources/resources" or "BES generation sources/resources" if the intent is to include solar.

R6: Does total capacity refer to Net, Gross, Other Total Capacity? Please define or clarify the phrase: …10% of the total capacity of the unit…

R6: Please define or clarify the phrase: …specified start-up time... This is a imprecise phrase since the following attributes are not defined: who specifies start-up time, where is it documented, how is it defined, what is its duration, etc.

R6: Consider clarifying which temperature(s) for R6 applies for the following since three Generating unit(s) minimum temperatures are listed in Part 3.4.2 (Design, Historical and Current): …time of the event are at or above the “temperature” documented in Part 3.4.2 shall…

Q7: Does “Sum of capacities (in MW)” refer to Net, Gross, Other Total Capacity? Please define or clarify the phrase.

Likes 0	
Dislikes 0	

Response

Michael Watt - Oklahoma Municipal Power Authority - 4

Answer	
Document Name	

Comment
I agree with TAPs comments, pasted below: TAPS appreciates the opportunity to comment on the draft standards, and we thank the SDT for their hard work in developing these important standards on an accelerated timeline. With limited exceptions, we do not disagree with the substance of the proposed standards; we do, however, have some significant concerns regarding clarity and unintended consequences. **R4** **Scope of R4.3; overlap between R4.3 and R1.4** We understand that the SDT intends R4.3 to apply only in the case where a GO's lowest temperature pursuant to R3.1 has changed since the last review, since the GO's existing freeze protection measures may not be adequate to meet the new, lower temperature. But the text as written requires a full self-audit of R1 compliance every 5 years regardless of whether the minimum temperature has changed. We suggest a minor edit to clarify the intended scope of R4.3. In addition, as noted above in response to Question 4, the current wording of R4.3 overlaps with the requirements of R1.4 and would lead to duplicative noncompliance; we suggest an edit to avoid that issue. **"Maintenance" of cold weather preparedness plan; possible combination of R4 with R3** R4 seems to set out, at least in part, how a GO "maintains" its plan, as required by R3. To avoid duplication, either the words "and maintain" should be deleted from R3, or R4 should be made a subrequirement of R3, prefaced by language along the lines of "Maintenance of the plan, which shall consist of the following reviews every five years:" Additional subrequirements could be added to ensure that the GO's 5-year review covers all aspects of its cold weather preparedness plan. **R6** **Derate threshold** We have both substantive and clarity/consistency concerns regarding R6. With respect to the substance, the choice of a derate of 10% of the unit's capacity as the threshold does not seem to be supported by any technical analysis, and would be unreasonable in the case of small generators. If a derate threshold is retained, the SDT should consider making it "the greater of" some percent of the unit's capacity or a MW value, e.g. "10% of the total capacity of the unit or 10 MW, whichever is greater," and/or tying it to reserve requirements. **Clarifications** **"a specified start-up time"** Failure to synchronize "within a specified start-up time" is vague to the point of unenforceability: it *could* mean the minimum start-up time that the GO has communicated to its BA (assuming that every GO has done so), but there is nothing in the proposed text preventing an auditor from deciding that some other "specified time" should have been used. We suggest that "minimum start-up time" be added to the cold weather preparedness plan in R3 (possibly under R3.4.1), and then referenced in R6, i.e. "a start-up failure where the unit fails to synchronize within the start-up time specified in the applicable cold weather preparedness plan." **Other necessary clarifications** The text of R6 is unclear in other ways. In particular, (1) the word "event" is used in different places to mean either (i) a derate, failure to start, or Forced Outage, or (ii) the cause of the derate, failure to start, or Forced Outage; (2) it is syntactically ambiguous whether the two numbered preconditions in R6 ("for which (i) the apparent cause(s) of the event…") must be met with respect to all three types of issue, or only with respect to Forced Outages; and (3) "freezing of equipment" is vague: does it include icing, or only freezing of the liquid components of generation equipment? We propose edits to address the first two concerns, including making R6 an if-then statement with three preconditions; if all three are satisfied, the subrequirements are applicable. This does not change the meaning of the SDT's proposed text; it simply clarifies it by making all three preconditions explicit.

Possible merging of R6 CAP requirements into R1.4

Finally, as noted above in response to Question 4, R6 is duplicative of R1.4; we suggest replacing R6's CAP requirements with a reference to R1.4, leaving just the identification and analysis of events in R6.

Alternative proposals

If the SDT retains a separate CAP requirement in R6, it should at minimum, as suggested in our response to Question 4, clarify in R1 that corrective actions in response to an R6 event are subject only to R6, not R1.4; it should also revise R6.2.6 consistent with the changes to R1.4.4 that we proposed in response to Question 4.

VSLs

Our comments on the VSLs address the appropriateness of the proposed VSLs with respect to the Requirements language as proposed by the SDT; we have not, for the most part, suggested additional conforming changes in line with our suggested revisions to the Requirements.

R1 and R2: percentage of noncompliant units is an inappropriate metric

R1 and R2 have VSLs based on the percent of a GO's units for which it did not comply. This is unfair to smaller entities, who may have only one or two units. It is also not a reasonable metric: a GO with 100 units, that entirely disregarded R1.1-R1.3 with respect to 10 units, would be a Moderate VSL, while a GO with a single unit, for which it met the criteria in R1.1 and R1.2 but not R1.3, would be a Severe VSL. A more reasonable approach with respect to R1.1-R1.3 would be VSLs along the lines of "had freeze protection measures compliant with R1.1 but not R1.2 and/or R1.3," "had freeze protection measures, but measures were not sufficient to meet R1.1-R1.3," "had no freeze protection measures," etc. If the SDT nevertheless retains percentages of units in the VSLs, it must at minimum clarify the denominator for each—we believe that for R1, the intent is the GO's applicable units, and for R2, it is the GO's applicable new units for which it cannot meet the R1 criteria due to technical commercial, or operational constraints. And the SDT would need to clarify the time period over which the R2 percentage is taken—e.g. if a GO has 10 applicable units with R2 constraints, two of which were identified in each year over a five-year period, and it failed to document its determination and the constraints with respect to one of the last two units, is that a Severe VSL (because it was noncompliant with respect to 50% of its applicable units in that year), or Moderate (because it was noncompliant with respect to 10% of its total applicable units, or 10% of the applicable units identified over a 5-year period)?

R1.4: need for Low, Medium, and High VSLs

While R1.1-R1.3 have multiple VSLs (even though those VSLs are based on an inappropriate metric), R1.4 has only a single VSL—Severe—where the GO "did not develop or implement a CAP as required by Requirement R1." This is unreasonable; a GO might develop a CAP but only partially implement it, or develop and implement a partially-compliant CAP, etc. In addition, if R1.4 had a deadline, as we suggest it should in response to Question 4, then VSLs could be based on degrees of lateness.

R2 and R4: unintended ambiguity depending on date of discovery of noncompliance

The VSLs for R2 and R4 do reflect degrees of lateness, but they have another flaw: one possibility for a Severe VSL is "did not complete a review"/"does not have a completed review," while a "High" VSL is "was late by greater than 60 calendar days." But what if the noncompliance is discovered in an audit 50 days after the deadline? Is it a Medium VSL (because it is not yet more than 60 days late) or Severe (because the review isn't (yet) done)? The VSLs for R2 and R4 should be revised so that High has a maximum number of days, and Severe is "more than [x] days" late.

R4: omission of updating of plan from Low, Medium, and High VSLs

The text of Requirement R4 requires GOs to review and, if necessary, update their plans. The Low, Medium, and High VSLs for R4 refer only to completing the required review. The Severe VSL includes "The Generator Owner does not have a completed review. OR The Generator Owner did not update the cold weather preparedness plan." The (likely inadvertent) omission of "updating" from the lower VSLs suggests that being a day late in updating a cold weather preparedness plan is just as bad as being 6 months late. The words "and any necessary update(s)" should be added to Low through High VSLs.

R5: ambiguous application

Because the R5 VSLs are based on the *absolute number* of applicable personnel "at a single generating unit" that haven't been trained, "or" the *percent* of the GO's "total" applicable personnel that haven't been trained, there are plausible scenarios where the appropriate VSL would be unclear, or where a violation could be considered either multiple lower-VSL violations or a single higher-VSL violation. We believe that this problem could be remedied by (1) making the metrics consistent, i.e. either (a) "one applicable personnel; or 5% or less of its total applicable personnel," or (b) "one applicable personnel at a single generating unit; or 5% or less of applicable personnel at a single generating unit"; and (2) specifying whether to use the greater of, or lesser of, those two options in each case—for example, for GO with a single unit with two applicable personnel, one untrained person (low VSL) would be more than 15% of applicable personnel (severe VSL).

R6: percentage of R6 events is an inappropriate metric

Assuming that R6's CAP requirement is not moved to R1.4, the VSLs for R6 should differentiate based on whether each required CAP was (1) developed, fully or partially, (2) consistent with some or all of the criteria, and (3) timely (with gradations of lateness), etc. The proposed VSLs are instead based on the percent of a GO's "total events listed in R6" for which it did not develop a fully-compliant CAP. This is an unreasonable metric, and unfair to smaller entities with a small number of units: A GO that experienced 100 R6 events and did nothing at all with respect to 10 of them would be a Medium VSL, while a GO that experienced one R6 event, for which it developed a partially-compliant CAP, would be a Severe VSL. The SDT should not retain the proposed VSLs for R6, but if it does, it must at minimum indicate over what time period the percentage is calculated—is it one winter season? One calendar year? Some other time period?

Proposed language for R3, R4, and R6

Scope of R4.3; overlap between R4.3 and R1.4

Proposed language

If the lowest temperature established pursuant to Requirement R1 has been updated in the cold weather preparedness plan pursuant to R4.1, review whether its generating units have the freeze protection measures required to operate at the updated lowest temperature. If freeze protection measures must be supplemented or modified as a result of the updated lowest temperature, the requirements of Part 1.4 apply.

"Maintenance" of cold weather preparedness plan; possible combination of R4 with R3

Proposed language

R3. Each Generator Owner shall implement and maintain one or more cold weather preparedness plan(s) for its generating units. The cold weather preparedness plan(s) shall include the following, at a minimum: *[Violation Risk Factor: High] [Time Horizon: Operations Planning and Real-time Operations]*

3.1. Documented minimum hourly temperature experienced at its location since 1/1/1975 or a lesser period if reliable data is not available to 1975;

3.2. Documented generating unit(s) freeze protection measures based on geographical location and plant configuration;

3.3. Annual inspection and maintenance of generating unit(s) freeze protection measures; and

3.4. Generating unit(s) cold weather data, to include:

3.4.1. Generating unit(s) operating limitations in cold weather to include:

3.4.1.1. Capability and availability;

3.4.1.2. Fuel supply and inventory concerns;

3.4.1.3. Fuel switching capabilities; and

3.4.1.4. Environmental constraints.

3.4.2. Generating unit(s) minimum:

· Design temperature;

· Historical operating temperature; or

· Current cold weather performance temperature determined by an engineering analysis.

3.5. Maintenance of the cold weather preparedness plan, which shall consist of the following reviews every five calendar years:

3.5.1. Review the documented minimum hourly temperature developed pursuant to Part 3.1, and update the cold weather preparedness plan with the lowest temperature as necessary;

3.5.2. Review its documented cold weather minimum temperature contained within its cold weather preparedness plan(s) for its generating units, pursuant to Part 3.4.2;

3.5.3. Review whether its generating units have the freeze protection measures required to operate at the lowest temperature established pursuant to Requirement R1 and, if not, implement appropriate modifications per the requirements of Part 1.4.;

3.5.4. Review procedures for annual inspection and maintenance of generating unit(s) freeze protection measures, and update as necessary; and

3.5.5. Review generating unit(s) cold weather operating limitations documented per R3.4.1, and update as necessary.

R6

Proposed language

R6. If (i) a generating unit experiences an event ("event") consisting of (a) a derate of more than 10% of the total capacity of the unit or 10 MW, whichever is greater, for longer than four hours in duration, (b) a start-up failure where the unit fails to synchronize within the start-up time specified in the applicable cold weather preparedness plan, or (c) a Forced Outage; (ii) the apparent cause(s) of the event is freezing of the Generator Owner's equipment within the Generator Owner's control; and (iii) the ambient conditions at the site at the time of the event are at or above the temperature documented in Part 3.4.2, then: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

6.1. No later than 150 days subsequent to the event or by July 1 that follows the event, whichever is earlier, the Generator Owner that owns the affected generating unit shall analyze and document:

6.1.1. A summary of the identified cause(s) for the freezing of equipment where applicable and any relevant associated data; and

6.1.2. A review of applicability to similar equipment at other generating units owned by the Generator Owner.

6.2. Corrective actions in response to the analysis required by R6.1, including new or modified freeze protection measures, are subject to the requirements of Part 1.4 and, if applicable, Part 1.5.

Likes 0	
Dislikes 0	

Response

Michael Jones - National Grid USA - 1	
Answer	

Document Name	
Comment	

RE: EOP-011-3: Please consider removing the "Interpretations" section of the standard. Please consider listing the Implementation Plan and Technical Rationale document in the "Associated Documents" section of the standard.

RE: EOP-012-1: Please consider listing the Technical Rationale document in the "Associated Documents" section of the standard. In the Compliance section, please consider if the titles of section 1.1 Compliance Enforcement Authority, 1.2 Evidence Retention, and 1.3 Compliance Monitoring and Enforcement Program should be on their own lines with the details following below, if there is a template for the Compliance section of standards, considering the difference in the layout between EOP-011-3 and EOP-012-1.

Likes 0	
Dislikes 0	
Response	

Amy Casuscelli - Amy Casuscelli On Behalf of: Gerry Huitt, Xcel Energy, Inc., 5, 3, 1; - Amy Casuscelli

Answer	
Document Name	
Comment	

Xcel Energy appreciates the work of the drafting team in addressing the reliability need related to this project. We look forward to supporting the next draft after the team has been able to consider comments.

Likes 0	
Dislikes 0	
Response	

Devon Tremont - Taunton Municipal Lighting Plant - 1

Answer	
Document Name	
Comment	

TMLP agrees with the comments submitted by Rebecca Baldiwn on behalf of TAPS Group for Question 10.

Likes 0	
Dislikes 0	
Response	

Joe McClung - JEA - 1	
Answer	
Document Name	
Comment	
We support LPPC's comments. Please reference our response to #4 about a time element and instance exclusion to continuous operations.	
Likes 0	
Dislikes 0	
Response	

Casey Perry - Casey Perry On Behalf of: Lynn Goldstein, PNM Resources - Public Service Company of New Mexico, 1, 3; - PNM Resources - Public Service Company of New Mexico - 3 - WECC	
Answer	
Document Name	
Comment	
PNM supports the EOP-011-3 and EOP-012-1 addition comments provided by EEI.	
Likes 0	
Dislikes 0	
Response	

Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
Minnesota Power has decades of operating experience in extreme cold temperatures with few events impacting reliability. Minnesota Power appreciates the proposed R6 requirement in EOP-012-1, which focuses on evaluating causes of failure due to freezing issues and identifies corrective actions to continuously improve reliability.	
Likes 0	
Dislikes 0	
Response	

Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	
Document Name	
Comment	
Capital Power supports the NAGF comments / concerns / suggested revisions related to this question.	
Likes 0	
Dislikes 0	
Response	

Mark Spencer - LS Power Development, LLC - 5	
Answer	
Document Name	
Comment	

There is no field to input comments to question #8 (it skips from #7 to #9) on my ballot so I offer the response here.

8. The SDT proposes that the modifications in EOP-011-3 and the newly drafted EOP-012-1 meet the key recommendations in The Report 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.

0 Yes

1 No

Comments:

The proposed requirement of being "capable of continuous operations at the documented minimum hourly temperature experienced at its location since 1/1/1975" imposes reliability requirements that far exceed the system planning standards and performance of the distribution system, and are not coordinated with other factors that may first cause load shedding. We need to take a step back and investigate more thoroughly how the extreme cold weather preparedness requirements match regional planning criteria and flange up with the supply chain elements outside the scope of the Standards that are equally as necessary to generate and deliver electricity. As an example, if a BA plans to a 1-in-10 LOLE and generator weatherization imposes a greater than 1-in 47 LOLE, load shedding due to insufficient capacity, not freezing, would likely occur first. Also, there are many other factors that impact generation availability during extreme cold weather events other than systems freezing. None of these other elements would be cold weather hardened to a similar degree, and power plants that are hardened in accordance with the proposed Standards may be unavailable for reasons outside the scope of the Reliability Standards – i.e., rail, pipeline, or truck deliveries; cooling water supplies; etc. Some resources may reach environmental limitations well before the specified low temperature is reached. It is critical that a more holistic approach to extreme weather performance be taken.

Other concerns are the specified ambient conditions appear overly conservative. Rational arguments can be made for the use of the coldest hourly temperature in the last 47 years as the basis, but not for the performance requirement at this temperature continuously. Creating a synthetic criteria that has not been observed naturally – i.e., the continuous application of the worst assumptions for temperature, precipitation and wind conditions that did not occur concurrently, does not seem reasonable.

In contrast, current freeze protection design takes into account a starting point and ending point, and examines the duration and depth of the extreme condition when specifying freeze protections measures. Mr. Mark Dittus, Black & Veatch, explained this "Time to Freeze" concept during the April 27, 2022 FERC technical conference. As an example, the proposed standard would obligate a generator located near Dallas, TX to be able to operate at -2° F continuously despite the fact the region has experienced only one hour at that temperature in the last 47 years. The proposed standard then goes further and imposes the requirement to "account for the cooling effect of wind" and the "impacts on operations due to precipitation" but offers no guidance on how to estimate the coincidence of these factors. As the temperature decreases the chance of precipitation also decreases, yet the standard tells generators to plan for the lowest observed temperature and precipitation. Notably, there was no recorded precipitation when the mercury dropped to -2° F in Dallas. The proposed standard layers on top of this approach to temperature and precipitation that generators must also account for wind; the wind speed was measured at 5 mph coincident with the temperature plunging to -2° F in Dallas. It is unclear how often these synthetic conditions may actually occur, but it is most assuredly less frequently than once every 47 years, yet the standard requires continuous performance at these conditions.

Compounding these issues is that compliance costs increase non-linearly with temperature. Most freeze protection measures are passive – i.e., insulation, and require naturally-occuring and frequent periods of thawing conditions to offset the prolonged freezing conditions the insulations resists. If the Standards specify continuous, below freezing conditions, passive measures are unsuitable and must be replaced with active measures – e.g., heat trace, space heating, auxiliary boilers, etc. That is, a power plant in Dallas, TX must have heat trace installed on all piping regardless of diameter in order to comply with the Standard. This will necessitate stripping insulation, adding electrical distribution feeders and circuits to handle the higher parasitic loads, and wrapping all pipe with heat trace. The backfeed costs of keeping these circuits energized during cold weather would also be substantial.

While Winter Strom Uri provides important and life-savings lessons, and we agree that enhanced performance standards are necessary, The Report notes that (i) certain generators failed to perform at their design conditions and (ii) other generators were unable to obtain fuel. The former concern may be addressed by better oversight or market design (under the purview of the BAs). The latter concern is outside the scope of this reliability standard, but may be address by the BAs through other means in coordination with implementing exteme cold weather preparedness.

In lieu of attempting to implement a vaguely defined standard that is left to each generator to interpret, we propose that NERC allow the BA's to define the specification but require that it overlap with the BA's planning assumptions. For example, if a BA creates load forecasts with 1-in-20 probabilities (i.e., 95th percentile) then the extreme cold weather standard should be slightly more conservative, but not significantly more, than the 1-in-20 year planning assumption. It would also be less prone to interpretation if the ambient conditions were based on weather reporting station(s) identified by the BAs, and the generator would then have to demonstrate to the BA that it is capable of operating at the specified conditions reported by the nearest designated weather station. In the event that there is significant elevation change or distance between the closest designated weather reporting station and the generator then the generator may be required to modify its performance target to local conditions through statistical sampling techniques that bias the weather station conditions. This further eliminates the potential that many generators may not have hourly weather data at their site prior to their construction, let alone back to 1975.

Additional comments for #10:

While the Reliability Standard does require generators to develop cold weather preparedness plans and train personnel on these plans, we offer that the standard could be more explicit and prescriptive. As was observed in 2011 and 2021 many generators had freeze protection installed that simply failed to work properly. We conjecture that if all installed freeze protection measures functioned properly these events would have been reduced in severity. Therefore, the Reliability Standard should require the generators to explicitly develop preventative maintenance plans that are performed at a frequency and in sufficient detail to ensure that installed systems are functioning as they were intended and be included as part of the plan. Additionally, the completed PM records should be maintained as part of the evidentiary record to demonstrate compliance with the standard.

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 Regional Standards Committee

Answer	
Document Name	

Comment

NPCC RSC has concerns with EOP-012, R2, and R2 states once every five years, but the evidence retention period is only 3 years, and GO/GOP are audited every 6+ years. There is a disconnect with the evidence retention period.

For R4, the retention period is: The Generator Owner shall retain the current cold weather preparedness plan(s), as evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirement R4 and Measure M4.

All requirements under this standard should have a retention period “since the last audit”.

For Canadian entities, the operation of hydroelectric generating units in cold weather conditions is part of the normal operating conditions. The design, maintenance, and operation of the generating units are done accordingly. For example, the generating units being installed indoors (either in a powerhouse or underground), these units do not require specific freezing measure protection.

Sub requirement 1.2.5.3 and 1.2.5.4 of Requirement 1.2.5 in EOP-011-3 state:

1.2.5.3. Provisions to minimize the overlap of circuits that are designated for manual Load shed

and circuits that are utilized for underfrequency load shed (UFLS) or undervoltage load shed

(UVLS); and

1.2.5.4. Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions.

If, for a certain region, there is no provision to minimize the overlap of the circuit because the load is insufficient, how does an entity comply with the requirement?

Sub requirement 1.2.5.1 of Requirement 1.2.5 in EOP-011-3 states:

1.2.5.1 Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;

What amount of load should be available for operator-controlled manual load shedding?

Consider removing the Time Horizon and VRF columns in the EOP-011-3 VSL Table.

Requirement R3 in EOP-012-1 reads that "each GO shall implement and maintain one or more cold weather preparedness plans …" whereas R5 refers to "implementing cold weather preparedness plans developed pursuant to R3.". The SDT should consider revising R3 to include "develop, implement and maintain one or more cold weather preparedness plans".

As proposed, EOP-011 has the unintended consequence of requiring transmission-only entities to implement provisions that, in fact, Distribution Providers and UFLS-Only Distribution Providers are required to perform in order to mitigate operating Emergencies. RSC requests that the Standard Drafting Team revise EOP-011 and the Technical Rationale with due consideration to areas of the ERO Enterprise for which the Transmission Operator does not serve as a Distribution Provider nor UFLS-Only Distribution Provider.

Having "Provisions to minimize the overlap of circuits" in 1.2.5.3. "Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for underfrequency load shed (UFLS) or undervoltage load shed (UVLS); and", can potentially allow for noncompliance with the coordination with other UFLS programs, required by PRC-006-NPCC-2 (i.e. coordination between the manual and automatic UFLS)

The suggestion is made that the word coordinated should be added to 1.5.2.1, as follow: "Provisions for **coordinated** manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;"

Suggestion is made that the word coordinated should be added to 1.5.2.2, as follow: "**Coordinate the** Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for **with the automatic** underfrequency load shed (UFLS) or **automatic** undervoltage load shed (UVLS); and".

Question 8 Comments:

For Canadian entities, the necessary cold weather practices are already in place. The administrative burden associated with the tasks being required in the standards outweighs the reliability benefits, as we already have a good handle on planning, operations, and maintenance activities in cold (and even extreme cold) weather.

Although RSC abstains from commenting on whether the modifications meet the key recommendations in The Report in a cost effective manner, RSC comments “No” here consistent with comments in response to Question 1. As proposed, EOP-011 has the unintended consequence of requiring RSC and other transmission-only entities to implement provisions that, in fact, Distribution Providers and UFLS-Only Distribution Providers are required to perform in order to mitigate operating Emergencies.

There is little to no benefit to grid reliability by imposing training requirements annually, across the board; this is not a cost effective approach.

The winterization program call-ups task are not knowledge based tasks and do not requires annual refresher for the maintenance personnel to be able to perform the maintenance as required by the maintenance package.

Moreover, for the operating personnel's annual training, a suggestion is made to have the operator's training included as part of the PER-006-1 Specific Training for Personnel, Requirement R1.

Likes 0	
Dislikes 0	

Response

Michele Richmond - Texas Competitive Power Advocates - NA - Not Applicable - Texas RE	
Answer	
Document Name	Additional TCPA Comments on NERC Weatherization 6-20-22.docx

Comment

Additional TCPA Comments attached

Likes 0	
Dislikes 0	

Response

Donna Johnson - Oglethorpe Power Corporation - 5	
Answer	
Document Name	

Comment

: The requirements should be re-arranged. Current R1 should be R2, current R3 should be R1, and current R2 should be R3, then so on… If done that way, you would not have to re-state what is currently in R1.1. After the shuffle: R2.1 would say: “Each generating unit shall be designed and maintained to be capable of continuous operations according to the temperature designated under R1.1” (R3.1 now).

Agree with ACES comment: “In regards to determining the minimum hourly temperature to which generating units should be designed and maintained to be capable of continuous operations: was there any consideration of utilizing future forecasted minimum temperature data rather than, or in addition to, historical temperature data?”

Likes 0	
Dislikes 0	

Response

Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County

Answer	
Document Name	

Comment

CHPD agrees with LPPC's comments.

Likes 0	
Dislikes 0	

Response

Alan Kloster - Alan Kloster On Behalf of: Allen Klassen, Evergy, 1, 3, 5, 6; Jennifer Flandermeyer, Evergy, 1, 3, 5, 6; Marcus Moor, Evergy, 1, 3, 5, 6; - Alan Kloster

Answer	
Document Name	

Comment

Evergy supports and includes by reference the comments of the Edison Electric Institute (EEI) for question #8 and their addtiional comments for this section.

Evergy believes that the Project 2021-07 SDT needs to carefully consider the possibility that these requirements will have the unintended consequence of driving some Generator Owners to decide that the cost of retrofit is too high and that it would be in the entity’s best interest to retire existing generation rather than retrofit a unit to prevent freezing at the lowest temperature since 1975. Given the current concerns about capacity shortages across the U.S., NERC should not unintentionally provide further economic justification for Generator Owners to retire existing dispatchable generation that could perform adequately in extreme, non-freezing weather events necessary to support grid reliability.

Likes 0	
Dislikes 0	

Response

Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3

Answer	
Document Name	

Comment

Comments: MidAmerican supports EEI's additional comments regarding EOP-011-3 and EOP-012-1.

MidAmerican recommends the SDT better define documented minimum hourly temperature if this is the term that the SDT is using. After a review of reliable weather sources, some data is missing and therefore MidAmerican understands it has the discretion to ignore missing data and choose the lowest reliable minimum hourly temperature for the nearest city.

To simplify this, MidAmerican recommends replacing "hourly" with the terminology from the technical rationale, using the "lowest recorded ambient temperature for the nearest city for which historical weather data is available". A review of the NOAA website shows daily minimums are available back to 1/1/1975. The use of daily meets the reliability objectives of the new NERC standard (as it wasn't the single lowest temperature that caused the loss of generation, rather it was sustained cold weather). NERC zero defect standard auditing could result in administratively burdensome costs if "hourly" is literally interpreted to mean 24 readings per day back to 1975, especially for those entities with large generating fleets in a diverse geographic area.

Hourly data may be available from 3rd party weather data aggregators or commercial weather enterprises; however, this data should come from trusted, government sources, as the reliability of the data coming from 3rd party sources cannot be easily verified.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	
Document Name	

Comment

Exelon concurs with the comments submitted by the EEI.

Submitted on behalf of Exelon (Segments 1 & 3)

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

In regards to determining the minimum hourly temperature to which generating units should be designed and maintained to be capable of continuous operations: was there any consideration of utilizing future forecasted minimum temperature data rather than, or in addition to, historical temperature data?

Likes 0	
Dislikes 0	

Response

Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF

Answer	
Document Name	

Comment

SIGE recognizes the work that the SDT has undertaken to address the first 4 requirements of the joint Report. SIGE also is appreciative of the opportunity to provide comments for consideration to this team.

While SIGE is generally in support of additionally criteria to improve reliability and protect the grid from extreme weather conditions, SIGE does have requests additional clarity on the following items:

- For EOP-012-1, what is the scope of equipment included in the definition of a "generating unit" in a technical sense EOP-012-1 R1. For example, does it include high or low side of the GSU, transmission equipment (e.g., transmission lines above the power station), etc. And how does the assessment consider equipment housed in a heated buildings?
- Additionally, what is the intended scope of "generating unit" from a renewable resource standpoint – specifically solar? Is it a singular inverter or the solar field as a whole plant? If it was intended to be wholistic, SIGE recommends the use of "generating plant" or other more expansive language.
- Are fuel issues such as frozen coal or gas storage/valve issues considered an operational constraint or is fuel supply viewed wholistically as part of the 'generating unit'? If the latter, that could have a significant impact on GOs regarding R1 and R6.
- Is R1.1, R1.2, R1.3 focused on unit design or freeze protection measures? The current language suggests unit design. SIGE suggests adding the term "freeze protection" or "freeze protection measures" to the sub requirement language for more clarity.

***C*omment 8 is missing from the SBS system. SIGE provides the following response to Comment 8.**

*The SDT proposes that the modifications in **EOP-011-3** and the newly drafted **EOP-012-1** meet the key recommendations in The Report in a cost-effective manner. 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.*

No; SIGE believes the generating unit should be reasonably expected to continuously operate at the generating plant's minimum design temperature, historical operating temperature, or current cold weather performance temperature determined by an engineering analysis (per R3.4.2). The use of the lowest one-hour temperature since 1975 for determining minimum operating criteria is not likely achievable for older generation plants and doesn't account for changing weather patterns. The resulting implications could be modifications that are too expensive or onerous which may unintentionally lead to more units retiring earlier and/or more units opting for (R1.4.4) constraints which would have a negative effect or no beneficial impact on the reliability of the grid.

Likes 0	
Dislikes 0	

Response

Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1, Group Name OGE Energy - Oklahoma Gas and Electric Co.

Answer	
Document Name	

Comment

For Question 8 (missing on form): Oklahoma Gas and Electric agrees with and endorses comments as submitted by EEI Reliability Technical Committee (RTC)

Likes 0	
Dislikes 0	

Response

Jennifer Blair - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC, Group Name PPL NERC Registered Affiliates

Answer	
Document Name	

Comment

PPL NERC Registered Affiliates support EEI comments on Question 10.

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	
Document Name	

Comment

Consider adding requirements or technical rationale document language to address utilities that may own generating units in different climates (northern utilities may require vastly different freeze protection than southern utilities).

Question 8 comment: Please provide some clarification on what constitutes appropriate cost effective manner. What return on investment is needed to meet this measure?

Likes 0	
Dislikes 0	

Response

Dwanique Spiller - Dwanique Spiller On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Dwanique Spiller

Answer	
Document Name	

Comment

NV Energy supports EEI's additional comments regarding EOP-011-3 and EOP-012-1.

NV Energy recommends the SDT better define documented minimum hourly temperature if this is the term that the SDT is using. After a review of reliable weather sources, some data is missing and therefore NV Energy understands it has the discretion to ignore missing data and choose the lowest reliable minimum hourly temperature for the nearest city.

To simplify this, NV Energy recommends replacing "hourly" with the terminology from the technical rationale, using the "lowest recorded ambient temperature for the nearest city for which historical weather data is available". A review of the NOAA website shows daily minimums are available back to 1/1/1975. The use of daily meets the reliability objectives of the new NERC standard (as it wasn't the single lowest temperature that caused the loss of generation, rather it was sustained cold weather). NERC zero defect standard auditing could result in administratively burdensome costs if "hourly" is literally interpreted to mean 24 readings per day back to 1975, especially for those entities with large generating fleets in a diverse geographic area.

Hourly data may be available from 3rd party weather data aggregators or commercial weather enterprises; however, this data should come from trusted, government sources, as the reliability of the data coming from 3rd party sources cannot be easily verified.

Likes 0	
Dislikes 0	

Response

Hillary Dobson - Colorado Springs Utilities - 3

Answer	
Document Name	
Comment	
CSU supports LPPC's comments.	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	
Document Name	
Comment	
Pertaining to Question 8, agree with comment supplied by the U.S. Bureau of Reclamation. To reiterate, the standard should be focused on those generation types proven to have problems with cold weather operation. The reliability gap the SAR addresses is not a widespread issue over the United States and Canada. It should be clear that generation interconnection transmission Facilities including supporting substations and stations are not applicable.	
Likes 0	
Dislikes 0	
Response	
Daniel Mason - Portland General Electric Co. - 6, Group Name PGE FCD	
Answer	
Document Name	
Comment	
• **Q8:** The SDT proposes that the modifications in EOP-011-3 and the newly drafted EOP-012-1 meet the key recommendations in The Report 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. **A8:** Yes, as long as Generator Owners retain the ability to determine corrective actions based upon factors which include the economic viability of the required plant investments. • **Q10:** Portland General Electric Company also supports the additonal comments for EOP-011-3 and EOP-012-1 provided by EEI.	

Likes 0	
Dislikes 0	

Response

Jun Hua - Austin Energy - 4

Answer	
Document Name	

Comment

I support comments made by Michael Dillard, Austin Energy, Segment 5

Likes 0	
Dislikes 0	

Response

Whitney Wallace - Calpine Corporation - 5 - WECC,Texas RE,NPCC,SERC,RF

Answer	
Document Name	

Comment

Calpine agrees with and incorporates by reference the comments provided by TCPA for this inquiry. Calpine also agrees with Luminant's comments that a Corrective Action Plan should be required no later than 150 days subsequent to an event, regardless of the month in which an event occurred.

Response for Question 8: No. Calpine agrees that EOP-011-3 and EOP-012-1 should meet the key recommendations in The Report "in a cost effective manner," but disagrees that that SDT meets these recommendations as currently drafted, specifically with regard to Key Recommendation #2 (cost recovery). In fact, this recommendation is not addressed at all in the SDT, which is particularly problematic for generators operating in the competitive areas of ERCOT and who do not have guaranteed cost recovery through a captive rate base, as alluded to elsewhere in these comments. Calpine also agrees with Luminant that generators operating in ERCOT are facting significant costs related to new weatherization requirements that will soon be adopted by the Public Utility Commission of Texas, and that the current ERCOT market design reforms under consideration do not contemplate cost recovery for compliance with these weatherization requirements. Moreover, even outside of ERCOT, generators are not guaranteed full cost recovery through their regulated rates. Compliance with EOP-012-1 should be tied to the availability of a cost recovery mechanism in the marketplace. If there is no provision available for cost recovery, Calpine agrees with TCPA that compliance with EOP-012-1 should be deferred until a suitable cost recovery mechanism is available to the generator.

Likes 0	
Dislikes 0	

Response

Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	
Document Name	
Comment	

No additional comments.

Likes 0	
Dislikes 0	
Response	

Natalie Johnson - Enel Green Power - 5

Answer	
Document Name	2021-07 Initial Ballot_EOP-012-1_clean_051922 (EGP Comments Final).docx
Comment	

It is recommended that the term "freeze" within the phrase "freeze protection measure" be clearly defined as *the ambient temperature below water freezing point of 32F*. Without this definition, there could be confusion on how the term is applied as it relates to cold weather preparedness as freezing is not consistently and reliably measurable with clear criteria. There are many variables that cause freezing of equipment and that impact operations such as temperature, humidity and surface material. Due to these variables, the term used by itself, does not provide a clear criteria for Generators to apply. Defining this term facilitates clear criteria for implementation.

The term generating unit causes confusion in how the standard applies to renewable resources. Although an attempt to clarify is provided, the term generating unit refers to each and every individual turbine or invertor. The revision recommended in the attached edits provided is adopted from PRC-024 and uses the same approach as to how this issue was resolved in that standard. *See section 4.2 in the attached for edits.*

In R1.1 the use of the phrase "continuous operations" is problematic for variable energy resources that are dependent on the wind or sun to generate and therefore are considered intermittent. *See R1.1 in the attached for edits.*

Generator Owners and Operators should not be required to deploy measures that are not based on industry standards or engineering best practices. It is suggested to clarify this in R3 of the draft as well as this should also be clarified in the rational. *See R3 in the attached for edits.*

The 10% derate threshold could cause corrective action plans for events that do not impact the Bulk Electric System. A possible solution is to adopt the same approach used in PRC-004 where misoperations that affect an aggregate nameplate rating of less than or equal to 75MVA of BES facilities are excluded. *See R6 in the attached for edits.*

In addition, Corrective Action Plans should focus on ambient temperature criteria as this is the basis of the operating envelope of a generating resource. This criteria is clearly defined and therefore can be clearly implemented and evaluated. Freezing as it applies to equipment operation is not measurable and can have many variables such as temperature, humidity and surface material. Including freezing as one of the initators for a CAP presents unclear criteria due to the many variables that could or could not apply. It is recommended that accounting for the impact of precipitation freezing issues within the Generators control is already covered in R1.3 and the Corrective Action Plan in the subsequent 1.4 and therefore should not be the initiator of another CAP in R6. *See R6 in the attached for edits.*

Edits provided clarify that capacity is AC power generating capacity helps make this requirement more accurate for solar facilities. Also clarifying that the threshold applies to a derate involving available generating units takes into consideration when solar farms are online but not producing at night. *See R6 in the attached for edits.*

Lastly consideration for safety of personnel during extreme cold weather events should be mentioned. *See R6 in the attached for edits.*

Please see the attached file for more information on how the above suggestions can be implemented.

Likes 0	

Dislikes 0	
Response	
Rebecca Baldwin - Transmission Access Policy Study Group - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	TAPS proposed language Q10.docx
Comment	

TAPS appreciates the opportunity to comment on the draft standards, and we thank the SDT for their hard work in developing these important standards on an accelerated timeline. With limited exceptions, we do not disagree with the substance of the proposed standards; we do, however, have some significant concerns regarding clarity and unintended consequences.

R4
Scope of R4.3; overlap between R4.3 and R1.4
We understand that the SDT intends R4.3 to apply only in the case where a GO's lowest temperature pursuant to R3.1 has changed since the last review, since the GO's existing freeze protection measures may not be adequate to meet the new, lower temperature. But the text as written requires a full self-audit of R1 compliance every 5 years regardless of whether the minimum temperature has changed. We suggest a minor edit to clarify the intended scope of R4.3. In addition, as noted above in response to Question 4, the current wording of R4.3 overlaps with the requirements of R1.4 and would lead to duplicative noncompliance; we suggest an edit to avoid that issue.

"Maintenance" of cold weather preparedness plan; possible combination of R4 with R3
R4 seems to set out, at least in part, how a GO "maintains" its plan, as required by R3. To avoid duplication, either the words "and maintain" should be deleted from R3, or R4 should be made a subrequirement of R3, prefaced by language along the lines of "Maintenance of the plan, which shall consist of the following reviews every five years:" Additional subrequirements could be added to ensure that the GO's 5-year review covers all aspects of its cold weather preparedness plan.

R6
Derate threshold
We have both substantive and clarity/consistency concerns regarding R6. With respect to the substance, the choice of a derate of 10% of the unit's capacity as the threshold does not seem to be supported by any technical analysis, and would be unreasonable in the case of small generators. If a derate threshold is retained, the SDT should consider making it "the greater of" some percent of the unit's capacity or a MW value, e.g. "10% of the total capacity of the unit or 10 MW, whichever is greater," and/or tying it to reserve requirements.

Clarifications
"a specified start-up time"
Failure to synchronize "within a specified start-up time" is vague to the point of unenforceability: it could mean the minimum start-up time that the GO has communicated to its BA (assuming that every GO has done so), but there is nothing in the proposed text preventing an auditor from deciding that some other "specified time" should have been used. We suggest that "minimum start-up time" be added to the cold weather preparedness plan in R3 (possibly under R3.4.1), and then referenced in R6, i.e. "a start-up failure where the unit fails to synchronize within the start-up time specified in the applicable cold weather preparedness plan."

Other necessary clarifications
The text of R6 is unclear in other ways. In particular, (1) the word "event" is used in different places to mean either (i) a derate, failure to start, or Forced Outage, or (ii) the cause of the derate, failure to start, or Forced Outage; (2) it is syntactically ambiguous whether the two numbered preconditions in R6 ("for which (i) the apparent cause(s) of the event…") must be met with respect to all three types of issue, or only with respect to Forced Outages; and (3) "freezing of equipment" is vague: does it include icing, or only freezing of the liquid components of generation equipment? We propose edits to address the first two concerns, including making R6 an if-then statement with three preconditions; if all three are satisfied, the subrequirements are applicable. This does not change the meaning of the SDT's proposed text; it simply clarifies it by making all three preconditions explicit.

Possible merging of R6 CAP requirements into R1.4
Finally, as noted above in response to Question 4, R6 is duplicative of R1.4; we suggest replacing R6's CAP requirements with a reference to R1.4, leaving just the identification and analysis of events in R6.

Proposed text for R3, R4, and R6 is attached in redline and clean form.

Alternative proposals
If the SDT retains a separate CAP requirement in R6, it should at minimum, as suggested in our response to Question 4, clarify in R1 that corrective actions in response to an R6 event are subject only to R6, not R1.4; it should also revise R6.2.6 consistent with the changes to R1.4.4 that we proposed in response to Question 4.

VSLs
Our comments on the VSLs address the appropriateness of the proposed VSLs with respect to the Requirements language as proposed by the SDT; we have not, for the most part, suggested additional conforming changes in line with our suggested revisions to the Requirements.

R1 and R2: percentage of noncompliant units is an inappropriate metric
R1 and R2 have VSLs based on the percent of a GO's units for which it did not comply. This is unfair to smaller entities, who may have only one or two units. It is also not a reasonable metric: a GO with 100 units, that entirely disregarded R1.1-R1.3 with respect to 10 units, would be a Moderate VSL, while a GO with a single unit, for which it met the criteria in R1.1 and R1.2 but not R1.3, would be a Severe VSL. A more reasonable approach with respect to R1.1-R1.3 would be VSLs along the lines of "had freeze protection measures compliant with R1.1 but not R1.2 and/or R1.3," "had freeze protection measures, but measures were not sufficient to meet R1.1-R1.3," "had no freeze protection measures," etc. If the SDT nevertheless retains percentages of units in the VSLs, it must at minimum clarify the denominator for each—we believe that for R1, the intent is the GO's applicable units, and for R2, it is the GO's applicable new units for which it cannot meet the R1 criteria due to technical commercial, or operational constraints. And the SDT would need to clarify the time period over which the R2 percentage is taken—e.g. if a GO has 10 applicable units with R2 constraints, two of which were identified in each year over a five-year period, and it failed to document its determination and the constraints with respect to one of the last two units, is that a Severe VSL (because it was noncompliant with respect to 50% of its applicable units in that year), or Moderate (because it was noncompliant with respect to 10% of its total applicable units, or 10% of the applicable units identified over a 5-year period)?

R1.4: need for Low, Medium, and High VSLs
While R1.1-R1.3 have multiple VSLs (even though those VSLs are based on an inappropriate metric), R1.4 has only a single VSL—Severe—where the GO "did not develop or implement a CAP as required by Requirement R1." This is unreasonable; a GO might develop a CAP but only partially implement it, or develop and implement a partially-compliant CAP, etc. In addition, if R1.4 had a deadline, as we suggest it should in response to Question 4, then VSLs could be based on degrees of lateness.

R2 and R4: unintended ambiguity depending on date of discovery of noncompliance
The VSLs for R2 and R4 do reflect degrees of lateness, but they have another flaw: one possibility for a Severe VSL is "did not complete a review"/"does not have a completed review," while a "High" VSL is "was late by greater than 60 calendar days." But what if the noncompliance is discovered in an audit 50 days after the deadline? Is it a Medium VSL (because it is not yet more than 60 days late) or Severe (because the review isn't (yet) done)? The VSLs for R2 and R4 should be revised so that High has a maximum number of days, and Severe is "more than [x] days" late.

R4: omission of updating of plan from Low, Medium, and High VSLs
The text of Requirement R4 requires GOs to review and, if necessary, update their plans. The Low, Medium, and High VSLs for R4 refer only to completing the required review. The Severe VSL includes "The Generator Owner does not have a completed review. OR The Generator Owner did not update the cold weather preparedness plan." The (likely inadvertent) omission of "updating" from the lower VSLs suggests that being a day late in updating a cold weather preparedness plan is just as bad as being 6 months late. The words "and any necessary update(s)" should be added to Low through High VSLs.

R5: ambiguous application
Because the R5 VSLs are based on the absolute number of applicable personnel "at a single generating unit" that haven't been trained, "or" the percent of the GO's "total" applicable personnel that haven't been trained, there are plausible scenarios where the appropriate VSL would be unclear, or where a violation could be considered either multiple lower-VSL violations or a single higher-VSL violation. We believe that this problem could be remedied by (1) making the metrics consistent, i.e. either (a) "one applicable personnel; or 5% or less of its total applicable personnel," or (b) "one applicable personnel at a single generating unit; or 5% or less of applicable personnel at a single generating unit"; and (2) specifying whether to use the greater of,

or lesser of, those two options in each case—for example, for GO with a single unit with two applicable personnel, one untrained person (low VSL) would be more than 15% of applicable personnel (severe VSL).

R6: percentage of R6 events is an inappropriate metric
Assuming that R6's CAP requirement is not moved to R1.4, the VSLs for R6 should differentiate based on whether each required CAP was (1) developed, fully or partially, (2) consistent with some or all of the criteria, and (3) timely (with gradations of lateness), etc. The proposed VSLs are instead based on the percent of a GO's "total events listed in R6" for which it did not develop a fully-compliant CAP. This is an unreasonable metric, and unfair to smaller entities with a small number of units: A GO that experienced 100 R6 events and did nothing at all with respect to 10 of them would be a Medium VSL, while a GO that experienced one R6 event, for which it developed a partially-compliant CAP, would be a Severe VSL. The SDT should not retain the proposed VSLs for R6, but if it does, it must at minimum indicate over what time period the percentage is calculated—is it one winter season? One calendar year? Some other time period?

Likes 0	
Dislikes 0	

Response

Quintin Lee - Eversource Energy - 1

Answer	
Document Name	

Comment

In EOP-011, the term 'critical load' should be limited to load critical to the Bulk Electric System. Currently, regarding 'critical loads', the associated Technical Rationale states, 'critical loads which may be essential to the integrity of the electric system, public health, or the welfare of the community.' However, since this is a NERC Reliability Standard, we suggest limiting EOP-011 use of critical load to loads to loads which may be essential to the integrity of the electric system.

As a suggestion, **R1.2.5.2** could be changed to: 'should separate the circuits that will be used for manual load shed from circuits used for underfrequency load shed (UFLS), undervoltage load shed (UVLS) or serving critical loads. (i.e., 'load essential to the integrity of the electric system')

Also, the Technical Rationale should be revised to acknowledge that there are other types of loads are critical but for for human safety or welfare.

GO/GOPs not TOPs should be required to provide the gas infrastructure that is necessary to run their plants to their associated DPs. DPs then can be required to pass the identified circuits to the TOPs.

Likes 0	
Dislikes 0	

Response

Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)

Answer	
Document Name	

Comment

Response to Question #8:

The SRC's review of EOP-012-1 (as currently proposed) is a minimal proposal that does not allow for a degree of consistency across the generation fleet in a given area, including the conditions the generating units would need to retrofit for. As a result, EOP-012-1 does not fully meet the intent behind the standard and the FERC/NERC Report.

(Please note: ERCOT abstains from the SRC comments to Question #8. ERCOT to provide separate comments in response to this question.)

Response to Question #10

The SRC requests the *following additions to EOP-012-1* and is meant to ensure the entities performing the Operational Planning Analysis, Real-time monitoring, and Real-time Assessments, as required by IRO-010-4 and TOP-003-5, have accurate and up-to-date information to ensure reliable operations. There is also a need for this data in performing planning studies and assessments to ensure accurate modeling since the improvements are not required to be implemented for an extended period of time The SRC recommends a template for the GOs to update annually that is prepopulated with the applicable entities (via the notifications below) and provided to NERC for dissemination. This would ease the administrative burden of the GOs and provide the notified entities with consistent data.

R1.4.5. A notification to the applicable Regional Entity, Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner and Transmission Operator of any CAP and its details.

R2.3.   A notification to the applicable Regional Entity, Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner and Transmission Operator of any constraints and the supporting determination.

R3.4.3 A notification to its applicable Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner and Transmission Operator of the generating unit cold weather Preparedness plan and details as described in R3.1 through 3.4.

R4.4.   A notification to the applicable Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner and Transmission Operator of any changes identified.

R6.1.1. This CAP to be communicated to the applicable Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner and Transmission Operator.

The ISO/RTO Council Standards Review Committee (IRC SRC) would like to take this opportunity to thank the Standard Drafting Team for all their hard work and attention to this Project. Your dedication to this Project is sincerely appreciated.

Likes 0	
Dislikes 0	

Response

Dana Showalter - Electric Reliability Council of Texas, Inc. - 2

Answer	
Document Name	EOP-012 redlines ERCOT for submittal.docx

Comment

Q8. ERCOT agrees that certain elements of the proposed standard may meet the recommendations in the Report in a cost-effective manner, but disagrees that some elements—such as the broad exemption language proposed in part 1.4.4—are consistent with the recommendations in the Report. Recommendation 1f in the FERC/NERC Report does not contemplate any sort of broad exception, although ERCOT agrees that a narrow exception to avoid retirements is helpful. ERCOT also agrees that a location-specific standard is appropriate

Q10. ERCOT supports the SRC comments provided in response to this question that address the notification to certain entities of the CAP and its details, including operational limitations, and expected time to resolve. ERCOT encourages a thoughtful and efficient process to achieve this awareness.

In addition to the changes to R1, R4, and R6 and the creation of new R7 (CAP) and R8 (exemptions) ERCOT proposed in response to Question 4, and the removal of R2 proposed in response to Question 5, ERCOT also proposes the following changes to R3 and R5:

ALTERNATE LANGUAGE PROPOSED (REDLINES PROVIDED IN ATTACHED DOCUMENT)

R3: ERCOT proposes the cold weather preparedness plan be reviewed periodically, at least once every five years, to provide the opportunity to update details and evaluate the ongoing effectiveness of its measures.

R3: The information included within the plan should be provide the same detail for each generating unit

R3.1: The plan should document the temperature initially determined in R1 and periodically updated in R4.

R3.2: The freeze protection measures should be appropriate to meet the temperature documented in R3.1, which considers unit location.

R5: ERCOT recommends changing "its" to "the" in the phrase "its maintenance or operations personnel responsible for implementing cold weather preparedness plan(s)," as the relevant personnel may not be employees or contractors of the entity providing the training.

Likes 0	
Dislikes 0	

Response

Sam Nietfeld - Public Utility District No. 1 of Snohomish County - 5

Answer	
Document Name	

Comment

Question 8: Yes

Question 10 Comments: SNPD supports comments submitted by LPPC and Tacoma Power. However, regarding requirements 1.1, 1.2, and 1.3, SNPD believes it will be difficult to prove compliance. Generator O&M manuals do not normally have a minimum continuous temperature rating, so evidence that the generating unit has been designed to be capable of operating down to a specifically defined temperature will be extremely difficult to achieve. Additionally, with the maintenance requirement, it will be difficult to present evidence to prove that maintenance performed on a generating unit will assure that it can operate down to a specifically defined temperature. In summary, SNPD is stating that it is unclear what evidence could be provided to an auditor to prove that our generators have been designed and maintained to continuously operate at a documented minimum hourly temperature.

Likes 0	
Dislikes 0	

Response

Teresa Krabe - Lower Colorado River Authority - 5

Answer	
Document Name	

Comment

LCRA agrees with the comments submitted by the North American Generator Forum.

Likes 0	
Dislikes 0	

Response

James Baldwin - Lower Colorado River Authority - 1

Answer	
Document Name	

Comment

LCRA agrees with the comments submitted by the North American Generator Forum.

Likes 0	
Dislikes 0	

Response

John Babik - JEA - 5

Answer	
Document Name	

Comment

We support LPPC’s comments. Please reference our response to #4 about a time element and instance exclusion to continuous operations.

Likes 0	
Dislikes 0	

Response

Ashley Scheelar - TransAlta Corporation - 5

Answer	
Document Name	

Comment

Question 8 Comments: Our responses is “No-do not agree”. TransAlta supports the comments of the U.S. Bureau of Reclamation for question 8. Reclamations comments are provided again here: "*The proposed modifications are not cost effective because they universally apply a compliance burden to solve a problem that exists only in a limited geographic area and that is limited to certain types of generation facilities. Further, the proposed ability for Generator Owners to limit the scope of their own applicability (i.e., use of “as defined by the Generator Owner”) precludes the implementation of meaningful change.]*"

Question 10 Comments:

TransAlta provides the following comments for the SDT to consider:

- There is certainly a need for requirements to be in place to address the events of winter storm of February 2021. However, there are generators that are faced with the cost and administrative burden these standards present with little or no reliability benefit to the regions they operate in.

- There are many parts of the EOP-012-1 standard where there is the possibility of varying interpretation for generators and the entities monitoring and enforcing these standards. For example, the data requirements from section 3.4.2 “Historical operating temperature”. I will present a hypothetical example based on my current understanding of the wording: Let’s say I can only produce historical operating temperature data for the generator since 2016. Would an auditor interpret then that I need to obtain an engineering study in place of that limited data set? There are multiple other scenarios related to this particular sub requirement that are subject to interpretation.

- TransAlta requests that the SDT reconsider the yearly requirement for training and instead keep the current wording “Awareness training on the roles and responsibilities of site personnel contained in the cold weather preparedness plan”. The knowledge being conveyed may not be beneficial to those receiving it, especially not on a yearly basis. I will highlight this point with an example: The way we implement training/awareness requirements is typically through a Learning Management System. The best way to implement training is to select a job-code or codes so that all individuals with that job code will automatically receive the training upon starting a role. This is beneficial when personnel changes occur as there is no need for a manual process to review and ensure each new employee is assigned training. To manually manage this would be impossible with a fleet of our size. In all cases where we apply this type of training (communications, protection systems), it makes sense to have a standard to require training as the knowledge is valuable to all those employees with a job code receiving the training. In the case of EOP-012-1, we would have to have potentially hundreds of maintenance staff trained on something only a few individuals at site are responsible for.

Likes 0	
Dislikes 0	

Response

Comments received by: Jeanne Kurzynowski – CMS Energy

Question 1 – Yes
Comments:
In many cases, UFLS and UVLS are implemented on the distribution system, and thus the TOP may not have available detailed information to reflect these in their manual load shedding operations.

Question 2 – Yes
Comments:
The Standard does not currently require the BA to determine the winter season. A new requirement should be added to ensure the BA provides the seasons to the GOs in its footprint. Suggested language for the Requirement: "The Balancing Authority shall determine the winter season for its footprint and shall inform each GO in its footprint of its determination, by [date] of each year for the ahead winter season commencing in that calendar year.

Question 3 – Yes
Comments: No comments

Question 4 – Yes
Comments:
The year 1975 pre-dates modern weather forecasting and recording capabilities. If desired to extend the monitoring period to that extent, we suggest that the requirement instead specify the minimum hourly temperature at the nearest National Weather Service location. Existing generating units should be required to analyze their designed operation parameters using the freeze protection factors to identify any cold weather limitations based on historic operations dating back to 1975, then develop a time limited Corrective Action Plan. Requirement 1 is an overreach of the Federal Power Act because it requires existing facilities to add equipment or retrofit its facilities.

Question 5 – Yes
Comments:
A declaration that the GO cannot meet the constraints is good, but the Requirement does not specify to whom the declaration must be made. Is it simply a compliance document, or should the requirement specify that the impacted BA(s) be notified of the constraint?

Question 6
Comments: Section 1600

Question 7 –
Comments: No comments

Question 8 – No
Comments:
The Standard is a gross overreach of Federal power. The costs for implementing the Changes to EOP-011-3 and EOP-012-1 will be mitigated through an extended implementation plan and through the suggested adjustments to the requirements of the Standards.

Question 9 – No
Comments:
The entirety of Standard EOP-012-1 should have a 5 year implementation plan. The Generator Owners will need sufficient time to develop compliant procedures and practices. Further, the scheduling and financing of modifications will require greater than 18 months.

Question 10

Comments: While the proposed standards provide criteria to guide GO/GOP to implement cold-weather operating capabilities, there is no requirement that the generators actually operate properly during cold weather. Without a results-based requirement that the generators actually operate properly in these conditions (e.g. a compliance violation should they not), the standards fall short

Consideration of Comments

Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination

Comments Received Summary

There were 108 sets of responses, including comments from approximately 249 different people from approximately 162 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, 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 the Vice President of Engineering and Standards, Howard Gugel (via email) or at (404) 446-9693.

Consideration of Comments

The Project 2021-07 Standard Drafting Team (SDT) thanks all of industry for your time and comments. The SDT revised the proposed EOP-012-1 standard based on industry comment and the final FERC, NERC, and Regional Entity Staff Report ("Joint Report"). Due to the similar nature of multiple comments received during the initial ballot and comment period, the SDT has chosen to respond to comments in summary format as provided for by section 4.2 of the Standard Processes Manual. Comments to Question 8 were include in the responses to Question 10.

NERC Jurisdiction

The Standard Drafting Team received several comments regarding the consistency of the proposed generator freeze protection retrofit requirement in proposed EOP-012-1 with Section 215 of the Federal Power Act or NERC's Market Principles (NERC Rules of Procedure Section 303 (Relationship between Reliability Standards and Competition), see also Market Principles). See, e.g., comments of Edison Electric Institute, Consumers Energy Company, NRG Energy, Inc., North American Generator Forum, and Dominion Resources, Inc. In response to these comments, the Standard Drafting Team states as follows:

The Project 2021-07 Standard Drafting Team has been charged with developing Reliability Standards to address the recommendations of the FERC, NERC, and Regional Entity Staff Report, *The February 2021 Cold Weather Outages in Texas and the South Central United States* (November 2021), available here ("Joint Staff Report"). One of the key recommendations of this report is for "Generator Owners to retrofit existing generating units, and when building new generating units, to operate to specific ambient temperatures and weather based on extreme temperature and weather data, and account for effects of precipitation and cooling effect of wind" (Recommendation 1f).

In developing draft Reliability Standards to address Recommendation 1f, the SDT has endeavored to draft proposed requirements that are consistent with all applicable laws, regulations, and NERC rules relating to the development of Reliability Standards. The SDT has consulted with NERC's Legal department throughout the development of proposed EOP-012-1.

The SDT concluded, in consultation with NERC Legal, that a generator retrofit requirement is permitted so long as: (1) the requirement provides for the reliable operation of the Bulk-Power System; and (2) does not require the enlargement (i.e. growth or expansion) of existing facilities or the construction of new generation capacity. As to the first prong, a Reliability Standard requirement to retrofit existing generating facilities to meet certain cold weather operating parameters would provide for reliable operation of the bulk-power system (consistent with Recommendation 1f of the Joint Staff Report). The purpose of such a requirement is to have existing generating units produce their existing power capacity more reliably during expected cold weather conditions, thereby supporting bulk-power system reliability during such conditions. The reliability need for such a requirement is well documented in reports addressing causes and recommendations for multiple cold weather events affecting reliability, including the Joint Staff Report.

As to the second prong, NERC Legal explained that while the resulting retrofit requirement may include operational and/or design approaches for existing facilities intended to improve cold weather reliability, it may not expressly (nor implicitly) call for either the expansion of existing facilities (such as by requiring an increase in nameplate capacity) or the construction of new generation capacity. Section 215 of the Federal Power Act expressly permits operational and design requirements in Reliability Standards to provide for reliable operation; the statute only excludes requirements that require the expansion of existing facilities (such as by requiring an increase in nameplate capacity) or the construction of new generation capacity, because those are matters Congress determined to leave to the states. Therefore, a retrofit requirement respecting these exclusions would appear to be permitted under the plain meaning of the statute.

The fact that there may be more of the existing generation capacity available during cold weather conditions because those generators would not be not forced off-line due to freezing issues should not alter this conclusion. A requirement that would have the effect of decreasing the percentage of existing generation capacity forced off-line due to freezing and therefore increasing the percentage of existing generation capacity that would be available to support reliability is not the same as a requirement to expand or construct new capacity.

The SDT has reviewed with NERC Legal the comment asserting that Section 215 of the Federal Power Act does not permit requirements for the design of "unplanned modifications" to facilities. NERC Legal explained that such an interpretation does not appear to reflect the plain words of the statute, nor does it comport with the overall framework of Section 215. NERC Legal explained that Congress granted broad reliability authority to FERC and the Electric Reliability Organization (i.e. NERC). The statutory exclusions to the ERO's authority are few and specific: Reliability Standards may not include requirements to enlarge existing facilities or construct new capacity. Outside of these exclusions, nothing in the statute prohibits Reliability Standards from requiring entities to make modifications, or plan to make modifications, that would promote the reliable operation of the BPS.

With respect to the question regarding permissibility of a generator retrofit requirement under the Market Principles, the SDT, in consultation with NERC Legal, has not identified any specific concern or impact on competition that would contravene NERC's Market Principles.

The proposed retrofit requirement would be generally applicable and unlikely to result in an unfair competitive advantage for any individual or group of participants. Commenters suggest that the proposed requirement would benefit the group of participants that could pass on the increased costs to ratepayers, but the commenters fail to explain how the availability of cost recovery would result in an unfair competitive advantage. Additionally, the proposed retrofit requirement would not mandate or prohibit a market structure, require disclosure of competitively sensitive information, or define an adequate amount or require expansion/enlargement of generation capacity. As noted above, a requirement that would have the effect of decreasing the percentage of existing generation capacity forced off-line due to freezing and therefore increasing the percentage of existing generation capacity that would be available to support reliability is not legally equivalent to a requirement to expand or construct new capacity.

The SDT is currently pursuing a Corrective Action Plan (CAP) approach to addressing Recommendation 1f of the Joint Staff Report regarding retrofitting. Under this approach, Generator Owners that opt to participate in the markets during the winter months would develop a CAP if they are unable to operate in accordance with the cold weather performance requirements of the standard. Such CAPs shall include corrective actions chosen by the Generator Owner to address identified issues, along with associated timetables for completion. If corrective actions will not be implemented under requirement R1 and R2 due to technical, commercial, or operational constraints, the Generator Owner shall explain as such in a declaration. While NERC Legal has advised that the SDT has flexibility under Section 215 of the Federal Power Act to consider any number of approaches to addressing Recommendation 1f, the SDT notes that a results-based CAP approach has been successfully used in other Reliability Standards found to be consistent with the requirements of Section 215 of the Federal Power Act and NERC's rules regarding Reliability Standards and approved by FERC (e.g., PRC-004-6, PRC-026-1).

As discussed below, the SDT has revised the proposed standard in response to comments and welcomes further comments on the revisions as it works to develop a consensus-based approach to the recommendations of the Joint Staff Report.

Market Rules/Cost Recovery

A few responses expressed thoughts that no new/additional cold weather standards should be implemented until Market rules addressing cold weather related BES emergencies are established by NERC.

Most commenters referenced Key Recommendation 2 which states, "Generator Owners should have the opportunity to be compensated for the costs of retrofitting their units to operate to a specified ambient temperature and weather conditions (or designing any new units they may build) through markets or through cost recovery approved by state public utility commissions (e.g., as a reliability surcharge) to be included in end users' service rates. The applicable ISOs/RTOs (market operators) and/or public utility commissions should identify how best to ensure Generator Owners have the opportunity to be compensated for making these infrastructure investments." As the ERO, NERC is responsible for the development of Reliability Standards to provide for the reliable operation of the Bulk-Power system. The SDT has been charged with developing Reliability Standards to address the standards-related recommendations from the FERC/ERO Enterprise Joint Staff Inquiry Report. In response to comments, the SDT has revised draft EOP-012-1 to better account for industry concerns. The SDT has also drafted requirements that do not discriminate against any type of generator of market type. The market-related recommendations from the Joint Staff Report, such as generator cost recovery, are outside the scope of this project. As referenced within Key Recommendation 2, the SDT urges commenters to work with their applicable market operators and/or PUC to identify potential avenues for compensation. The SDT will pass the concerns to NERC Management.

Definitions

Extreme Cold Weather Temperature

The starting date chosen by the SDT to gather data to determine the lowest temperature that occurred near a facility is based on the completion of the modernization of the National Weather Service project known as MAR (Modernization and Associated Restructuring). This project was completed in the year 2000. Therefore, the SDT adjusted the starting date from 1/1/1975 to 1/1/2000. In general, the National Weather Service modernization provided weather data to be available at most large airports at a 99%+ availability. This will make it fairly accessible for companies to gather data and perform the analysis needed as stated in the requirement. With the adjustment of the date, the SDT also recognized that instead of picking the lowest temperature seen by a facility it would be to the best interest of the industry to use a percentile methodology in determining the appropriate temperature. After reviewing datasets from those members on the SDT, it was agreed that the temperature to be used would be determined on the lowest 0.2 percentile temperature from the dataset. The SDT selected the 0.2 percentile of winter month temperatures since 1/1/2000 to identify a temperature which has been rarely surpassed, but which allows some margin for a Generator Owner to have previously demonstrated successful operation. The SDT is working on a document detailing step by step instructions for obtaining cold weather temperatures and calculating the 0.2 percentile temperature for a site.

Generator Cold Weather Critical Component

Based on industry concerns, the SDT felt that clarity around the scope of the application of freeze protection measures was warranted for both existing and new generating units. The most feasible approach presented itself in the form of a new defined term. The foundation for the definition is based on the ERO Enterprise Reliability Guideline Generating Unit Winter Weather Readiness – Current Industry Practices. This guideline provides a reference for GOs with some examples to consider. Entities should review their plant design and configuration, identify areas with potential exposure to the elements, ambient temperatures, or both and tailor their freeze protection measures accordingly. Based on this guideline and previous cold weather events, a typical subset of problem areas include:

- Level transmitters
  - Drum level transmitters and sensing lines
  - Condensate tank level transmitters and sensing lines

    - De-aerator tank level transmitters and sensing lines
    - Hotwell level transmitters and sensing lines
    - Fuel oil tank level transmitters / indicators
- Pressure Transmitters
    - Gas turbine combustor pressure transmitters and sensing lines
    - Feed water pump pressure transmitters and sensing lines
    - Condensate pump pressure transmitters and sensing lines
    - Steam pressure transmitters and sensing lines
- Flow Transmitters
    - Steam flow transmitters and sensing lines
    - Feed water pump flow transmitters and sensing lines
    - High pressure steam at temperator flow transmitters and sensing lines
- Instrument Air System
- Motor-Operated Valves, Valve Positioners, and Solenoid Valves
- Drain Lines, Steam Vents, and Intake Screens

The other part of the definition limits the list to those components, elements, or pieces of equipment that if lost could result in the generating unit experiencing a (1) forced derate of more than 10% of the total capacity of the unit and exceeding 20 MWs for longer than four hours in duration, (2) a start-up failure where the unit fails to synchronize within a specified start-up time, or (3) a Forced Outage. Additionally, the Public Utility Commission of Texas (PUCT) implemented a similar definition providing a successful example. The elements applicable to GOs in the PUCT definition were used in this proposed definition as a starting point and to ensure a conflict does not exist. This definition is the first step in the process to address recommendations 1a and 1b from the Joint Staff Report.

Cold Weather Reliability Event

Key recommendation 1d from the report recommends a standard that requires Generator Owners to develop a CAP for generating units that experience outages, failures to starts, or derates due to freezing. The Report identifies that most of the outages and derates in the February 2021 event were due to freezing of instrumentation, transmitters, sensing lines, or wind turbine blades (p 166 in report). As such, the team followed the Report recommendation to require a CAP when the apparent cause of the event is freezing. The Project 2021-07 SDT has developed parameters around these events to clarify a reasonable baseline of what level of de-rate qualifies as an event, and provide additional language to identify what constitutes a start-up failure. With the additional clarifications, the SDT determined that the standard would benefit from a defined term, to clearly and efficiently state what constitutes an event. The result is a new defined term, Generator Cold Weather Reliability Event, that defines the circumstances for which a CAP is required (i.e., when a freezing event effects the equipment within the control of the Generator

Owner). The defined term will make the standard easier to understand and implement by providing clear and reasonable factors to determine whether the impact of an event requires mitigation.

Applicable Facilities

Multiple comments asked the SDT to refine and clarify the exception criteria for generating units that would not operate in Extreme Cold Weather (and thus not be required to implement Cold Weather freeze protection measures), the continued exemption if a BES generating were called upon by the respective BA to operate in an emergency or that "Summer peaking" BES generator were defined in other NERC standards.

With Industry's responses in mind, the SDT edited section 4.2 Facilities to delineate the criteria for exempting BES Generating units from implementing measure requirements of EOP-012-1. The revised applicability definition includes all BES units committed or obligated to serve a Balancing Authority load pursuant to an OATT or other contractual arrangement, unless they are typically not available at or below thirty-two (32) degrees Fahrenheit (zero degrees C) for more than four hours. These generators would remain exempted if they were called upon by the respective BA to operate during BES Emergencies, Capacity Emergencies or Energy Emergencies, even if below 32 degrees Fahrenheit. The SDT made clear that all Blackstart Resource are included and not exempted.

The majority of commenters favored the Balancing Authority as the entity to determine the "winter season;" however, multiple comments questioned the need to define "winter weather."

After discussion, the drafting team determined that the function of the Facilities section warranted removal of the Balancing Authority's determination of the winter season for its area. First, multiple comments pointed out that the inclusion of that provision in the Facilities section created an obligation on the Balancing Authority without a requirement, as the Balancing Authority is not a functional entity identified in EOP-12. Further, due to the vast diversity of geography in the footprint, defining a winter season within even a single Balancing Authority with a large footprint could be challenging. Finally, commenters stressed that the Facilities section should be clarified to state which type of generating unit falls under the requirements and which units are exempted. These and related comments made compelling arguments that favored revising the Facilities section to be more consistent with the section's purpose. Therefore, the drafting team is proposing to eliminate the provision that requires the Balancing Authority to determine the winter season; and includes new language focused on what generating units are subject to the standards, and clearly identifying which generating units fit the narrow exemption provided by FERC.

Multiple comments expressed the thought that no BES generator should be exempted for extreme cold weather operating requirements of EOP-012-1 as this would inevitably result in similar BES emergencies as experienced over the previous decade.

The SDT feels that it is not realistic to mandate a BES generating unit that was never designed/intended to operate in freezing conditions, and/or cannot obtain fuel to operate during the winter time frame to comply with EOP-012-1 freeze protection requirements.

Additional responses provided example language for the definition of "Generating Unit," 2 responses asked for clarification of "Generating Unit," and 2 responses expressed thoughts that EOP-012 should

only apply to units that operate in the "winter market."
With Industry's responses in mind, the SDT edited section 4.2 Facilities to clarify in the simplest manner possible which BES generating units are to comply with NERC standard EOP-012.

One commenter observes that different definitions of the same term are likely to cause confusion, especially in areas where a single entity has facilities under the jurisdiction of multiple BAs. The suggestion was made that instead of defining "winter season" as a time period, the standard should direct entities to begin cold weather preparations when temperatures decrease toward 40 degrees and to implement preparations as temperatures decrease toward 30 degrees.
Thank you for your comments. The team discussed multiple ways to revise the Facilities section to focus more on generating unit applicability rather than defining cold weather. The drafting team decided to not dictate the timeframe for when to begin cold weather preparations or when to implement the cold weather preparedness plan. The current proposal is to key on units that will operate at freezing conditions and below.

Two comments were received stating there could be potential for disagreement over what constitutes a "plan" to operate and that EOP-012-1 Section 4.2 could be revised to include communication of the GO's plan to its BA.
The drafting team appreciates the ambiguities associated with the simple verbiage of "plan to operate." Please see the revisions being proposed that clarify that subject generating units are those that are committed or obligated to serve load in a Balancing Authority pursuant to an OATT or contractual arrangement.

One commenter stated the terminology for winter season is widely used for Facility Ratings, System Operating Limits, and Planning purposes. To avoid possible confusion, some consideration might be given to allowing the PC or RC to make this determination which could allow for consistent terminology between cold weather operations and planning activities. Another consideration is whether it is appropriate to allow a Generator Only BA to establish the winter season for the benefit of its own generation. Another alternative or additional language might include a requirement that the BA determine and identify the "winter season" criteria, make formal declarations of the seasonal status, and communicate those to the GO/GOP.
The drafting team agrees with many of your points regarding the interests of the PC and RC in the determination of the winter season, and the potential issues with allowing Generator only BAs to determine the season for itself. As a result, the drafting team has decided to not define winter season within the standard. Please see the proposed changes focusing on generating unit inclusion and limited exclusions as a means to determine applicability.
Multiple comments indicated the need for the EOP-012 standard to apply to summer emergencies, in addition to winter operation.
The SDT remains focused on extreme cold weather operation, as defined by the SAR for Project 2021-07.

EOP-012-1 Requirement Language

Comments were received stating that the application of EOP-012-1 is too broad and should apply differently based upon climate zones or historical cold weather generator performance.

The SDT has considered the climate where generating facilities are located as evidenced with the Extreme Cold Weather Temperature definition. Regardless of historical performance, the SDT believes the requirements within EOP-012-1 will promote reliable operation during extreme cold weather in the future.

A comment recommended modifying the verbiage in Requirement Parts 1.4.4 and 6.2.6 from "a declaration" to "Documentation, where deemed appropriate by the Generator Owner based on the review of Parts 1.4.1 through 1.4.3, that no revisions to the cold weather preparedness plan(s) are required…". Additionally, it is recommended that this information be submitted to the BA so the BA is aware of the generating units within its footprint.
The SDT believes the verbiage within the Measures for the Requirements that allow a declaration to be sufficient. Additionally, the SDT believes requiring additional submittals to the BA to be an administrative burden.

Multiple comments expressed that the requirement to implement new or modify existing freeze protection measures to continuously withstand the temperature represented by the single coldest hour since 1/1/1975 was inappropriately conservative.
The SDT understands this concern and is now proposing 1) the new statistically defined term "Extreme Cold Weather Temperature" utilizing local publicly available weather data, 2) a shortened lookback time period to 1/1/2000, and 3) a 12-hour minimum period for new facilities to withstand the Extreme Cold Weather Temperature. The Extreme Cold Weather Temperature represents the lowest 0.2 percentile of the hourly temperatures measured in December, January, and February only back to 1/1/2000. The SDT believes this statistical approach addresses the geographical climate diversity experienced across North America and will not require burdensome retrofits for locations that rarely, if ever, experience freezing conditions for significant periods of time. The edits to the standard also eliminated the requirement to run indefinitely at the extreme low temperature condition and instead require the capability to run for a defined period. For generating units with a COD after the effective date of EOP-012-1, that period is 12 hours. For generating units already in commercial operation, that defined period is 1 hour.

Several comments expressed concern about ambiguity regarding the cooling effects of wind and precipitation.
To take the cooling effect of wind into consideration for new plants, a relatively common windspeed of 20 mph is to be assumed to occur concurrent with the Extreme Cold Weather Temperature for exposed Generator Cold Weather Critical Components. The SDT recognizes that higher and lower windspeeds can and will occur and that winds typically vary in intensity over a 12-hour period. Nevertheless, requiring protection against the heat removing effect of a constant 20 mph wind over such a period provides a strong, yet realistic freeze protection standard.

For existing plants, the cooling effects of wind are to be taken into consideration in the cold weather preparedness plans as determined necessary by the Generator Owner. All units should protect Generator Cold Weather Critical Components from precipitation as appropriate for the specific components in the local climate. The SDT believes this approach appropriately addresses the geographical climate diversity experienced across North America.

Another common comment was that retrofitting existing units to the same standards as new units would be costly and difficult to implement and result in marginal benefit for the existing, and largely already freeze-protected, generating units.
The SDT recognized the need to balance the new vs. existing requirements and drafted R1 for new generating units and R2 for existing generating units to account for those differences. These changes include modifying the minimum duration generating units should be capable of running at the Extreme Cold Weather Temperature. For generating units with a COD after the effective date of EOP-012, that period is 12 hours. For generating units already in commercial operation, that defined period is 1 hour.

Several comments expressed concerns regarding the use of the word "design".
The SDT resolved this concern by removing references that could be construed as requiring re-design of existing systems and instead utilized a performance or capability-based language in the requirements.

Some comments expressed concerns that one standard being applied to different types of generation units in widely varying climatological conditions could be inefficient or burdensome.
The SDT believes that the revised structure and requirements of the standard adequately consider the varying conditions in places from south Florida to northern Canada to the Imperial Valley of southern California. Utilizing the location-specific, statistically derived Extreme Cold Weather Temperature definition along with limited durations that extreme cold must be withstood results in a standard that will deliver additional reliability where most needed while requiring little or no physical modifications for generating units that have already been adequately equipped with freeze protection measures.

Multiple comments report concern that the requirement for continuous operation is too burdensome.
The SDT understands industry's concern and around continuous operation and is now proposing changes modifying the minimum duration generating units should be capable of running at the Extreme Cold Weather Temperature. For generating units with a COD after the effective date of EOP-012, that period is 12 hours. For generating units already in commercial operation, that defined period is 1 hour.

Multiple comments recommended combining R2 with R1 and extending to all generators, or combining R4 with R2.
R1 and R2 were rewritten to provide a similar compliance path for generating units built prior to the standard as well as new generating units. And R2 and R4 have been revised and reworded to identify work that is required upfront versus periodic review requirements.

Comments also asked for consideration of an exemption for generators with a proven history of cold weather performance.
Requirement R2 now allows GOs to take credit for historical performance in cold weather, but does not go so far as to provide an exemption altogether. The SDT selected the 0.2 percentile of winter month temperatures since 1/1/2000 to identify an extreme cold temperature which has rarely been surpassed, but which allows some margin for a Generator Owner to have previously demonstrated successful operation at that temperature. The SDT has reviewed a sample set of generating units and determined

that units with a history of operating well during cold weather should be able to prove compliance to Requirement R2 by providing historical performance data.

Multiple comments expressed that GOs should not be given a separate requirement that allows them to, in perpetuity, have the ability to not meet the freeze protections measures set in EOP-012.
The proposed EOP-012 standard has been significantly updated after the first ballot to address concerns surrounding exceptions and the differences in handling new units versus existing units. The SDT believes we have provided reasonable compromises that will enhance cold weather reliability without placing onerous and costly burdens on GOs.

One comment suggested replacement of "commercial, or operations constraints" with "regulatory constraints" while other commenters expressed concerns that the "commercial operation constraint' option in the declaration renders the entire Standard moot for anyone who chooses not to spend money to implement freeze protection measures.
The SDT believes commercial (e.g., a unit is due to be retired soon) and operational (e.g., a unit is unable to obtain an outage in a timely manner) to be valid constraints and allow for GO's to have flexibility around performing CAPs. It is not the intention of this Reliability Standard or the SDT to provide an avenue for GOs to opt out at will. The SDT was presented with real world examples of situations where commercial constraints exist (i.e., units designated for retirement) for whom it is not commercially feasible to upgrade existing freeze protection measures. The SDT discussed "commercial constraints" at length and is expressing confidence in the integrity of applicable GOs to make appropriate decisions regarding declarations of commercial constraints. The inclusion of commercial constraints was primarily driven by concerns regarding decreased system reliability resulting from new regulations have the potential to drive premature retirements of generating unit(s) that otherwise would have continued operating.

A comment expressed concern that there is no ending timeframe for Corrective Action Plans.
The SDT believes the timeframe is inherent in the NERC Glossary of Terms definition of CAP as it is defined as, "A list of actions and an associated timetable for implementation to remedy a specific problem." It is anticipated that Generator Operators will complete corrective actions as soon as practicable. The SDT recognizes that many variables influence timetables and felt it was not necessary to establish a hard deadline for the completion of corrective actions.

Some comments expressed concerns that EOP-012 made no mention of start-up capability.
The modifications to the proposed EOP-012 standard include start-up capability in the new Generator Cold Weather Reliability Event definition. The SDT believes this addresses industry concerns that this issue, as stated in the Joint Report, was missing from the standard.

Some commenters expressed concern that the first draft was unclear and confusing due to disorganization and grammar.
The SDT believes that the revised structure and requirements of the standard adequately address this concern.

One commenter asked that the training requirement not be limited to maintenance or operations personnel.
The SDT attempted, where appropriate, to not modify language previously approved by industry. The only change to the training requirement was to add the word annual. As with all Reliability Standards, this is the minimum requirement. An entity is free to expand their training audience as they deem necessary to ensure the reliable operation of their generating unit(s).

Several commenters expressed concern with the lack of deadline for development of a Corrective Action Plan (CAP).
The SDT believes that the revisions to the CAP requirements under R6 address this issue using language similar to PRC-004 which also requires a CAP and is already in effect in an enforceable Reliability Standard.

Several commenters expressed concerns with open interpretation of the applicability of "freezing".
With the development of the defined term Generator Cold Weather Critical Component, the SDT believes clarity is provided on what should be protected in order to mitigate the chance of a significant derate, a forced outage, or a failure to start. The application of freeze protection measures to the Generator Cold Weather Critical Components narrows the focus and scope to the applicable equipment, components, and systems.

Some commenters felt that the Standard should be part of a regional variance for those regions that see sub-freezing temperatures as part of a normal winter.
The SDT believes that the revised structure and requirements of the standard adequately consider the varying conditions in places from south Florida to northern Canada to the Imperial Valley of southern California. Utilizing the location-specific, statistically derived Extreme Cold Weather Temperature definition along with limited durations that extreme cold must be withstood results in a standard that will deliver additional reliability where most needed while requiring little or no physical modifications for generating units that have already been adequately equipped with freeze protection measures.

Data Submittal and Additional Communication Requirements

The team appreciated the feedback regarding which section of the ROP a data submittal best fits. The team will be discussing in Phase 2 the recommendations for improved communication between registered entities. The team believes these two issues are joined together and will continue the discussion of an ERO data submittal in conjunction with the phase 2 recommendations. Therefore, the data submittal element to track progress over the implementation period is not included in this ballot.

- **Multiple comments stated Interconnection studies should include provisions to meet this standard.**
  There is nothing in this standard that would prevent an interconnection study from including provisions to meet this standard.
- **Multiple comments inquired who should receive declarations of constraints or CAPs, and suggested requirements that these documents be shared with the BA. Other comments suggested extending the five-year review period to a longer duration.**

The SDT views the declarations and CAPs as compliance documents that can be shared as communication tools but are not required to be turned over to other entities. After review, the SDT team believes that a five-year review period is sufficient to meet needs. CAPs can be generated, but do not have to be completed in the five-year timeframe.

Cost Effectiveness of EOP-011-3 and EOP-012-1

Most commenters did not agree that the key recommendations in The Report were being met in a cost-effective manner

Commenters were concerned that without cost recovery or compensation in place, actions taken to meet the requirements could not be done in a cost-effective manner. These concerns are addressed in both the Market Rules/Principles and Cost Recovery portions of this document. It should also be noted that within EOP-012-1, the SDT developed language to allow Generator Owners to declare any technical, commercial, or operational constraints where appropriate. The SDT believes this language allows the requirements to be met in a cost-effective manner.

Multiple comments were received concerning potential administrative burden associated with EOP-012-1.

Most commenters were concerned around the potential administrative burden in two areas. First, commenters believed documenting the minimum hourly temperature since 1975 would be too onerous. Second, for smaller units such as wind turbine generators, analyzing possible freezing events for potential CAPs would be overly burdensome. These concerns have been alleviated by the revised language of the requirements. Historical temperature data going back to 1975 is no longer necessary as defined within Extreme Cold Weather Temperature. Additionally, EOP-012-1 Requirement 6 added criteria that the forced derate exceeds 20 MWs before actions are required.

UFLS/UVLS in EOP-011-3

Concerns were raised that the TOP does not have sufficient data to minimize overlap manual load shed circuits with UFLS circuits because the Planning Coordinator is not required to provide UFLS database data to the TOP. EOP-011-3 passed ballot and will not be re-balloted during this draft.

The SDT notes that PRC-010-2 R8 already contains language that should accommodate any TOP’s need for additional information about UFLS, UVLS, manual load shed, and critical load circuits. Specifically, “…and other functional entities with a reliability need.”, therefore the SDT decided to not make any modifications to PRC-010 at this time.

Multiple responses support review of PRC-006-5 and PRC-010 during next logical review cycle.

The SDT will pass along the suggestion to modify PRC-006-5 R7 to include a Requirement that Planning Coordinators shall provide UFLS and/or UVLS (as applicable) program database data to Transmission Operator’s upon request, to NERC, so that the next time that this Standard comes forward for periodic review, this Requirement modification will be considered.

Comments were received that stated TOPs that are not also DPs need method to obtain UFLS, UVLS, manual load shed, and critical load data from DPs.
Whereas some TOPs may require additional UFLS, UVLS, manual load shed, and critical load circuit information from DPs, UFLS-only DPs, or TOs, the SDT noted the TOP data specification required in TOP-003-3 provides a mechanism for the TOP to request this data and a requirement for these entities to provide the requested data to the TOP. This aligns with the Standard Efficiency Review efforts to not add additional administrative Requirements.

Suggestions were made to add DP, UFLS-only DP, and TO to applicability section of EOP-011 to highlight importance of coordination between TOP and these registered entities.
The SDT will consider adding functional registrations (e.g. DP, UFLS-only DP, TO) to EOP-011 in Phase 2 of the project. The SDT notes that these changes may be needed when addressing Key Recommendation 1i (from the FERC/NERC joint report on the February 2021 cold weather event), which will deal with critical natural gas infrastructure.

A comment was received stating that it is difficult to avoid overlap between manual load shed circuits and circuits that are utilized for UFLS/UVLS.
As discussed in the Technical Rationale for EOP-011-3, the SDT elected to keep the phrase “minimize the overlap” instead of moving to language that specifically requires the separation of circuits. This decision was made in recognition of the fact that it is not always practical or warranted to completely separate circuits used for each of these purposes. EOP-011-3 R1 1.2.5.4 does not prohibit the utilization of UFLS or UVLS circuits for manual load shed but rather states that this should be limited to situations where warranted by system conditions.

A comment was received stating that the changes in EOP-011-3 should not be applicable continent-wide.
The SDT has determined that the changes in EOP-011-3 should be applicable regardless of geographic location because they are foundational to certain components of Transmission Operator’s Operating Plans which are used to respond to many different types of system conditions.
A comment was received stating that it is not appropriate to require the minimization of overlap between circuits used for manual load shed and circuits used for UFLS/UVLS because a manual load shed event is not a “frequency sensitive event.”
The SDT disagrees with the concept of manual load shed not being a “frequency sensitive event.” The SDT agrees with the Final Report, and previous revisions of EOP-011, in that it is important to minimize the overlap of circuits used for manual load shed and circuits used for UFLS/UVLS. The integrity of UFLS programs should be prioritized at all times since sudden changes to frequency can occur at any time and arguably are more likely to occur during a short-supply situation when generation reserves are minimal.

Additional EOP-011-3 Concerns

One commenter seeks clarity on why the title of EOP-011 is being changed to the term preparedness. EOP-011 still contains a preparedness aspect and the planning horizons are still being used in the requirements.

The SDT believes after moving EOP-011-2 Requirements 7 and 8 to EOP-012-1, it would be clearer for only EOP-012-1 to include 'Preparedness' within the title of the standard.

Implementation Time Frame

The SDT has reviewed the comments received from the Industry on the Implementation Plan suggested for the new EOP-012-1.

Most commenters believed that the implementation plan suggested by the SDT was achievable. Those that responded No, believed that the timeframe to implement was too short and the industry needs more time than what was proposed. The SDT made revisions to the proposed EOP-012-1 based on industry feedback received in other questions.

Based on the changes made to the standard, and since the majority of commenters were in agreement with the proposed timeframe from the first draft of EOP-012-1, and that work that is currently being done to implement EOP-011-2, the timeframe for the implementation of EOP-012 will remain as proposed with one modification at the five-year review as stated in R4 will have a 78-month implementation timeframe.

Comments were received stating that the implementation timeline did not provide adequate time for EOP-012-1 Requirements 1 and 2.

The SDT believes the implementation plan provides adequate time to comply with the requirements and is in alignment with previous Reliability Standard implementation plans.

Multiple commenters asked for clarity on when is a generator new and when is it existing during the implementation period.

This distinction has been clarified by the SDT in the latest draft. Generators that come into service after the implementation date of requirement R1 of the standard are considered "new" for the purposes of this 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 for a formal 30-day comment period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	11/17/2021
SAR posted for comment	11/22/21 – 12/21/21
30-day formal or informal comment period with ballot	5/19/22 – 6/21/22

Anticipated Actions	Date
30-day formal or informal comment period with additional ballot	8/3/22- 9/1/22
10-day final ballot	September 2022
Board adoption	October 2022

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):

Generator Cold Weather Critical Component - Any generating unit component or associated fixed fuel supply component, that is under the Generator Owner's control and is susceptible to freezing issues, the occurrence of which would likely lead to a Generator Cold Weather Reliability Event.

Extreme Cold Weather Temperature – The temperature equal to the lowest 0.2 percentile of the hourly temperatures measured in December, January, and February from 1/1/2000 through the date the temperature is calculated.

Generator Cold Weather Reliability Event - One of the following events:

(1) a forced derate of more than 10% of the total capacity of the unit and exceeding 20 MWs for longer than four hours in duration;

(2) a start-up failure where the unit fails to synchronize within a specified start-up time; or

(3) a Forced Outage,

for which the apparent cause(s) is due to freezing of equipment within the Generator Owner's control and the dry bulb temperature at the time of the event was at or above the Extreme Cold Weather Temperature.

A. Introduction

1. **Title:** **Extreme Cold Weather Preparedness and Operations**

2. **Number:** EOP-012-1

3. **Purpose:** To address the effects of operating in extreme cold weather by ensuring each Generator Owner has developed and implemented plan(s) to mitigate the reliability impacts of extreme cold weather on its generating units.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Generator Owner

   4.1.2. Generator Operator

   4.2. Facilities: For purposes of this standard, the term "generating unit" subject to these requirements means:

   4.2.1 A Bulk Electric System generating unit:

   4.2.1.1 That commits or is obligated to serve a Balancing Authority load pursuant to an Open Access Transmission Tariff (OATT) or other contractual arrangement;

   4.2.1.1.1 The term excludes a Bulk Electric System generating unit that is typically not available at or below thirty-two (32) degrees Fahrenheit (zero degrees Celsius) for any continuous run of more than four hours. The exclusion applies even when such BES generator has been called to assist in the mitigation of BES Emergencies, Capacity Emergencies, or Energy Emergencies during periods at or below 32 degrees Fahrenheit.

   4.2.1.2 That is identified as a Blackstart Resource.

5. **Effective Date:** See Implementation Plan for Project 2021-07.

B. Requirements and Measures

R1. For each generating unit(s) with a commercial operation date subsequent to [Effective Date of this requirement], the Generator Owner shall: [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning, Operations Planning*]

- Implement freeze protection measures that provide capability to operate for a period of not less than twelve (12) continuous hours at the Extreme Cold Weather Temperature for the unit(s), assuming a concurrent twenty (20) mph wind speed on any exposed Generator Cold Weather Critical Components; or
- Explain in a declaration, any technical, commercial, or operational constraints as defined by the Generator Owner that preclude the ability to implement

appropriate freeze protection measures to provide capability of operating for twelve (12) hours at the documented Extreme Cold Weather Temperature..

M1. Each Generator Owner will have dated evidence that demonstrates it has the capability to operate in accordance with Requirement R1. Acceptable evidence may include, but is not limited to, the following (electronic or hardcopy format): Documentation of cold weather preparedness plan, documentation of design features. Any declaration that contains dated documentation to support constraints identified by the Generator Owner.

R2. For each generating unit(s) in commercial operation prior to [Effective Date of this requirement], the Generator Owner shall ensure its generating unit(s) add new or modify existing freeze protection measures as needed to provide the capability to operate for a period of not less than one (1) hour at the unit(s) Extreme Cold Weather Temperature. Generating unit(s) that are not capable of operating for one (1) hour at its Extreme Cold Weather Temperature shall develop a Corrective Action Plan (CAP) for the identified issues, including identification of any needed modifications to the cold weather preparedness plan required under Requirement R3. [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning, Operations Planning*]

M2. Each Generator Owner will have dated evidence that demonstrates it has freeze protection measures for its unit(s) in accordance with R2, or it has developed a CAP for the identified issues. Acceptable evidence may include the following (electronic or hardcopy format): Identification of generating units minimum temperature per Part 3.5.2 which is equal to or less than the unit's Extreme Cold Weather Temperature, documentation of freeze protection measures, cold weather preparedness plan, and CAP(s).

R3. Each Generator Owner shall implement and maintain one or more cold weather preparedness plan(s) for its generating units. The cold weather preparedness plan(s) shall include the following, at a minimum: *[Violation Risk Factor: High] [Time Horizon: Operations Planning and Real-time Operations]*

3.1 The Extreme Cold Weather Temperature for their unit(s) including the calculation date and source of temperature data;

3.2 Documentation identifying the Generator Cold Weather Critical Components;

3.3 Documentation of freeze protection measures implemented on Generator Cold Weather Critical Components which may include measures used to reduce the cooling effects of wind determined necessary by the Generator Owner to protect against heat loss, and where applicable, the effects of freezing precipitation (e.g., sleet, snow, ice, and freezing rain);

3.4 Annual inspection and maintenance of generating unit(s) freeze protection measures; and

3.5 Generating unit(s) cold weather data, to include:

3.5.1 Generating unit(s) operating limitations in cold weather to include:

3.5.1.1 Capability and availability;

3.5.1.2 Fuel supply and inventory concerns;

3.5.1.3 Fuel switching capabilities; and

3.5.1.4 Environmental constraints.

3.5.2 Generating unit(s) minimum:

- Design temperature;
- Historical operating temperature; or
- Current cold weather performance temperature determined by an engineering analysis.

M3. Each Generator Owner will have evidence documenting that its cold weather preparedness plan(s) was implemented and maintained in accordance with Requirement R3.

R4. Once every five calendar years, each Generator Owner shall for each generating unit: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning, Real-Time Operations]*

4.1 Calculate the Extreme Cold Weather Temperature and update the cold weather preparedness plan if this temperature is now lower than the previous lowest calculation;

4.2 Review its documented generating unit(s) minimum temperature contained within its cold weather preparedness plan(s), pursuant to Part 3.5.2; and

4.3 Review whether its generating units have the freeze protection measures required to operate at the Extreme Cold Weather Temperature pursuant to R1 or R2 as applicable, and if not develop a CAP for the identified issues, including identification of any needed modifications to the cold weather preparedness plan required under Requirement R3.

M4. Each Generator Owner will have evidence documenting that it reviewed documented temperature data and updated its cold weather preparedness plan(s) in accordance with Requirement R4.

R5. Each Generator Owner in conjunction with its Generator Operator shall identify the entity responsible for providing the generating unit-specific training, and that identified entity shall provide annual training to its maintenance or operations personnel responsible for implementing the cold weather preparedness plan(s) developed pursuant to Requirement R3. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]*

M5. Each Generator Operator or Generator Owner will have documented evidence that the applicable personnel completed annual training of the Generator Owner's cold weather preparedness plan(s). This evidence may include, but is not limited to, documents such as personnel training records, training materials, date of training, agendas or learning objectives, attendance at pre-work briefings, review of work order tasks, tailboards, attendance logs for classroom training, and completion records for computer-based training in fulfillment of Requirement R5.

R6. Each Generator Owner that owns a generating unit that experiences a Generator Cold Weather Reliability Event shall develop a CAP, within 150 days or by July 1, whichever is earlier, that contains at a minimum: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

6.1 A summary of the identified cause(s) for the Generator Cold Weather Reliability Event where applicable and any relevant associated data;

6.2 A review of applicability to similar equipment at other generating units owned by the Generator Owner;

6.3 An identification of any temporary operating limitations or impacts to the cold weather preparedness plan, that would apply until execution of the corrective action(s) identified in the CAP.

M6. Acceptable evidence for these requirements may include, but is not limited to, the following dated documentation (electronic or hardcopy format): CAP(s) and updated cold weather preparedness plan(s) where indicated as needed by the CAP.

R7. Each Generator Owner shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

7.1 Implement each CAP developed pursuant to Requirements R2, R4, or R6, or explain in a declaration why corrective actions are not being implemented due to any technical, commercial, or operational constraints as defined by the Generator Owner.

7.2 Update each CAP if actions or timetables change, until completed.

M7. Each Generator Owner shall have dated evidence that demonstrates it implemented each CAP, including updating actions or timetables, or has explained in a declaration why corrective actions are not being implemented. Acceptable evidence for Requirement R7 may include, but is not limited to the following dated documentation (electronic or hardcopy format): records that document the implementation of each CAP and the completion of actions for each CAP including revision history of each CAP. Evidence may also include work management program records, work orders, and maintenance records. Any declaration shall contain dated documentation to support constraints identified by the Generator Owner.

C. Compliance

1. **Compliance Monitoring Process**

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

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

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

    - The Generator Owner shall keep data or evidence to show compliance for three years for Requirement R1, R3, and R5 and Measure M1, M3, and M5.
    - The Generator Owner shall keep data or evidence to show compliance for three years, or until any Corrective Action Plan under Requirement R2 is complete, whichever timeframe is greater, for Requirement R2 and Measure M2.
    - The Generator Owner shall retain the current cold weather preparedness plan(s), as evidence of review or revision history, plus each version issued since the last audit and evidence of compliance since the last audit for Requirement R4 and Measure M4. The Generator Owner shall retain any Corrective Action Plans under Requirement R4 Part 4.3 for three years or until the Corrective Action Plan is complete, whichever timeframe is greater.
    - The Generator Owner shall keep data or evidence to show compliance for three years, or until any Corrective Action Plan under Requirement R6 is complete, whichever timeframe is greater, for Requirement R6 and Measure M6.
    - The Generator Owner shall keep data or evidence to show compliance for three years, or until any Corrective Action Plan is complete, whichever time frame is greater, for Requirement R7 and Measure M7.

    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.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 for 5% or less of its units. OR The Generator Owner did not explain in a declaration any technical, commercial, or operational constraints that preclude the ability to implement appropriate freeze protection measures for 5% or less of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 for more than 5%, but less than or equal to 10% of its units. OR The Generator Owner did not explain in a declaration any technical, commercial, or operational constraints that preclude the ability to implement appropriate freeze protection measures for more than 5%, but less than or equal to 10% of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 for more than 10%, but less than or equal to 20% of its units. OR The Generator Owner did not explain in a declaration any technical, commercial, or operational constraints that preclude the ability to implement appropriate freeze protection measures for more than 10%, but less than or equal to 20% of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 for more than 20% of its units. OR The Generator Owner did not explain in a declaration any technical, commercial, or operational constraints that preclude the ability to implement appropriate freeze protection measures for more than 20% of its units.
R2.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R2 for 5% or less of its units. OR The Generator Owner did not develop a CAP as required by	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R2 for more than 5%, but less than or equal to 10% of its units. OR The Generator Owner did not develop a CAP as required by Requirement R2 for more than	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R2 for more than 10%, but less than or equal to 20% of its units. OR The Generator Owner did not develop a CAP as required by Requirement R2 for more than	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R2 for more than 20% of its units. OR The Generator Owner did not develop a CAP as required by

	Requirement R2 for 5% or less of its units.	5%, but less than or equal to 10% of its units.	10%, but less than or equal to 20% of its units.	Requirement R2 for more than 20% of its units.
R3.	The Generator Owner implemented a cold weather preparedness plan(s), but failed to maintain it.	The Generator Owner's cold weather preparedness plan failed to include one of the applicable Parts within Requirement R3.	The Generator Owner had and maintained a cold weather preparedness plan(s), but failed to implement it. OR The Generator Owner's cold weather preparedness plan failed to include two of the applicable requirement parts within Requirement R3.	The Generator Owner does not have cold weather preparedness plan(s). OR The Generator Owner's cold weather preparedness plan failed to include three or more of the applicable requirement parts within Requirement R3.
R4.	The Generator Owner completed the actions required in Requirement R4, but was late by 30 calendar days or less.	The Generator Owner completed the actions required in Requirement R4, but was late by greater than 30 calendar days, but less than or equal to 60 calendar days.	The Generator Owner failed to complete one of the applicable requirement parts in Requirement R4 Parts 4.1 through 4.3; OR The Generator Owner completed the actions required in Requirement R4, but was late by greater than 60 calendar days.	The Generator Owner failed to complete two or more of the applicable requirement parts in Requirement R4 Parts 4.1 through 4.3.
R5.	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5 to the greater of:	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5 to the greater of:	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5 to the greater of:	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5 to the greater of:

	• one applicable personnel at a single generating unit; or • 5% or less of its total applicable personnel.	• two applicable personnel at a single generating unit; or • more than 5%, but less than or equal to 10% of its total applicable personnel.	• three applicable personnel at a single generating unit; or • more than 10%, but less than or equal to 15% of its total applicable personnel.	• four applicable personnel at a single generating unit; or • more than 15% of its total applicable personnel.
R6.	The Generator Owner developed a CAP, but not within 150 days or by July 1 as required in Requirement R6.	The Generator Owner's CAP failed to comply with one of the elements in Requirement R6, Parts 6.1 through 6.3.	The Generator Owner's CAP failed to comply with two of the elements in Requirement R6, Parts 6.1 through 6.3.	The Generator Owner's CAP failed to comply with three of the elements in Requirement R6, Parts 6.1 through 6.3. OR The Generator Owner did not develop a CAP as required by Requirement R6.
R7.	The Generator Owner implemented a CAP or explained in a declaration why corrective actions are not being implemented, but failed to update the CAP when actions or timetables changed, in accordance with Requirement R7.	N/A	N/A	The Generator Owner failed to implement a CAP or explain in a declaration why corrective actions are not being implemented in accordance with Requirement R7.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	TBD	Drafted by Project 2021-07	New

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 ~~first~~ second draft of the proposed standard for a formal 30-day comment period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	11/17/2021
SAR posted for comment	11/22/21 – 12/21/21
30-day formal or informal comment period with ballot	5/19/22 – 6/21/22

Anticipated Actions	Date
30-day formal or informal comment period with additional ballot	8/3/22- 9/1/22
10-day final ballot	September 2022
Board adoption	October 2022

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):

~~None~~

Generator Cold Weather Critical Component - Any generating unit component or associated fixed fuel supply component, that is under the Generator Owner's control and is susceptible to freezing issues, the occurrence of which would likely lead to a Generator Cold Weather Reliability Event.

Extreme Cold Weather Temperature – The temperature equal to the lowest 0.2 percentile of the hourly temperatures measured in December, January, and February from 1/1/2000 through the date the temperature is calculated.

Generator Cold Weather Reliability Event - One of the following events:

(1) a forced derate of more than 10% of the total capacity of the unit and exceeding 20 MWs for longer than four hours in duration;

(2) a start-up failure where the unit fails to synchronize within a specified start-up time; or

(3) a Forced Outage,

for which the apparent cause(s) is due to freezing of equipment within the Generator Owner's control and the dry bulb temperature at the time of the event was at or above the Extreme Cold Weather Temperature.

A. Introduction

1. **Title:** **Extreme Cold Weather Preparedness and Operations**

2. **Number:** EOP-012-1

3. **Purpose:** To address the effects of operating in extreme cold weather by ensuring each Generator Owner has developed and implemented plan(s) to mitigate the reliability impacts of extreme cold weather on its generating units.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Generator Owner

   4.1.2. Generator Operator

   4.2. Facilities: For purposes of this standard, the term "generating unit" ~~means those Bulk Electric System generators that plan to operate during the winter season. The winter season will be determined by the generating unit's applicable Balancing Authority. The term excludes those generators that do not operate during the winter season except when called upon by the Balancing Authority to be available during Capacity Emergencies or Energy Emergencies.~~subject to these requirements means:

   4.2.1 A Bulk Electric System generating unit:

   4.2.1.1 That commits or is obligated to serve a Balancing Authority load pursuant to an Open Access Transmission Tariff (OATT) or other contractual arrangement;

   4.2.1.1.1 The term excludes a Bulk Electric System generating unit that is typically not available at or below thirty-two (32) degrees Fahrenheit (zero degrees Celsius) for any continuous run of more than four hours. The exclusion applies even when such BES generator has been called to assist in the mitigation of BES Emergencies, Capacity Emergencies, or Energy Emergencies during periods at or below 32 degrees Fahrenheit.

   4.2.1.2 That is identified as a Blackstart Resource.

5. **Effective Date:** See Implementation Plan for Project 2021-07.

B. Requirements and Measures

R1. ~~Each~~ For each generating unit(s) with a commercial operation date subsequent to [Effective Date of this requirement], the Generator Owner shall ~~ensure generating units implement freeze protection measures based on the following minimum criteria~~: [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning, Operations Planning*]

~~**1.1.** Each generating unit shall be designed and maintained to be capable of continuous operations at the documented minimum hourly temperature experienced at its location since 1/1/1975 or a lesser period if reliable data is not available to 1975;~~

~~**1.2.** The generating unit design shall account for the cooling effect of wind;~~

~~**1.3.** The generating unit design shall account for the impacts on operations due to precipitation (e.g., sleet, snow, ice, and freezing rain); and~~

~~**1.4.** For each existing generating unit that requires either new freeze protection measures or modification of existing freeze protection measures, the Generator Owner shall develop and implement a Corrective Action Plan (CAP) which includes the following at a minimum:~~

~~**1.5.0.** An identification of corrective action (s) for the affected unit(s), including any necessary modifications to the Generator Owner's cold weather preparedness plan(s);~~

~~**1.6.0.** A timetable for implementing the corrective action(s) from Part 1.4.1 which considers any technical, commercial, or operational constraints, as defined by the Generator Owner;~~

~~**1.7.0.** An identification of any temporary operating limitations that would apply until execution of the corrective action(s) identified in the CAP; and~~

- Implement freeze protection measures that provide capability to operate for a period of not less than twelve (12) continuous hours at the Extreme Cold Weather Temperature for the unit(s), assuming a concurrent twenty (20) mph wind speed on any exposed Generator Cold Weather Critical Components; or

- ~~A declaration, where deemed appropriate by the Generator Owner based on the review of Parts 1.4.1 through 1.4.3, that no revisions to the cold weather preparedness plan(s) are required and that no further corrective actions will be taken. The Generator Owner shall document~~ Explain in a declaration, any technical, commercial, or operational constraints as defined by the Generator Owner ~~as support for such declaration~~that preclude the ability to implement appropriate freeze protection measures to provide capability of operating for twelve (12) hours at the documented Extreme Cold Weather Temperature..

M1. Each Generator Owner will have dated evidence that demonstrates it has the capability to operate in accordance with Requirement R1. Acceptable evidence may include, but is not limited to, the following (electronic or hardcopy format): Documentation of cold weather preparedness plan, documentation of design features. Any declaration that contains dated documentation to support constraints identified by the Generator Owner.

R2. For each generating unit(s) in commercial operation prior to [Effective Date of this requirement], the Generator Owner shall ensure its generating unit(s) add new or modify existing freeze protection measures as needed to provide the capability to operate for a period of not less than one (1) hour at the unit(s) Extreme Cold Weather Temperature. Generating unit(s) that are not capable of operating for one (1) hour at its Extreme Cold Weather Temperature shall develop a Corrective Action Plan (CAP) for the identified issues, including identification of any needed modifications to the cold weather preparedness plan required under Requirement R3. [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning, Operations Planning*]

~~M1.~~M2. Each Generator Owner will have dated evidence that demonstrates it has freeze protection measures for its unit(s) in accordance with ~~R1~~R2, or it has developed a CAP for the identified issues. Acceptable evidence may include the following (electronic or hardcopy format): ~~Documentation of extreme temperature used for the freeze protection design~~Identification of generating units minimum temperature per Part 3.5.2 which is equal to or less than the unit's Extreme Cold Weather Temperature, documentation of freeze protection measures, ~~Facility~~ cold weather preparedness plan, and CAP(s).

~~**R3.** Each Generator Owner that is not able to implement freeze protection measures for new generating unit(s) as required by Requirement R1 due to technical, commercial, or operational constraints as defined by the Generator Owner shall: *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*~~

~~**4.0.** Document its determination and the constraints on implementation; and~~

~~**5.0.** Review its determination every five calendar years to determine whether the documented constraints on implementation remain applicable.~~

~~**M6.** Each Generator Owner will have dated evidence that demonstrates it documented constraints on implementation of freeze protection measures and conducted a review of its units in accordance with Requirement R2. Acceptable evidence may include the following dated documentation (electronic or hardcopy format): Documentation of technical, commercial, or operational constraint. Documentation of five calendar year reviews as applicable.~~

~~R7.~~R3. Each Generator Owner shall implement and maintain one or more cold weather preparedness plan(s) for its generating units. The cold weather preparedness plan(s) shall include the following, at a minimum: *[Violation Risk Factor: High] [Time Horizon: Operations Planning and Real-time Operations]*

~~**3.1.** Documented minimum hourly temperature experienced at its location since 1/1/1975 or a lesser period if reliable data is not available to 1975;~~

~~**3.2.** Documented generating unit(s) freeze protection measures based on geographical location and plant configuration;~~

3.1 The Extreme Cold Weather Temperature for their unit(s) including the calculation date and source of temperature data;

3.2 Documentation identifying the Generator Cold Weather Critical Components;

3.3 Documentation of freeze protection measures implemented on Generator Cold Weather Critical Components which may include measures used to reduce the cooling effects of wind determined necessary by the Generator Owner to protect against heat loss, and where applicable, the effects of freezing precipitation (e.g., sleet, snow, ice, and freezing rain);

~~3.3~~3.4 Annual inspection and maintenance of generating unit(s) freeze protection measures; and

~~3.4~~3.5 Generating unit(s) cold weather data, to include:

~~3.4.1~~3.5.1 Generating unit(s) operating limitations in cold weather to include:

~~3.4.1.1~~3.5.1.1 Capability and availability;

~~3.4.1.2~~3.5.1.2 Fuel supply and inventory concerns;

~~3.4.1.3~~3.5.1.3 Fuel switching capabilities; and

~~3.4.1.4~~3.5.1.4 Environmental constraints.

~~3.4.2~~3.5.2 Generating unit(s) minimum:

- Design temperature;
- Historical operating temperature; or
- Current cold weather performance temperature determined by an engineering analysis.

~~M2.~~M3. Each Generator Owner will have evidence documenting that its cold weather preparedness plan(s) was implemented and maintained in accordance with Requirement R3.

~~R8.~~R4. Once every five calendar years, each Generator Owner shall for each generating unit: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning, Real-Time Operations]*

4.1 ~~Review the documented minimum hourly temperature developed pursuant to Part 3.1~~Calculate the Extreme Cold Weather Temperature~~,~~ and update the cold weather preparedness plan ~~with the lowest~~ if this temperature ~~as necessary~~is now lower than the previous lowest calculation;

4.2 Review its documented ~~cold weather~~ generating unit(s) minimum temperature contained within its cold weather preparedness plan(s) ~~for its generating units~~, pursuant to Part ~~3.4.2~~3.5.2; and

4.3 Review whether its generating units have the freeze protection measures required to operate at the ~~lowest temperature established pursuant to Requirement R1 and, if not, implement appropriate modifications per the requirements of Part 1.4~~Extreme Cold Weather Temperature pursuant to R1 or R2 as applicable, and if not develop a CAP for the identified issues, including identification of any needed modifications to the cold weather preparedness plan required under Requirement R3.

~~M3.~~M4. Each Generator Owner will have evidence documenting that it reviewed documented temperature data and updated its cold weather preparedness plan(s) in accordance with Requirement R4.

~~R9.~~R5. Each Generator Owner in conjunction with its Generator Operator shall identify the entity responsible for providing the generating unit-specific training, and that identified entity shall provide annual training to its maintenance or operations personnel responsible for implementing the cold weather preparedness plan(s) developed pursuant to Requirement R3. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]*

~~M4.~~M5. Each Generator Operator or Generator Owner will have documented evidence that the applicable personnel completed annual training of the Generator Owner's cold weather preparedness plan(s). This evidence may include, but is not limited to, documents such as personnel training records, training materials, date of training, agendas or learning objectives, attendance at pre-work briefings, review of work order tasks, tailboards, attendance logs for classroom training, and completion records for computer-based training in fulfillment of Requirement R5.

~~R10.~~R6. Each Generator Owner that owns a generating unit that experiences ~~an event resulting in a derate of more than 10% of the total capacity of the unit for longer than four hours in duration, a start-up failure where the unit fails to synchronize within a specified start-up time, or a Forced Outage for which (i) the apparent cause(s) of the event is due to freezing of the Generator Owner's equipment within the Generator Owner's control, and (ii) the ambient conditions at the site at the time of the event are at or above the temperature documented in Part 3.4.2 shall~~a Generator Cold Weather Reliability Event shall develop a CAP, within 150 days or by July 1, whichever is earlier, that contains at a minimum: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

~~**1.1.** No later than 150 days subsequent to the event or by July 1 that follows the event, whichever is earlier, develop a CAP.~~

~~**1.2.** The CAP shall contain at a minimum:~~

~~6.3~~6.1 A summary of the identified cause(s) for the ~~equipment freezing event~~ Generator Cold Weather Reliability Event where applicable and any relevant associated data;

~~6.4~~6.2 A review of applicability to similar equipment at other generating units owned by the Generator Owner;

~~6.5~~6.3 An identification of ~~corrective action(s) for the affected unit(s) and identified similar units, including any necessary modifications to the Generator Owner's~~ any temporary operating limitations or impacts to the cold weather preparedness plan~~(s);~~, that would apply until execution of the corrective action(s) identified in the CAP.

- ~~A timetable for implementing the identified corrective action(s) from Part 6.2.3 which considers any technical, commercial, or operational constraints as defined by the Generator Owner;~~
- ~~An identification of any temporary operating limitations that would apply until execution of the corrective action(s) identified in the CAP; and~~
- ~~A declaration, where deemed appropriate by the Generator Owner based on the review of Parts 6.2.1 through 6.2.5 that no revisions to the cold weather preparedness plan are required and that no further corrective actions will be taken. The Generator Owner shall document technical, commercial, or operational constraints as defined by the Generator Owner as support for such declaration.~~

~~M9.~~M6. Acceptable evidence for these requirements may include, but is not limited to, the following dated documentation (electronic or hardcopy format): CAP(s) and updated cold weather preparedness plan(s) where indicated as needed by the CAP.

R7. Each Generator Owner shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

7.1 Implement each CAP developed pursuant to Requirements R2, R4, or R6, or explain in a declaration why corrective actions are not being implemented due to any technical, commercial, or operational constraints as defined by the Generator Owner.

7.2 Update each CAP if actions or timetables change, until completed.

M7. Each Generator Owner shall have dated evidence that demonstrates it implemented each CAP, including updating actions or timetables, or has explained in a declaration why corrective actions are not being implemented. Acceptable evidence for Requirement R7 may include, but is not limited to the following dated documentation (electronic or hardcopy format): records that document the implementation of each CAP and the completion of actions for each CAP including revision history of each CAP. Evidence may also include work management program records, work orders, and maintenance records. Any declaration shall contain dated documentation to support constraints identified by the Generator Owner.

C. Compliance

1. Compliance Monitoring Process

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

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

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

~~**R1.** The Generator Owner shall keep data or evidence to show compliance for three years or until any Corrective Action Plan under Part 1.4 is complete, whichever timeframe is greater, for Requirement R1 and Measure M1.~~

- The Generator Owner shall keep data or evidence to show compliance for three years for Requirement ~~R2~~R1, R3, and R5 and Measure ~~M2~~M1, M3, and M5.
- The Generator Owner shall keep data or evidence to show compliance for three years, or until any Corrective Action Plan under Requirement R2 is complete, whichever timeframe is greater, for Requirement R2 and Measure M2.
- The Generator Owner shall retain the current cold weather preparedness plan(s), as evidence of review or revision history, plus each version issued since the last audit and evidence of compliance since the last audit for Requirement R4 and Measure M4. The Generator Owner shall retain any Corrective Action Plans under Requirement R4 Part 4.3 for three years or until the Corrective Action Plan is complete, whichever timeframe is greater.
- The Generator Owner shall keep data or evidence to show compliance for three years, or until any Corrective Action Plan under ~~6.2~~ Requirement R6 is complete, whichever timeframe is greater, for Requirement R6 and Measure M6.
- The Generator Owner shall keep data or evidence to show compliance for three years, or until any Corrective Action Plan is complete, whichever time frame is greater, for Requirement R7 and Measure M7.

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.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 ~~Parts 1.1 – 1.3~~ for ~~up to~~ 5% or less of its units. OR The Generator Owner did not explain in a declaration any technical, commercial, or operational constraints that preclude the ability to implement appropriate freeze protection measures for 5% or less of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 ~~Parts 1.1 – 1.3~~ for more than 5%, but less than or equal to 10% of its units. OR The Generator Owner did not explain in a declaration any technical, commercial, or operational constraints that preclude the ability to implement appropriate freeze protection measures for more than 5%, but less than or equal to 10% of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 ~~Parts 1.1 – 1.3~~ for more than 10%, but less than or equal to 20% of its units. OR The Generator Owner did not explain in a declaration any technical, commercial, or operational constraints that preclude the ability to implement appropriate freeze protection measures for more than 10%, but less than or equal to 20% of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 ~~Parts 1.1 – 1.3~~ for more than 20% of its units~~;~~. OR The Generator Owner did not ~~develop or implement a CAP as required by Requirement R1~~explain in a declaration any technical, commercial, or operational constraints that preclude the ability to implement appropriate freeze protection measures for more than 20% of its units.
R2.	~~The Generator Owner completed the review required in Requirement R2, but was late by 30 calendar days or less.~~ ~~OR~~ The Generator Owner did not ~~document its determination and the constraints described~~	The Generator Owner ~~completed the review required~~ did not have freeze protection measure(s) meeting the criteria in Requirement R2~~, but was late by greater~~ for more than ~~30 calendar days~~5%, but less than or equal to ~~60 calendar days~~10% of its units.	~~The Generator Owner completed the review required in Requirement R2, but was late by greater than 60 calendar days.~~ ~~OR~~ The Generator Owner did not ~~document its determination and the constraints described~~	The Generator Owner did not ~~complete a review.~~have freeze protection measure(s) meeting the criteria ~~OR~~ ~~The Generator Owner did not document its determination and the constraints described~~

	have freeze protection measure(s) meeting the criteria in Requirement R2 ~~Part 2.1~~ for ~~up to~~ 5% or less of its units. OR The Generator Owner did not develop a CAP as required by Requirement R2 for 5% or less of its units.	OR The Generator Owner did not ~~document its determination and the constraints described in~~ develop a CAP as required by Requirement ~~R1 Part 2.1~~ R2 for more than 5%, but less than or equal to 10% of its units.	have freeze protection measure(s) meeting the criteria in Requirement ~~R1 Part 2.1~~ R2 for more than 10%, but less than or equal to 20% of its units. OR The Generator Owner did not develop a CAP as required by Requirement R2 for more than 10%, but less than or equal to 20% of its units.	in Requirement ~~R1 Part 2.1~~ R2 for more than 20% of its units. OR The Generator Owner did not develop a CAP as required by Requirement R2 for more than 20% of its units.
R3.	The Generator Owner implemented a cold weather preparedness plan(s), but failed to maintain it.	The Generator Owner's cold weather preparedness plan failed to include one of the applicable Parts within Requirement R3.	The Generator Owner had and maintained a cold weather preparedness plan(s), but failed to implement it. OR The Generator Owner's cold weather preparedness plan failed to include two of the applicable requirement parts within Requirement R3.	The Generator Owner does not have cold weather preparedness plan(s). OR The Generator Owner ~~has a~~ 's cold weather preparedness plan~~, but~~ failed to include ~~any~~ three or more of the applicable requirement parts within Requirement R3.
R4.	The Generator Owner completed the ~~review~~ actions required in Requirement R4, but was late by 30 calendar days or less.	The Generator Owner completed the ~~review~~ actions required in Requirement R4, but was late by greater than 30 calendar days, but less than or equal to 60 calendar days.	The Generator Owner~~'s review~~ failed to ~~include~~ complete one of the applicable requirement parts in Requirement R4 Parts 4.1 through 4.3; OR The Generator Owner completed the ~~review~~ actions	The Generator Owner~~'s review~~ failed to ~~include~~ complete two or more of the applicable requirement parts in Requirement R4 Parts 4.1 through 4.3~~;~~. ~~OR~~

			required in Requirement R4, but was late by greater than 60 calendar days.	~~The Generator Owner does not have a completed review.~~ ~~OR~~ ~~The Generator Owner did not update the cold weather preparedness plan.~~
R5.	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5 to the greater of: • one applicable personnel at a single generating unit; or • 5% or less of its total applicable personnel.	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5 to the greater of: • two applicable personnel at a single generating unit; or • more than 5%, but less than or equal to 10% of its total applicable personnel.	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5 to the greater of: • three applicable personnel at a single generating unit; or • more than 10%, but less than or equal to 15% of its total applicable personnel.	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5 to the greater of: • four applicable personnel at a single generating unit; or • more than 15% of its total applicable personnel.
R6.	The Generator Owner ~~did not develop a CAP meeting the elements in Requirement R6 parts 6.1 and 6.2 for 5% or less of its total events listed~~ developed a CAP, but not within 150 days or by July 1 as required in Requirement R6.	The Generator Owner ~~did not develop a CAP meeting~~ 's CAP failed to comply with one of the elements in Requirement R6 ~~parts 6.1 and 6.2 for more than 5%, but less than or equal to 10% of its total events listed in Requirement R6~~, Parts 6.1 through 6.3.	The Generator Owner ~~did not develop a CAP meeting~~ 's CAP failed to comply with two of the elements in Requirement R6 ~~parts 6.1 and 6.2 for more than 10%, but less than or equal to 15% of its total events listed in Requirement R6~~, Parts 6.1 through 6.3.	The Generator Owner's CAP failed to comply with three of the elements in Requirement R6, Parts 6.1 through 6.3. OR The Generator Owner did not develop a CAP ~~meeting the elements in Requirement R6 parts 6.1 and 6.2 for more than15% of its total events~~

				~~listed in Requirement R6.~~as required by Requirement R6.
R7.	The Generator Owner implemented a CAP or explained in a declaration why corrective actions are not being implemented, but failed to update the CAP when actions or timetables changed, in accordance with Requirement R7.	N/A	N/A	The Generator Owner failed to implement a CAP or explain in a declaration why corrective actions are not being implemented in accordance with Requirement R7.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	TBD	Drafted by Project 2021-07	New

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Implementation Plan

Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination
Reliability Standards EOP-011-3 and EOP-012-1

Applicable Standard(s)

- EOP-011-3 Emergency Preparedness and Operations
- EOP-012-1 Extreme Cold Weather Preparedness and Operations

Requested Retirement(s)

- EOP-011-2

Prerequisite Standard(s)

- None

Proposed Definition(s)

- Generator Cold Weather Critical Component
- Extreme Cold Weather Temperature
- Generator Cold Weather Reliability Event

Applicable Entities

- See subject Reliability Standards.

Background

The purpose of Project 2021-07 is to develop Reliability Standards to enhance the reliability of the Bulk Electric System (BES) through improved operations, preparedness, and coordination during extreme cold weather, as recommended by the Federal Energy Regulatory Commission (FERC), NERC, and Regional Entity Joint Staff Inquiry into the February 2021 extreme cold weather event (the "Report").[1]

The February 2021 Event

From February 8 through 20, 2021, extreme cold weather and precipitation caused large numbers of generating units to experience outages, derates, or failures to start, resulting in energy and transmission emergencies (referred to as "the Event"). The total Event firm load shed was the largest controlled firm load shed event in U.S. history and was the third largest in quantity of

[1] *See* FERC, NERC and Regional Entity Staff Report, *The February 2021 Cold Weather Outages in Texas and the South Central United States* (Nov. 2021) (referred to as "the Report").

outaged megawatts (MW) of load after the August 2003 northeast blackout and the August 1996 west coast blackout. The Event was most severe from February 15 through February 18, 2021, and it contributed to power outages affecting millions of electricity customers throughout the regions of ERCOT, SPP, and MISO South.

Extreme cold weather has repeatedly challenged the reliable operation of the bulk-power system (BPS). The Event was the fourth in the past 10 years which jeopardized BPS reliability. In February 2011, an arctic cold front impacted the southwest U.S. and resulted in numerous generation outages, natural gas facility outages, and emergency power grid conditions with firm customer load shed. In January 2014, a polar vortex affected Texas, central and eastern U.S, which triggered many generation outages, natural gas availability issues, and resulted in emergency conditions including load shed. In January 2018, an arctic high-pressure system and below average temperatures in the south-central U.S. resulted in many generation outages and voluntary load management measures.

Project 2021-07

Project 2021-07 is a two-phase project to address the 10 sub-recommendations in Key Recommendation 1 of the Report for new or enhanced NERC Reliability Standards. This implementation plan addresses Reliability Standards EOP-011-3 and EOP-012-1, which were developed to address the first phase of Reliability Standards recommendations.

Proposed Reliability Standard EOP-012-1 is a new extreme cold weather preparedness and operations Reliability Standard that addresses Recommendations 1d, 1e, and 1f of the Report. This standard includes requirements for implementing freeze protection measures for new and existing BES generating units to operate at location-specific temperature (Requirements R1 and R2), and for addressing the causes of outages, de-rates, and failures to synchronize caused by freezing (Requirement R6). For accountability, the proposed Reliability Standard includes a requirement to implement any required Corrective Action Plans under the standard and update such plans if actions or timetables change (Requirement R7). The proposed Reliability Standard also includes requirements for cold weather preparedness plans and training (Requirements R3 and R5), originally included in Reliability Standard EOP-011-2. Proposed Reliability Standard EOP-012-1 builds upon the existing cold weather preparedness plans and training requirements by requiring entities to periodically review their local cold weather conditions to ensure the continued effectiveness of cold weather operating plans and freeze protection measures (Requirement R4) by making any updates that are needed based on changes in the local weather, and by specifying that cold weather training under Requirement R5 must be completed on an annual basis.

Proposed Reliability Standard EOP-011-3 is a revised Reliability Standard that addresses Recommendation 1j of the Report, minimizing the overlap of manual Load shed and automatic Load shed programs such as underfrequency Load shed (UFLS) and undervoltage Load shed (UVLS). This revision also removes Requirements R7 and R8, as this language was moved to the new EOP-012-1, noted above.

General Considerations

This implementation plan reflects consideration that entities will need time to develop, implement, and maintain cold weather plans and freeze protection measures. This implementation plan covers the key recommendations from the Report identified for phase one only, Recommendations 1d, 1e, 1f, and 1j.

Effective Date and Phased-In Compliance Dates

The effective dates for the proposed Reliability Standards are provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of a proposed Reliability Standard (i.e., an entire Requirement or a portion thereof), the additional time for compliance with that section is specified below. The phased-in compliance date for those particular sections represents the date 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.

Please see Figure 1 EOP-012 Implementation Timeline below for an illustration of the implementation timeline in those jurisdictions where governmental approval is required.

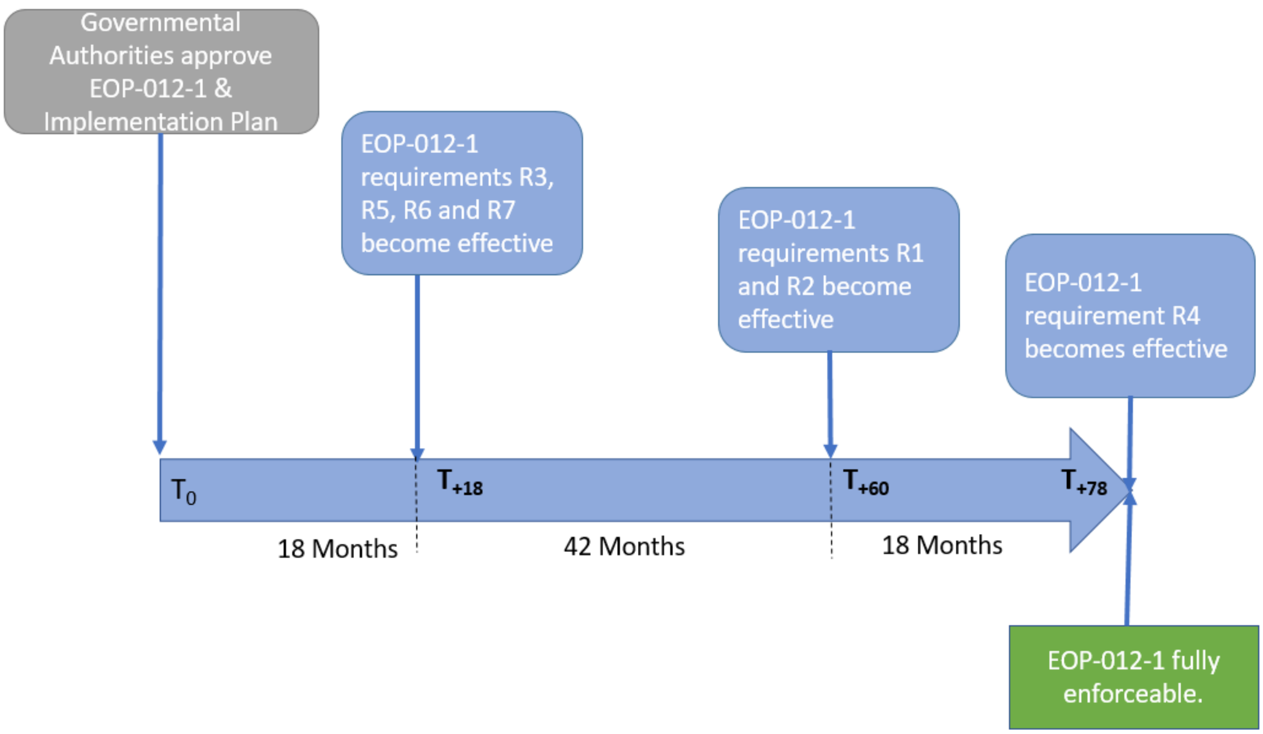

Figure 1 EOP-012 Implementation Timeline

Standard EOP-011-3

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 18 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 18 months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Standard EOP-012-1
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Compliance Date for EOP-012-1 - Requirement R1 and R2
Entities shall not be required to comply with Requirement R1 and R2 until 42 months after the effective date of Reliability Standard EOP-012-1.

Compliance Date for EOP-012-1 - Requirement R4
Entities shall not be required to comply with Requirement R4 until 60 months after the effective date of Reliability Standard EOP-012-1.

Retirement Date

Standard EOP-011-2
Reliability Standard EOP-011-2 shall be retired immediately prior to the effective date of Reliability Standards EOP-011-3 and EOP-012-1 in the particular jurisdiction in which the revised standards are becoming effective.

Initial Performance of Periodic Requirements
Entities shall perform their first periodic review under Reliability Standard EOP-012-1 Requirement R4 by the Compliance Date (i.e. no more than 60 months after the effective date of EOP-012-1). Subsequent periodic reviews under Requirement R4 shall be performed once every five calendar years.

Implementation Plan

Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination
Reliability Standards EOP-011-3 and EOP-012-1

Applicable Standard(s)

- EOP-011-3 Emergency Preparedness and Operations
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Requested Retirement(s)

- EOP-011-2

Prerequisite Standard(s)

- None

Proposed Definition(s)

- Generator Cold Weather Critical Component
- Extreme Cold Weather Temperature
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Applicable Entities

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Background

The purpose of Project 2021-07 is to develop Reliability Standards to enhance the reliability of the Bulk Electric System (BES) through improved operations, preparedness, and coordination during extreme cold weather, as recommended by the Federal Energy Regulatory Commission (FERC), NERC, and Regional Entity Joint Staff Inquiry into the February 2021 extreme cold weather event~~.[1]~~ (the "Report").[1]

The February 2021 Event

From February 8 through 20, 2021, extreme cold weather and precipitation caused large numbers of generating units to experience outages, derates, or failures to start, resulting in energy and transmission emergencies (referred to as "the Event"). The total Event firm load shed was the

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largest controlled firm load shed event in U.S. history and was the third largest in quantity of outaged megawatts (MW) of load after the August 2003 northeast blackout and the August 1996 west coast blackout. The Event was most severe from February 15 through February 18, 2021, and it contributed to power outages affecting millions of electricity customers throughout the regions of ERCOT, SPP, and MISO South.

Extreme cold weather has repeatedly challenged the reliable operation of the bulk-power system (BPS). The Event ~~is~~ was the fourth in the past 10 years which jeopardized BPS reliability. In February 2011, an arctic cold front impacted the southwest U.S. and resulted in numerous generation outages, natural gas facility outages, and emergency power grid conditions with firm customer load shed. In January 2014, a polar vortex affected Texas, central and eastern U.S, which triggered many generation outages, natural gas availability issues, and resulted in emergency conditions including load shed. In January 2018, an arctic high-pressure system and below average temperatures in the south-central U.S. resulted in many generation outages and voluntary load management measures.

Project 2021-07

Project 2021-07 is a two-phase project to address the 10 sub-recommendations in Key Recommendation 1 of the Report for new or enhanced NERC Reliability Standards. This implementation plan addresses Reliability Standards EOP-011-3 and EOP-012-1, which were developed to address the first phase of Reliability Standards recommendations.

Proposed Reliability Standard EOP-012-1 is a new extreme cold weather preparedness and ~~operation~~ operations Reliability Standard that addresses Recommendations 1d, 1e, and 1f of the Report. This standard includes requirements for implementing freeze protection measures for new and existing BES generating units to operate at location-specific temperature (Requirements R1 and R2), and for addressing the causes of outages, de-rates, and failures to synchronize caused by freezing (Requirement R6). For accountability, the proposed Reliability Standard includes a requirement to implement any required Corrective Action Plans under the standard and update such plans if actions or timetables change (Requirement R7). The proposed Reliability Standard also includes requirements for cold weather preparedness plans and training (Requirements R3 and R5), originally included in Reliability Standard EOP-011-2 ~~by Project 2019-06, Cold Weather Preparedness and Communication Requirements between Functional Entities~~. Proposed Reliability Standard EOP-012-1 builds upon the existing cold weather preparedness plans and training requirements by requiring entities to periodically review their local cold weather conditions to ensure the continued ~~validity~~ effectiveness of cold weather operating plans and freeze protection measures (Requirement R4) by making any updates that are needed based on changes in the local weather, and by specifying that cold weather training under Requirement R5 must be completed on an annual basis.

Proposed Reliability Standard EOP-011-3 is a revised Reliability Standard that addresses Recommendation 1j of the Report, minimizing the overlap of manual Load shed and automatic Load shed programs such as underfrequency Load shed (UFLS) and undervoltage Load shed (UVLS). This revision also removes Requirements R7 and R8, as this language was moved to the new EOP-012-1, noted above.

General Considerations

This implementation plan reflects consideration that entities will need time to develop, implement, and maintain cold weather plans and freeze protection measures. This implementation plan covers the key recommendations from the Report identified for phase one only, Recommendations 1d, 1e, 1f, and 1j.

Effective Date and Phased-In Compliance Dates

The effective dates for the proposed Reliability Standards are provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of a proposed Reliability Standard (i.e., an entire Requirement or a portion thereof), the additional time for compliance with that section is specified below. The phased-in compliance date for those particular sections represents the date 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.

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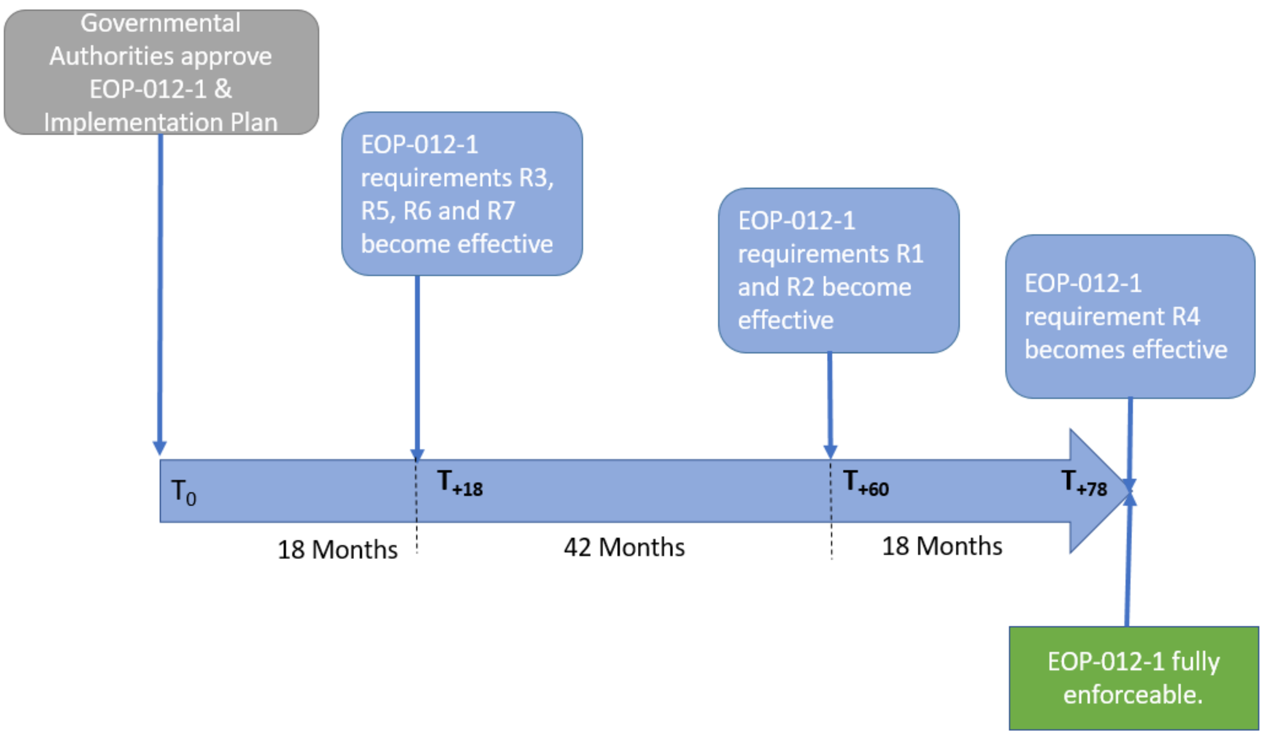

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Standard EOP-012-1

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Compliance Date for EOP-012-1 - Requirement R1 and R2

Entities shall not be required to comply with Requirement R1 and R2 until 42 months after the effective date of Reliability Standard EOP-012-1.

Compliance Date for EOP-012-1 - Requirement R4

Entities shall not be required to comply with Requirement R4 until 60 months after the effective date of Reliability Standard EOP-012-1.

Retirement Date

Standard EOP-011-2

Reliability Standard EOP-011-2 shall be retired immediately prior to the effective date of Reliability ~~Standard~~ Standards EOP-011-3 and EOP-012-1 in the particular jurisdiction in which the revised ~~standard is~~ standards are becoming effective.

Initial Performance of Periodic Requirements

Entities shall perform their first periodic review under Reliability Standard EOP-012-1 Requirement R4 by the Compliance Date (i.e. no more than 60 months after the effective date of EOP-012-1). Subsequent periodic reviews under Requirement R4 shall be performed once every five calendar years.

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Unofficial Comment Form

Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination

Do not use this form for submitting comments. Use the [Standards Balloting and Commenting System (SBS)] to submit comments on **Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination** by **8 p.m. Eastern, September 1, 2022.**

Additional information is available on the [project page]. If you have questions, contact Senior Standards Developer, [Alison Oswald] (via email), or at 404-446-9668.

Background Information
From February 8 through February 20, 2021, extreme cold weather and precipitation caused large numbers of generating units to experience outages, derates or failures to start, resulting in energy and transmission emergencies (referred to as "the Event"). The total Event firm Load shed was the largest controlled firm Load shed event in U.S. history and was the third largest in quantity of outaged megawatts (MW) of Load after the August 2003 northeast blackout and the August 1996 west coast blackout. The Event was most severe from February 15 through February 18, 2021, and it contributed to power outages affecting millions of electricity customers throughout the regions of ERCOT, SPP, and MISO South. Additionally, the February 2021 event is the fourth cold weather event in the past 10 years, which jeopardized bulk-power system reliability. A joint inquiry was conducted to discover reliability-related findings and recommendations from FERC, NERC, and Regional Entity staff. The FERC, NERC, and Regional Entity staff Joint Staff Inquiry into the February 2021 Cold Weather Grid Operations ("Joint Inquiry Report") was published on November 16, 2021.

The scope of the proposed project is to address the ten recommendations for new or enhanced NERC Reliability Standards proposed by the Joint Inquiry Report. In November 2021, the NERC Board of Trustees (Board) approved a Board Resolution directing that new or revised Reliability Standards addressing these recommendations be completed in accordance with the timelines recommended by the joint inquiry team, as follows:

- New and revised Reliability Standards to be submitted for regulatory approval before Winter 2022/2023: development completed by September 30, 2022, for the Board's consideration in October 2022 to address Key Recommendations 1d, 1e, 1f, and 1j;
- New and revised Reliability Standards to be submitted for regulatory approval before Winter 2023/2024: development completed by September 30, 2023, for the Board's consideration in October 2023 to address Key Recommendations 1a, 1b, 1c, 1g, 1h, and 1i.

Questions

1. The SDT is proposing three new definitions from the initial posting of EOP-012. Does adding definitions of Extreme Cold Weather Temperature, Generator Cold Weather Critical Component, and Generator Cold Weather Reliability Event provide additional clarity to the requirements of EOP-012? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

   ☐ Yes
   ☐ No

   Comments:

2. Do you agree with the proposed definitions of Extreme Cold Weather Temperature, Generator Cold Weather Critical Component, and Generator Cold Weather Reliability Event? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

   ☐ Yes
   ☐ No

   Comments:

3. Is the revised Applicability Section language clear? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

   ☐ Yes
   ☐ No

   Comments:

4. Do you support the SDT proposed 12-hour timeframe to require new Generation units to be capable of performing at or below the Extreme Cold Weather Temperature? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

   ☐ Yes
   ☐ No

   Comments:

5. Do you support the SDT proposed 1-hour timeframe to allow existing Generation units to demonstrate their performance at or below the Extreme Cold Weather Temperature? If you do

not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

☐ Yes
☐ No

Comments:

6. Do you support the addition of a 20 megawatt minimum (corresponding to the definition of a BES impacting generating unit) for requiring CAPS for derates? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

☐ Yes
☐ No

Comments:

7. The SDT believes that with the proposed modifications to EOP-012-1, the initial proposed implementation plan is appropriate with one change. The 18-month implementation time frame is for all revised and new requirements in EOP-012-1, except Requirements R1 and R2 which have a 60-month implementation time frame, and R4 which has a 78-month implementation time frame. Do you agree with this implementation time frame? If you think an alternate timeframe is needed, please propose an alternate implementation plan and time period, and provide a detailed explanation of actions planned to meet the implementation deadline.

☐ Yes
☐ No

Comments:

8. The SDT proposes that the modifications in the proposed EOP-012-1 meet the key recommendations in The Report 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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Mapping Document

Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination

Summary

This mapping document maps the recommendations from The February 2021 Cold Weather Outages in Texas and the South Central United States report (The Report) to the creation of new standard EOP-012 as well as the revised EOP-011-3.

Recommendation 1d

Generator Owners that experience outages, failures to start, or derates due to freezing are to review the generating unit's outage, failure to start, or derate and develop and implement a corrective action plan (CAP) for the identified equipment, and evaluate whether the CAP applies to similar equipment for its other generating units. Based on the evaluation, the Generator Owner will either revise its cold weather preparedness plan to apply the CAP to the similar equipment, or explain in a declaration (a) why no revisions to the cold weather preparedness plan are appropriate, and (b) that no further corrective actions will be taken. The Standard Drafting Team should specify the specific timing for the CAP to be developed and implemented after the outage, derate or failure to start, but the CAP should be developed as quickly as possible, and be completed by no later than the beginning of the next winter season.

Standard: EOP-012-1		
Requirement in Approved Standard	**Transition to New Standard or Other Action**	**Description and Change Justification**
This requirement does not exist in an already approved standard. It is new to EOP-012-1.	**EOP-012-1 Requirement R6** **R6.** Each Generator Owner that owns a generating unit that experiences a Generator Cold Weather Reliability Event shall develop a CAP, within 150 days or by July 1, whichever is earlier, that contains at a minimum: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*	This requirement addresses recommendation 1d for Generator Owners to develop and implement a CAP following an outage, failure to start, or derate. CAPs will be required any time a generating unit experiences a Generator Cold Weather Reliability Event. The CAP requirement thus applies to any forced outage due to freezing, regardless of duration. Derates which are short-lived or of small capacity impact are excluded from the Generator Cold Weather Reliability Event definition, and therefore from the CAP requirement. R6 requires the GO to act within 150 days or July 1 to develop

	6.1 A summary of the identified cause(s) for the Generator Cold Weather Reliability Event where applicable and any relevant associated data; **6.2** A review of applicability to similar equipment at other generating units owned by the Generator Owner; **6.3** An identification of any temporary operating limitations or impacts to the cold weather preparedness plan, that would apply until execution of the corrective action(s) identified in the CAP. **New Glossary Definition, Generator Cold Weather Reliability Event** Generator Cold Weather Reliability Event - One of the following events: (1) a forced derate of more than 10% of the total capacity of the unit and exceeding 20 MWs for longer than four hours in duration; (2) a start-up failure where the unit fails to synchronize within a specified start-up time; or (3) a Forced Outage, for which the apparent cause(s) is due to freezing of equipment within the Generator Owner's	the CAP. This timeframe was chosen to allow Generator Owners to review multiple events holistically following a winter season, and create one CAP for equipment with common failure causes while meeting the recommendation charge to be "developed as quickly as possible".

	control and the dry bulb temperature at the time of the event was at or above the Extreme Cold Weather Temperature.	
This requirement does not exist in an already approved standard. It is new to EOP-012-1.	**R7.** Each Generator Owner shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]* **7.1** Implement each CAP developed pursuant to Requirements R2, R4, or R6, or explain in a declaration why corrective actions are not being implemented due to any technical, commercial, or operational constraints as defined by the Generator Owner. **7.2** Update each CAP if actions or timetables change, until completed.	The recommendation in 1d continues to be addressed through Requirement R7. Generator Owners shall implement any CAPs for equipment freezing events developed under Requirement R6 or explain in a declaration why corrective actions are not being implemented. The declaration in Requirement R7 applies to any CAP developed in R2 (existing generators freeze protection measures), R4 (5-year review) or R6 (CAP for Cold Weather Reliability Event).

Recommendation 1e

To revise EOP-011-2, R8, to require Generator Owners and Generator Operators are to conduct annual unit-specific cold weather preparedness plan training

Standard: EOP-012-1		
Requirement in Approved Standard	**Transition to New Standard or Other Action**	**Description and Change Justification**
EOP-011-2 Requirement R8 **R8.** Each Generator Owner in conjunction with its Generator Operator shall identify the entity responsible for providing the generating unit-specific training, and that identified entity shall provide the training to its maintenance or operations personnel responsible for implementing cold weather preparedness plan(s) developed pursuant to Requirement R7.	**EOP-012-1 Requirement R5** **R5.** Each Generator Owner in conjunction with its Generator Operator shall identify the entity responsible for providing the generating unit-specific training, and that identified entity shall provide annual training to its maintenance or operations personnel responsible for implementing the cold weather preparedness plan(s) developed pursuant to Requirement R3.	EOP-011-2 Requirement R8 was moved to new standard EOP-012-1 Requirement R5. The language remains the same with the addition of the word annual to meet the charge in recommendation 1e of The Report.

Recommendation 1f

To require Generator Owners to retrofit existing generating units, and when building new generating units, to design them to operate to a specified ambient temperature and weather conditions (e.g., wind, freezing precipitation). The specified ambient temperature and weather conditions should be based on available extreme temperature and weather data for the generating unit's location.

Standard: EOP-012-1		
Requirement in Approved Standard	**Transition to New Standard**	**Description and Change Justification**
This requirement does not exist in an already approved standard. It is new to EOP-012-1.	**EOP-012-1 Requirement R1** **R1.** For each generating unit(s) with a commercial operation date subsequent to [Effective Date of this requirement], the Generator Owner shall: [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning, Operations Planning*] ● Implement freeze protection measures that provide capability to operate for a period of not less than twelve (12) continuous hours at the Extreme Cold Weather Temperature for the unit(s), assuming a concurrent twenty (20) mph wind speed on any exposed Generator Cold Weather Critical Components; or ● Explain in a declaration, any technical, commercial, or operational constraints as defined by the Generator Owner that preclude the ability to implement appropriate freeze protection measures to provide capability of operating for twelve (12) hours at the documented Extreme Cold Weather Temperature.	This requirement addresses new build generation to have freeze protection measures to meet the criteria listed. This criteria include operating for 12 hours at the Extreme Cold Weather Temperature which is based on the available temperature and weather data for the unit's location, and accounting for the cooling effects of wind, as suggested by the recommendation. If the unit cannot implement appropriate freeze protection measures it must be explained in a declaration. Following regulatory approval, the bracketed language, [Effective Date of this requirement], will be replaced with the date by which entities shall be compliant with this requirement. It is the intent of the Project 2021-07 drafting team that this date will remain static in any future versions of the EOP-012 standard, to distinguish between requirements applicable to generation that exists at the time the first version of the standard becomes effective, and requirements applicable to generation that comes online after the first standard becomes effective, unless a future drafting team determines an alternative approach is appropriate.

This requirement does not exist in an already approved standard. It is new to EOP-012-1.	**R2.** For each generating unit(s) in commercial operation prior to [Effective Date of this requirement], the Generator Owner shall ensure its generating unit(s) add new or modify existing freeze protection measures as needed to provide the capability to operate for a period of not less than one (1) hour at the unit(s) Extreme Cold Weather Temperature. Generating unit(s) that are not capable of operating for one (1) hour at its Extreme Cold Weather Temperature shall develop a Corrective Action Plan (CAP) for the identified issues, including identification of any needed modifications to the cold weather preparedness plan required under Requirement R3. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]*	This requirement addresses existing generation to have freeze protection measures to provide for the capability to operate for one hour at the calculated Extreme Cold Weather temperature. If the unit cannot meet these criteria, then a CAP is required to address the identified issues. FERC staff from the Joint Inquiry Report team clarified to the SDT that the reliability goal of the recommendation for existing generating units is to have the necessary freeze protection measures to be able to operate at extreme cold temperatures and weather for the generating unit's location. For example, those measures may consist of existing or new, permanent and/or temporary measures to maintain operation during extreme cold temperatures. Following regulatory approval, the bracketed language, [Effective Date of this requirement], will be replaced with the date by which entities shall be compliant with this requirement. It is the intent of the Project 2021-07 drafting team that this date will remain static in any future versions of the EOP-012 standard, to distinguish between requirements applicable to generation that exists at the time the first version of the standard becomes effective, and requirements applicable to generation that comes online after the first standard becomes effective, unless a future drafting team determines an alternative approach is appropriate.

Recommendation 1j

In minimizing the overlap of manual and automatic load shed, the load shed procedures of Transmission Operators, Transmission Owners (TOs) and Distribution Providers (DPs) should separate the circuits that will be used for manual load shed from circuits used for underfrequency load shed (UFLS)/undervoltage load shed (UVLS) or serving critical load. UFLS/UVLS circuits should only be used for manual load shed as a last resort and should start with the final stage (lowest frequency).

Standard: EOP-011-3		
Requirement in Approved Standard	**Transition to New Standard or Other Action**	**Description and Change Justification**
EOP-011-2 Requirement R1 Part 1.2.5 **1.2.5** Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and	**EOP-011-3 Requirement R1 Part 1.2.5** **1.2.5.** Operator-controlled manual Load shedding during an Emergency that accounts for each of the following: **1.2.5.1.** Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency; **1.2.5.2.** Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that serve designated critical loads; **1.2.5.3.** Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for underfrequency load shed (UFLS) or undervoltage load shed (UVLS); and **1.2.5.4.** Provisions for limiting the	The second posting does not include any changes to EOP-011-3 since the initial posting. EOP-011-3 adds additional provisions and clarifies what the TOP must include in their Operating Plan to mitigate operating Emergencies. Specific clarifications are to minimize the overlap of manual Load shed and circuits that serve designated critical loads; minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for underfrequency load shed (UFLS) or undervoltage load shed (UVLS); and provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed. The SDT elected to keep the phase “minimize the overlap” instead of moving to language that specifically requires the separation of circuits in recognition of the fact that it is not always practical or warranted to completely separate circuits used for each of these purposes.

	utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions.	
EOP-011-2 Requirement R2 Part 2.2.8 **2.2.8.** Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and	**EOP-011-3 Requirement R2 Part 2.2.8** **2.2.8.** Provisions for Transmission Operators to implement operator-controlled manual Load shed in accordance with Requirement R1 Part 1.2.5; and	The second posting does not include any changes to EOP-011-3 since the initial posting. This part of R2 has been modified to refer back to Requirement R1, Part 1.2.5 in an effort to clarify that the Transmission Operator is responsible for addressing operator-controlled manual load shed requirements in their Operating Plan. Balancing Authorities are expected to specify manual load shed requirements for Transmission Operators within their areas in accordance with Part 1.2.5, but do not have the control or visibility to design and implement manual load shed programs and UFLS/UVLS programs that meet the requirements of Part 1.2.5.

Mapping Document

Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination

Summary

This mapping document maps the recommendations from The February 2021 Cold Weather Outages in Texas and the South Central United States report (The Report) to the creation of new standard EOP-012 as well as the revised EOP-011-3.

Recommendation 1d

Generator Owners that experience outages, failures to start, or derates due to freezing are to review the generating unit's outage, failure to start, or derate and develop and implement a corrective action plan (CAP) for the identified equipment, and evaluate whether the CAP applies to similar equipment for its other generating units. Based on the evaluation, the Generator Owner will either revise its cold weather preparedness plan to apply the CAP to the similar equipment, or explain in a declaration (a) why no revisions to the cold weather preparedness plan are appropriate, and (b) that no further corrective actions will be taken. The Standard Drafting Team should specify the specific timing for the CAP to be developed and implemented after the outage, derate or failure to start, but the CAP should be developed as quickly as possible, and be completed by no later than the beginning of the next winter season.

Standard: EOP-012-1		
Requirement in Approved Standard	**Transition to New Standard or Other Action**	**Description and Change Justification**
This requirement does not exist in an already approved standard. It is new to EOP-012-1.	**EOP-012-1 Requirement R6** **R6.** Each Generator Owner that owns a generating unit that experiences a Generator Cold Weather Reliability Event shall develop a CAP, within 150 days or by July 1, whichever is earlier, that contains at a minimum: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*	This requirement addresses recommendation 1d for Generator Owners to develop and implement a CAP following an outage, failure to start, or derate. CAPs will be required any time a generating unit experiences a Generator Cold Weather Reliability Event. The CAP requirement thus applies to any forced outage due to freezing, regardless of duration. Derates which are short-lived or of small capacity impact are excluded from the Generator Cold Weather Reliability Event definition, and therefore from the CAP requirement. R6 requires the GO to act within 150 days or July 1 to develop

	6.1 A summary of the identified cause(s) for the Generator Cold Weather Reliability Event where applicable and any relevant associated data; **6.2** A review of applicability to similar equipment at other generating units owned by the Generator Owner; **6.3** An identification of any temporary operating limitations or impacts to the cold weather preparedness plan, that would apply until execution of the corrective action(s) identified in the CAP. **New Glossary Definition, Generator Cold Weather Reliability Event** Generator Cold Weather Reliability Event - One of the following events: (1) a forced derate of more than 10% of the total capacity of the unit and exceeding 20 MWs for longer than four hours in duration; (2) a start-up failure where the unit fails to synchronize within a specified start-up time; or (3) a Forced Outage, for which the apparent cause(s) is due to freezing of equipment within the Generator Owner's	the CAP. This timeframe was chosen to allow Generator Owners to review multiple events holistically following a winter season, and create one CAP for equipment with common failure causes while meeting the recommendation charge to be "developed as quickly as possible".

	control and the dry bulb temperature at the time of the event was at or above the Extreme Cold Weather Temperature.	
This requirement does not exist in an already approved standard. It is new to EOP-012-1.	**R7.** Each Generator Owner shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]* **7.1** Implement each CAP developed pursuant to Requirements R2, R4, or R6, or explain in a declaration why corrective actions are not being implemented due to any technical, commercial, or operational constraints as defined by the Generator Owner. **7.2** Update each CAP if actions or timetables change, until completed.	The recommendation in 1d continues to be addressed through Requirement R7. Generator Owners shall implement any CAPs for equipment freezing events developed under Requirement R6 or explain in a declaration why corrective actions are not being implemented. The declaration in Requirement R7 applies to any CAP developed in R2 (existing generators freeze protection measures), R4 (5-year review) or R6 (CAP for Cold Weather Reliability Event).

Recommendation 1e

To revise EOP-011-2, R8, to require Generator Owners and Generator Operators are to conduct annual unit-specific cold weather preparedness plan training

Standard: EOP-012-1		
Requirement in Approved Standard	**Transition to New Standard or Other Action**	**Description and Change Justification**
EOP-011-2 Requirement R8 **R8.** Each Generator Owner in conjunction with its Generator Operator shall identify the entity responsible for providing the generating unit-specific training, and that identified entity shall provide the training to its maintenance or operations personnel responsible for implementing cold weather preparedness plan(s) developed pursuant to Requirement R7.	**EOP-012-1 Requirement R5** **R5.** Each Generator Owner in conjunction with its Generator Operator shall identify the entity responsible for providing the generating unit-specific training, and that identified entity shall provide ~~the~~ annual training to its maintenance or operations personnel responsible for implementing the cold weather preparedness plan(s) developed pursuant to Requirement R3.	EOP-011-2 Requirement R8 was moved to new standard EOP-012-1 Requirement R5. The language remains the same with the addition of the word annual to meet the charge in recommendation 1e of The Report.

Recommendation 1f

To require Generator Owners to retrofit existing generating units, and when building new generating units, to design them to operate to a specified ambient temperature and weather conditions (e.g., wind, freezing precipitation). The specified ambient temperature and weather conditions should be based on available extreme temperature and weather data for the generating unit's location.

Standard: EOP-012-1		
Requirement in Approved Standard	**Transition to New Standard**	**Description and Change Justification**
This requirement does not exist in an already approved standard. It is new to EOP-012-1.	**EOP-012-1 Requirement R1** **R1.** For each generating unit(s) with a commercial operation date subsequent to [Effective Date of this requirement], the Generator Owner shall: [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning, Operations Planning*] • Implement freeze protection measures that provide capability to operate for a period of not less than twelve (12) continuous hours at the Extreme Cold Weather Temperature for the unit(s), assuming a concurrent twenty (20) mph wind speed on any exposed Generator Cold Weather Critical Components; or • Explain in a declaration, any technical, commercial, or operational constraints as defined by the Generator Owner that preclude the ability to implement appropriate freeze protection measures to provide capability of operating for twelve (12) hours at the documented Extreme Cold Weather Temperature.	This requirement addresses new build generation to have freeze protection measures to meet the criteria listed. This criteria include operating for 12 hours at the Extreme Cold Weather Temperature which is based on the available temperature and weather data for the unit's location, and accounting for the cooling effects of wind, as suggested by the recommendation. If the unit cannot implement appropriate freeze protection measures it must be explained in a declaration. Following regulatory approval, the bracketed language, [Effective Date of this requirement], will be replaced with the date by which entities shall be compliant with this requirement. It is the intent of the Project 2021-07 drafting team that this date will remain static in any future versions of the EOP-012 standard, to distinguish between requirements applicable to generation that exists at the time the first version of the standard becomes effective, and requirements applicable to generation that comes online after the first standard becomes effective, unless a future drafting team determines an alternative approach is appropriate.

This requirement does not exist in an already approved standard. It is new to EOP-012-1.	**R2.** For each generating unit(s) in commercial operation prior to [Effective Date of this requirement], the Generator Owner shall ensure its generating unit(s) add new or modify existing freeze protection measures as needed to provide the capability to operate for a period of not less than one (1) hour at the unit(s) Extreme Cold Weather Temperature. Generating unit(s) that are not capable of operating for one (1) hour at its Extreme Cold Weather Temperature shall develop a Corrective Action Plan (CAP) for the identified issues, including identification of any needed modifications to the cold weather preparedness plan required under Requirement R3. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]*	This requirement addresses existing generation to have freeze protection measures to provide for the capability to operate for one hour at the calculated Extreme Cold Weather temperature. If the unit cannot meet these criteria, then a CAP is required to address the identified issues. FERC staff from the Joint Inquiry Report team clarified to the SDT that the reliability goal of the recommendation for existing generating units is to have the necessary freeze protection measures to be able to operate at extreme cold temperatures and weather for the generating unit's location. For example, those measures may consist of existing or new, permanent and/or temporary measures to maintain operation during extreme cold temperatures. Following regulatory approval, the bracketed language, [Effective Date of this requirement], will be replaced with the date by which entities shall be compliant with this requirement. It is the intent of the Project 2021-07 drafting team that this date will remain static in any future versions of the EOP-012 standard, to distinguish between requirements applicable to generation that exists at the time the first version of the standard becomes effective, and requirements applicable to generation that comes online after the first standard becomes effective, unless a future drafting team determines an alternative approach is appropriate.

Recommendation 1j

In minimizing the overlap of manual and automatic load shed, the load shed procedures of Transmission Operators, Transmission Owners (TOs) and Distribution Providers (DPs) should separate the circuits that will be used for manual load shed from circuits used for underfrequency load shed (UFLS)/undervoltage load shed (UVLS) or serving critical load. UFLS/UVLS circuits should only be used for manual load shed as a last resort and should start with the final stage (lowest frequency).

Standard: EOP-011-3		
Requirement in Approved Standard	**Transition to New Standard or Other Action**	**Description and Change Justification**
EOP-011-2 Requirement R1 Part 1.2.5 **1.2.5** Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and	**EOP-011-3 Requirement R1 Part 1.2.5** **1.2.5.** Operator-controlled manual Load shedding during an Emergency that accounts for each of the following: **1.2.5.1.** Provisions for ~~operator-controlled~~ manual Load shedding ~~that minimizes the overlap with automatic Load shedding and are~~ capable of being implemented in a timeframe adequate for mitigating the Emergency; ~~and~~ **1.2.5.2.** Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that serve designated critical loads; **1.2.5.3.** Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for underfrequency	The second posting does not include any changes to EOP-011-3 since the initial posting. EOP-011-3 adds additional provisions and clarifies what the TOP must include in their Operating Plan to mitigate operating Emergencies. Specific clarifications are to minimize the overlap of manual Load shed and circuits that serve designated critical loads; minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for underfrequency load shed (UFLS) or undervoltage load shed (UVLS); and provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed. The SDT elected to keep the phase “minimize the overlap” instead of moving to language that specifically requires the separation of circuits in recognition of the fact that it is not always practical or warranted to completely separate circuits used for each of these purposes.

	load shed (UFLS) or undervoltage load shed (UVLS); and **1.2.5.4.** Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions.	
EOP-011-2 Requirement R2 Part 2.2.8 **2.2.8.** Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and	**EOP-011-3 Requirement R2 Part 2.2.8** **2.2.8.** Provisions for Transmission Operators to implement operator-controlled manual Load shed~~ding~~ in accordance with Requirement R1 Part 1.2.5~~that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency~~; and	The second posting does not include any changes to EOP-011-3 since the initial posting. This part of R2 has been modified to refer back to Requirement R1, Part 1.2.5 in an effort to clarify that the Transmission Operator is responsible for addressing operator-controlled manual load shed requirements in their Operating Plan. Balancing Authorities are expected to specify manual load shed requirements for Transmission Operators within their areas in accordance with Part 1.2.5, but do not have the control or visibility to design and implement manual load shed programs and UFLS/UVLS programs that meet the requirements of Part 1.2.5.

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Violation Risk Factor and Violation Severity Level Justifications

Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination

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 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination. 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.

EOP-011-3

VRF Justification for EOP-011-3, Requirement R1

The VRF did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VSL Justification for EOP-011-3, Requirement R1

The VSL did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VRF Justification for EOP-011-3, Requirement R2

The VRF did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VSL Justification for EOP-011-3, Requirement R2

The VSL did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VRF Justification for EOP-011-3, Requirement R3

The VRF did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VSL Justification for EOP-011-3, Requirement R3

The VSL did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VRF Justification for EOP-011-3, Requirement R4

The VRF did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VSL Justification for EOP-011-3, Requirement R4

The VSL did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VRF Justification for EOP-011-3, Requirement R5

The VRF did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VSL Justification for EOP-011-3, Requirement R5

The VSL did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VRF Justification for EOP-011-3, Requirement R6
The VRF did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VSL Justification for EOP-011-3, Requirement R6
The VSL did not change from the previously FERC approved EOP-011-2 Reliability Standard.
EOP-012-1

VRF Justifications for EOP-012-1, Requirement R1	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that not designing or implementing freeze protection measures for a unit to operate during the local cold weather that can be expected could directly affect the electrical state or the capability of the bulk electric system. In addition, a violation of this 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. Therefore, it is in line with the definition of a Medium VRF.
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	This VRF is in line with the definition of a medium VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
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 EOP-012-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 for 5% or less of its units. OR The Generator Owner did not explain in a declaration any technical, commercial, or operational constraints that preclude the ability to implement appropriate freeze protection measures for 5% or less of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 for more than 5%, but less than or equal to 10% of its units. OR The Generator Owner did not explain in a declaration any technical, commercial, or operational constraints that preclude the ability to implement appropriate freeze protection measures for more than 5%, but less than or equal to 10% of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 for more than 10%, but less than or equal to 20% of its units. OR The Generator Owner did not explain in a declaration any technical, commercial, or operational constraints that preclude the ability to implement appropriate freeze protection measures for more than 10%, but less than or equal to 20% of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 for more than 20% of its units. OR The Generator Owner did not explain in a declaration any technical, commercial, or operational constraints that preclude the ability to implement appropriate freeze protection measures for more than 20% of its units.

VSL Justifications for EOP-012-1, 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 VSLs 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 VSLs 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 EOP-012-1, Requirement R2	
Proposed VRF	**Low**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that not implementing freeze protection measures for a unit to operate during the local cold weather that can be expected could directly affect the electrical state or the capability of the bulk electric system. In addition, a violation of this 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. Therefore, it is in line with the definition of a Medium VRF.
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	This VRF is in line with the definition of a medium VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
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 EOP-012-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R2 for 5% or less of its units. OR The Generator Owner did not develop a CAP as required by Requirement R2 for 5% or less of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R2 for more than 5%, but less than or equal to 10% of its units. OR The Generator Owner did not develop a CAP as required by Requirement R2 for more than 5%, but less than or equal to 10% of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R2 for more than 10%, but less than or equal to 20% of its units. OR The Generator Owner did not develop a CAP as required by Requirement R2 for more than 10%, but less than or equal to 20% of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R2 for more than 20% of its units. OR The Generator Owner did not develop a CAP as required by Requirement R2 for more than 20% of its units.

VSL Justifications for EOP-012-1, 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 VSLs 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	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.

VSL Justifications for EOP-012-1, Requirement R2	
Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs 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 Justification for EOP-012-1, Requirement R3

The VRF did not change from the previously FERC approved EOP-011-2 Requirement R7 Reliability Standard.

VSL Justification for EOP-012-1, Requirement R3

The VSL did not change from the previously FERC approved EOP-011-2 Requirement R7 Reliability Standard.

VRF Justifications for EOP-012-1, Requirement R4	
Proposed VRF	**Low**
NERC VRF Discussion	A VRF of Low is appropriate due to the fact that this 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
FERC VRF G1 Discussion	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.

VRF Justifications for EOP-012-1, Requirement R4	
Proposed VRF	**Low**
Guideline 1- Consistency with 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	This VRF is in line with the definition of a low VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
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 EOP-012-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner completed the actions required in Requirement R4, but was late by 30 calendar days or less.	The Generator Owner completed the actions required in Requirement R4, but was late by greater than 30 calendar days, but less than or equal to 60 calendar days.	The Generator Owner failed to complete one of the applicable requirement parts in Requirement R4 Parts 4.1 through 4.3; OR	The Generator Owner failed to complete two or more of the applicable requirement parts in Requirement R4 Parts 4.1 through 4.3.

		The Generator Owner completed the actions required in Requirement R4, but was late by greater than 60 calendar days.	

VSL Justifications for EOP-012-1, 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 VSLs 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 VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment	Each VSL is based on a single violation and not cumulative violations.

VSL Justifications for EOP-012-1, Requirement R4	
Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	

VRF Justification for EOP-012-1, Requirement R5
The VRF did not change from the previously FERC approved EOP-011-2 Requirement R8 Reliability Standard.

VSL Justification for EOP-012-1, Requirement R5
The VSL did not substantively change from the previously FERC approved EOP-011-2 Requirement R8 Reliability Standard. The language was only updated to reflect the annual nature of the revised requirement language.

VRF Justifications for EOP-012-1, Requirement R6	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate. If violated, this requirement to take corrective actions if a generating unit experiences a derate, failure to start or forced outage due to freezing event 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.
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.

VRF Justifications for EOP-012-1, Requirement R6	
Proposed VRF	**High**
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is in line with the definition of a high VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
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 EOP-012-1, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner developed a CAP, but not within 150 days or by July 1 as required in Requirement R6.	The Generator Owner's CAP failed to comply with one of the elements in Requirement R6, Parts 6.1 through 6.3.	The Generator Owner's CAP failed to comply with two of the elements in Requirement R6, Parts 6.1 through 6.3.	The Generator Owner's CAP failed to comply with three of the elements in Requirement R6, Parts 6.1 through 6.3. OR The Generator Owner did not develop a CAP as required by Requirement R6.

VSL Justifications for EOP-012-1, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.

VSL Justifications for EOP-012-1, Requirement R6	
Current 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 VSLs 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 EOP-012-1, Requirement R7	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of medium is appropriate due to the fact that this requirement to implement a CAP develop pursuant to Requirement R2, R4 and R6, if violated, could, directly affect the electrical state or the capability of the bulk electric

VRF Justifications for EOP-012-1, Requirement R7	
Proposed VRF	**Medium**
	system. In addition, a violation of this 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. Therefore, it is in line with the definition of a Medium VRF.
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	This VRF is in line with the definition of a medium VRF requirement per the criteria filed with FERC as part of the ERO’s Sanctions Guidelines.
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 EOP-012-1, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner implemented a CAP or explained in a declaration why corrective actions are not being implemented, but failed to update the CAP when actions or timetables changed, in accordance with Requirement R7.	N/A	N/A	The Generator Owner failed to implement a CAP or explain in a declaration why corrective actions are not being implemented in accordance with Requirement R7.

VSL Justifications for EOP-012-1, 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 VSLs 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 do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for EOP-012-1, Requirement R7	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs 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

Extreme Cold Weather Preparedness

Technical Rationale and Justification for EOP-012-1

August 2022

RELIABILITY | RESILIENCE | SECURITY




3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

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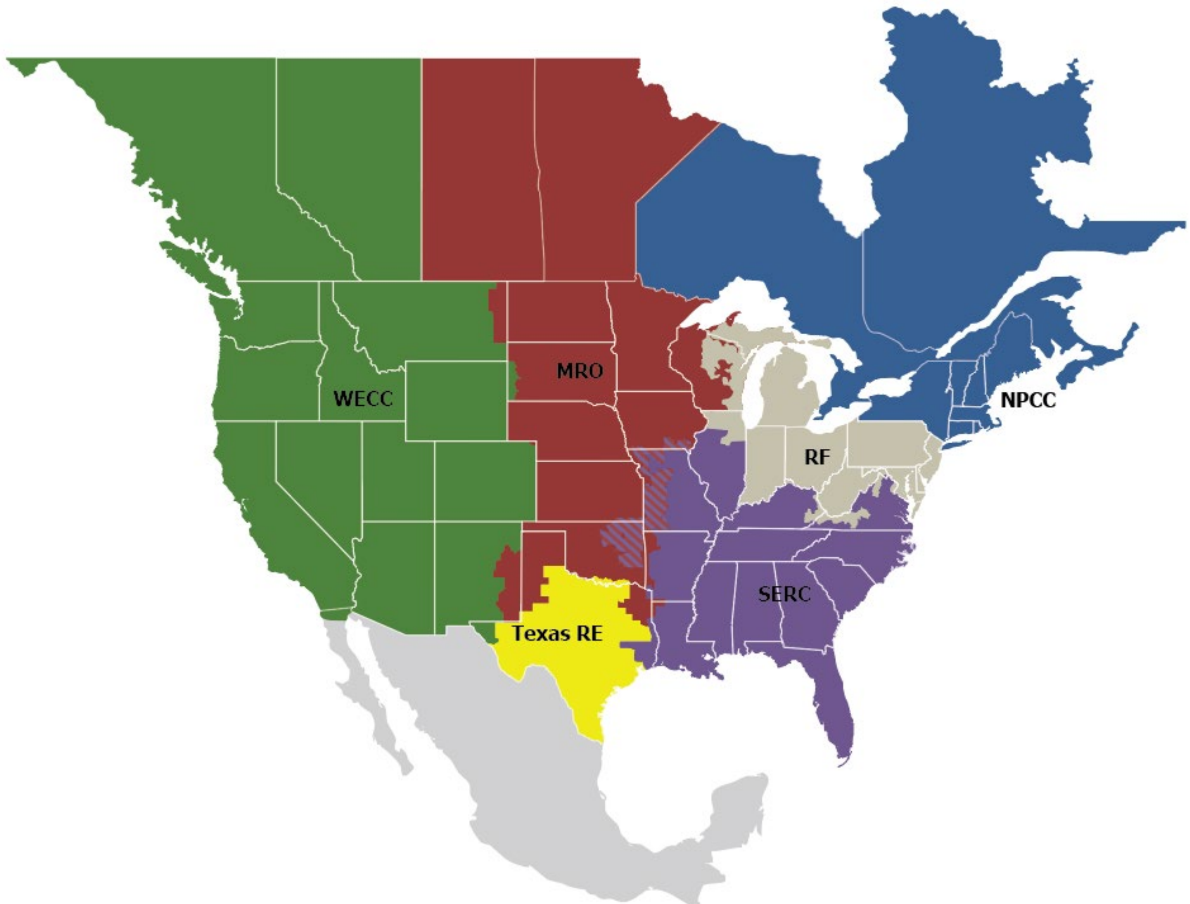
Preface

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 the North American Electric Reliability Corporation (NERC) and the six Regional Entities, is a highly reliable 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 Entity boundaries as shown in the map and 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 EOP-012-1. 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 EOP-012-1 is not a Reliability Standard and should not be considered mandatory and enforceable.

Background

From February 8 through February 20, 2021, extreme cold weather and precipitation caused large numbers of generating units to experience outages, derates or failures to start, resulting in energy and transmission emergencies (referred to as "the Event"). The total Event firm load shed was the largest controlled firm load shed event in U.S. history and was the third largest in quantity of outaged megawatts (MW) of load after the August 2003 northeast blackout and the August 1996 west coast blackout. The Event was most severe from February 15 through February 18, 2021, and it contributed to power outages affecting millions of electricity customers throughout the regions of ERCOT, SPP, and MISO South. Additionally, the February 2021 event is the fourth cold weather event in the past 10 years, which jeopardized bulk-power system reliability. A joint inquiry was conducted to discover reliability-related findings and develop recommendations from FERC, NERC, and Regional Entity staff. The FERC, NERC, and Regional Entity Staff Report into the February 2021 Cold Weather Outages ("Joint Inquiry Report") was published on November 16, 2021.

The scope of the proposed project is to address the ten recommendations for new or enhanced NERC Reliability Standards proposed by the Joint Inquiry Report. In November 2021, the NERC Board of Trustees (Board) approved a Board Resolution directing that new or revised Reliability Standards addressing these recommendations be completed in accordance with the timelines recommended by the joint inquiry team, as follows:

- New and revised Reliability Standards to be submitted for regulatory approval before Winter 2022/2023: development completed by September 30, 2022, for the Board's consideration in October 2022 to address Key Recommendations 1d, 1e, 1f, and 1j;
- New and revised Reliability Standards to be submitted for regulatory approval before Winter 2023/2024: development completed by September 30, 2023, for the Board's consideration in October 2023 to address Key Recommendations 1a, 1b, 1c, 1g, 1h, and 1i.

EOP-012-1

Facilities

4. *Facilities: For purposes of this standard, the term "generating unit" subject to these requirements means:*

4.1. *A Bulk Electric System generating unit:*

4.1.1. *That commits or is obligated to serve a Balancing Authority load pursuant to an Open Access Transmission Tariff (OATT) or other contractual arrangement;*

4.1.1.1. *The term excludes a Bulk Electric System generating unit that is typically not available at or below thirty-two (32) degrees Fahrenheit (zero degrees Celsius) for any continuous run of more than four hours. The exclusion applies even when such BES generator has been called to assist in the mitigation of BES Emergencies, Capacity Emergencies or Energy Emergencies during periods at or below 32 degrees Fahrenheit.*

4.1.2. *Blackstart Resources*

In the Joint Inquiry Report, Key Recommendation 1f includes support information, which states "consideration should be given to designing all new generation plants and designing modifications to existing plants (unless committed solely for summer peaking purposes)…[.][1] FERC staff from the Joint Inquiry Report team clarified to the standard drafting team (SDT) that the reference to summer peaking units acknowledges that some units have not implemented freeze protection measures or may not be able to secure fuel in the winter and therefore, plan to commit solely to serve Balancing Authority load during non-winter conditions. The intent of the proposed standard is not to mandate that all generating units provide capacity in extreme cold weather, but instead to ensure that those units that commits or is obligated to serve Balancing Authority load during periods at or below freezing are subject to the winterization requirements. Additionally, summer units called upon during extreme cold weather emergency contingencies should be able to respond to the Balancing Authority's commitment requests without triggering the requirements. This language ensures that this intent is satisfied for all requirements that follow.

To meet the intent of the recommendation as clarified by FERC staff, a generator is excluded from the requirements if the generator typically is not available at or below freezing conditions for more than a four-hour continuous run. The SDT chose the four-hour timeframe in consideration of generators that typically do not commit during freezing conditions but are running when conditions drop below freezing for a short period of time (under four hours) and would therefore not automatically be subject to the standard. Additionally, such exclusion applies even when such generator is called upon to assist in the mitigation of a declared energy contingency (defined in the NERC Glossary of Terms as a BES Emergency, Capacity Emergency, or Energy Emergency). The language works as a blanket inclusion of all BES generating units that serve Balancing Authority load for a period of more than four hours, with the exception of summer units that are not typically available during non-winter conditions; and the exception includes even those summer peaking units that are committed for a short period during energy contingencies.

Defined Terms

The SDT developed three terms to be added to the NERC Glossary to make the requirements easier to read and understand. These three terms are:

Extreme Cold Weather Temperature

The temperature equal to the lowest 0.2 percentile of the hourly temperatures measured in December, January, and February from 1/1/2000 through the date the temperature is calculated.

[1] See Report, page 189.

The definition of Extreme Cold Weather Temperature was developed by the SDT to provide clarity to the Generator Owner on determining what temperature triggers the requirement obligations. Each Generator Owner should select a reliable source of data from a recording location near the plant to determine their Extreme Cold Weather Temperature. Sources would include, for example, the National Weather Service (NWS) or National Oceanographic and Atmospheric Administration (NOAA) weather stations, Federal Aviation Administration (FAA) weather stations, or Environment and Climate Change Canada location for Canadian entities[2], etc. NOAA's National Centers for Environmental Information provides Climate Data Online (CDO) as a free resource that includes quality-controlled weather data and 30-year Climate Normals[3]. In general, Generator Owners should use the location nearest the plant, but may select a further location if geographic or local climatic patterns make a further location more representative of the weather at the generating unit. Generator Owners may use on-site weather stations if data, which reasonably matches reliable nearby off-site sources since January 1, 2000, is available. The starting period chosen by the SDT to gather data to determine the lowest temperatures that occur near a facility is based on the completion of the modernization of the National Weather Service project known as MAR (Modernization and Associated Restructuring). This project was completed in the year 2000. In general, the National Weather Service modernization provides weather data to be available at most large airports at a 99%+ availability. This will make it fairly accessible for companies to gather data and perform the required analysis. The December through February timeframe was selected to correspond to the meteorological winter, as defined by NOAA.[4]

The SDT discussed methods for determining an Extreme Cold Weather Temperature with engineering design professionals, and it was determined that it is typical engineering practice to use a statistical approach to determine the design temperature when implementing generation facility freeze protection measures. The SDT determined that only winter temperature values (i.e. between December and February) shall be used for the statistical approach and based on analysis of multiple sites, it was determined that by using the lowest 0.2 percentile, there will be sufficient data points to ensure that a single hour at a temperature that may not be accurate, or may be a statistical anomaly, doesn't result in an overly conservative design or preclude the ability of the Generator Owner to use historical operating data to prove compliance to the standards. The SDT selected the 0.2 percentile of winter month temperatures since 1/1/2000 to identify a temperature which has been rarely surpassed, but which allows some margin for a Generator Owner to have previously demonstrated successful operation. The SDT considered using the lowest recorded hourly ambient temperature but, upon further review of the historical weather data and generally accepted design principles, determined that the statistical approach to setting the extreme cold weather temperature for a site was more reasonable.

Generator Cold Weather Critical Component

Any generating unit component or associated fixed fuel supply component, that is under the Generator Owner's control and that is susceptible to freezing issues, the occurrence of which would likely lead to a generating unit(s): (1) forced derate of more than 10% of the total capacity of the unit and exceeding 20 MWs for longer than four hours in duration, (2) a start-up failure where the unit fails to synchronize within a specified start-up time, or (3) a Forced Outage.

The SDT felt the best method to address where freeze protection measures should be implemented was to define a term which specifies a subset of components that may be susceptible to freezing, and are critical to the operation of generating units. A fixed fuel supply component is intended to cover non-mobile equipment that supports the reliable delivery of fuel to the generating unit that is controlled by the Generator Owner. It would include gaseous, liquid, or solid fuel handling components that are installed as fixed parts of the fuel delivery system that are under the Generator Owner's control. It would not include mobile equipment such as trains, bulldozers, or other equipment that are not fixed in one location.

[2] Environment and Climate Change Canada - Canada.ca
[3] https://www.ncei.noaa.gov/products/land-based-station/us-climate-normals
[4] https://www.ncei.noaa.gov/news/meteorological-versus-astronomical-seasons

Generator Cold Weather Reliability Event

One of the following events:

(1) a forced derate of more than 10% of the total capacity of the unit and exceeding 20 MWs for longer than four hours in duration;

(2) a start-up failure where the unit fails to synchronize within a specified start-up time; or

(3) a Forced Outage, for which the apparent cause(s) is due to freezing of equipment within the Generator Owner's control and the dry bulb temperature at the time of the event was at or above the Extreme Cold Weather Temperature.

For more explanation on this definition please see Requirement R6 Technical Rationale Below.

Requirement R1 and R2

R1. *For a generating unit(s) with a commercial operation date subsequent to [Effective Date of this requirement], the Generator Owner shall: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]*

- *Implement freeze protection measures that provide capability to operate for a period of not less than twelve (12) continuous hours at the Extreme Cold Weather Temperature for the unit(s), assuming a concurrent twenty (20) mph wind speed on any exposed Generator Cold Weather Critical Components; or*
- *Explain in a declaration, any technical, commercial, or operational constraints as defined by the Generator Owner that preclude the ability to implement appropriate freeze protection measures to provide capability of operating for twelve (12) hours at the documented Extreme Cold Weather Temperature.*

R2. *For each generating unit(s) in commercial operation prior to [Effective Date of this requirement], the Generator Owner shall ensure its generating unit(s) add new or modify existing freeze protection measures as needed to provide the capability to operate for a period of not less than one (1) hour at the unit(s) Extreme Cold Weather Temperature. Generating unit(s) that are not capable of operating for one (1) hour at its Extreme Cold Weather Temperature shall develop a Corrective Action Plan (CAP) for the identified issues, including identification of any needed modifications to the cold weather preparedness plan required under Requirement R3. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]*

Key Recommendation 1f: To require Generator Owners to retrofit existing generating units, and when building new generating units, to design them to operate to a specified ambient temperature and weather conditions (e.g., wind, freezing precipitation). The specified ambient temperature and weather conditions should be based on available extreme temperature and weather data for the generating unit's location.

General Considerations

As referenced in Key Recommendation 1f above, the specified ambient temperature and weather conditions should be based on available extreme temperature and weather data for the generating unit's location. FERC staff from the Joint Inquiry Report team clarified to the SDT that the reliability goal of the recommendation for existing generating units is to have the necessary freeze protection measures to be able to operate at extreme cold temperatures and weather for the generating unit's location. For example, those measures may consist of existing[5] or new, permanent and/or temporary measures[6] to maintain operation during extreme cold temperatures. Therefore, FERC staff clarified that the joint team's intent of the word retrofit is "to implement new, and/or make modifications to existing freeze protection measures for existing generating units."

In discussions with the Joint Inquiry Report team and in reading the Joint Inquiry Report itself, it is clearly stated that "consideration should be given to designing all new generation plants and designing modifications to existing plants (unless committed solely for summer peaking purposes) to be able to perform at the lowest recorded ambient temperature for the nearest city for which historical weather data is available …)". The Report went on to provide evidence that "Not only did generating units fail to perform at the lowest recorded ambient temperature for the nearest city, but many failed to perform at their own ambient design temperatures". The Joint Inquiry Report also notes that "Over 40 percent of the GOs/GOPs in the south-central U.S. regions where "freezing issues" were identified as the predominant cause of unplanned generation outages, derates or failures to start stated that they did not incorporate specific generator-related recommendations from the 2011 Report[7] or specific recommendations from the Guideline[8]."

Based on the generating unit data contained in the Joint Inquiry Report, many generating units that operate in the winter season are not properly winterized to remain in reliable service during the most extreme cold weather conditions that they may reasonably be expected to experience at their locations. As the load on the grid is the most elevated at these extreme conditions, these are the periods when it is most critical that these generating units maintain their reliability. As such, Requirement 1 ensures that generating units are proactively taking steps to design and maintain their units to maintain their reliability during extreme cold weather.

Requirement R1

The Joint Inquiry Report key recommendation 1f references recommendation 12 of the 2011 report suggesting that consideration should be given to designing all new generation plants and designing modifications to existing plants (unless committed solely for summer peaking purposes) to be able to perform at the lowest recorded ambient temperature for the nearest city for which historical weather data is available. The Joint Inquiry Report states "The Standard Drafting Team can decide what additional specificity is desirable for this requirement, for example, specifying the number of years of weather data to be considered in establishing the required ambient temperature and weather conditions, and the source of the extreme temperature and weather data". The SDT considered several options of how many years back historical data should be analyzed (e.g., 10 years, 30 years, 50 years, 100 years). There is concern that some geographical areas may not have reliable data dating back 100 years. The SDT's meteorological research finds that significant improvements were made and modernization of weather stations implemented in the early years of the 21st century. Given this, the SDT settled on the look back date of January 1, 2000.

The key recommendation identifies wind and freezing precipitation as examples of weather conditions to consider during the design of new generating units and modifications to existing plants. Realizing the many differences in weather that generator sites face across the Regions, the 2021-07 SDT developed language to provide additional context and detail around these weather conditions, while allowing flexibility for site-specific circumstances. The requirement language considers wind at a specific rate when designing new facilities. New units with commercial operation dates after the effective date of EOP-012-1 shall implement freeze protection measures such that their

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[5] While the dictionary definition of the word retrofit includes to install (new or modified parts or equipment) in something previously manufactured or constructed, its origin suggests the need for replacing existing equipment with new technologies, which was not the intent of the joint team in this case. See Merriam-Webster definition.

[6] Some freeze protection measures may need to be removed for summer temperature operation.

[7] Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011

[8] Reliability Guideline Generating Unit Winter Weather Readiness - Current Industry Practices

facilities are capable of continuous operation for not less than 12 hours at the Extreme Cold Weather Temperature assuming a concurrent twenty (20) mph wind speed on any exposed Generator Cold Weather Critical Component.

Because R1 is applicable to newly designed facilities, there is no allowance for a CAP. However, it is recognized that technical, commercial, or operational constraints may exist that prevent a new generating unit(s) from being capable of twelve (12) continuous hours of operation at their identified Extreme Cold Weather Temperature. Thus, the SDT included in R1, the option for the Generator Owner to make a declaration supporting why technical, commercial, or operational constraints preclude the ability to implement appropriate freeze protection measures. The SDT chose 12 hours of continuous operation because it is a typical length of the nighttime in winter and the maximum amount of time that generating units would experience the Extreme Cold Weather Temperature.

Requirement R2

The SDT created a requirement to develop a CAP for generating units in commercial operation prior to the effective date of EOP-012-1 that requires either new freeze protection measures, or modification of existing freeze protection measures, to be capable of one hour of continuous operation at their identified Extreme Cold Weather Temperature. The SDT chose one hour as opposed to 12 hours for existing generation to recognize the fact that it is extremely difficult to perform the same level of design analysis, and/or documented historical operation on existing generation as on new generation. However, it is recognized that modifications or corrective actions may not be feasible under all circumstances due to technical, commercial, or operational constraints.

Additionally, the SDT considered the potential for unintended consequences, such as limiting participation by generation units in cold temperatures or accelerating generator retirements, caused by requirements to develop and implement CAPs to be capable of operations under the conditions defined in R2.

The SDT discussed setting a timeframe needed for the CAP to be completed during the drafting phase. While it is important that the CAP be completed, it would be difficult to set a definite timeframe due to the number of variables that could impact the completion of the CAP once the cause is determined. The requirements five-year implementation plan is focused solely on the development of the CAP, not completion of the CAP. The SDT believes that it is more important to develop a CAP that identifies the solution and resolves the situation correctly regardless of time. Therefore, the team did not define a time when the CAP needs to be completed.

Requirement R3

R3. *Each Generator Owner shall implement and maintain one or more cold weather preparedness plan(s) for its generating units. The cold weather preparedness plan(s) shall include the following, at a minimum: [Violation Risk Factor: High] [Time Horizon: Operations Planning and Real-time Operations]*

3.1 *The Extreme Cold Weather Temperature for their unit(s) including the calculation date and source of temperature data;*

3.2 *Documentation identifying the Generator Cold Weather Critical Components;*

3.3 *Documentation of freeze protection measures implemented on Generator Cold Weather Critical Components which may include measures used to reduce the cooling effects of wind determined necessary by the Generator Owner to protect against heat loss, and where applicable, the effects of freezing precipitation (e.g., sleet, snow, ice, and freezing rain);*

3.4 *Annual inspection and maintenance of generating unit(s) freeze protection measures; and*

3.5 *Generating unit(s) cold weather data, to include:*

3.5.1 *Generating unit(s) operating limitations in cold weather to include:*

3.5.1.1 *Capability and availability;*

3.5.1.2 *Fuel supply and inventory concerns;*

3.5.1.3 *Fuel switching capabilities; and*

3.5.1.4 *Environmental constraints.*

3.5.2 *Generating unit(s) minimum:*

- *Design temperature;*
- *Historical operating temperature; or*
- *Current cold weather performance temperature determined by an engineering analysis.*

General Considerations

Requirement R3 requires Generator Owners to develop and maintain cold weather preparedness plans for its unit(s) and describes the information and documentation required in such plans. It is an expansion of the cold weather preparedness plan required under Requirement R7 of EOP-011-2, and is intended to be used and reviewed regularly by the Generator Owner; R3.4 requires the GO to annually inspect the freeze protection measures. Working in concert with other parts of EOP-012, including R4 and R5, the plan will be regularly reviewed and updated and the GO is required to annually train personnel on its requirements.

Requirement R3 Part 3.1

In R3.1, the Generator Owner is required to determine the Extreme Cold Weather Temperature, as defined in the standard, for each unit using reliable source of data. The SDT believes that the GO is in the best position to select the most representative weather information relative to its generating unit.

Requirement R3 Part 3.2

In R3.2, the Generator Owner identifies the Generator Cold Weather Critical Components to help inform their decision on where to implement appropriate freeze protection measures. The document *Reliability Guideline, Generating Unit Winter Weather Readiness – Current Industry Practices*[9]*,* NERC, 2012 presents a suggested list of components that Generator Owners may choose to utilize when developing their own Generator Cold Weather Critical Component inventory.

Requirement R3 Part 3.3

R3.3 requires GOs to document the freeze protection measures implemented on cold-weather-critical components. These freeze protection measures may include those to reduce the cooling effects of wind. Requirement R3 does not require Generator Owners to install new freeze protection measures to reduce the cooling effects of wind, but rather to document those measures. These measures would include temporary measures such as wind breaks. There is no expectation for entities to list all climate controlled areas as freeze protection measures. Similar to the cooling effects of wind, R3 requires Generator Owners to document freeze protection measures taken to reduce the effects of freezing precipitation on cold-weather-critical components, as the Generator Owners determines is necessary (e.g. water-resistant insulation, protective shielding, insulated boxes, etc.).

Requirement R3 Part 3.4

R3.4 is carried over from the previously approved EOP-011-2 standard, and requires annual inspection and maintenance of the freeze protection measures identified in the cold weather preparedness plan. This requirement ensures these freeze protection measures will be ready and serviceable when needed. Examples of documentation to demonstrate inspections and maintenance has been completed would be completed work order(s) from the

[9] Reliability Guideline Generating Unit Winter Weather Readiness – Current Industry Practices

Generator Owner's work management system and/or freeze protection checklists identifying the measures inspected and maintained.

Requirement R3 Part 3.5

R3.5 is carried over from the previously approved EOP-011-2 standard, and requires the Generator Owner to document several cold weather performance parameters for the unit. This information is valuable, and in some cases, must be shared with other entities. Defining the operating limitations in R3.5.1 will make affected personnel more aware of unit capabilities and constraints as well as systems and practices that may be necessary to ensure reliability in cold weather, particularly when alternative fuels are involved. In addition, the unit minimum temperature identified in R3.5.2 is used to demonstrate compliance with R2 for existing units.

Requirement R4

R4. *Once every five calendar years, each Generator Owner shall for each generating unit: [Violation Risk Factor: Low] [Time Horizon: Operations Planning, Real-Time Operations]*

4.1 *Calculate the Extreme Cold Weather Temperature, and update the cold weather preparedness plan if this temperature is now lower than the previous lowest calculation;*

4.2 *Review its documented generating unit(s) minimum temperature contained within its cold weather preparedness plan(s), pursuant to Part 3.5.2; and*

4.3 *Review whether its generating units have the freeze protection measures required to operate at the Extreme Cold Weather Temperature pursuant to R1 or R2 as applicable, and if not develop a CAP for the identified issues, including identification of any needed modifications to the cold weather preparedness plan required under Requirement R3.*

The SDT has developed the new standard with language that supports the ongoing consideration of new technologies when protecting against extreme cold weather, and an ongoing review requirement to validate or update the Extreme Cold Weather Temperature associated with each unit. This five-year review supports the desire for Generator Owners to periodically vet these new technologies and consider whether any technical, commercial, or operational constraints are still applicable.

Requirement R5

R5. *Each Generator Owner in conjunction with its Generator Operator shall identify the entity responsible for providing the generating unit-specific training, and that identified entity shall provide annual training to its maintenance or operations personnel responsible for implementing cold weather preparedness plan(s) developed pursuant to Requirement R3. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]*

<u>Key Recommendation 1e:</u> To revise EOP-011-2, R8, to require Generator Owners and Generator Operators to conduct annual unit-specific cold weather preparedness plan training.

Project 2019-06 Cold Weather established the requirement that the Generator Owner, in conjunction with its Generator Operator, would provide generating unit-specific training for its personnel responsible for implementing cold weather preparedness plan(s) for its generating units. The Joint Inquiry Report recommended that EOP-011-2 R8 be revised to require the generating unit-specific training be provided on an "annual" basis. The report explains "Responses from the GOs/GOPs involved in the Event show that annual training is not yet universal in the Event Area." To address this recommendation, the SDT has utilized the existing language in EOP-011-2 and added the word "annual" to require the training on an annual basis. The requirement is deleted from EOP-011-3, and will be placed as a requirement in a new EOP-012-1 Reliability Standard dedicated solely to extreme cold weather preparedness.

Requirement R6

R6. *Each Generator Owner that owns a generating unit that experiences a Generator Cold Weather Reliability Event shall develop a CAP, within 150 days or by July 1, whichever is earlier, that contains at a minimum: [Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

6.1 *A summary of the identified cause(s) for the Generator Cold Weather Reliability Event where applicable and any relevant associated data;*

6.2 *A review of applicability to similar equipment at other generating units owned by the Generator Owner;*

6.3 *An identification of any temporary operating limitations or impacts to the cold weather preparedness plan, that would apply until execution of the corrective action(s) identified in the CAP.*

Key Recommendation 1d: To require Generator Owners that experience outages, failures to start, or derates due to freezing to review the generating unit's outage, failure to start, or derate and develop and implement a corrective action plan (CAP) for the identified equipment, and evaluate whether the CAP applies to similar equipment for its other generating units. Based on the evaluation, the Generator Owner will either revise its cold weather preparedness plan to apply the CAP to the similar equipment, or explain in a declaration (a) why no revisions to the cold weather preparedness plan are appropriate, and (b) that no further corrective actions will be taken. The standard drafting team should specify the specific timing for the CAP to be developed and implemented after the outage, derate, or failure to start, but the CAP should be developed as quickly as possible, and be completed by no later than the beginning of the next winter season.

The key recommendation from the report recommends a standard the requires Generator Owners to develop a CAP for generating units that experience outages, failures to starts, or derates due to freezing. The Report identifies that most of the outages and derates in the February 2021 event were due to freezing of instrumentation, transmitters, sensing lines, or wind turbine blades (p 166 in report). As such, the team followed the Report recommendation to require a CAP when the apparent cause of the event is freezing. The Project 2021-07 SDT has developed parameters around these events to clarify a reasonable baseline of what level of de-rate qualifies as an event, and provide additional language to identify what constitutes a start-up failure. With the additional clarifications, the SDT determined that the standard would benefit from a defined term, to clearly and efficiently state what constitutes an event. The result is to a new defined term, Generator Cold Weather Reliability Event, that defines the circumstances for which a CAP is required (i.e., when a freezing event effects the equipment within the control of the Generator Owner). The defined term will make the standard easier to understand and implement by providing clear and reasonable factors to determine whether the impact of an event requires mitigation.

General Considerations for All CAPs

To simplify the proposed requirements related to creating a CAP, the SDT has modified the proposed requirements addressing the need for a CAP while better incorporating the NERC Definition of a CAP. The CAP definition reads "A list of actions and an associated timetable for implementation to remedy a specific problem." As written, the definition requires two parts for a document to qualify as a CAP, i.e., a list of items to be addressed and a timeline for completion. In the original posting, the SDT included both items in separate bullets to be included in the CAP. To simplify the requirements, the SDT has removed the bullets. As these two elements are both required for a document to qualify as a CAP, there is no need to list these items separately within the standard. A CAP without both a list of actions and the timeline to implement is not complete.

Requirement R6

The CAP requirement applies to any forced outage due to freezing, regardless of duration. Derates, which are short-lived (specified as 4 hours by the SDT) or of small capacity impact (specified as less than 20 MW by the SDT, which corresponds with the threshold for BES impacting Generation units), are excluded from the CAP requirement to limit the administrative burden to Generator Owners for events that are minimally impacting to the BES. It should be noted that nothing in this standard prevents a Generator Owner from taking its own corrective actions resulting from such events. Startup failures are defined using the GADS definition with the removal of “following an outage or reserve shutdown”, since the definition of Reserve shutdown is different in GADS than it is in some of the RTO’s.

R6 requires the Generator Owner to act within 150 days or by July 1 to develop the CAP. These timeframe options were chosen by the SDT to allow Generator Owner’s to review multiple events holistically following a winter season if that scenario occurs, and create one CAP for components with common failure causes.

The SDT determined that CAPs will be required for any freezing event that occurs at temperatures above the site’s Extreme Cold Weather Temperature. By using the site’s Extreme Cold Weather Temperature as opposed to the Generator Unit Minimum Temperature as defined by the Generator Owner as the threshold, this achieves the following:

- Provides a consistent basis for the temperature at which CAPS are required for all Generator Owners
- Provides a consistent basis for when CAPS are required for all Generation types
- Provides a consistent basis for when CAPS are required regardless of the level of effort that Generators may have applied to-date winterizing their generators such that they can operate to the Extreme Cold Weather Temperature that their sites will reasonably experience
- Removes any incentive (perceived or real) to not further winterize Generator Owner’s sites to meet the Extreme Cold Weather temperature at the Generator Owner site by not providing a window where one site might not be subject to the CAP requirement while sites in the same vicinity experiencing the same temperatures are subject to this requirement
- Removes any disincentive for Generator Owner’s to design the units to operate well below the Extreme Cold Weather Temperature for a site by not requiring them to perform CAPs while sites in the same vicinity experiencing the same temperatures are subject to this requirement

Requirement R7

R7. Each Generator Owner shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

7.1 Implement each CAP developed pursuant to Requirements R2, R4, or R6, or explain in a declaration why corrective actions are not being implemented due to any technical, commercial, or operational constraints as defined by the Generator Owner.

7.2 Update each CAP if actions or timetables change, until completed.

The SDT has also separated the requirement to implement a CAP from the requirement to create a CAP. This is similar in structure to PRC-004-6 R5 and R6. For CAPs developed pursuant to Requirements R2, R4, and R6 in the proposed standard, the Generator Owner creates a document with a date of approximately the time of the event/determination of the need to make changes. This shows that the Generator Owner identified issues caused by cold weather. Implementation of the CAP is demonstrated through updates to the original document or completion of the tasks listed in the CAP under a separate requirement. The separation of these distinct functions facilitates administration of the process and makes it less likely for a CAP to be written but not implemented. Requirement R7 also defines the requirement to make a declaration when technical, commercial, or operational constraints are asserted.

NERC

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Calculating Extreme Cold Weather Temperature

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3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
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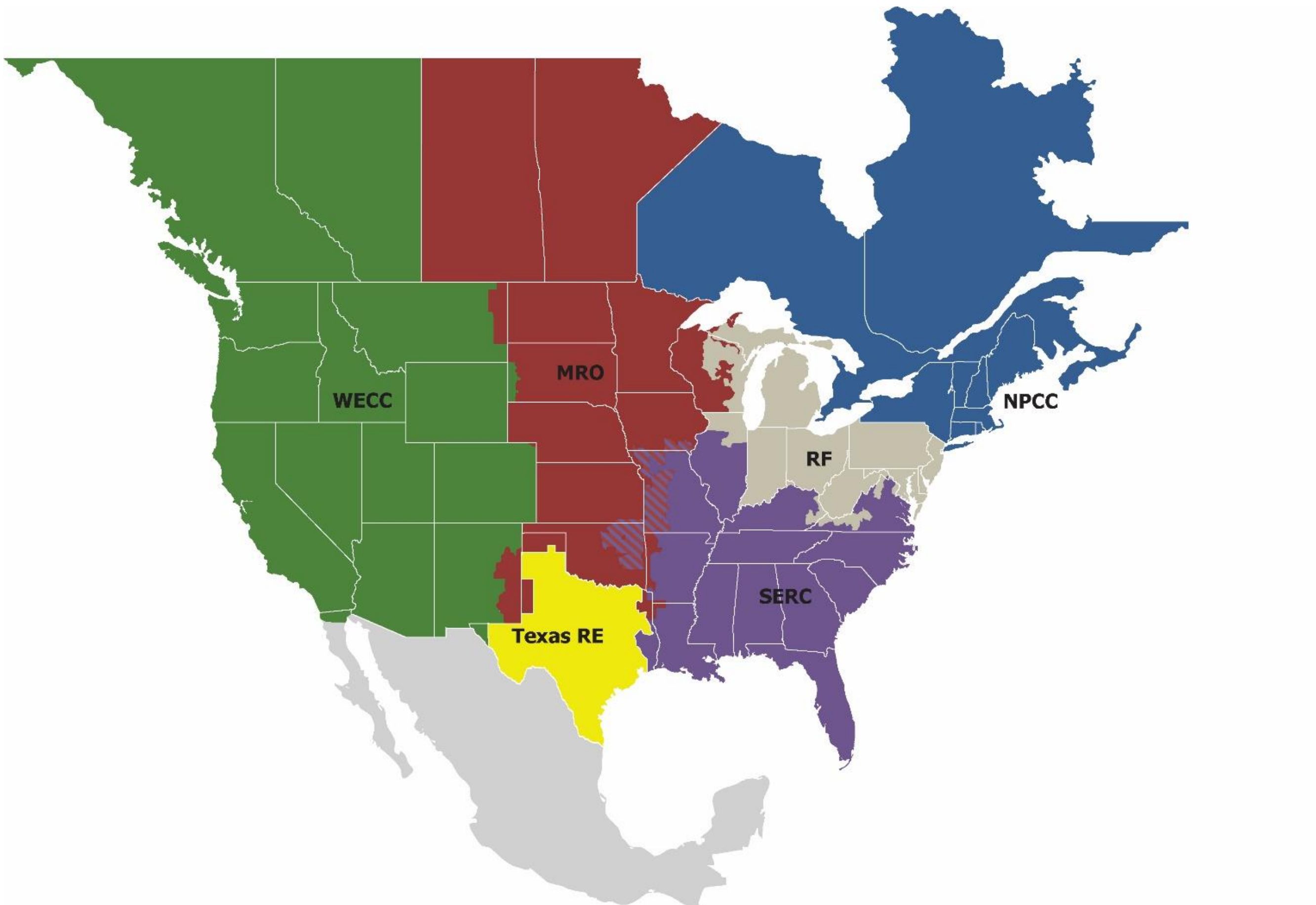
Preface

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 Entity boundaries as shown in the map and 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

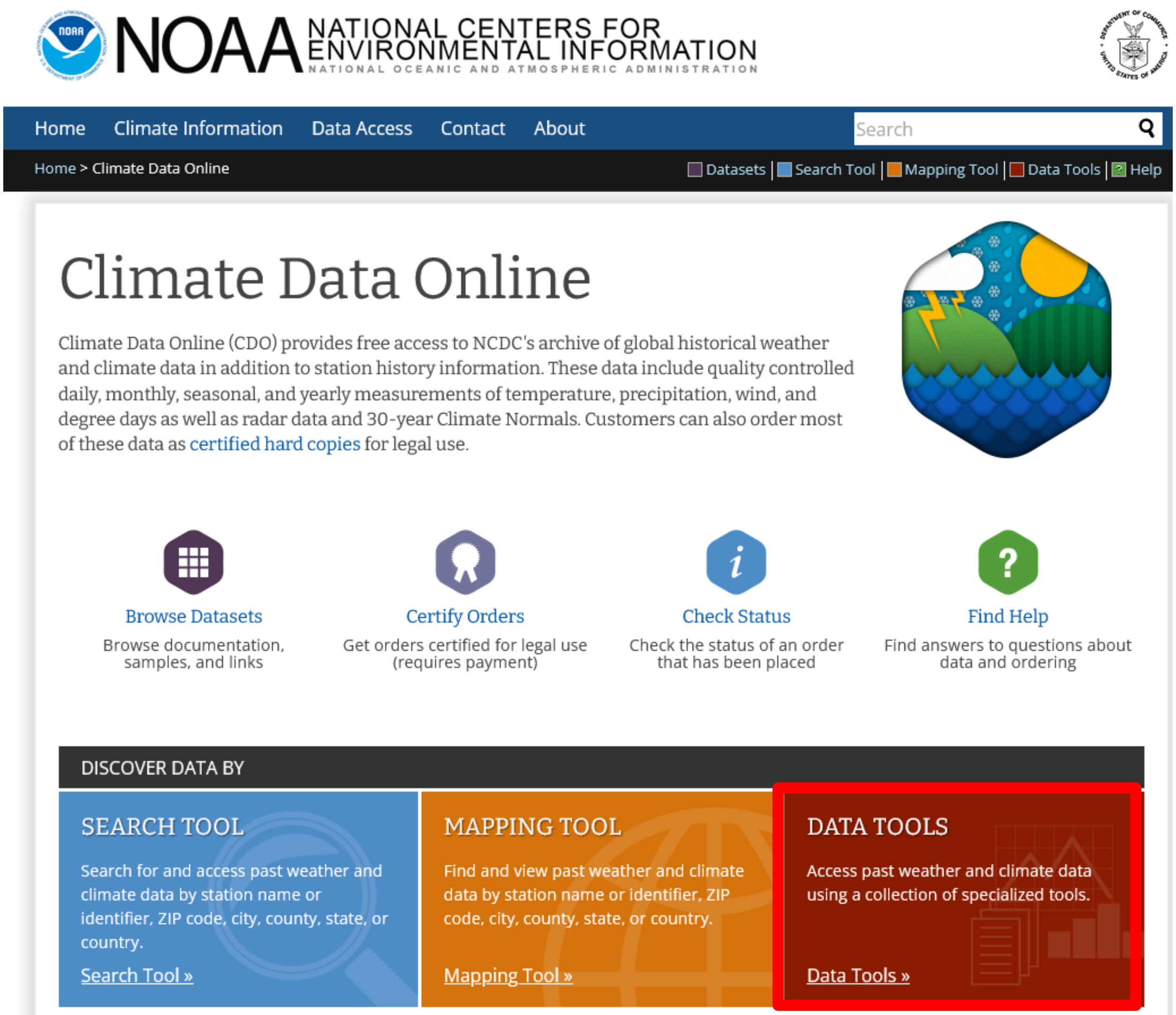
This document will demonstrate one method for acquiring the necessary data for a given location and a method of performing the statistical analysis of the data to determine the Extreme Cold Weather Temperature for a given location. This example is focused on United States and will use data obtained from NOAA's Climate Data Online database and perform the statistical analysis with Microsoft Excel. The method shown in this document only shows the collection of data from a single source and two methods of analyzing this data, both using Microsoft Excel.

Determination of Location’s Extreme Cold Weather Temperature

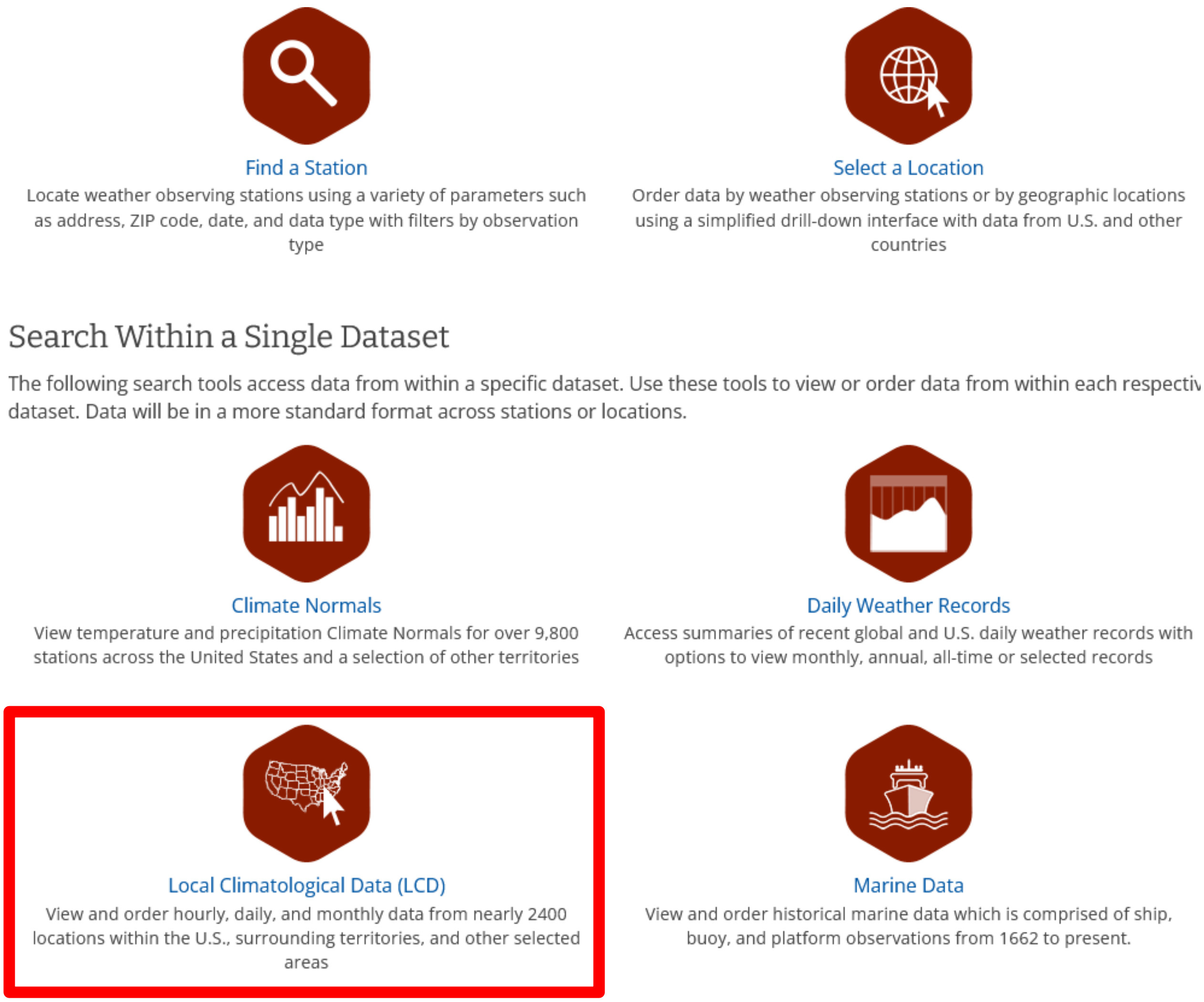
Gathering the Data

Navigate to https://www.ncdc.noaa.gov/cdo-web/

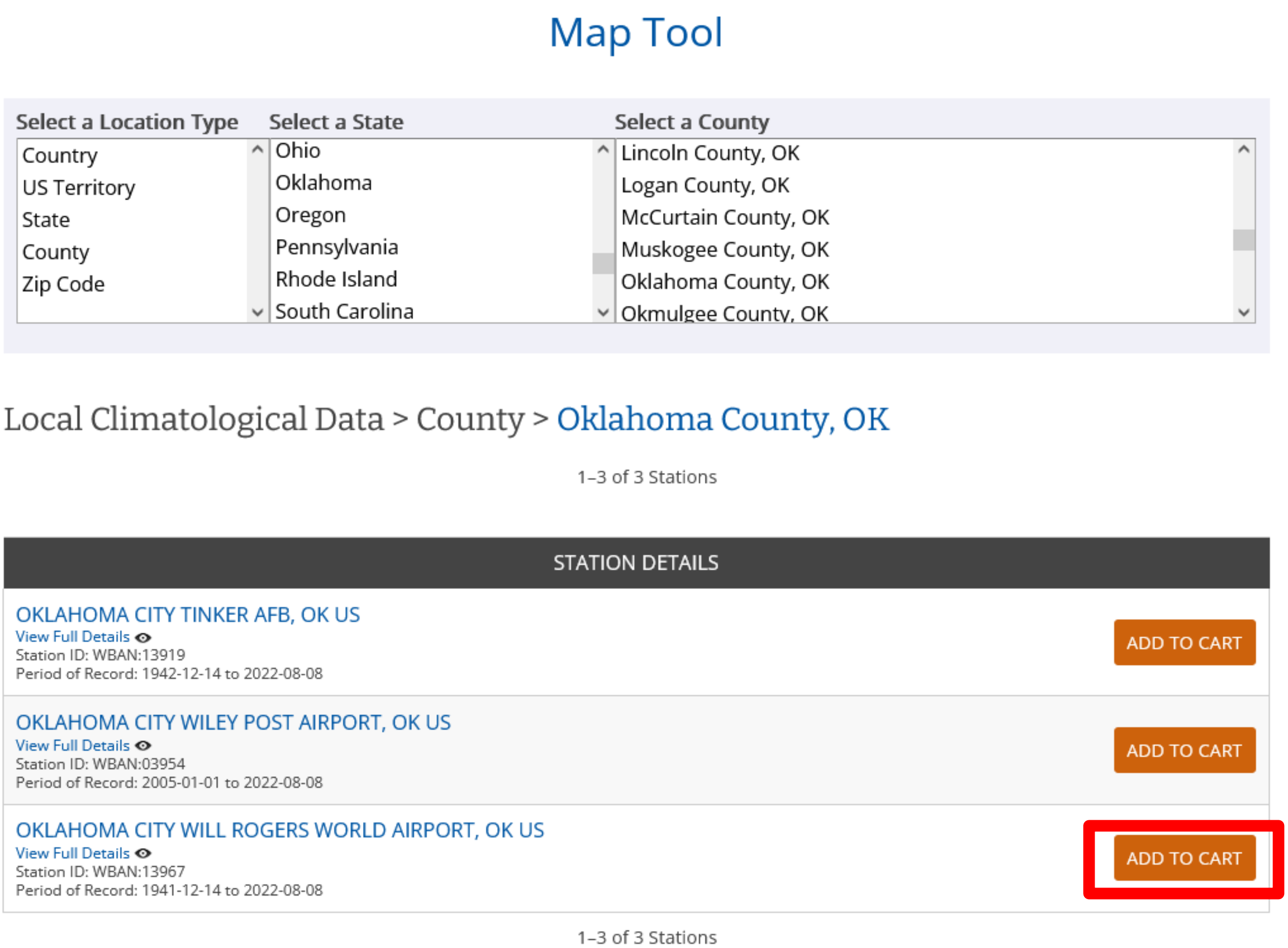
1. Select **Data Tools.**



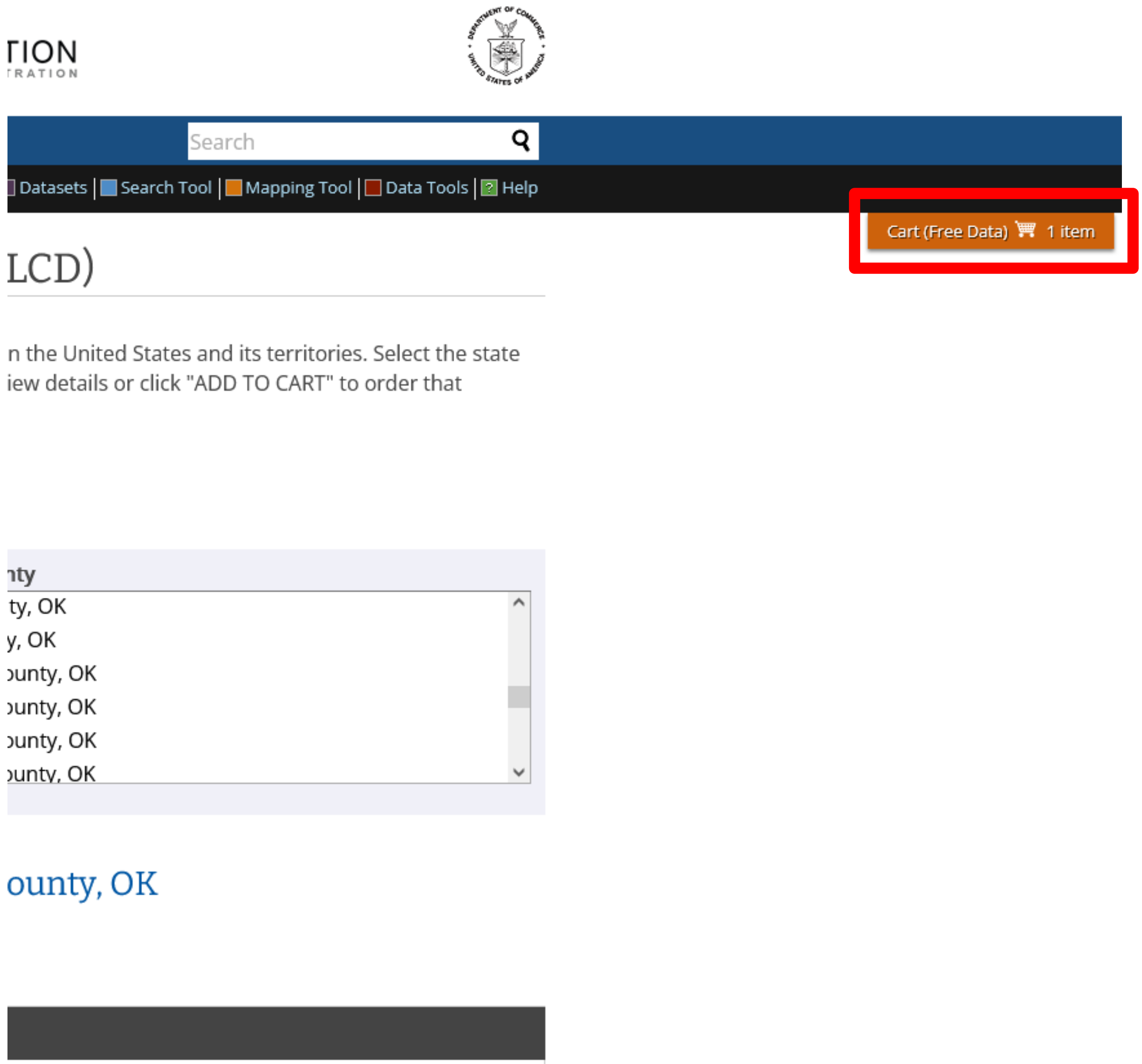
2. Scroll down if necessary and select **Local Climatological Data (LCD).**



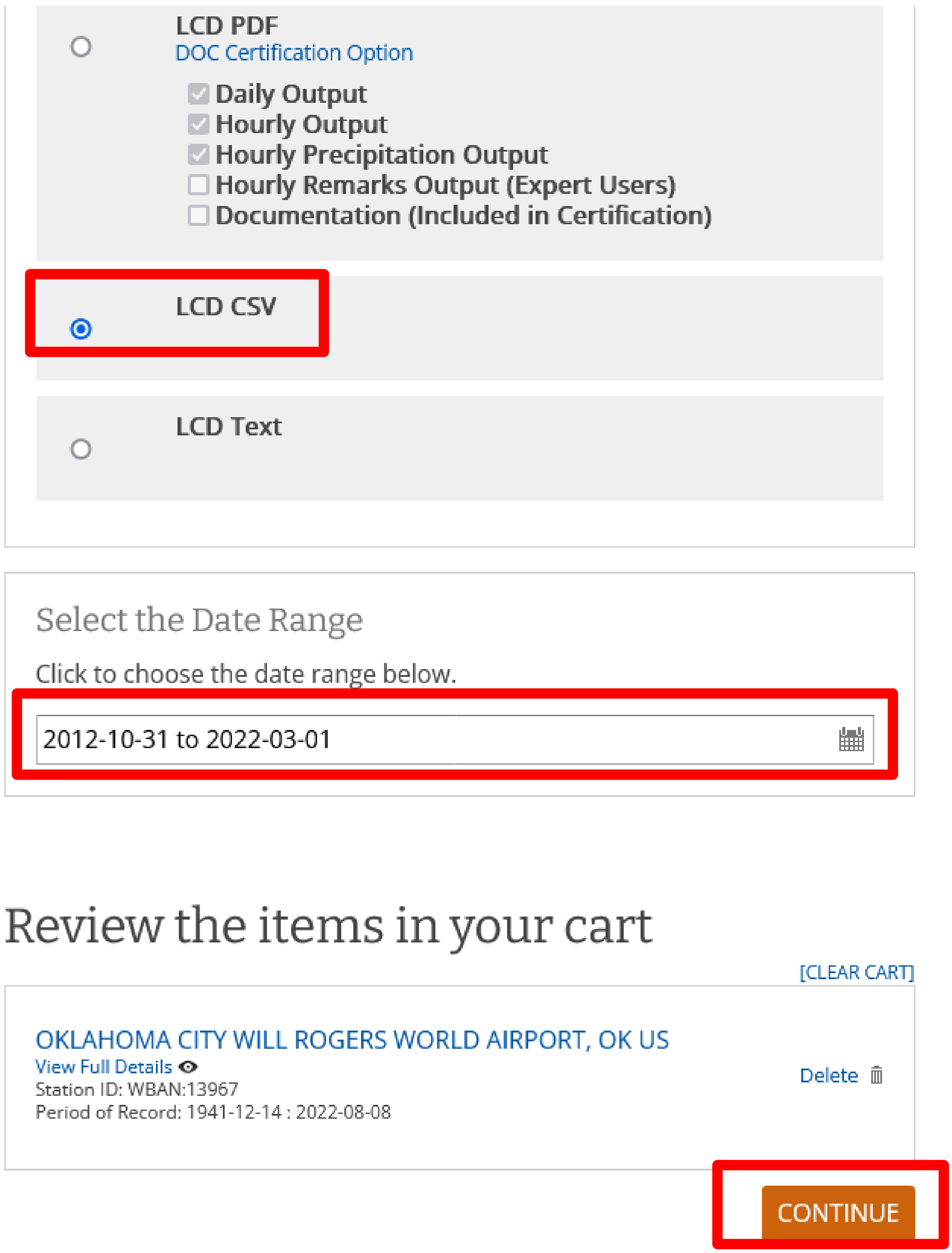
3. Use the selection tool to find a weather station appropriate for your location and click ADD TO CART.



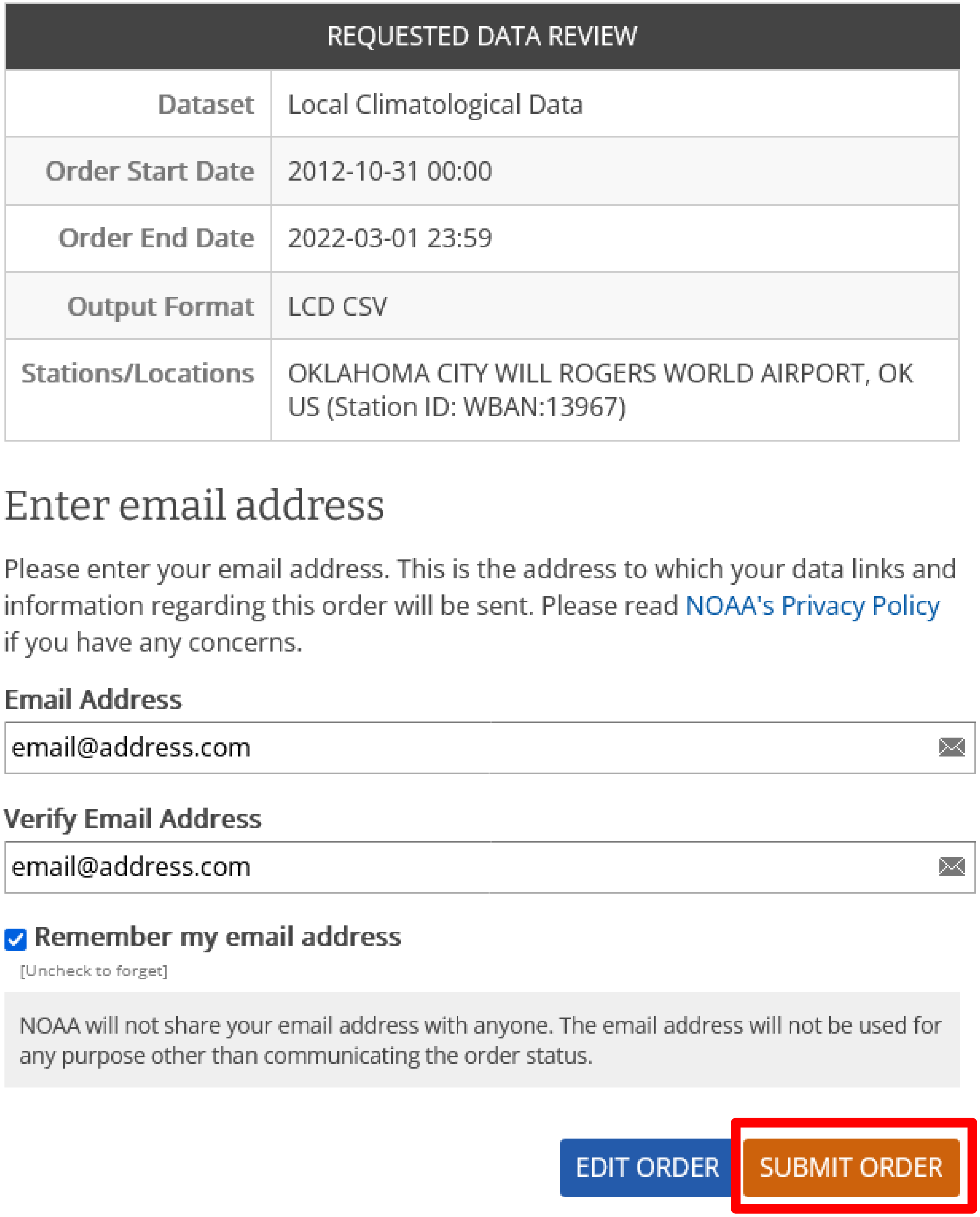
4. Click on the **cart icon** in the upper right-hand portion of the page.



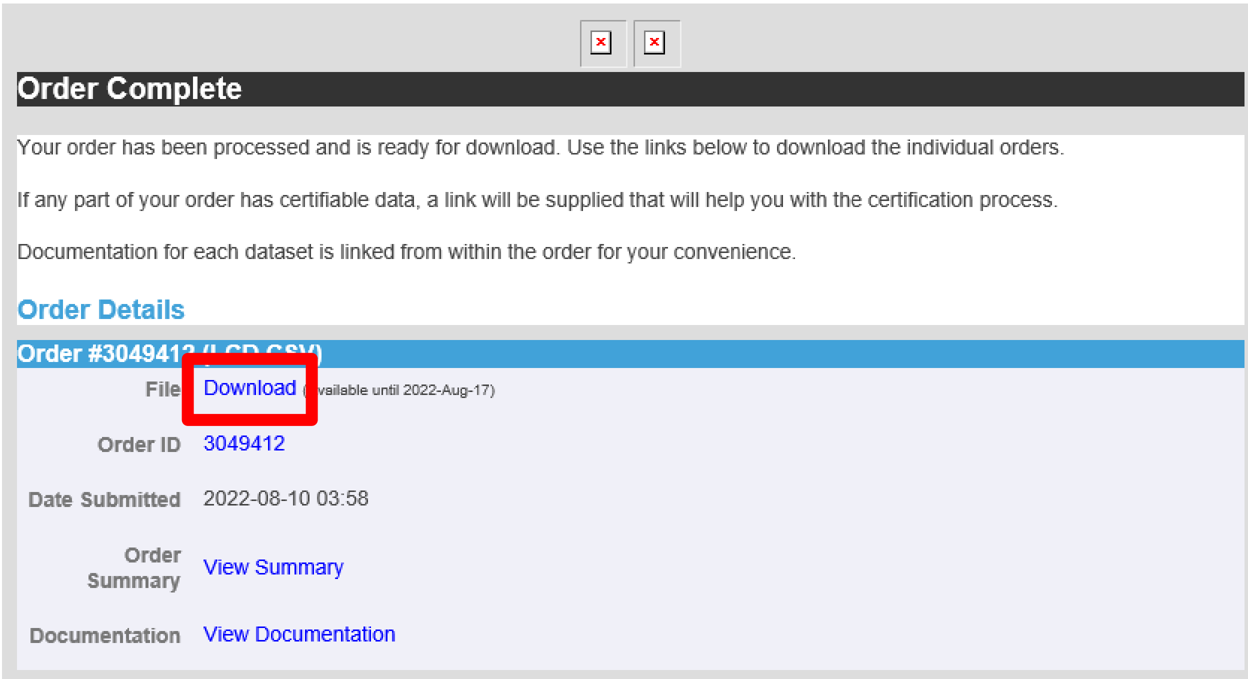
5. Select LCD CSV, your desired date range, and then click continue. (Note: date ranges must be less than 10 years, so this process might have to be repeated several times and multiple files combined into one in order to get all data necessary to perform the analysis to determine the Extreme Cold Weather Temperature)



6. Enter and verify your email address and click **Submit Order.** You will receive an email when your request has been processed and is ready to download.



7. Click **Download** in the email that you will receive from NOAA to download your dataset.



Analyzing the Data

Option 1

1. Open the .csv file that was downloaded using the previous steps (and combine with other .csv files as necessary to cover the required date range).

2. Add filters to the first row and filter on "Report Type", column C, to only show report type FM-15, this is the standard METAR data.

STATION	DATE	REPORT	SOURCE	AWND	Backup	Backup	Backup	Backup	Backup	Backup	Backup	Backup
72353013967	2012-10-31T00:52:00	FM-15	7									
72353013967	2012-10-31T01:52:00	FM-15	7									
72353013967	2012-10-31T02:52:00	FM-15	7									
72353013967	2012-10-31T03:52:00	FM-15	7									
72353013967	2012-10-31T04:52:00	FM-15	7									
72353013967	2012-10-31T05:52:00	FM-15	7									
72353013967	2012-10-31T06:52:00	FM-15	7									
72353013967	2012-10-31T07:52:00	FM-15	7									
72353013967	2012-10-31T08:52:00	FM-15	7									
72353013967	2012-10-31T09:52:00	FM-15	7									
72353013967	2012-10-31T10:52:00	FM-15	7									
72353013967	2012-10-31T11:52:00	FM-15	7									
72353013967	2012-10-31T12:52:00	FM-15	7									
72353013967	2012-10-31T13:52:00	FM-15	7									
72353013967	2012-10-31T14:52:00	FM-15	7									
72353013967	2012-10-31T15:52:00	FM-15	7									
72353013967	2012-10-31T16:52:00	FM-15	7									
72353013967	2012-10-31T17:52:00	FM-15	7									
72353013967	2012-10-31T18:52:00	FM-15	7									
72353013967	2012-10-31T19:52:00	FM-15	7									
72353013967	2012-10-31T20:52:00	FM-15	7									
72353013967	2012-10-31T21:52:00	FM-15	7									
72353013967	2012-10-31T22:52:00	FM-15	7									
72353013967	2012-10-31T23:52:00	FM-15	7									
72353013967	2012-11-01T00:52:00	FM-15	7									
72353013967	2012-11-01T01:52:00	FM-15	7									
72353013967	2012-11-01T02:52:00	FM-15	7									
72353013967	2012-11-01T03:52:00	FM-15	7									
72353013967	2012-11-01T04:52:00	FM-15	7									
72353013967	2012-11-01T05:52:00	FM-15	7									

3. Select the Date column, column B, by clicking on the column, scroll over to the HourlyDryBulbTemperature column, column AS, and holding down the CTRL key, select that column. Copy and paste both columns into a new sheet named "Clean and Filter".

DATE	HourlyDryBulbTemperature
2012-10-31T00:52:00	52
2012-10-31T01:52:00	51
2012-10-31T02:52:00	50
2012-10-31T03:52:00	47
2012-10-31T04:52:00	46
2012-10-31T05:52:00	46
2012-10-31T06:52:00	44
2012-10-31T07:52:00	48
2012-10-31T08:52:00	52
2012-10-31T09:52:00	57
2012-10-31T10:52:00	61
2012-10-31T11:52:00	65
2012-10-31T12:52:00	67
2012-10-31T13:52:00	68
2012-10-31T14:52:00	71
2012-10-31T15:52:00	71
2012-10-31T16:52:00	70
2012-10-31T17:52:00	66
2012-10-31T18:52:00	62
2012-10-31T19:52:00	59
2012-10-31T20:52:00	54
2012-10-31T21:52:00	51
2012-10-31T22:52:00	52
2012-10-31T23:52:00	52
2012-11-01T00:52:00	53

4. Using the data on the "Clean and Filter" sheet, type **Month** in column C1, type the formula "=mid(A2,6,2)" in cell C2, and copy that formula in column C to the last row of the data set. Then Filter month to only show months 1, 2, 12 (January, February, and December).

5. You can then filter by HourlyDryBulbTemperature (Column B) to find and address bad data as appropriate. Now Select, Copy, and Paste the remaining data to a new sheet named ECWT.

	A	B	C	D
1	DATE	HourlyDryBulbTemperatur	Month	
747	2012-12-01T00:52:00	58	12	
748	2012-12-01T01:52:00	58	12	
749	2012-12-01T02:52:00	59	12	
750	2012-12-01T03:52:00	59	12	
751	2012-12-01T04:52:00	58	12	
752	2012-12-01T05:52:00	59	12	
753	2012-12-01T06:52:00	58	12	
754	2012-12-01T07:52:00	60	12	
755	2012-12-01T08:52:00	61	12	
756	2012-12-01T09:52:00	63	12	
757	2012-12-01T10:52:00	66	12	
758	2012-12-01T11:52:00	71	12	
759	2012-12-01T12:52:00	74	12	
760	2012-12-01T13:52:00	75	12	
761	2012-12-01T14:52:00	77	12	
762	2012-12-01T15:52:00	76	12	
763	2012-12-01T16:52:00	73	12	
764	2012-12-01T17:52:00	67	12	
765	2012-12-01T18:52:00	64	12	
766	2012-12-01T19:52:00	63	12	
767	2012-12-01T20:52:00	58	12	
768	2012-12-01T21:52:00	61	12	
769	2012-12-01T22:52:00	52	12	
770	2012-12-01T23:52:00	50	12	
771	2012-12-02T00:52:00	48	12	
772	2012-12-02T01:52:00	46	12	
773	2012-12-02T02:52:00	45	12	
774	2012-12-02T03:52:00	43	12	
775	2012-12-02T04:52:00	44	12	
776	2012-12-02T05:52:00	43	12	

6. Using Excel's built in Percentile function, the Extreme Cold Weather Temperature (ECWT) can now be determined. While on the ECWT sheet, in a blank cell use the function "=PERCENTILE.INC()" and select all temperature data in Column B (HourlyDryBulbTemperature) on the "ECWT" sheet and use 0.002 for the percentile value. The formula will look similar to this, "=PERCENTILE.INC(B:B,0.002)" (using 0.002 for the second argument in this function returns the two-tenths percentile temperature of the hourly temperatures measured in the dataset used).

   <u>This value should be representative of the Extreme Cold Weather Temperature based on the given dataset.</u>

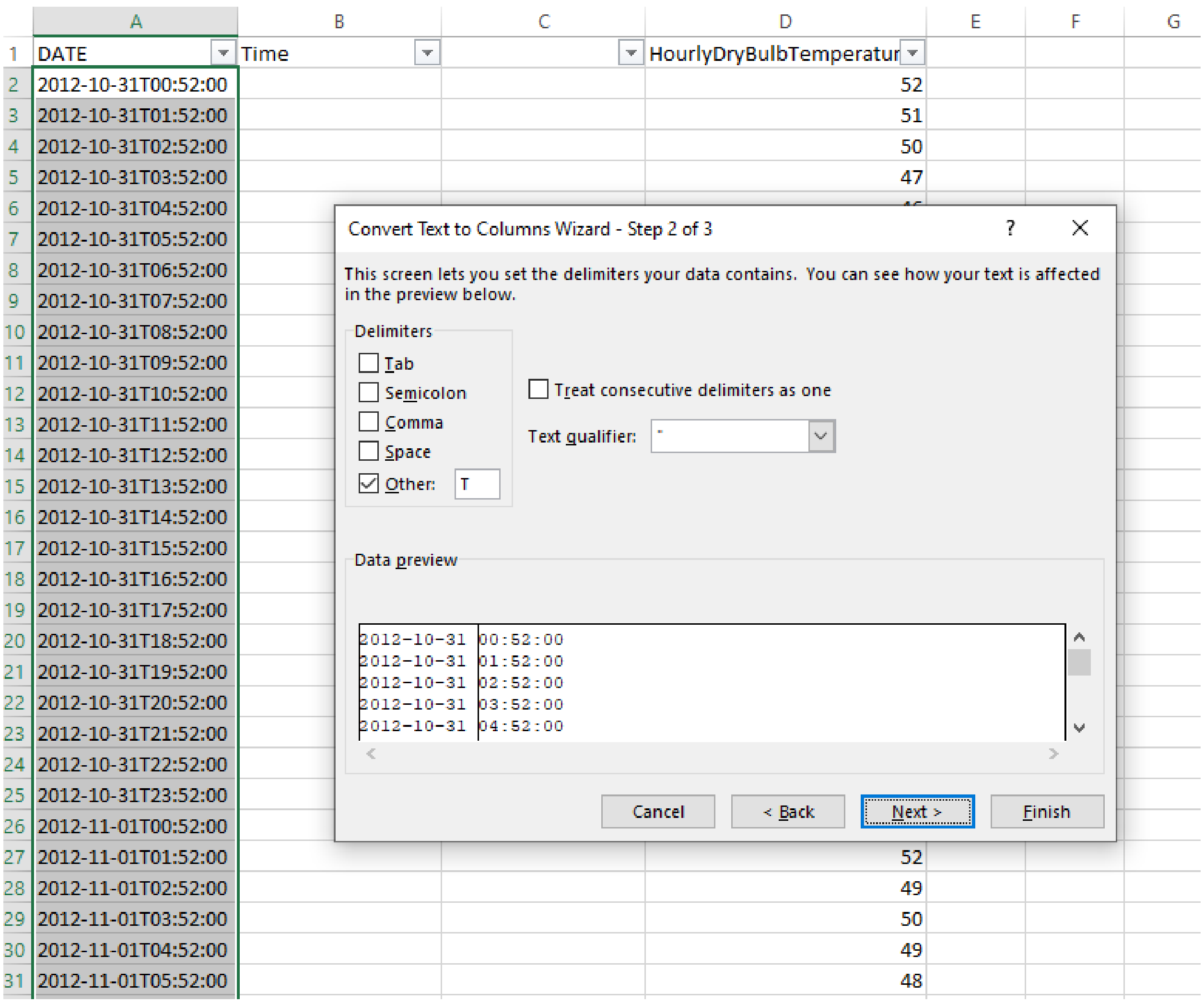
E5 | =PERCENTILE.INC(B:B,0.002)

	A	B	C	D	E	F	G
1	DATE	HourlyDryBulbTemperature	Month				
2	2012-12-01T00:52:00	58	12				
3	2012-12-01T01:52:00	58	12				
4	2012-12-01T02:52:00	59	12		ECWT		
5	2012-12-01T03:52:00	59	12		2		
6	2012-12-01T04:52:00	58	12				
7	2012-12-01T05:52:00	59	12				
8	2012-12-01T06:52:00	58	12				
9	2012-12-01T07:52:00	60	12				
10	2012-12-01T08:52:00	61	12				
11	2012-12-01T09:52:00	63	12				
12	2012-12-01T10:52:00	66	12				
13	2012-12-01T11:52:00	71	12				
14	2012-12-01T12:52:00	74	12				
15	2012-12-01T13:52:00	75	12				
16	2012-12-01T14:52:00	77	12				
17	2012-12-01T15:52:00	76	12				
18	2012-12-01T16:52:00	73	12				
19	2012-12-01T17:52:00	67	12				

Option 2

These next few steps demonstrate how to view the distribution of temperatures from the data set and obtain the Extreme Cold Weather Temperature by a slightly different method.

1. On the "Clean and Filter" sheet, insert two new columns between column A and column B. Select column A and use Excel's *Text to Columns* feature and selected the delimited option and use the letter "T" to split the date data into a date component and a time component by hitting "Next" and "Finish".



2. Add in column C, add the date in column A to time in column B, and copy this formula for all rows of the data set.

C2 | =A2+B2

	A	B	C	D
1	DATE	Time	Date/Time	HourlyDryBulbTemperatur
2	10/31/2012	0:52:00	10/31/2012 0:52	52
3	10/31/2012	1:52:00	10/31/2012 1:52	51
4	10/31/2012	2:52:00	10/31/2012 2:52	50
5	10/31/2012	3:52:00	10/31/2012 3:52	47
6	10/31/2012	4:52:00	10/31/2012 4:52	46
7	10/31/2012	5:52:00	10/31/2012 5:52	46
8	10/31/2012	6:52:00	10/31/2012 6:52	44
9	10/31/2012	7:52:00	10/31/2012 7:52	48
10	10/31/2012	8:52:00	10/31/2012 8:52	52
11	10/31/2012	9:52:00	10/31/2012 9:52	57
12	10/31/2012	10:52:00	10/31/2012 10:52	61
13	10/31/2012	11:52:00	10/31/2012 11:52	65
14	10/31/2012	12:52:00	10/31/2012 12:52	67
15	10/31/2012	13:52:00	10/31/2012 13:52	68
16	10/31/2012	14:52:00	10/31/2012 14:52	71
17	10/31/2012	15:52:00	10/31/2012 15:52	71
18	10/31/2012	16:52:00	10/31/2012 16:52	70
19	10/31/2012	17:52:00	10/31/2012 17:52	66
20	10/31/2012	18:52:00	10/31/2012 18:52	62
21	10/31/2012	19:52:00	10/31/2012 19:52	59
22	10/31/2012	20:52:00	10/31/2012 20:52	54
23	10/31/2012	21:52:00	10/31/2012 21:52	51

3. Type Month in cell E1, and in cell E2 use the formula "=month(C2)". Copy the formula for all rows of the data set, then filter based on month, only selecting 1,2,12 for the desired months. Then copy remaining data from column C and column D to a sheet named Histogram.

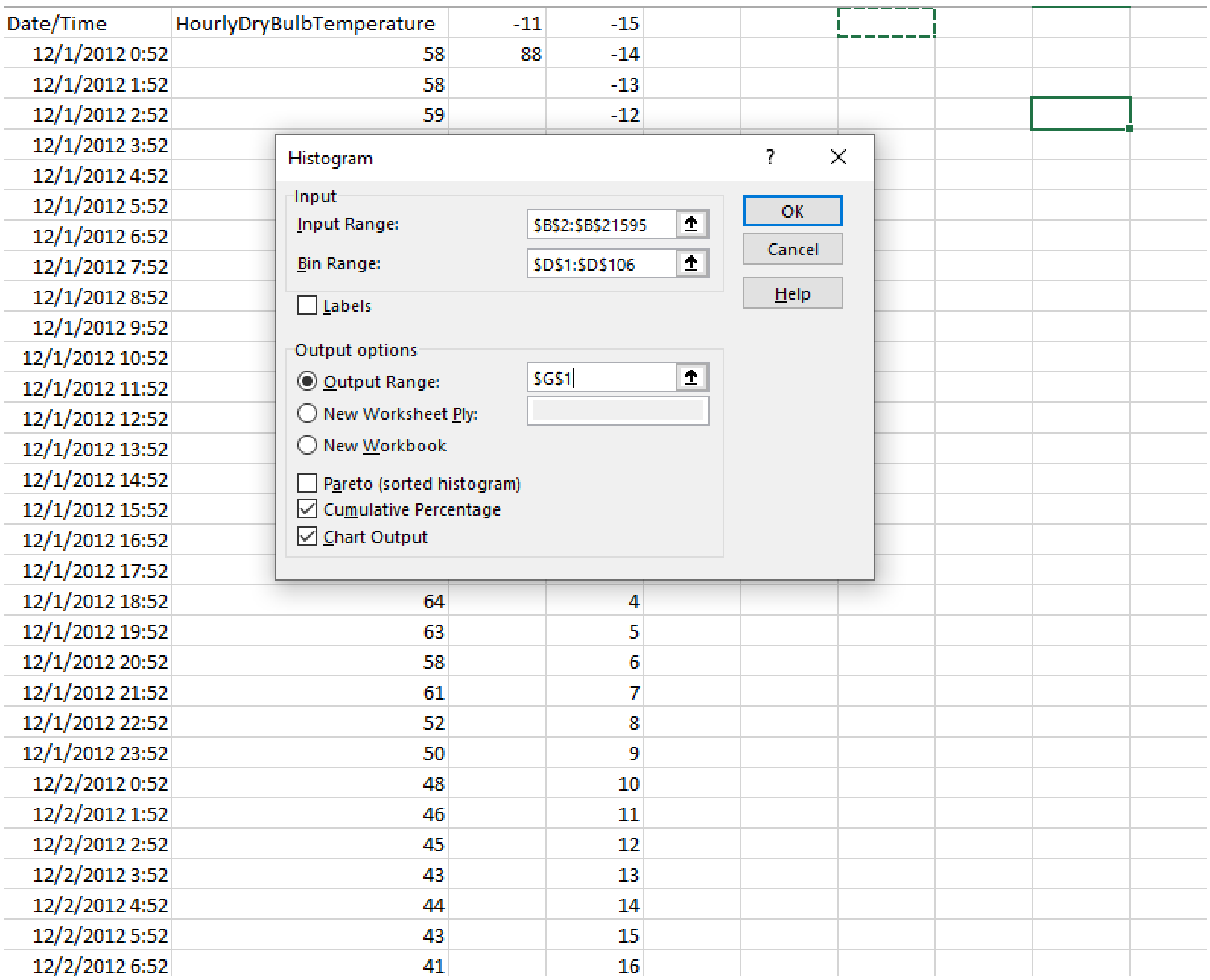
E747 =MONTH(C747)

	A	B	C	D	E	F	G
1	DATE	Time	Date/Time	HourlyDryBulbTemperatur	month		
747	12/1/2012	0:52:00	12/1/2012 0:52	58	12		
748	12/1/2012	1:52:00	12/1/2012 1:52	58	12		
749	12/1/2012	2:52:00	12/1/2012 2:52	59	12		
750	12/1/2012	3:52:00	12/1/2012 3:52	59	12		
751	12/1/2012	4:52:00	12/1/2012 4:52	58	12		
752	12/1/2012	5:52:00	12/1/2012 5:52	59	12		
753	12/1/2012	6:52:00	12/1/2012 6:52	58	12		
754	12/1/2012	7:52:00	12/1/2012 7:52	60	12		
755	12/1/2012	8:52:00	12/1/2012 8:52	61	12		
756	12/1/2012	9:52:00	12/1/2012 9:52	63	12		
757	12/1/2012	10:52:00	12/1/2012 10:52	66	12		
758	12/1/2012	11:52:00	12/1/2012 11:52	71	12		
759	12/1/2012	12:52:00	12/1/2012 12:52	74	12		
760	12/1/2012	13:52:00	12/1/2012 13:52	75	12		
761	12/1/2012	14:52:00	12/1/2012 14:52	77	12		
762	12/1/2012	15:52:00	12/1/2012 15:52	76	12		
763	12/1/2012	16:52:00	12/1/2012 16:52	73	12		
764	12/1/2012	17:52:00	12/1/2012 17:52	67	12		
765	12/1/2012	18:52:00	12/1/2012 18:52	64	12		

4. On the Histogram sheet, enter "=min(B:B)" in cell C1, and "=max(B:B)" in cell C2. This will give you the minimum and maximum temperatures in the dataset. We will use the temperatures to set range for this histogram. In Column D start with a value, a few degrees below the min, then list every degree to a few degrees above the max.

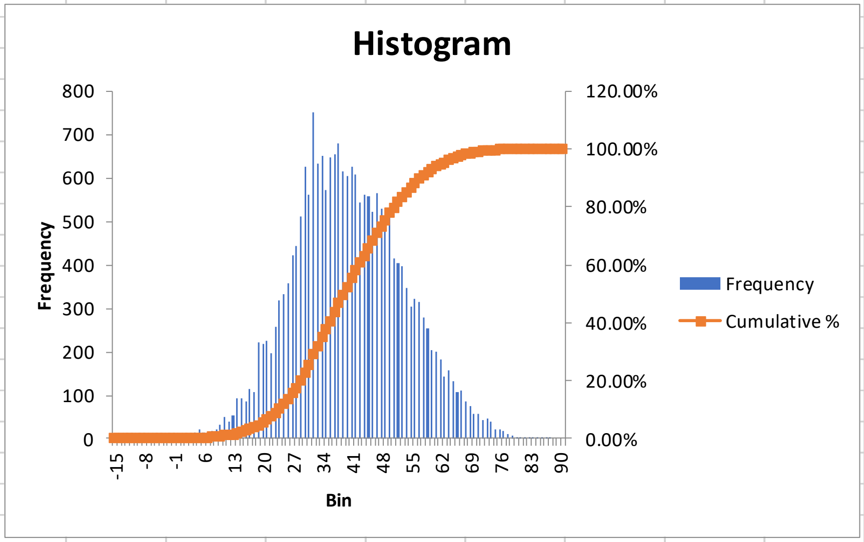
Date/Time	HourlyDryBulbTemperature	-11	-15	
12/1/2012 0:52	58	88	-14	
12/1/2012 1:52	58		-13	
12/1/2012 2:52	59		-12	
12/1/2012 3:52	59		-11	
12/1/2012 4:52	58		-10	
12/1/2012 5:52	59		-9	
12/1/2012 6:52	58		-8	
12/1/2012 7:52	60		-7	
12/1/2012 8:52	61		-6	
12/1/2012 9:52	63		-5	
12/1/2012 10:52	66		-4	
12/1/2012 11:52	71		-3	
12/1/2012 12:52	74		-2	
12/1/2012 13:52	75		-1	
12/1/2012 14:52	77		0	
12/1/2012 15:52	76		1	
12/1/2012 16:52	73		2	
12/1/2012 17:52	67		3	
12/1/2012 18:52	64		4	
12/1/2012 19:52	63		5	
12/1/2012 20:52	58		6	
12/1/2012 21:52	61		7	
12/1/2012 22:52	52		8	
12/1/2012 23:52	50		9	
12/2/2012 0:52	48		10	
12/2/2012 1:52	46		11	
12/2/2012 2:52	45		12	
12/2/2012 3:52	43		13	
12/2/2012 4:52	44		14	
12/2/2012 5:52	43		15	
12/2/2012 6:52	41		16	
12/2/2012 7:52	38		17	
12/2/2012 8:52	44		18	

5. In the Data Analysis ToolPak in excel, select histogram. Select all dry bulb temperatures for your Input Range. Select all the Temperatures in column D for our Bin Range. Select an empty cell for your Output Range. Check the Cumulative Percentage and Chart Output boxes.



6. The output from this will provide a listing of percentile rankings for the listed temperatures, as well as a graph output of the distribution of temperatures contained in this dataset. The "Bin" column shows the temperature, "Frequency" shows how many times that temperature occurred within he dataset, and "Cumulative %" shows the percentile ranking for each temperature. Choose the temperature at or closest to the 0.2 percentile level.

Bin	*Frequency*	*Cumulative %*
-15	0	0.00%
-14	0	0.00%
-13	0	0.00%
-12	0	0.00%
-11	1	0.00%
-10	0	0.00%
-9	2	0.01%
-8	0	0.01%
-7	1	0.02%
-6	4	0.04%
-5	4	0.06%
-4	4	0.07%
-3	1	0.08%
-2	4	0.10%
-1	6	0.13%
0	5	0.15%
1	3	0.16%
2	11	**0.21%**
3	5	0.24%
4	13	0.30%
5	22	0.40%
6	14	0.46%
7	12	0.52%
8	17	0.60%
9	23	0.70%
10	32	0.85%
11	50	1.08%
12	39	1.26%
13	53	1.51%
14	93	1.94%
15	92	2.37%
16	86	2.76%



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Updated

Standards Announcement

Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination

Formal Comment Period Open through September 1, 2022

Now Available

A formal comment period for **Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination** is open through **8 p.m. Eastern, Thursday, September 1, 2022** for the following standard and implementation plan:

- EOP-012-1 – Extreme Cold Weather Preparedness and Operations – Generator Cold Weather Reliability Event definition formatting updated in clean version to align with redline version
- Implementation Plan

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 non-binding polls of the associated Violation Risk Factors and Violation Severity Levels, will be conducted **August 23 – September 1, 2022**.

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

For more information or assistance, contact Senior Standards Developer, Alison Oswald (via email) or at 404-446-9668. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify "Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination observer list" in the Description Box.

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Suite 600, North Tower
Atlanta, GA 30326
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BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/256)
Ballot Name: 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination EOP-012-1 AB 2 ST
Voting Start Date: 8/23/2022 12:01:00 AM
Voting End Date: 9/1/2022 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 287
Total Ballot Pool: 314
Quorum: 91.4
Quorum Established Date: 9/1/2022 2:21:30 PM
Weighted Segment Value: 69.43

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	87	1	50	0.758	16	0.242	0	12	9
Segment: 2	7	0.6	1	0.1	5	0.5	0	0	1
Segment: 3	68	1	45	0.763	14	0.237	0	3	6
Segment: 4	19	1	13	0.813	3	0.188	0	3	0
Segment: 5	77	1	41	0.612	26	0.388	0	4	6
Segment: 6	49	1	29	0.69	13	0.31	0	2	5
Segment: 7	1	0.1	1	0.1	0	0	0	0	0
Segment: 8	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: 9	0	0	0	0	0	0	0	0	0
Segment: 10	6	0.4	4	0.4	0	0	0	2	0
Totals:	314	6.1	184	4.235	77	1.865	0	26	27

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	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski	Brandon Smith	Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Arkansas Electric Cooperative Corporation	Jennifer Loiacano		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Micah Runner		Negative	Comments Submitted
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		None	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Third-Party Comments
1	Colorado Springs Utilities	Mike Braunstein		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Affirmative	N/A
1	Dairyland Power Cooperative	Steve Ritscher		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Negative	Comments Submitted
1	Duke Energy	Laura Lee		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Edison International - Southern California Edison Company	Jose Avendano Mora		Affirmative	N/A
1	Entergy	Brian Lindsey		Negative	Comments Submitted
1	Evergy	Kevin Frick	Alan Kloster	Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Negative	Comments Submitted
1	Gainesville Regional Utilities	David Owens	LaKenya VanNorman	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Negative	Comments Submitted
1	IDACORP - Idaho Power Company	Sean Steffensen		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Joe 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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Nazra Gladu		None	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Nikki Carson-Marquis	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Negative	Third-Party Comments
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		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Negative	Third-Party Comments
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Negative	Comments Submitted
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Ohio Valley Electric Corporation	Scott Cunningham		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer	Gul Khan	Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Orlando Utilities Commission	Aaron Staley		Abstain	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Affirmative	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		Abstain	N/A
1	Platte River Power Authority	Matt Thompson		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle Longo		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Kyle Down		Abstain	N/A
1	Public Utility District No. 1 of Chelan County	Diane Landry		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Negative	Comments Submitted
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Chris Hofmann		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Negative	Third-Party Comments
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seattle City Light	Michael Jang		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Sempra - San Diego Gas and Electric	Mo Derbas		None	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	Taunton Municipal Lighting Plant	Devon Tremont		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	Comments Submitted
1	VELCO -Vermont Electric Power Company, Inc.	Randy Buswell		Abstain	N/A
1	Western Area Power Administration	sean erickson		Negative	Third-Party Comments
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
2	California ISO	Darcy O'Connell		Negative	Third-Party Comments
2	Independent Electricity System Operator	Leonard Kula		None	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		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	PJM Interconnection, L.L.C.	Tom Foster	Elizabeth Davis	Negative	Third-Party Comments
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	AEP	Kent Feliks		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Michael Dieringer		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs		Negative	Comments Submitted
3	Bonneville Power Administration	Ken Lanehome		None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Cowlitz County PUD	Russell Noble		Negative	Comments Submitted
3	CPS Energy	Glenn Pressler		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Schroeder		Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Karie Barczak		Negative	Comments Submitted
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Entergy	James Keele		Negative	Comments Submitted
3	Evergy	Marcus Moor	Alan Kloster	Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Florida Municipal Power Agency	Carl Turner	LaKenya VanNorman	Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Imperial Irrigation District	Glen Allegranza	Denise Sanchez	Affirmative	N/A
3	JEA	Marilyn Williams		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Steve Marshall		None	N/A
3	Lincoln Electric System	Angelica Valencia		Affirmative	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		None	N/A

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3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		None	N/A
3	MGE Energy - Madison Gas and Electric Co.	Ronald Bauer		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera	Shelly Dineen	Negative	Third-Party Comments
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney	James Mearns	Negative	Third-Party Comments
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	LaKenya VanNorman	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Abstain	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	William Berry		Abstain	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Platte River Power Authority	Wade Kiess		None	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	maria pardo		Abstain	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	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Negative	Third-Party Comments
3	Sempra - San Diego Gas and Electric	Bryan Bennett		None	N/A
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		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Abshier		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Negative	Comments Submitted
3	WEC Energy Group, Inc.	Christine Kane		Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	American Public Power Association	John McCaffrey		Abstain	N/A
4	Austin Energy	Jun Hua		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
4	DTE Energy	patricia ireland		Affirmative	N/A
4	Electricities of North Carolina	Marcus Freeman		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
4	Florida Municipal Power Agency	Dan O'Hagan	LaKenya VanNorman	Affirmative	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain	N/A
4	Indiana Municipal Power Agency	Jack Alvey		Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Adam Lee		Affirmative	N/A
4	Northern California Power Agency	Marty Hostler	James Mearns	Negative	Third-Party Comments
4	Oklahoma Municipal Power Authority	Michael Watt		Abstain	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Negative	Comments Submitted
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Affirmative	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.	Brian Evans-Mongeon		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	Acciona Energy North America	George Brown		Negative	Comments Submitted
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	Austin Energy	Michael Dillard		None	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Amanda Wangler		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
5	Black Hills Corporation	Derek Silbaugh	Jennifer Malon	None	N/A
5	Bonneville Power Administration	Scott Winner		None	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Cogentrix Energy Power Management, LLC	Gerry Adamski		Negative	Comments Submitted
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Con Ed - Consolidated Edison Co. of New York	Haizhen Wang		Affirmative	N/A
5	Constellation	Alison Mackellar		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Negative	Comments Submitted
5	CPS Energy	Robert Stevens		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Decatur Energy Center LLC	Shannon Ferdinand		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Adrian Raducea		Negative	Comments Submitted
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Enel Green Power	Natalie Johnson		Negative	Comments Submitted
5	Entergy - Entergy Services, Inc.	Gail Golden		Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Corporation	Robert Loy		Negative	Comments Submitted
5	Florida Municipal Power Agency	Chris Gowder	LaKenya VanNorman	Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	Greybeard Compliance Services, LLC	Michael Gabriel		Negative	Third-Party Comments
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Invenergy LLC	Rhonda Jones		Negative	Comments Submitted
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Jason Fortik		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		None	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
5	LS Power Development, LLC	Mark Spencer		Negative	Comments Submitted
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
5	NB Power Corporation	David Melanson		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Negative	Third-Party Comments
5	NextEra Energy	Summer Esquerre		Negative	Comments Submitted
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Northern California Power Agency	Jeremy Lawson	James Mearns	Negative	Third-Party Comments
5	NRG - NRG Energy, Inc.	Patricia Lynch		Negative	Comments Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	OTP - Otter Tail Power Company	Tammy Kubela		Affirmative	N/A
5	Pacific Gas and Electric Company	Frank Lee	Michael Johnson	Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Negative	Comments Submitted
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		Negative	Comments Submitted
5	Sacramento Municipal Utility District	Nicole Goi	Tim Kelley	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Marty Watson		Negative	Third-Party Comments
5	Sempra - San Diego Gas and Electric	Jennifer Wright		None	N/A
5	Southern Company - Southern Company Generation	James Howell		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	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Talen Generation, LLC	Donald Lock		Negative	Comments Submitted
5	Tenaska, Inc.	Mark Young		Negative	Comments Submitted
5	Tennessee Valley Authority	M Lee Thomas		Affirmative	N/A
5	TransAlta Corporation	Ashley Scheelar		Abstain	N/A
5	Tri-State G and T Association, Inc.	Ryan Walter		Negative	Comments Submitted
5	U.S. Bureau of Reclamation	Wendy Kalidass		Negative	Comments Submitted
5	Vistra Energy	Dan Roethemeyer		Negative	Comments Submitted
5	WEC Energy Group, Inc.	Clarice Zellmer		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP	JT Kuehne		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	Claudine Bates		Negative	Comments Submitted
6	Bonneville Power Administration	Andrew Meyers		None	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Michael Foley		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Constellation	Kimberly Turco		Affirmative	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	Kenya Streeter		None	N/A
6	Entergy	Julie Hall		Negative	Comments Submitted
6	Evergy	Jennifer Flandermeyer	Alan Kloster	Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted
6	Florida Municipal Power Agency	Jade Bulitta	LaKenya VanNorman	Affirmative	N/A
6	Florida Municipal Power Pool	Aaron Casto	LaKenya VanNorman	Affirmative	N/A
6	Great River Energy	Donna Stephenson		Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Invenergy LLC	Colin Chilcoat		Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Manitoba Hydro	Simon Tanapat-Andre		None	N/A
6	Muscatine Power and Water	Nick Burns		Negative	Third-Party Comments
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.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet	James Mearns	Negative	Third-Party Comments
6	NRG - NRG Energy, Inc.	Martin Sidor		Negative	Comments Submitted
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	Powerex Corporation	Raj Hundal		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Negative	Comments Submitted
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Pam Syrjala		Affirmative	N/A
6	Santee Cooper	Glenda Horne		Negative	Third-Party Comments
6	Snohomish County PUD No. 1	John Liang		Negative	Comments Submitted
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Southern Indiana Gas and Electric Co.	Erin Spence		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	Tennessee Valley Authority	Armando Rodriguez		Affirmative	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
7	Oxy - Occidental Chemical	Venona Greaff		Affirmative	N/A
10	Midwest Reliability Organization	William Steiner		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Abstain	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	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

Showing 1 to 314 of 314 entries

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BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/256)
Ballot Name: 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination Implementation Plan AB 2 OT
Voting Start Date: 8/23/2022 12:01:00 AM
Voting End Date: 9/1/2022 8:00:00 PM
Ballot Type: OT
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 283
Total Ballot Pool: 312
Quorum: 90.71
Quorum Established Date: 9/1/2022 2:53:05 PM
Weighted Segment Value: 78.7

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	86	1	57	0.905	6	0.095	0	14	9
Segment: 2	7	0.5	0	0	5	0.5	0	1	1
Segment: 3	68	1	51	0.895	6	0.105	0	5	6
Segment: 4	18	1	12	0.857	2	0.143	0	4	0
Segment: 5	77	1	48	0.762	15	0.238	0	6	8
Segment: 6	49	1	33	0.846	6	0.154	0	5	5
Segment: 7	1	0.1	1	0.1	0	0	0	0	0
Segment: 8	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: 9	0	0	0	0	0	0	0	0	0
Segment: 10	6	0.2	2	0.2	0	0	0	4	0
Totals:	312	5.8	204	4.565	40	1.235	0	39	29

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	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski	Brandon Smith	Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Arkansas Electric Cooperative Corporation	Jennifer Loiacano		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Micah Runner		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		None	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Affirmative	N/A
1	Dairyland Power Cooperative	Steve Ritscher		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Affirmative	N/A
1	Duke Energy	Laura Lee		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Edison International - Southern California Edison Company	Jose Avendano Mora		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Alan Kloster	Affirmative	N/A
1	Eversource Energy	Quintin Lee		Abstain	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Gainesville Regional Utilities	David Owens	LaKenya VanNorman	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Negative	Comments Submitted
1	IDACORP - Idaho Power Company	Sean Steffensen		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Joe 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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Nazra Gladu		None	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Nikki Carson-Marquis	Affirmative	N/A
1	Muscatine Power and Water	Andy 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		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Negative	Third-Party Comments
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Ohio Valley Electric Corporation	Scott Cunningham		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer	Gul Khan	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Orlando Utilities Commission	Aaron Staley		Abstain	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Affirmative	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle Longo		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Kyle Down		Abstain	N/A
1	Public Utility District No. 1 of Chelan County	Diane Landry		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Negative	Comments Submitted
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Chris Hofmann		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Negative	Third-Party Comments
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Taunton Municipal Lighting Plant	Devon Tremont		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	Comments Submitted
1	VELCO -Vermont Electric Power Company, Inc.	Randy Buswell		Abstain	N/A
1	Western Area Power Administration	sean erickson		Abstain	N/A
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
2	California ISO	Darcy O'Connell		Abstain	N/A
2	Independent Electricity System Operator	Leonard Kula		None	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		Negative	Third-Party Comments
2	PJM Interconnection, L.L.C.	Tom Foster	Elizabeth Davis	Negative	Third-Party Comments
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	AEP	Kent Feliks		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Michael Dieringer		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	CPS Energy	Glenn Pressler		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Schroeder		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Alan Kloster	Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Florida Municipal Power Agency	Carl Turner	LaKenya VanNorman	Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Imperial Irrigation District	Glen Allegranza	Denise Sanchez	Affirmative	N/A
3	JEA	Marilyn Williams		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Steve Marshall		None	N/A
3	Lincoln Electric System	Angelica Valencia		Affirmative	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		None	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		None	N/A
3	MGE Energy - Madison Gas and Electric Co.	Ronald Bauer		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera	Shelly Dineen	Negative	Third-Party Comments
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney	James Mearns	Negative	Third-Party Comments
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	LaKenya VanNorman	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Abstain	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	William Berry		Abstain	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Affirmative	N/A
3	Platte River Power Authority	Wade Kiess		None	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	maria pardo		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Negative	Third-Party Comments
3	Sempra - San Diego Gas and Electric	Bryan Bennett		None	N/A
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		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Abshier		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	American Public Power Association	John McCaffrey		Abstain	N/A
4	Austin Energy	Jun Hua		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
4	DTE Energy	patricia ireland		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Florida Municipal Power Agency	Dan O'Hagan	LaKenya VanNorman	Affirmative	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain	N/A
4	Indiana Municipal Power Agency	Jack Alvey		Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Adam Lee		Affirmative	N/A
4	Northern California Power Agency	Marty Hostler	James Mearns	Negative	Third-Party Comments
4	Oklahoma Municipal Power Authority	Michael Watt		Abstain	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Negative	Comments Submitted
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Abstain	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	Acciona Energy North America	George Brown		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	Austin Energy	Michael Dillard		None	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Amanda Wangler		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
5	Black Hills Corporation	Derek Silbaugh	Jennifer Malon	None	N/A
5	Bonneville Power Administration	Scott Winner		None	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Cogentrix Energy Power Management, LLC	Gerry Adamski		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Haizhen Wang		Affirmative	N/A
5	Constellation	Alison Mackellar		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	CPS Energy	Robert Stevens		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Decatur Energy Center LLC	Shannon Ferdinand		None	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Enel Green Power	Natalie Johnson		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	LaKenya VanNorman	Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	Greybeard Compliance Services, LLC	Michael Gabriel		Negative	Third-Party Comments
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	Invenergy LLC	Rhonda Jones		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Jason Fortik		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		None	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
5	LS Power Development, LLC	Mark Spencer		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
5	NB Power Corporation	David Melanson		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Negative	Third-Party Comments
5	NextEra Energy	Summer Esquerre		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Northern California Power Agency	Jeremy Lawson	James Mearns	Negative	Third-Party Comments
5	NRG - NRG Energy, Inc.	Patricia Lynch		Negative	Comments Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Abstain	N/A
5	OTP - Otter Tail Power Company	Tammy Kubela		None	N/A
5	Pacific Gas and Electric Company	Frank Lee	Michael Johnson	Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Negative	Comments Submitted
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		Negative	Comments Submitted
5	Sacramento Municipal Utility District	Nicole Goi	Tim Kelley	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Marty Watson		Negative	Third-Party Comments
5	Sempra - San Diego Gas and Electric	Jennifer Wright		None	N/A
5	Southern Company - Southern Company Generation	James Howell		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	Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		Negative	Comments Submitted
5	Tenaska, Inc.	Mark Young		Negative	Comments Submitted
5	Tennessee Valley Authority	M Lee Thomas		Affirmative	N/A
5	TransAlta Corporation	Ashley Scheelar		Abstain	N/A
5	Tri-State G and T Association, Inc.	Ryan Walter		Negative	Comments Submitted
5	U.S. Bureau of Reclamation	Wendy Kalidass		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Vistra Energy	Dan Roethemeyer		Negative	Comments Submitted
5	WEC Energy Group, Inc.	Clarice Zellmer		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP	JT Kuehne		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	Claudine Bates		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		None	N/A
6	Cleco Corporation	Robert Hirchak		Abstain	N/A
6	Con Ed - Consolidated Edison Co. of New York	Michael Foley		Affirmative	N/A
6	Constellation	Kimberly Turco		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Jennifer Flandermeyer	Alan Kloster	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
6	Florida Municipal Power Agency	Jade Bulitta	LaKenya VanNorman	Affirmative	N/A
6	Florida Municipal Power Pool	Aaron Casto	LaKenya VanNorman	Affirmative	N/A
6	Great River Energy	Donna Stephenson		Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Invenergy LLC	Colin Chilcoat		Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Manitoba Hydro	Simon Tanapat-Andre		None	N/A
6	Muscatine Power and Water	Nick Burns		Abstain	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet	James Mearns	Negative	Third-Party Comments
6	NRG - NRG Energy, Inc.	Martin Sidor		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Negative	Comments Submitted
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Pam Syrjala		Affirmative	N/A
6	Santee Cooper	Glenda Horne		Negative	Third-Party Comments
6	Snohomish County PUD No. 1	John Liang		Negative	Comments Submitted
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Erin Spence		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	Tennessee Valley Authority	Armando Rodriguez		Affirmative	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
7	Oxy - Occidental Chemical	Venona Greaff		Affirmative	N/A
10	Midwest Reliability Organization	William Steiner		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	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

Showing 1 to 312 of 312 entries

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BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/256)
Ballot Name: 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination EOP-012-1 | Non-binding Poll AB 2 NB
Voting Start Date: 8/23/2022 12:01:00 AM
Voting End Date: 9/1/2022 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 267
Total Ballot Pool: 300
Quorum: 89
Quorum Established Date: 9/1/2022 3:50:06 PM
Weighted Segment Value: 72.36

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	82	1	38	0.776	11	0.224	25	8
Segment: 2	7	0.3	0	0	3	0.3	3	1
Segment: 3	64	1	37	0.771	11	0.229	10	6
Segment: 4	17	1	10	0.833	2	0.167	5	0
Segment: 5	76	1	35	0.648	19	0.352	11	11
Segment: 6	47	1	21	0.7	9	0.3	10	7
Segment: 7	1	0	0	0	0	0	1	0
Segment: 8	0	0	0	0	0	0	0	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	0.3	3	0.3	0	0	3	0
Totals:	300	5.6	144	4.028	55	1.572	68	33

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski	Brandon Smith	Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
1	Arkansas Electric Cooperative Corporation	Jennifer Loiacano		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Abstain	N/A
1	Avista - Avista Corporation	Mike Magruder		Abstain	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		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		Affirmative	N/A
1	Black Hills Corporation	Micah Runner		Abstain	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		None	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Comments Submitted
1	Colorado Springs Utilities	Mike Braunstein		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Affirmative	N/A
1	Dairyland Power Cooperative	Steve Ritscher		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Negative	Comments Submitted
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Jose Avendano Mora		Abstain	N/A
1	Entergy	Brian Lindsey		Negative	Comments Submitted
1	Evergy	Kevin Frick	Alan Kloster	Affirmative	N/A
1	Eversource Energy	Quintin Lee		Abstain	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Gainesville Regional Utilities	David Owens	LaKenya VanNorman	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Abstain	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Negative	Comments Submitted
1	IDACORP - Idaho Power Company	Sean Steffensen		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Joe 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	Lower Colorado River Authority	James Baldwin		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Nikki Carson-Marquis	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Negative	Comments Submitted

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		Affirmative	N/A
1	NB Power Corporation	Jeffrey Streifling		Abstain	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Negative	Comments Submitted
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Ohio Valley Electric Corporation	Scott Cunningham		Abstain	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Orlando Utilities Commission	Aaron Staley		Abstain	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Affirmative	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		Abstain	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 Longo		None	N/A
1	PSEG - Public Service Electric and Gas Co.	Kyle Down		Abstain	N/A
1	Public Utility District No. 1 of Chelan County	Diane Landry		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Negative	Comments Submitted
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Chris Hofmann		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seattle City Light	Michael Jang		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		None	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	Taunton Municipal Lighting Plant	Devon Tremont		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Abstain	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	VELCO -Vermont Electric Power Company, Inc.	Randy Buswell		Abstain	N/A
1	Western Area Power Administration	sean erickson		Negative	Comments Submitted
2	California ISO	Darcy O'Connell		Negative	Comments Submitted
2	Independent Electricity System Operator	Leonard Kula		None	N/A
2	ISO New England, Inc.	John Pearson	Keith Jonassen	Negative	Comments Submitted
2	Midcontinent ISO, Inc.	Bobbi Welch		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		Negative	Comments Submitted
2	PJM Interconnection, L.L.C.	Tom Foster	Elizabeth Davis	Abstain	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
3	AEP	Kent Feliks		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Michael Dieringer		Abstain	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Bonneville Power Administration	Ken Lanehome		None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Negative	Comments Submitted
3	CPS Energy	Glenn Pressler		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Schroeder		Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Karie Barczak		Negative	Comments Submitted
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Entergy	James Keele		Negative	Comments Submitted
3	Evergy	Marcus Moor	Alan Kloster	Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Florida Municipal Power Agency	Carl Turner	LaKenya VanNorman	Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Imperial Irrigation District	Glen Allegranza	Denise Sanchez	Affirmative	N/A
3	JEA	Marilyn Williams		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Steve Marshall		None	N/A
3	Lincoln Electric System	Angelica Valencia		Abstain	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		None	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Negative	Comments Submitted
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera	Shelly Dineen	Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney	James Mearns	Negative	Comments Submitted
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	LaKenya VanNorman	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	William Berry		Abstain	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Affirmative	N/A
3	Platte River Power Authority	Wade Kiess		None	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	PSEG - Public Service Electric and Gas Co.	maria pardo		Abstain	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	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		None	N/A
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		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Abshier		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Negative	Comments Submitted
3	WEC Energy Group, Inc.	Christine Kane		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	American Public Power Association	John McCaffrey		Abstain	N/A
4	Austin Energy	Jun Hua		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
4	DTE Energy	patricia ireland		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Florida Municipal Power Agency	Dan O'Hagan	LaKenya VanNorman	Affirmative	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain	N/A
4	Indiana Municipal Power Agency	Jack Alvey		Abstain	N/A
4	Northern California Power Agency	Marty Hostler	James Mearns	Negative	Comments Submitted
4	Oklahoma Municipal Power Authority	Michael Watt		Abstain	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Negative	Comments Submitted
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Jonathan Robbins		Affirmative	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.	Brian Evans-Mongeon		Abstain	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	Acciona Energy North America	George Brown		Negative	Comments Submitted
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	Austin Energy	Michael Dillard		None	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Amanda Wangler		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
5	Black Hills Corporation	Derek Silbaugh	Jennifer Malon	None	N/A
5	Bonneville Power Administration	Scott Winner		None	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Cogentrix Energy Power Management, LLC	Gerry Adamski		Abstain	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Con Ed - Consolidated Edison Co. of New York	Haizhen Wang		Affirmative	N/A
5	Constellation	Alison Mackellar		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Negative	Comments Submitted
5	CPS Energy	Robert Stevens		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Decatur Energy Center LLC	Shannon Ferdinand		None	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Adrian Raducea		Negative	Comments Submitted
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		None	N/A
5	Enel Green Power	Natalie Johnson		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Corporation	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	LaKenya VanNorman	Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	Greybeard Compliance Services, LLC	Michael Gabriel		Negative	Comments Submitted
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	Invenergy LLC	Rhonda Jones		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Jason Fortik		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		None	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
5	LS Power Development, LLC	Mark Spencer		Negative	Comments Submitted
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
5	NB Power Corporation	David Melanson		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender		Abstain	N/A
5	New York Power Authority	Zahid Qayyum		Negative	Comments Submitted
5	NextEra Energy	Summer Esquerre		Negative	Comments Submitted
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Northern California Power Agency	Jeremy Lawson	James Mearns	Negative	Comments Submitted
5	NRG - NRG Energy, Inc.	Patricia Lynch		Negative	Comments Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	OTP - Otter Tail Power Company	Tammy Kubela		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Pacific Gas and Electric Company	Frank Lee	Michael Johnson	Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Abstain	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Negative	Comments Submitted
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		Negative	Comments Submitted
5	Sacramento Municipal Utility District	Nicole Goi	Tim Kelley	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Marty Watson		Abstain	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		None	N/A
5	Southern Company - Southern Company Generation	James Howell		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	Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
5	Tenaska, Inc.	Mark Young		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Tennessee Valley Authority	M Lee Thomas		Abstain	N/A
5	Tri-State G and T Association, Inc.	Ryan Walter		Negative	Comments Submitted
5	U.S. Bureau of Reclamation	Wendy Kalidass		Negative	Comments Submitted
5	Vistra Energy	Dan Roethemeyer		Negative	Comments Submitted
5	WEC Energy Group, Inc.	Clarice Zellmer		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		None	N/A
6	AEP	JT Kuehne		Abstain	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		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A
6	Black Hills Corporation	Claudine Bates		Abstain	N/A
6	Bonneville Power Administration	Andrew Meyers		None	N/A
6	Cleco Corporation	Robert Hirchak		Abstain	N/A
6	Con Ed - Consolidated Edison Co. of New York	Michael Foley		Affirmative	N/A
6	Constellation	Kimberly Turco		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	John Sturgeon		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
6	Entergy	Julie Hall		Negative	Comments Submitted
6	Evergy	Jennifer Flandermeyer	Alan Kloster	Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
6	Florida Municipal Power Agency	Jade Bulitta	LaKenya VanNorman	Affirmative	N/A
6	Florida Municipal Power Pool	Aaron Casto	LaKenya VanNorman	Affirmative	N/A
6	Great River Energy	Donna Stephenson		Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Invenergy LLC	Colin Chilcoat		None	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	Nick Burns		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet	James Mearns	Negative	Comments Submitted
6	NRG - NRG Energy, Inc.	Martin Sidor		Negative	Comments Submitted
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		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	Joseph Neglia		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Negative	Comments Submitted
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Pam Syrjala		Affirmative	N/A
6	Santee Cooper	Glenda Horne		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		Negative	Comments Submitted
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Erin Spence		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	Tennessee Valley Authority	Armando Rodriguez		None	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Affirmative	N/A
7	Oxy - Occidental Chemical	Venona Greaff		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	Midwest Reliability Organization	William Steiner		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Abstain	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	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 300 of 300 entries

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Comment Report

Project Name:	2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Draft 2
Comment Period Start Date:	8/3/2022
Comment Period End Date:	9/1/2022
Associated Ballots:	2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination EOP-012-1 | Non-binding Poll AB 2 NB 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination EOP-012-1 AB 2 ST 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination Implementation Plan AB 2 OT

There were 100 sets of responses, including comments from approximately 237 different people from approximately 158 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. The SDT is proposing three new definitions from the initial posting of EOP-012. Does adding definitions of Extreme Cold Weather Temperature, Generator Cold Weather Critical Component, and Generator Cold Weather Reliability Event provide additional clarity to the requirements of EOP-012? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

2. Do you agree with the proposed definitions of Extreme Cold Weather Temperature, Generator Cold Weather Critical Component, and Generator Cold Weather Reliability Event? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

3. Is the revised Applicability Section language clear? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

4. Do you support the SDT proposed 12-hour timeframe to require new Generation units to be capable of performing at or below the Extreme Cold Weather Temperature? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

5. Do you support the SDT proposed 1-hour timeframe to allow existing Generation units to demonstrate their performance at or below the Extreme Cold Weather Temperature? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

6. Do you support the addition of a 20 megawatt minimum (corresponding to the definition of a BES impacting generating unit) for requiring CAPS for derates? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

7. The SDT believes that with the proposed modifications to EOP-012-1, the initial proposed implementation plan is appropriate with one change. The 18-month implementation time frame is for all revised and new requirements in EOP-012-1, except Requirements R1 and R2 which have a 60-month implementation time frame, and R4 which has a 78-month implementation time frame. Do you agree with this implementation time frame? If you think an alternate timeframe is needed, please propose an alternate implementation plan and time period, and provide a detailed explanation of actions planned to meet the implementation deadline.

8. The SDT proposes that the modifications in the proposed EOP-012-1 meet the key recommendations in The Report 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
DTE Energy - Detroit Edison Company	Adrian Raducea	5		DTE Energy - DTE Electric	Karie Barczak	DTE Energy - Detroit Edison Company	3	RF
					Adrian Raducea	DTE Energy - Detroit Edison	5	RF
					patricia ireland	DTE Energy	4	RF
Portland General Electric Co.	Brooke Jockin	1		Portland General Electric Co.	Brooke Jockin	Portland General Electric	1	WECC
					Dan Mason	Portland General Electric	6	WECC
					Ryan Olson	Portland General Electric	5	WECC
					Adam Menendez	Portland General Electric Co.	3	WECC
WEC Energy Group, Inc.	Christine Kane	3		WEC Energy Group	Christine Kane	WEC Energy Group	3	RF
					Matthew Beilfuss	WEC Energy Group, Inc.	4	RF
					Clarice Zellmer	WEC Energy Group, Inc.	5	RF
					David Boeshaar	WEC Energy Group, Inc.	6	RF
PPL - Louisville Gas and Electric Co.	Devin Shines	3,5,6	RF,SERC	Louisville Gas and Electric Company and Kentucky Utilities Company	Charles Freibert	PPL - Louisville Gas and Electric Co.	3	SERC
					JULIE HOSTRANDER	PPL - Louisville Gas and Electric Co.	5	SERC
					Linn Oelker	PPL - Louisville Gas and Electric Co.	6	SERC
OGE Energy - Oklahoma	Donald Hargrove	3		OGE Energy	Donald Hargrove	OGE Energy - Oklahoma	3	MRO

Gas and Electric Co.						Gas and Electric Co.		
					Terri Pyle	OGE Energy - Oklahoma Gas and Electric Co.	1	MRO
					Patrick Wells	OGE Energy - Oklahoma Gas and Electric Co.	5	MRO
					Ashley Stringer	OGE Energy - Oklahoma Gas and Electric Co.	6	MRO
Elizabeth Davis	Elizabeth Davis		RF,SERC	ISO/RTO Council (IRC) Standards Review Committee (SRC)	Mike Del Viscio	PJM	2	RF
					Becky Davis	PJM	2	RF
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Charles Yeung	Southwest Power Pool, Inc. (RTO)	2	MRO
					Helen Lainis	IESO	2	NPCC
					Bobbi Welch	Midcontinent ISO, Inc.	2	RF
					Kathleen Goodman	ISO-NE	2	NPCC
					Nathan Bigbee	ERCOT	2	Texas RE
					Ali Miremadi	California ISO	2	WECC
Lincoln Electric System	Eric Ruskamp	6		LES	Eric Ruskamp	Lincoln Electric System	6	MRO
					Dan Pudenz	Lincoln Electric System	1	MRO
					Jason Fortik	Lincoln Electric System	3	MRO
					Kayleigh Wilkerson	Lincoln Electric System	5	MRO
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
					Marc Donaldson	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
ACES Power Marketing	Jodirah Green	6	MRO,NA - Not Applicable,RF,SERC,Texas RE,WECC	ACES Standard Collaborations	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	SERC
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					Scott Berry	Wabash Valley Power Association	3	RF
					Nick Fogleman	Prairie Power, Inc.	1	SERC
					Ryan Strom	Buckeye Power, Inc.	5	RF
					Ellen Watkins	Sunflower Electric Power Corporation	1	MRO
					Patti Metro	National Rural Electric Cooperative Association	3	NA - Not Applicable
					Patti Metro	National Rural Electric Cooperative Association	3	NA - Not Applicable

Entergy	Julie Hall	6		Entergy	Oliver Burke	Entergy - Entergy Services, Inc.	1	SERC
					Jamie Prater	Entergy	5	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
					LaTroy Brumfield	American Transmission Company, LLC	1	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
					David Heins	Omaha Public Power District	1,3,5,6	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
Duke Energy	Kim Thomas	1,3,5,6	FRCC,RF,SERC,Texas RE	Duke Energy	Laura Lee	Duke Energy	1	SERC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
LaKenya VanNorman	LaKenya VanNorman		SERC	Florida Municipal Power Agency (FMPA)	Chris Gowder	Florida Municipal Power Agency	5	SERC
					Dan O'Hagan	Florida Municipal Power Agency	4	SERC
					Carl Turner	Florida Municipal Power Agency	3	SERC
					Jade Bulitta	Florida Municipal Power Agency	6	SERC
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
					Tricia Bynum	FirstEnergy - FirstEnergy Corporation	6	RF
					Mark Garza	FirstEnergy-FirstEnergy	4	RF
Public Utility District No. 1 of Chelan County	Meaghan Connell	5		PUD No. 1 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
					Glen Pruitt	Public Utility District No. 1	6	WECC

						of Chelan County		
					Meaghan Connell	Public Utility District No. 1 Chelan County	5	WECC
Michael Johnson	Michael Johnson		WECC	PG&E All Segments	Marco Rios	Pacific Gas and Electric Company	1	WECC
					Sandra Ellis	Pacific Gas and Electric Company	3	WECC
					James Mearns	Pacific Gas and Electric Company	5	WECC
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
					Jim Howell	Southern Company - Southern Company Services, Inc. - Gen	5	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC Regional Standards Committee	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Alan Adamson	New York State	7	NPCC

	Reliability Council		
David Burke	Orange & Rockland Utilities	3	NPCC
Harish Vijay Kumar	IESO	2	NPCC
David Kiguel	Independent	7	NPCC
Nick Kowalczyk	Orange and Rockland	1	NPCC
Joel Charlebois	AESI - Acumen Engineered Solutions International Inc.	5	NPCC
Mike Cooke	Ontario Power Generation, Inc.	4	NPCC
Salvatore Spagnolo	New York Power Authority	1	NPCC
Shivaz Chopra	New York Power Authority	5	NPCC
Deidre Altobell	Con Ed - Consolidated Edison	4	NPCC
Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
Cristhian Godoy	Con Ed - Consolidated Edison Co. of New York	6	NPCC
Nurul Abser	NB Power Corporation	1	NPCC
Randy MacDonald	NB Power Corporation	2	NPCC

					Michael Ridolfino	Central Hudson Gas and Electric	1	NPCC
					Vijay Puran	NYSPS	6	NPCC
					ALAN ADAMSON	New York State Reliability Council	10	NPCC
					Sean Cavote	PSEG - Public Service Electric and Gas Co.	1	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					John Pearson	ISONE	2	NPCC
					Nicolas Turcotte	Hydro-Qu?bec TransEnergie	1	NPCC
					Chantal Mazza	Hydro-Quebec	2	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	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
Western Electricity Coordinating Council	Steven Rueckert	10		WECC Entity Monitoring	Steve Rueckert	WECC	10	WECC
					Phil O'Donnell	WECC	10	WECC

Tim Kelley	Tim Kelley		WECC	SMUD / 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
					Stephen Pogue	M and A Electric Power Cooperative	3	SERC
					William Price	M and A Electric Power Cooperative	1	SERC
					Peter Dawson	Sho-Me Power Electric Cooperative	1	SERC
					Mark Ramsey	N.W. Electric Power Cooperative, Inc.	1	NPCC
					John Stickley	NW Electric Power Cooperative, Inc.	3	SERC
					Tony Gott	KAMO Electric Cooperative	3	SERC

					Micah Breedlove	KAMO Electric Cooperative	1	SERC
					Kevin White	Northeast Missouri Electric Power Cooperative	1	SERC
					Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	3	SERC
					Ryan Ziegler	Associated Electric Cooperative, Inc.	1	SERC
					Brian Ackermann	Associated Electric Cooperative, Inc.	6	SERC
					Brad Haralson	Associated Electric Cooperative, Inc.	5	SERC

1. The SDT is proposing three new definitions from the initial posting of EOP-012. Does adding definitions of Extreme Cold Weather Temperature, Generator Cold Weather Critical Component, and Generator Cold Weather Reliability Event provide additional clarity to the requirements of EOP-012? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6

Answer	No
Document Name	

Comment

These definitions continue to add an administrative burden on those entities who operate, and are designed to operate in cold climates. Specifically, many hydro projects in northern climates that operate in sub-zero weather have dealt with extreme temperature operations successfully. How much more planning and preparation must be made when we already operate to -28 F during the winter? We may see seasons with more river ice, but that is not unusual. Months of preplanning will not prevent river icing, or the work that must be done to mitigate the effects.

Likes 0	
Dislikes 0	

Response

Donald Lock - Talen Generation, LLC - 5

Answer	No
Document Name	

Comment

The proposed definitions are insufficient; another is needed for temperature. The issue at hand cannot be addressed using only readings from thermometers (dry bulb temperature, DBT). Generic references to, “the temperature,” as in the Extreme Cold Weather Temperature definition, therefore degrade clarity due to lack of specificity.

The parameter of interest for conventional generation plants is the wind chill temperature (WCT), combining the effects of DBT and wind speed in causing heat transfer. Winter Storm Uri, the Polar Vortex of 2014, and the 2011 Southwest Cold Weather Event all achieved an “extreme” classification by virtue of involving high winds, and any standard on the subject must explicitly address this point. RCs, BAs and TOPs cannot adequately plan for winter storm-related threats to the BES if using DBT-based generation plant capability data for an inherently WCT-based phenomenon.

Some manufacturers of wind turbines offer winterization packages based on DBT, however, so it may be necessary for EOP-012-1 to say that WCT or DBT is to be used as applicable for the generation technology at hand. An alternative, universal approach is to say that “temperature” in the present context means DBT plus a 20 mph wind, this being a typical sustained wind condition for the worst hours of the aforementioned grid emergencies.

The Guidance section of EOP-012-1 should then explain that the WCT scale is to be used for transposing capability data. A conventional plant that is protected to -10 F DBT with a 5 mph wind (-22 F WCT), for example, is to state its EOP-012-1 capability as being 0 F DBT (-22 F WCT when combined with a 20 mph wind).

A definition is also needed for freezing, and it should clarify how precipitation fits into the picture. We propose, “The transition of water to ice, or congealing of fluids to the point of affecting operations (e.g. for lube oil, fuel oil and water treatment chemicals). The effects of precipitation stand separate from freezing." The Guidance section of the standard should add, "A unit having a freeze prevention capability of -15 F DBT with a 20 mph wind, for example, might be forced offline by a snow or ice storm at 30 F."

Likes 0	
Dislikes 0	

Response

Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6

Answer	No
Document Name	

Comment

Talen Marketing LLC supports Talen Generation's comments.

Likes 0	
Dislikes 0	

Response

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer	No
Document Name	

Comment

Reclamation disagrees that the proposed Glossary Terms provide clarity for the proposed requirements of EOP-012. The most significant issues are what is meant by "susceptible to freezing issues" and "fuel supply component." The phrase "susceptible to freezing" is not relevant for solar and wind. While this equipment may have frozen precipitation on them, the component itself is not frozen. The phrase "fuel supply component" is not relevant for hydro, solar, and wind. Exempting components located inside temperature controlled buildings that are not susceptible to freezing would allow entities to focus on components that actually pose a risk to the BES. This seems to be the intent of the SDT, but needs to be clearly written in the standard.

A reliability standard should be applicable to specific reliability functions (e.g., Generator Owner, Generator Operator), specific geographic locations (e.g., south of 35 degrees latitude), and/or specific equipment (e.g., gas, solar, wind). Reclamation observes that undue effort is being spent on precisely identifying the specific cold weather conditions under which the standard applies. Reclamation asserts this effort will result in a disservice to the intent of ensuring electric reliability during cold weather because the narrow applicability will allow critical electrical infrastructure to be exempt from the proposed requirements. Reclamation observes that many of the issues the SDT appears to be trying to address and that entities have commented about would be better addressed in a forum outside of electric reliability standards, e.g., marketing issues. It appears that the electric industry is being inappropriately tasked with solving a problem the root cause of which may not be within its purview.

Likes 0	
Dislikes 0	

Response

LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	No
Document Name	
Comment	
The definitions do not meet their objective as described in question 2.	
Likes 0	
Dislikes 0	
Response	
Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	No
Document Name	
Comment	
Capital Power supports the North American Generators Forum (NAGF) response to this question.	
Likes 0	
Dislikes 0	
Response	
Whitney Wallace - Calpine Corporation - 5 - WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
Outages on GO controlled transmission lines caused by ice storms should not be included in a Generator Cold Weather Reliability Event (GCWRE). Also, GOs should be exempted from including forced outages as GCWREs if the forced outage was caused by a loss of offsite power caused by a BES grid event (e.g., load shed, low frequency, sub-synchronous resonance, etc.) or other transmission events unrelated to the GO Operation. In addition, GO operators should be exempted from including forced outages due to loss of fuel supply for any reason outside of the GO's control. For these events, the exemption should apply to not only the time of the event, but also to any recovery time required to implement corrective actions needed as a direct result of the causal event.	
Likes 0	
Dislikes 0	

Response

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1

Answer	No
Document Name	

Comment

Likes 0

Dislikes 0

Response

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group

Answer	Yes
Document Name	

Comment

The proposed definitions for Extreme Cold Weather Temperature, Generator Cold Weather Critical Component, and Generator Cold Weather Reliability Event provide needed additional clarity to the requirements for EOP-012. However, we have some concerns with the proposed definition of Generator Cold Weather Critical Component and Generator Cold Weather Reliability Event.

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

Southern Company agrees that the addition of these key terms provide additional clarity to the proposed standard.

Likes 0

Dislikes 0

Response

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	

Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Avista agrees that the proposed definitions for Extreme Cold Weather Temperature, Generator Cold Weather Critical Component, and Generator Cold Weather Reliability Event provide needed clarity to the requirements for EOP-012-1. However, we recommend additional revisions to the definitions of Generator Cold Weather Critical Component and Generator Cold Weather Reliability Event to provide enhanced clarity, to be addressed during the 2nd phase of this project. (See our response to Question 2)	
Likes 0	
Dislikes 0	
Response	

Brooke Jockin - Portland General Electric Co. - 1, Group Name Portland General Electric Co.	
Answer	Yes
Document Name	
Comment	
Portland General Electric Company supports the survey response provided by EEI.	
Likes 0	
Dislikes 0	
Response	

Scott Kinney - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Avista agrees that the proposed definitions for Extreme Cold Weather Temperature, Generator Cold Weather Critical Component, and Generator Cold Weather Reliability Event provide needed clarity to the requirements for EOP-012-1. However, we recommend additional revisions to the definitions of Generator Cold Weather Critical Component and Generator Cold Weather Reliability Event to provide enhanced clarity, to be addressed during the 2nd phase of this project. (See our response to Question 2)	
Likes 0	
Dislikes 0	
Response	

Mark Spencer - LS Power Development, LLC - 5	
Answer	Yes
Document Name	
Comment	
We agree appropriately formed definitions would provide additional clarity if the comments below are addressed.	
Likes 1	Vistra Energy, 5, Roethemeyer Dan
Dislikes 0	
Response	

David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Ameren agrees with the EEI and the NAGF comments.	
Likes 0	
Dislikes 0	
Response	

Joe Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Xcel Energy supports comments from EEI.	
Likes 0	
Dislikes 0	
Response	

Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3, Group Name OGE Energy	
Answer	Yes
Document Name	
Comment	
OG&E supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	Yes
Document Name	
Comment	
PG&E agrees to the proposed definitions and the recommendations supplied by EEI on additional revisions during Phase Two of the Cold Weather project.	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5

Answer	Yes
Document Name	
Comment	

AEP would like to express its support of EEI’s response to this question.

Likes 0	
Dislikes 0	
Response	

Devin Shines - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company

Answer	Yes
Document Name	
Comment	

LouisvilleG&E/KU support EEI's comments.

Likes 0	
Dislikes 0	
Response	

Kimberly Turco - Constellation - 6

Answer	Yes
Document Name	
Comment	

Constellation has no additional comments.

Kimberly Turco, on behalf of Segments 5 and 6

Likes 0	
Dislikes 0	
Response	

Alison Mackellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco, on behalf of Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	
"Please see comments submitted by the Edison Electric Institute"	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	
PNM agrees that the proposed definitions for Extreme Cold Weather Temperature, Generator Cold Weather Critical Component, and Generator Cold Weather Reliability Event. PNM also supports the comments provided by EEI.	
Likes 0	
Dislikes 0	
Response	

Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	Yes
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for question #1.	
Likes 0	
Dislikes 0	
Response	
Dan Roethemeyer - Vistra Energy - 5	
Answer	Yes
Document Name	
Comment	
Adding the proposed defined terms provides additional clarity to the requirements of EOP-012, and Vistra supports inclusion of definitions for those terms in the Reliability Standard. However, Vistra recommends refinements to the definitions as described below under Question 2.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon agrees that the proposed definitions provide additional clarity to EOP-012-1. Submitted on behalf of Exelon, Segments 1 & 3	
Likes 0	
Dislikes 0	

Response	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Southern Indiana Gas & Electric Company (SIGE) agrees the added definitions of Extreme Cold Weather Temperature, Generator Cold Weather Critical Component, and Generator Cold Weather Reliability Event provide additional clarity to the requirements of EOP-012. However, similar to EEI, SIGE also has concerns with the proposed definition of Generator Cold Weather Critical Component and Generator Cold Weather Reliability Event – as addressed in SIGE's response to Question 2.	
Likes 0	
Dislikes 0	
Response	
Stewart Rake - Luminant Mining Company LLC - 7	
Answer	Yes
Document Name	
Comment	
Adding the proposed defined terms provides additional clarity to the requirements of EOP-012, and Vistra supports inclusion of definitions for those terms in the Reliability Standard. However, Vistra recommends refinements to the definitions as described below under Question 2.	
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 agrees that for the context of the new EOP-012 Standard these definitions are needed for clarification purposes, however some modifications to those definitions may be needed as described in Question 2 Comments by the SRC and ISO-NE.	
Likes 0	

Dislikes 0	

Response

Jamison Cawley - Nebraska Public Power District - 1

Answer	Yes
Document Name	

Comment

Yes, the addition of the definitions provides additional clarity to the requirements. The proposed definitions as stand-alone items in the NERC Glossary of Terms will also help to provide uniformity across future Standards dealing with extreme weather such as TPL-001 recently focused on by a FERC NOPR.

Likes 0	
Dislikes 0	

Response

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4

Answer	Yes
Document Name	

Comment

Alliant Energy supports the comments submitted by the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	Yes
Document Name	

Comment

Yes, the addition of the definitions provides additional clarity to the requirements. The MRO NSRF would like to suggest that the three proposed Terms (Generator Cold Weather Critical Component, Extreme Cold Weather Temperature & Generator Cold Weather Reliability Event) be placed in a new section, §6. Definitions Used in this proposed standard, similar to NERC Reliability Standard PRC-005-6 Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance, rather than the NERC Glossary of Terms. The proposed definitions are dependent on NERC Reliability Standard EOP-012-1 – Extreme Cold Weather Preparedness and Operations, §4.2 term "generating unit" to ensure a comprehensive and complete definition. As such, placing the three proposed terms into the NERC Glossary of Terms would prevent them from being fully defined as intended by the Standards Drafting Team and subject to unintentional misinterpretation. The MRO NSRF suggests consideration be given to including these definitions in the NERC Glossary of Terms during future revisions.

Likes 0	
Dislikes 0	

Response

Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3

Answer	Yes
Document Name	

Comment

MidAmerican Energy supports the MRO NSRF as well as EEI comments for this question.

Likes 0	
Dislikes 0	

Response

Imane Mrini - Austin Energy - 6

Answer	Yes
Document Name	

Comment

The definition of Generator Cold Weather Reliability Event, item 1 is not entirely clear. Is the intent to exclude derates equal to 20MW (if they are more than 10%) or equal to 10% of total unit capacity (when more than 20MW)? Suggest rewording to : a forced derate exceeding 10% of the total capacity of the unit but no less than 20 MW for longer than four hours in duration;"

Likes 0	
Dislikes 0	

Response

Bobbi Welch - Midcontinent ISO, Inc. - 2

Answer	Yes
Document Name	

Comment

MISO supports the comments submitted by the ISO/RTO Council Standards Review Committee (IRC SRC). In addition, we are submitting comments on behalf of MISO as an individual entity.

MISO thanks the Standard Drafting Team (SDT) for adopting the recommendation in MISO's comments from **Project 2019-06: Cold Weather** to develop a "cold weather" definition. Having a national reference will drive consistency of application across the NERC footprint.

Likes 0	
Dislikes 0	

Response

Ronald Bauer - MGE Energy - Madison Gas and Electric Co. - 3

Answer	Yes
Document Name	

Comment

Madison Gas and Electric supports the comments from the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Adam Lee - MGE Energy - Madison Gas and Electric Co. - 4

Answer	Yes
Document Name	

Comment

Madison Gas and Electric supports the comments of the MRO NSRF

Likes 0	
Dislikes 0	

Response

Colin Chilcoat - Invenergy LLC - 6

Answer	Yes
Document Name	

Comment

The defined terms do make the proposed requirements clearer. However, there are still areas of ambiguity that Invenergy recommends be addressed. Those recommendations can be found in our response to Question 2.	
Likes 0	
Dislikes 0	
Response	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	Yes
Document Name	
Comment	
We agree the definitions would provide additional clarity.	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	Yes
Document Name	
Comment	
Acciona Energy supports Midwest Reliability Organization's (MRO) NERC Standards Review Forum's (NSRF) comments on this question.	
Likes 0	
Dislikes 0	
Response	
Deanna Carlson - Cowlitz County PUD - 5	
Answer	Yes
Document Name	
Comment	
Deanna Carlson, Cowlitz PUD, 5, 9/1/22	

Likes 0	
Dislikes 0	

Response

Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)

Answer	Yes
Document Name	

Comment

The ISO/RTO Council (IRC) Standards Review Committee (SRC) supports the addition of definitions for Extreme Cold Weather Temperature, Generator Cold Weather Critical Component, and Generator Cold Weather Reliability Event.

Likes 0	
Dislikes 0	

Response

Mike Magruder - Avista - Avista Corporation - 1

Answer	Yes
Document Name	

Comment

Avista agrees that the proposed definitions for Extreme Cold Weather Temperature, Generator Cold Weather Critical Component, and Generator Cold Weather Reliability Event provide needed clarity to the requirements for EOP-012-1. However, we recommend additional revisions to the definitions of Generator Cold Weather Critical Component and Generator Cold Weather Reliability Event to provide enhanced clarity, to be addressed during the 2nd phase of this project. (See our response to Question 2)

Likes 0	
Dislikes 0	

Response

Rhonda Jones - Invenergy LLC - 5

Answer	Yes
Document Name	

Comment

The defined terms do make the proposed requirements clearer. However, there are still areas of ambiguity that Invenergy recommends be addressed. Those recommendations can be found in our response to Question 2.	
Likes 0	
Dislikes 0	
Response	
Natalie Johnson - Enel Green Power - 5	
Answer	Yes
Document Name	
Comment	
Yes, the addition of the definitions provides additional clarity to the requirements. However, Enel agrees with the MRO NSRF comments that these definitions should also be added to the NERC Glossary of Terms.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI agrees that the proposed definitions for Extreme Cold Weather Temperature, Generator Cold Weather Critical Component, and Generator Cold Weather Reliability Event provide additional clarity to the requirements for EOP-012-1. However, we recommend additional revisions to the definitions of Generator Cold Weather Critical Component and Generator Cold Weather Reliability Event to provide enhanced clarity, that can be addressed during the 2nd phase of this project. (See our response to Question 2)	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
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	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
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

Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 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

Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Evans-Mongeon - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Watt - Oklahoma Municipal Power Authority - 4	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Devon Tremont - Taunton Municipal Lighting Plant - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Glenn Pressler - CPS Energy - 3

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Sean Steffensen - IDACORP - Idaho Power Company - 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	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lenise Kimes - City and County of San Francisco - 1,5 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Josh Combs - Black Hills Corporation - 3	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tony Skourtas - Los Angeles Department of Water and Power - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 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	
Donna Johnson - Oglethorpe Power Corporation - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott McGough - Georgia System Operations Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruchi Shah - AES - AES Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Eric Ruskamp - Lincoln Electric System - 6, Group Name LES	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Sconce - EDF Renewable Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Young - Tenaska, Inc. - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Foung Mua, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Wei Shao, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; - Tim Kelley, Group Name SMUD / BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
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	
John Liang - Snohomish County PUD No. 1 - 6	
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	
LaKenya VanNorman - LaKenya VanNorman On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name Florida Municipal Power Agency (FMPA)	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

2. Do you agree with the proposed definitions of Extreme Cold Weather Temperature, Generator Cold Weather Critical Component, and Generator Cold Weather Reliability Event? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	

Comment

EEI supports all three definitions for this first phase, but we also propose additional revisions to the Generator Cold Weather Critical Component and the Cold Weather Reliability Event because additional clarity is needed that can be addressed during the next phase of this project. (See below.)

Generator Cold Weather Critical Component: Use of the undefined term "fixed fuel supply component" within the proposed definition of Generator Cold Weather Critical Component creates confusion. While we support the explanation provided by the SDT in the Technical Rationale, the Technical Rationale has no standing as a compliance document. For this reason, we recommend defining this term within the framework of the next phase of this project. We suggest the following:

Fixed Fuel Supply Component: Are non-mobile equipment that support the reliable delivery of fuel to the generating unit and under the control the Generator Owner at a plant site. Gaseous, liquid, or solid fuel handling components that are installed on site as fixed parts of the fuel delivery system that are under the Generator Owner's control would be included. Components that would not be included would be mobile equipment such as trains, bulldozers, or other equipment that are not fixed in one location.

Generator Cold Weather Reliability Event: EEI is concerned with the use of the term "specified", as it relates to the start-up time of a generator during cold weather events, because it is unclear who would be responsible for specifying the start-up time. Results Based Standards should "define a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome." (NERC Results Based Standards – Performance Based; https://www.nerc.com/pa/Stand/Pages/ResultsBasedStandards.aspx#:~:text=Results%20based%20standards%20are%20standards,the%20NERC%20Standard%20Processes%20Manual.)

Likes 0	
Dislikes 0	

Response

Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)	
Answer	No
Document Name	IRC SRC supporting tabled temperatures.pdf

Comment

The SRC believes two definitions require revising, specifically:

1. **Extreme Cold Weather Temperature (ECWT)**: The SRC evaluated this temperature and found it is not low enough to capture the critical hours during cold weather periods, such as Winter Storm Uri, The South Central United States Cold Weather Event of January 17, 2018, The 2014 Polar Vortex, the February 2011 Southwest Cold Weather Event and the Cold Wave in January 1994. The following information supports the request to lower the ECWT and cover events such as Winter Storm Uri.

The SDT apparently chose a "look back" date of the year 2000 based on statements on the NOAA website indicating it made some improvements in weather infrastructure around that time. That reason does not justify limiting the look back to 1/1/2000 and misinterprets the NOAA website language. The NOAA website notes it completed its "Modernization and Associated Restructuring" (MAR) effort in 2000. That effort, as the website describes, "modernized" its surface observational infrastructure by incorporating more automation. However, nothing in that effort changed the availability or quality of previous temperature data of NOAA (and its predecessor the National Weather Bureau).

During the NERC presentation on 8/16/22, the Standard Drafting Team (SDT) presented the ECWT for the Dallas, Texas area (12°F). The actual temperature in the Dallas area during Winter Storm Uri was -2°F.

Next, the PJM region experienced extremely cold conditions with a direct impact on reliability (through freezing of coal piles, canal locks and natural gas infrastructure) in 1994. The conditions at that time were the type of conditions the standard should address as they parallel those experienced during Winter Storm Uri. However, limiting the look back to the year 2000 would ignore even this relatively recent (1994) experience for determining ECWT in the PJM region.

The attached chart compares the impact of the proposed ECWT in the PJM region and illustrates how much the 0.2 percentile factor moves the requirement for winterization away from the actual temperature experienced. The results call into question the value of the 0.2 percentile factor.

Some examples included in the chart (please reference additional data and details via the attached file) - all temperatures in degrees Farenheit:

Weather Station = Allentown Lehigh Valley International Airport; Minimum Temp = -9.75; 0.2 Percentile = -0.75; 0.02 Percentile = -6.00; and average lowest temperature over a six hour period = -7.50

Weather Station = Atlantic City International Airport; Minimum Temp = -12.50; 0.2 Percentile = 0.00; 0.02 Percentile = -7.50; and average lowest temperature over a six hour period = -8.33

Weather Station = Chicago O'Hare International Airport; Minumum Temp = -26.00; 0.2 Percentile = -14.00; 0.02 Percentile = -23.00; and average lowest temperature over a six hour period = -24.33

Further, MISO examined two cities in its footprint - Lake Charles, Louisiana (LCH) and Little Rock, Arkansas (LIT) - adversely affected during the February, 2021 event. For LCH, the proposed ECWT would be 24.98° F. When reviewing the hourly data from December 1991 to February 2022, 206 hours meet or fall below that ECWT over thirty-eight days and twenty-five events. LCH also had sixteen hours during Winter Storm Uri the proposed ECWT would exclude.

The proposed ECWT for LIT is 12.92° F. In the hourly data from December 1991 to February 2022, 183 hours meet or fall below that ECWT over thirty-two days and twenty-one events. LIT also had fifty-seven hours during Winter Storm Uri the proposed ECWT would exclude.

In light of the foregoing, the SRC recommends using a fifty year look back period (replacing the year 2000 with the year 1972). The SRC also recommends striking the 0.2 percentile entirely or, at least, changing it to the 0.**02** percentile so the resulting ECWT more accurately reflects actual cold temperatures.

As an alternative to the addition of a percentile adjustment while avoiding requiring winterization to one extremely cold anomalous hour, the SRC recommends the SDT consider, as a viable alternative, defining the ECWT as a period of sustained cold temperatures (*e.g.*, the average of the lowest recorded six hours at a given location). In short, the day would be divided into six hour blocks (e.g. midnight to 6AM, 6AM to noon, noon to 6PM and 6PM to midnight) with the average coldest temperature during those six hour blocks determine the ECWT. The table attached demonstrates the results for all these options. The SDT may need to do additional work in this area, however, the SRC has seen insufficient justification for using the proposed 0.2 percentile factor.

Please note: *The Public Utility Commission of Texas is currently working on a proposed rule establishing a cold weather temperature standard. Accordingly, ERCOT does not support or oppose the SRC's comments on the Extreme Cold Weather Temperature definition.*

2. **Generator Cold Weather Reliability Event (GCWRE)**: The SRC believes the terms "generating unit" or "unit" does not make it clear the Standard applies to an entire *facility/plant*. The NERC Glossary does not define generation "unit," but many industry people consider an individual turbine/generator a *unit* (*e.g.*, a plant may have four quick start

Combustion Turbine *units* and one combined cycle *unit*). The SDT should review and revise the "Applicability" section of EOP-012-2 to clearly identify how the standard applies to dispersed generation resources. This is not a new concept and is supported by the work previously completed under Project 2014-01: Standards Applicability for Dispersed Generation Resources.

The NERC Glossary defines a *Facility* as "a set of electrical equipment that operates as a single Bulk Electric System Element (*e.g.*, a line, a generator, a shunt compensator, transformer, *etc.*)" and an *Element* as, "any electrical device with terminals that may be connected to other electrical devices...." Those definitions do not, however, clearly indicate whether "generator" includes *all* the associated equipment/components the Standard seeks to cover. By way of example, other NERC Glossary definitions use "generating unit" and/or "generating facility" but not always in the same way, for example:

- Blackstart Resource ("A generating unit(s) and its associated set of equipment….")

- Cranking Path ("A portion of the electric system that can be isolated and then energized to deliver electric power from a generation source to enable the startup of one or more other generating units")

- Economic Dispatch ("The allocation of demand to individual generating units on line to effect the most economical production of electricity")

- Forced Outage ("1. The removal from service availability of a generating unit…for emergency reasons….")

- Frequency Measurable Event ("…a cumulative change in generating unit/ generating facility, DC tie and/or firm load pre-perturbation megawatt value to post-perturbation megawatt value absolute deviation greater than 550 MW….")

Thus, referring to the NERC Glossary does not provide an easy solution for this issue. The SRC believes the SDT should include a standard-only definition of *generating unit* or *generating facility*, particularly to ensure it captures dispersed resources adequately. A Standard-only definition could include, for example, "the technology used to convert a primary fuel into electricity including generators, inverters, associated control systems, valves, actuators, other mechanical and electrical components, *etc*." Such an approach would capture PV, wind, natural gas, nuclear, hydro, fuel oil, biomass, *etc*. and ensure the rule covers individual parts of facilities.

Likes 0	
Dislikes 0	

Response

Natalie Johnson - Enel Green Power - 5

Answer	No
Document Name	

Comment

Extreme Cold Weather Temperature: On a positive note, Enel prefers the updated criteria. It is a clearer criteria to assess and apply, especially with the focus on December to January months. Enel does support the MRO NSRF comments that industry meteorological experts (i.e NOAA, NWS) should be consulted and involved in this process.

Generator Cold Weather Reliability Event: Enel would like to recommend a few additional edits to the Generator Cold Weather Reliability Event definition. The additional criteria is a step in the right direction but could still lead to undue administrative burden without a corresponding reliability benefit. The 10% of the total capacity and exceeding 20MW is still far too low and could cause Corrective Action Plans for events that do not impact the Bulk Electric System resulting in substantial and unnecessary burdens. Enel suggests again that NERC adopt the same approach used in PRC-004, where misoperations that affect an aggregate nameplate rating of less than or equal to 75MVA of BES facilities **are excluded**. For this reason Enel agrees with the MRO NSRF comments on this defined term. In addition, Enel would like to ensure that criteria is applied to "available" capacity as indicated by the forecasted power curve. Renewables cannot generate during low wind or solar conditions and therefore criteria should not be applied to unavailable capacity or nameplate.

Likes 0	

Dislikes 0	

Response

Rhonda Jones - Invenergy LLC - 5	
Answer	No
Document Name	

Comment

Invenergy does not agree with the definitions as currently drafted and offers the following recommendations.

Generator Cold Weather Reliability Event:

As noted below in response to Question 6, Invenergy recommends setting the forced derate threshold in a manner consistent with NERC's BES criteria, using a minimum of 20 MVA for individual generating units and a minimum of 75 MVA for dispersed power producing resources.

Invenergy proposes the following change to condition (1) of the definition:

(1) A forced derate of:

- More than 10% of the total capacity of the unit and exceeding 20 MVA for generating units identified under Inclusion I2 of the BES definition; or
- More than 10% of the total capacity of the generating facility and exceeding 75 MVA for generating units identified under Inclusion I4 of the BES definition.

Additionally, Invenergy recommends removing the word "apparent" from the definition.

Extreme Cold Weather Temperature:

The proposed definition improves on the previous draft by using a percentile instead of the single minimum hourly temperature and data starting on 1/1/2000 rather than 1/1/1975.

As Invenergy did in response to the first ballot, we propose that the methodology use a multi-day average temperature rather than hourly temperatures, and a reliability analysis-based percentile rather than the 0.2 proposed in the latest draft. Without endorsing the exact values proposed, we note the proposal by Commission Staff at the Public Utility Commission of Texas (see Project No. 53401, Electric Weather Preparedness Standards-Phase II, Memorandum and Proposal for Publication dated May 19, 2022) would be expected to yield a more reasonable requirement: "…the lesser of the minimum ambient temperature at which the resource has experienced sustained operations or the 95th percentile minimum average 72-hour temperature reported in ERCOT's historical weather study…for the weather zone in which the resource is located." (Emphasis added.)

To demonstrate the need for this alternative approach, consider solar generators. Under the SDT's proposal, the calculation of the Extreme Cold Weather Temperature will be heavily influenced by colder nighttime temperatures, when there is no solar generation. Using a multi-day period would more reasonably set the minimum temperature standard for these facilities.

Finally, Generator Owners need additional detail on the mechanics of calculating the Extreme Cold Weather Temperature as it is presently defined. For example, if hourly temperature data back to 1/1/2000 at a Generator Owner's nearest weather station(s) are unavailable, should the Generator Owner use only the data available at that station, or use an alternative station regardless of the distance from the facility? What fraction of the data from the nearest station must be missing before an alternative station is used?

Likes 0	
Dislikes 0	

Response

Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	

Comment

Avista supports all three definitions for this first phase, but we also propose additional revisions to the Generator Cold Weather Critical Supply Component and the Cold Weather Reliability Event because additional clarity is needed and that can be addressed during the next phase of this project. (See below)

Generator Cold Weather Critical Supply Component: Use of the undefined term "fixed fuel supply component" within the proposed definition of Generator Cold Weather Critical Component creates confusion. While we support the explanation provided by the SDT in the Technical Rationale, the Technical Rationale has no standing as a compliance document. For this reason, we ask the SDT to consider defining this term within the framework of the next phase of this project. We suggest the following for SDT consideration:

Fixed Fuel Supply Component: Are non-mobile equipment that support the reliable delivery of fuel to the generating unit and under the control the Generator Owner at a plant site. Gaseous, liquid, or solid fuel handling components that are installed on site as fixed parts of the fuel delivery system that are under the Generator Owner's control would be included. Components that would not be included would be mobile equipment such as trains, bulldozers, or other equipment that are not fixed in one location.

Generator Cold Weather Reliability Event: EEI is concerned with the use of the term "specified", as it relates to the start-up time of a generator during cold weather events, because it is unclear clear who would be responsible for specifying the start-up time. Results Based Standards should "define a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome." (NERC Results Based Standards – Performance Based; https://www.nerc.com/pa/Stand/Pages/ResultsBasedStandards.aspx#:~:text=Results%20based%20standards%20are%20standards,the%20NERC%20Standard%20Processes%20Manual.)

Likes 0	
Dislikes 0	

Response

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	

Comment

AEPC has signed on to ACES comments, please see their responses.

Likes 0	
Dislikes 0	

Response

Deanna Carlson - Cowlitz County PUD - 5

Answer	No
Document Name	
Comment	

Agree with comments provided by Russell Noble.

Likes 0	
Dislikes 0	

Response

Russell Noble - Cowlitz County PUD - 3

Answer	No
Document Name	
Comment	

While Cowlitz appreciates the effort so far, further improvements are needed. We agree with comments provided by the North American Generator Forum.

Likes 0	
Dislikes 0	

Response

Michelle Amarantos - APS - Arizona Public Service Co. - 5

Answer	No
Document Name	
Comment	

APS supports all three definitions for this phase. However, we support EEI's proposed revisions to Generator Cold Weather Critical Component and Cold Weather Reliability Event during the next phase of the project.

Specifically, APS supports EEI's proposal to add a definition for Fixed Fuel Supply Component to eliminate confusion within the Generator Cold Weather Critical Component definition. Additionally, APS agrees that within the Generator Cold Weather Reliability definition, the use of term "specified" as it relates to the start-up time of a generator during cold weather events is ambiguous, as it unclear who would be responsible for specifying the start-up time.

Likes 0	
Dislikes 0	

Response

Whitney Wallace - Calpine Corporation - 5 - WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	

See comment for Question 1. For Start Failure, the line should read, "a start-up failure where the unit fails to synchronize within a specified and scheduled start-up time." The addition of "**and scheduled**" makes it clear that a failed start resulting from a GO starting a unit on its own accord or during testing would not be reported as a failed start under the winterization program.

The definition of GCWRE should be clarified to state (changes are bold):

Generator Cold Weather Reliability Event: **A failure of a Generator Cold Weather Critical Component that causes** one of the following events:

(1) a forced derate of more than 10% of the total capacity of the unit and exceeding 20 MWs for longer than four hours in duration;

(2) a start-up failure where the unit fails to synchronize within a specified **and scheduled** start-up time; or

(3) a Forced Outage, for which the apparent cause(s) is due to freezing of equipment within the Generator Owner's control and the dry bulb temperature at the time of the event was at or above the Extreme Cold Weather Temperature.

Furthermore, a component failure that occurs during a cold weather event but was not caused by the cold weather event should not fall under this Standard. NERC should revise the Standard to make this clear.

Likes 0	
Dislikes 0	
Response	

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Foung Mua, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Wei Shao, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; - Tim Kelley, Group Name SMUD / BANC

Answer	No
Document Name	
Comment	

The proposed definition for Cold Weather Reliability Event uses the language "total capacity of the unit" which is vague and not defined in the NERC Glossary of Terms. SMUD recommends that the language "Facility Rating of the unit" be used which is more specific and includes a NERC defined term that is referenced in other reliability standards.

Likes 0	
Dislikes 0	
Response	

George Brown - Acciona Energy North America - 5

Answer	No
Document Name	
Comment	

Acciona Energy supports Midwest Reliability Organization's (MRO) NERC Standards Review Forum's (NSRF) comments on this question.

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring

Answer	No
Document Name	
Comment	

For the second item, the "specified time" is ambiguouse. If it is completely up to the generator operator, then is is not a standard. Perhaps the specified time could be required to be included in the Operating Plan or Data requirements of R3.

Likes 0	
Dislikes 0	

Response

Colin Chilcoat - Invenergy LLC - 6

Answer	No
Document Name	
Comment	

Invenergy does not agree with the definitions as currently drafted and offers the following recommendations.

Generator Cold Weather Reliability Event:

As noted below in response to Question 6, Invenergy recommends setting the forced derate threshold in a manner consistent with NERC's BES criteria, using a minimum of 20 MVA for individual generating units and a minimum of 75 MVA for dispersed power producing resources.

Invenergy proposes the following change to condition (1) of the definition:

(1) A forced derate of:

- More than 10% of the total capacity of the unit and exceeding 20 MVA for generating units identified under Inclusion I2 of the BES definition; **or**
- More than 10% of the total capacity of the generating facility and exceeding 75 MVA for generating units identified under Inclusion I4 of the BES definition.

Additionally, Invenergy recommends removing the word “apparent” from the definition.

Extreme Cold Weather Temperature:

The proposed definition improves on the previous draft by using a percentile instead of the single minimum hourly temperature and data starting on 1/1/2000 rather than 1/1/1975.

As Invenergy did in response to the first ballot, we propose that the methodology use a multi-day average temperature rather than hourly temperatures, and a reliability analysis-based percentile rather than the 0.2 proposed in the latest draft. Without endorsing the exact values proposed, we note the proposal by Commission Staff at the Public Utility Commission of Texas (see Project No. 53401, Electric Weather Preparedness Standards-Phase II, Memorandum and Proposal for Publication dated May 19, 2022) would be expected to yield a more reasonable requirement: “…the lesser of the minimum ambient temperature at which the resource has experienced sustained operations or **the 95th percentile minimum average 72-hour temperature** reported in ERCOT’s historical weather study…for the weather zone in which the resource is located.” (Emphasis added.)

To demonstrate the need for this alternative approach, consider solar generators. Under the SDT’s proposal, the calculation of the Extreme Cold Weather Temperature will be heavily influenced by colder nighttime temperatures, when there is no solar generation. Using a multi-day period would more reasonably set the minimum temperature standard for these facilities.

Finally, Generator Owners need additional detail on the mechanics of calculating the Extreme Cold Weather Temperature as it is presently defined. For example, if hourly temperature data back to 1/1/2000 at a Generator Owner’s nearest weather station(s) are unavailable, should the Generator Owner use only the data available at that station, or use an alternative station regardless of the distance from the facility? What fraction of the data from the nearest station must be missing before an alternative station is used?

Likes 0	
Dislikes 0	

Response

Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations

Answer	No
Document Name	

Comment

The current definitions as written leave ample room for interpretation. While this is often desired, we believe that in this instance they do not provide enough clarity to the requirements of EOP-012. The specific concerns with the current verbiage are as follows:

Generator Cold Weather Critical Component: While the open-endedness of “any generating unit component” is desired in that it allows the GO to identify critical components on a per-unit basis, it does not appear to include any “common” equipment shared between units. Examples would include service water, instrument air, ammonia, ash handling, common bus isolation breakers/switches, etc.

The proposed modification to the definition is: “Any generating unit component or associated fixed fuel supply component, to include any critical equipment shared between multiple units (i.e. Balance of Plant (BOP) and/or Common equipment), that is under the Generator Owner’s control and is susceptible to freezing issues, the occurrence of which would likely lead to a Generator Cold Weather Reliability Event.”

Extreme Cold Weather Temperature: The flexibility and intent behind using the “lowest 0.2 percentile” is greatly appreciated; however, the requirement to use “the hourly temperatures measured” seems a bit excessive. Given the inherent difficulty of compiling a dataset containing greater than 49,000 data points and then calculating the lowest 0.2 percentile, we recommend modifying the definition to include daily minimum temperatures from the same time period. This modification would reduce the size of the dataset significantly (down to ~2076 total days) and should not change the resulting Extreme Cold Weather Temperature by any significant statistical margin given that the daily minimum will contain the hourly minimums.

Lastly, the requirement to use a fixed data start date of 01/01/2000 means the dataset will grow by approximately 2,160 data points if using the hourly metric while only 90 data points if using the daily minimum metric. Therefore, it is our recommendation to use a 20-year rolling time period if staying with the hourly metric.

If the hourly metric is to remain, a proposed modification to the definition would be: "The temperature equal to the lowest 0.2 percentile of the actual hourly temperatures measured in December, January, and February from the previous 20 years immediately prior to the date the temperature is calculated. "

The preferred modification would be to abandon the hourly metric in favor of the daily minimum metric. Thus the *preferred* proposed modification to the definition is: "The temperature equal to the lowest 0.2 percentile of the actual daily minimum temperatures measured in December, January, and February from 1/1/2000 through the date the temperature is calculated."

Generator Cold Weather Reliability Event: Pertaining to event type 2 that may constitute a Generator Cold Weather Reliability Event (GCWE):

2. "A start-up failure where the unit fails to synchronize within a specified start-up time": Who specifies the start-up time? Per the draft Technical Rationale and Justification for EOP-012-1, start-up failures are defined using a modified version of the GADS definition in order to ensure consistency across all jurisdictions for this standard. Our concern stems from the language in R2 that references the GADS definition of "specified start-up time" without providing the additional clarification found in the 2022 GADS Data Reporting Instructions. Our recommendation is to modify this subsection as follows: "A start-up failure where the unit fails to synchronize within a specified start-up time. The specified start-up time period for each unit is determined by the GO/GOP based on the condition of the unit at the time of start-up."

Likes 0	
Dislikes 0	

Response

Adam Lee - MGE Energy - Madison Gas and Electric Co. - 4

Answer	No
Document Name	

Comment

Madison Gas and Electric supports the comments of the MRO NSRF

Likes 0	
Dislikes 0	

Response

Ronald Bauer - MGE Energy - Madison Gas and Electric Co. - 3

Answer	No
Document Name	

Comment

Madison Gas and Electric supports the comments from the MRO NSRF.

Likes 0	
Dislikes 0	
Response	
Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	No
Document Name	
Comment	

Capital Power supports the North American Generators Forum (NAGF) response to this question.

Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	

MISO supports the comments submitted by the ISO/RTO Council Standards Review Committee (IRC SRC). In addition, we are submitting comments on behalf of MISO as an individual entity.

In analyzing the proposed Extreme Cold Weather Temperature, MISO discovered that it doesn't go far enough to capture many of the hours in recent major cold weather events, including Winter Storm Uri (February 2021), South Central Cold Weather Event (January 2018) and the Polar Vortex (January 2014). **Without an adequate temperature definition, the standard will not achieve its intended outcome or provide a measurable reliability benefit as the balance of winterization requirements hinge upon the adequacy of this definition**.

The current **Extreme Cold Weather Temperature (ECWT)** definition sets "the temperature equal to the lowest 0.2 percentile of the hourly temperatures measured in December, January, and February from 1/1/2000 through the date the temperature is calculated."

In analyzing the proposed definition, we found that **the lowest 0.2 percentile is insufficient to capture many of the hours in past extreme events** (*see* detailed analysis below). Therefore, we recommend the SDT modify the percentile. One option is to model this threshold after an established industry percentile; e.g. the Loss of Load Expectation (LOLE) which is equivalent to one day in ten years. This equates to:

LOLE = 1 day/(10 years x 365 days/year) = 0.000274 or **0.0274 percentile** almost 10 times less than the current benchmark.

In contrast, the current 0.2 percentile in the ECWT definition equates to:

ECWT = 1 day/(0.002 x 365 days/year) = **1 day every 1.37 years** which indicates a need to plan for a loss of load expectation (LOLE) on an almost annual or yearly basis.

Planning to shed load in support of a major event on an annual basis fails to adequately address the findings from past major events and will not provide measurable reliability benefits. Therefore, **MISO recommends the SDT adopt a more stringent percentile such as that for LOLE (of 0.0274)** in determining the Extreme Cold Weather Temperature definition.

Using a smaller percentile also has the added benefit of addressing Generator Owner concerns that the definition not be based on the single coldest hour experienced; but rather a temperature for which has been realized on multiple occasions over a period of time.

MISO Temperature Analysis

To evaluate the adequacy of the Extreme Cold Weather Temperature definition, MISO examined two cities in its footprint - Lake Charles, Louisiana (LCH) and Little Rock, Arkansas (LIT) – both of which were adversely affected during the Winter Storm Uri (February 2021) event.

For LCH, the proposed ECWT would be 24.98° F. When reviewing the hourly data from December 1991 to February 2022, 206 hours meet or fall below that ECWT over thirty-eight days and twenty-five events. LCH also had sixteen hours (16) during Winter Storm Uri the proposed ECWT would exclude.

The proposed ECWT for LIT is 12.92° F. In the hourly data from December 1991 to February 2022, 183 hours meet or fall below that ECWT over thirty-two days and twenty-one events. LIT also had fifty-seven (57) hours during Winter Storm Uri the proposed ECWT would exclude.

In light of the foregoing, the SRC recommends using a fifty year look back period (replacing the year 2000 with the year 1972). The SRC also recommends striking the 0.2 percentile entirely or, at least, changing it to the 0.**02** percentile so the resulting ECWT more accurately reflects *extreme* cold temperatures.

Likes 0	
Dislikes 0	
Response	
Imane Mrini - Austin Energy - 6	
Answer	No
Document Name	
Comment	

The definition of Generator Cold Weather Reliability Event, item 1 is not entirely clear. Is the intent to exclude derates equal to 20MW (if they are more than 10%) or equal to 10% of total unit capacity (when more than 20MW)? Suggest rewording to : a forced derate exceeding 10% of the total capacity of the unit but no less than 20 MW for longer than four hours in duration;"

Likes 0	
Dislikes 0	
Response	
Mark Young - Tenaska, Inc. - 5	
Answer	No
Document Name	
Comment	

Generator Cold Weather Reliability Event - In (1), (2), and (3), change “unit” to “unit or combined cycle block”.

The event descriptions do not specifically indicate events relating to freezing.

Suggested change:

*(1) a forced derate **due to freezing equipment**, which results in more than 10% of the total capacity of the unit and exceeding 20 MWs for longer than four hours in duration*

*(2) a start-up failure where the unit fails to synchronize within a specified start-up time **due to freezing equipment.***

On a temperature related note, unless there has been some analysis of historical data to substantiate it, imposing the 20mph wind assumption on top of the temperature requirement will likely cause plants to design for a theoretical weather condition that has never existed. Given the costs and challenges involved with this effort, we should not be basing design on arbitrary assumptions.

Also relating to temperature, “Design temperature”, “historical operating temperature”, or “current cold weather performance temperature” do not have a practical meaning for wind turbines with respect to cold weather reliability. Wind turbines are often rated to perform at extremely low temperatures. The reliability issue is icing “conditions” which usually happen at temperatures much higher than the lowest rated temperature. Icing conditions are related to a combination of temperature and moisture vs a specific low temperature. Additionally, there is no known technology that reliably mitigates all icing concerns.

Likes 0	
Dislikes 0	

Response

Steven Sconce - EDF Renewable Energy - 5

Answer	No
Document Name	

Comment

The term Generator is not clearly defined. Please refer to our comments in question #4 and #5. EDF supports the comments of NAGF and EEI.

Likes 0	
Dislikes 0	

Response

Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3

Answer	No
Document Name	

Comment

MidAmerican Energy supports the EEI and NSRF comments for this question. We would also expound on NSRF's comments that one location's weather data would mean over 175,000 points of data.

Likes 0	
Dislikes 0	

Response

Carl Pineault - Hydro-Qu?bec Production - 1,5

Answer	No
Document Name	

Comment

How is the BA held responsible for determining what is considered the "winter season"? EOP-012-1 section 4.2 lacks clarity and there are no requirements concerning this responsibility, nor is it mentioned in the TR.

Likes 0	
Dislikes 0	

Response

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	

Comment

- Generator Cold Weather Reliability Event

The MRO NSRF disagrees with the definition of Generator Cold Weather Reliability Event as written. We believe that 10% of the total capacity and exceeding 20MW is far too low for many generating units. The MRO NSRF appreciates the Standard Drafting Teams (SDT) adding the "and exceeding 20MW" prose for a Generator Cold Weather Reliability Event. However, we would suggest tying the magnitude back to a reliability concept such as the BES Definition: 75MVA/20MVA. The simple reasoning is that for a 100MVA facility identified under Inclusion I4 of the BES Definition, a derate of 10% (10MVA) and 20MW would not constitute a reliability concern as it does not even meet the thresholds to be BES for generation facilities identified under inclusion I4. Given that, the MRO NSRF believes the threshold for a Generator Cold Weather Reliability Event as currently proposed is adding an undue administrative burden without a clear increase in reliability.

The MRO NSRF suggests the following language modification to this Definition:

Generator Cold Weather Reliability Event - One of the following events, for which the apparent cause(s) is due to freezing of equipment within the Generator Owner's control and the dry bulb temperature at the time of the event was at or above the Extreme Cold Weather Temperature:

(1) a forced derate of:

- *10% or greater than or equal to 20MVA of the Facility Rating, whichever is greater, for generating units identified under Inclusion I2 of the BES definition* *or*

- *10% or greater than or equal to 75MVA of the Facility Rating, whichever is greater, for generating units identified under Inclusion I4 of the BES definition*

for longer than four hours in duration;

(2) a start-up failure where the *generating* unit fails to synchronize within a specified start-up time;

or

(3) a Forced Outage.

If the current ballot gains approval without changes to the proposed language of the Standard, the MRO NSRF would like to suggest addressing the aforemention comments in a future phase of this project.

- Extreme Cold Weather Temperature

Regarding Extreme Cold Weather Temperature, the MRO NSRF would like to thank the SDT for the changes incorporated from Draft 1 to Draft 2. While we appreciate the effort to reduce the burden on Generator Owner and Generator Operators to evaluate the Extreme Cold Weather Temperature, we disagree with the proposed definition for several reasons. First, the MRO NSRF would suggest the SDT to work with the National Oceanic and Atmospheric Administration (NOAA), National Weather Service (NWS), team members of the FERC, NERC and Regional Entity Staff Report to develop the appropriate percentile this definition will require Generator Owners and Generator Operators to meet in Requirements R1 and R2. Within the technical rationale, the SDT states “select the 0.2 percentile of winter month temperatures since 1/1/2000 to identify a temperature which has been rarely surpassed, but which allows some margin for a Generator Owner to have previously demonstrated successful operation”. While we agree with a statistical approach, we cannot support the level of 0.2 percentile without a scientific and statistical analysis to determine if 0.2 is appropriate.

As it relates to the portion of the of the definition that states “from 1/1/2000 through the date the temperature is calculated”, the MRO NSRF suggests two items. First, confer with the members from NOAA, NWS and ECCC to confirm that keeping 1/1/2000 as the baseline date is appropriate (for example, not dropping the oldest 5 year period for each new calculation) or if it should be on a latest 15, 20, 30 winter season basis. Secondly, the way the current language is proposed, in conjunction with requirement R4, we are concerned of an overlap between the effective date of the standard and implementation date of the requirement could cause inadvertent confusion as to when to calculate the winter season temperature. For example, if the effective date of the standard is 1/1/2023, does an entity calculate the Extreme Cold Weather Temperature to 12/31/2022? Therefore, the MRO NSRF proposes to clarify “through the date the temperature is calculated” to “through the end of the previous winter season of the date the temperature is calculated”.

The MRO NSRF requests clarification on data souce location. Historical hourly temperature data for many project locations is nonexistent. Several of our members have considered National Weather Service data from small airports, but these stations can be many miles away from the project locations. The NSRF requests modification to the language in the definition to the effect of, “the closest NWS site data is adequate for calculating this temperature (ECWT)”.

Additionally, the MRO NSRF request the SDT consider changing the beginning date of records for the Extreme Cold Weather Temperature from 1/1/2000 to 1/1/2005. While there is certainly temperature data on the NOAA NCEI website for most airports located near large population centers that goes back to the 1/1/2000 date, there is abundantly more data available for some more remote areas starting in 2005. This would help entities obtain a more accurate temperature for the local area that generators may be in, which for some generation facilities such as wind or solar farms may be quite remote and several hundred miles away from any major population area.

In consideration of this data calculation, perhaps NERC can work with NOAA’s National Climatic Data Center (NCDC) on setting up this data for download for industry members. In the June 2013 issue of the Bulletin of the American Meteorological Society, “Alternative Climate Normals: Impacts to the Energy Industry”, the article states that NCDC has been expanding its “proactive engagement” with various sectors and has analyzed what data the energy sector requires for climate normals. To ensure Generator Owners and Generator Operators are using the same data, the NSRF would like to propose that NERC and NCDC develop a data set so industry members do not have to manipulate large sets of data. The winter season data set will be over 2,000 data points and currently as proposed over a 20 year span. Forward looking, this data manipulation will require an abundance of resources to complete for new and existing generation resources.

Alternative Climate Normals: Impacts to the Energy Industry in: Bulletin of the American Meteorological Society Volume 94 Issue 6 (2013) (ametsoc.org)

Likes 0	
Dislikes 0	

Response	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	No
Document Name	
Comment	
Alliant Energy supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	No
Document Name	
Comment	
NPPD agrees with the definition of as proposed, with the following exceptions: Cold Weather Reliability Event definition: we request the definition be modified to the following: *"(1) a forced derate of more than 10% of the* ***Facility Rating*** *of the unit and exceeding 20 MWs for longer than four hours in duration;*". We believe the basis should be the Facility Rating of the generator rather than the capacity. We believe this modification would provide additional clarity and provide for a more accurate calculation. Extreme Cold Weather Temperature definition: historical hourly temperature data for many project locations is nonexistent. Several entities have considered National Weather Service data from small airports, but these stations can be many miles away from the facility locations. We request modification to the language in the definition to the effect of, "the closest NWS site data is adequate for calculating this temperature (ECWT)". Also, NPPD requests the SDT consider changing the beginning date of records for the Extreme Cold Weather Temperature from 1/1/2000 to 1/1/2005. While there is certainly temperature data on the NOAA NCEI website for most airports located near large population centers that goes back to the 1/1/2000 date, there is abundantly more data available for some more remote areas starting in 2005. This would help entities obtain a more accurate temperature for the local area that generators may be in, which for some facilities may be quite remote and several hundred miles away from any major population area.	
Likes 0	
Dislikes 0	
Response	
Eric Ruskamp - Lincoln Electric System - 6, Group Name LES	
Answer	No
Document Name	
Comment	

The definition for Extreme Cold Weather Temperature seems overly complicated and will require a lot of data crunching to reach a number that could be attained by looking at lowest recorded temperature in each year, without having to retrieve hourly data and perform statistical analysis.

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

ECWT: The EOP-012 standard as written would not have mitgated much of the events that happened during Feb 2021 in the Southern US. It looks like the Standard is written to ensure that Generators are able to operate to the “normal” experienced low temperatures experienced during the winter months. The ECWT definition does not address the “Extreme” cold weather. It specifies something that sounds good, but in reality leaves the “equipment freezes” door wide open: the criterion is that fixed portions of cold-weather sensitive equipment should not freeze when exposed to 0.2% of the coldest winter hours in the past 20 years. To give an example: Dallas, TX got down to -2degF for quite a while during storm Uri – the standard requires protection down to 14degF. This means that for the Dallas area, this standard would have minimal influence during a similar extreme event.

ISO-NE supports the recommendation from the SRC Comments that the Standard should consider a period of sustained cold temperatures (e.g., the average of the lowest recorded six hours at a given location) as the ECWT.

GCWRE: Additionally, the term Generating unit is vague and is open to interpretation. Does this mean each generating unit or is it an entire facility. Depending on the interpretation of unit by a GO, they could declare each unit separate in the large plant with many units which could preclude them from the applicability section of this standard as well as exempt form the CAP requirements outlined in Requirement 6.

Likes 0	
Dislikes 0	

Response

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	No
Document Name	

Comment

The NAGF agrees with creation of the definitions. The NAGF has concerns with the proposed definitions as written.

- The definition of Generator Cold Weather Reliability Event is not clear. Use of the word “apparent” in the definition has the potential to cause disagreements during an audit due to the multiple meanings of the word. It would be better to use a word that has a consistent definition rather than a word with multiple different meanings. Synonyms for apparent include assumed, evident, ostensible, ostensive, presumed, prima facie, putative, reputed, seeming, supposed. Based on this list of words, if an auditor assumes that an outage was caused by freezing based on the timing of the outage the auditor would be correct to expect a CAP for that event. (As written, an auditor can take the position any outage that is assumed to be caused by freezing requires a CAP to be created. Then the CAP must either be implemented, or a declaration made that the CAP will not be implemented.) While we do not believe this is the intent of the SDT, the NAGF asks the SDT to address this potential conflict by replacing the word apparent with a word that provides clearer intent.

- The Generator Cold Weather Reliability Event uses the term “freezing of equipment” and Generator Cold Weather Critical Component uses “susceptible to freezing issue” without clearly defining what is meant. While the SDT has spent a significant amount of time discussing what they mean by freezing, that discussion does not appear to be captured well in this documentation. The NAGF recommends that this issue be clearly explained to ensure that all entities understand what issues are to be addressed.
- The SDT has used the Extreme Cold Weather Temperature in the definition of Generator Cold Weather Reliability Event which will cause a Generator Owner to do a CAP under R6. This definition should instead use the term “generator minimum operating temperature as identified in the cold weather plan” to better address reliability. The NAGF agrees with the Technical Rationale document that using the Extreme Cold Weather Temperature treats everyone equally. However, in this case, treating everyone equally does not address the reliability concerns raised in the Joint Inquiry Report. The NAGF explain this position in more detail under question 8.

Likes 0	
Dislikes 0	

Response

Ruchi Shah - AES - AES Corporation - 5

Answer	No
Document Name	

Comment

AES Clean Energy supports comments submitted by NAGF.

Likes 0	
Dislikes 0	

Response

LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6

Answer	No
Document Name	

Comment

The defined Extreme Cold Weather Temperature does not result in a temperature that would cause a Generator Cold Weather Reliability Event (as defined by this standard). It should be no higher than the lowest historically recorded temperature for the region.

Likes 0	
Dislikes 0	

Response

Stewart Rake - Luminant Mining Company LLC - 7	
Answer	No
Document Name	

Comment

The definition of "Extreme Cold Weather Temperature"--though an improvement over the cold weather standard in the previous version of EOP-012, which required continuous operations at the documented lowest hourly temperature experienced at the particular location since Jan. 1, 1975--remains problematic and could exacerbate resource adequacy challenges facing the nation (particularly in the Texas Reliability Entity, Inc. (TRE) region), without actually improving reliability outcomes—i.e., if the costs to achieve these standards prove substantial, the adoption of the standards could contribute to early retirements or cancellations or delays of planned resources, which could harm long-term resource adequacy and thus reliability. The new proposal is still extremely conservative, effectively equating to a 99.8th percentile coldest hourly temperature experienced at the applicable weather station for a resource since 2000, during the months of December, January, and February—in other words, a temperature that is colder than the temperature experienced in 99.8 percent of the total hours studied. In the draft Technical Requirements document (NERC's Calculating Extreme Cold Weather Temperatures), the 0.2 percentile lowest temperature for the example weather station was 2 degrees Fahrenheit, which apparently had occurred in only 11 hours in the study period (dating back to January 1, 2000), and those 11 hours seemingly were not contiguous.

A requirement for new resources to operate for 12 consecutive hours, and existing resources to operate for 1 continuous hour, at a temperature experienced so few times in the past 22 years could require the Generator Owner to make significant capital expenditures (e.g., depending on the design specifications of the resource and depending on whether the SDT clarifies the meaning of "freeze protection measures" as recommended by Vistra under Question 5) to prepare for an extremely unlikely future occurrence, without any way for the Generator Owner to recoup the costs. The proposed definition and the accompanying standard based on that definition for new resources (R1) seems especially unworkable and unreasonable, as it would require new resources to operate for 12 consecutive hours at a temperature that would have occurred for one hour on only a handful of (apparently separate) occasions over the past two decades—in other words, new resources would be required to prove they could operate in conditions that have apparently never occurred, at least during the lookback period (i.e., while the temperature would have reached the Extreme Cold Weather Temperature for 1-hour periods at least a few times since 2000, it is unlikely that the Extreme Cold Weather Temperature would have occurred for 12 consecutive hours since 2000). In lieu of making those unrecoverable expenditures in an attempt to prepare their resource to operate in speculative future extended extreme cold temperatures, investors may forego or cancel resource additions. Similarly, an existing Generator Owner that cannot operate for one hour at its Extreme Cold Weather Temperature may decide to retire early in lieu of making significant expenditures to attempt to operate at that temperature for one hour in the future.

Notably, the new proposal is far more conservative than the proposed extreme weather standard under consideration for the TRE region, by the Public Utility Commission of Texas (PUCT). In a pending rulemaking, the PUCT has proposed an extreme cold weather standard based on sustaining operations at either the 95th percentile minimum average 72-hour temperature as published in a recurring study by the balancing authority (which will be filed every 5 years and will examine weather outcomes dating back over 100 years) or the lowest ambient temperature at which the particular resource has experienced sustained operations. While Vistra has urged the PUCT to not adopt the alternative "lowest ambient temperature" standard for a variety of reasons (notably that it may effectively override the 72-hour average standard and impose different weather standards for different resources), and while the PUCT has yet to adopt its final rule establishing its standards, Vistra believes the intent of the "lowest temperature" standard proposed by the PUCT is actually to require resources to maintain weatherization measures that go above and beyond the standard, rather than to supplant the 72-hour average standard. In any event, the PUCT's proposed "lowest temperature" standard would still be preferable to the 0.2 percentile standard proposed by the SDT, since the PUCT standard would take into account the resource's demonstrated capabilities, not require it to sustain operations at a temperature at which it has never sustained operations, and not require new resources to sustain operations at that temperature for durations and in compounding weather conditions that are extremely unlikely to have any historical precedent.

Vistra urges the SDT to reconsider the proposed 0.2 percentile lowest hourly temperature since Jan. 1, 2000 in favor of something closer to the PUCT standard, i.e., either an average lowest ambient temperature (at the 95th or even 99th percentile) over a specified number of hours (e.g., 12 hours, 24 hours, 72 hours, etc.) since a specified date (e.g., Jan. 1, 2000) or a standard based on actual operations (for existing resources) or design specifications (for new or existing resources). If the SDT were to redefine "Extreme Cold Weather Temperature" to incorporate an average lowest ambient temperature, then the NERC guide for Calculating Extreme Cold Weather Temperature would also need to be modified to develop a methodology for calculating that temperature, or alternatively, the balancing authority for each region (e.g., ERCOT for the TRE region) could be responsible for publishing the applicable average temperatures on some periodicity (e.g., every five years). It may be preferable to have the balancing authority publish that data periodically, since that provides a common reference point for all resources operating in the region.

The definition of "Generator Cold Weather Reliability Event" also should be clarified in a couple of ways. First, the phrase that begins "for which the apparent cause(s)" should be moved up to clarify that it modifies all three paragraphs of the definition (i.e., relating to (1) derates, (2) start-up failures, and (3) forced outages), rather than appearing directly at the end of paragraph (3) without any paragraph break, which could provide the impression that it only modifies that last paragraph. In addition, the definition for paragraph (2) (relating to start-up failures) should be modified to clarify that the term “start-up failure” will have the same meaning that it does for purposes of Generating Availability Data System (GADS) reporting. For instance, the definition could be modified to state that “Generator Cold Weather Reliability Event” means:

“One of the following events, if the apparent cause(s) of that event(s) is due to freezing of equipment within the Generator Owner’s control and the dry bulb temperature at the time of the event was at or above the Extreme Cold Weather Temperature:

(1) a forced derate of more than 10% of the total capacity of the unit and exceeding 20 MWs for longer than four hours in duration;

(2) a start-up failure where the unit fails to synchronize within a specified start-up time, as defined in the instructions for mandatory reporting of startup failures in the Generating Availability Data System; or

(3) a Forced Outage

Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	No
Document Name	
Comment	

The Extreme Cold Weather Temperature definition differs from the language/method in the Public Utility Commission of Texas Project No. 53401 to define the minimum temperature at which a resource is reasonably expected to ensure sustained operation.

LCRA offers the following revisions to events 1 and 2 of the Generator Cold Weather Reliability Event definition:

(1) a forced derate of more than 10 of the *seasonally adjusted High Sustainable Limit (HSL)* of the unit and exceeding 20 MWs for longer than four hours in duration;

(2) a start-up failure where the unit fails to synchronize within *the Balancing Authority’s* specified start-up time; or”

Likes 0	
Dislikes 0	
Response	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	No
Document Name	
Comment	

SIGE is requesting the Standard Drafting Team consider the following recommendations:

For **Generator Cold Weather Reliability Event**:

- As written, bullets 1 and 2 could apply at any time during the year. SIGE is proposing the addition of a qualify to define the applicability of bullets 1 and 2. Additionally, SIGE is proposing increasing 10% to 15% to allow larger units capacity for everyday variances:

Generator Cold Weather Reliability Event: One of the following events ***occurring when the ambient temperature is at or below 32 degrees****:*

(1) a forced derate of more than ***15%*** *of the total capacity of the unit and or exceeding 20 MWs,* ***whichever is greater****, for longer than four hours in duration;*

(2) a start-up failure where the unit fails to synchronize within a specified start-up time; or

(3) a Forced Outage, for which the apparent cause(s) is due to freezing of equipment within the Generator Owner's control and the dry bulb temperature at the time of the event was at or above the Extreme Cold Weather Temperature

- In alignment with EEI's comment, SIGE is also voicing concern that use of the term "specified" in bullet 2 is unclear as to whom is responsible or what is determining the 'specifying' of the start-up time.

For **Generator Cold Weather Critical Component**, SIGE believes that the inclusion of the phrase "fixed fuel supply component" in the proposed definition is not clear and supports EEI's proposed definition of "fixed fuel supply component".

Likes 0	
Dislikes 0	

Response

Dan Roethemeyer - Vistra Energy - 5

Answer	No
Document Name	

Comment

The definition of "Extreme Cold Weather Temperature"--though an improvement over the cold weather standard in the previous version of EOP-012, which required continuous operations at the documented lowest hourly temperature experienced at the particular location since Jan. 1, 1975--remains problematic and could exacerbate resource adequacy challenges facing the nation (particularly in the Texas Reliability Entity, Inc. (TRE) region), without actually improving reliability outcomes—i.e., if the costs to achieve these standards prove substantial, the adoption of the standards could contribute to early retirements or cancellations or delays of planned resources, which could harm long-term resource adequacy and thus reliability. The new proposal is still extremely conservative, effectively equating to a 99.8th percentile coldest hourly temperature experienced at the applicable weather station for a resource since 2000, during the months of December, January, and February—in other words, a temperature that is colder than the temperature experienced in 99.8 percent of the total hours studied. In the draft Technical Requirements document (NERC's Calculating Extreme Cold Weather Temperatures), the 0.2 percentile lowest temperature for the example weather station was 2 degrees Fahrenheit, which apparently had occurred in only 11 hours in the study period (dating back to January 1, 2000), and those 11 hours seemingly were not contiguous.

A requirement for new resources to operate for 12 consecutive hours, and existing resources to operate for 1 continuous hour, at a temperature experienced so few times in the past 22 years could require the Generator Owner to make significant capital expenditures (e.g., depending on the design specifications of the resource and depending on whether the SDT clarifies the meaning of "freeze protection measures" as recommended by Vistra under Question 5) to prepare for an extremely unlikely future occurrence, without any way for the Generator Owner to recoup the costs. The proposed definition and the accompanying standard based on that definition for new resources (R1) seems especially unworkable and unreasonable, as it would require new resources to operate for 12 consecutive hours at a temperature that would have occurred for one hour on only a handful of (apparently separate) occasions over the past two decades—in other words, new resources would be required to prove they could operate in conditions that have apparently never occurred, at least during the lookback period (i.e., while the temperature would have reached the Extreme Cold Weather Temperature for 1-hour periods at least a few times since 2000, it is unlikely that the Extreme Cold Weather Temperature would have occurred for 12 consecutive hours since 2000). In lieu of making those unrecoverable expenditures in an attempt to prepare their resource to operate in speculative future extended extreme cold temperatures, investors may forego or cancel resource additions. Similarly, an existing Generator Owner that cannot operate for one hour at its Extreme Cold Weather Temperature may decide to retire early in lieu of making significant expenditures to attempt to operate at that temperature for one hour in the future.

Notably, the new proposal is far more conservative than the proposed extreme weather standard under consideration for the TRE region, by the Public Utility Commission of Texas (PUCT). In a pending rulemaking, the PUCT has proposed an extreme cold weather standard based on sustaining operations at either the 95th percentile minimum average 72-hour temperature as published in a recurring study by the balancing authority (which will be filed every 5 years and will examine weather outcomes dating back over 100 years) or the lowest ambient temperature at which the particular resource has experienced sustained operations. While Vistra has urged the PUCT to not adopt the alternative "lowest ambient temperature" standard for a variety of reasons (notably that it may effectively override the 72-hour average standard and impose different weather standards for different resources), and while the PUCT has yet to adopt its final rule establishing its standards, Vistra believes the intent of the "lowest temperature" standard proposed by the PUCT is actually to require resources to maintain weatherization measures that go above and beyond the standard, rather than to supplant the 72-hour average standard. In any event, the PUCT's proposed "lowest temperature" standard would still be preferable to the 0.2 percentile standard proposed by the SDT, since the PUCT standard would take into account the resource's demonstrated capabilities, not require it to sustain operations at a temperature at which it has never sustained operations, and not require new resources to sustain operations at that temperature for durations and in compounding weather conditions that are extremely unlikely to have any historical precedent.

Vistra urges the SDT to reconsider the proposed 0.2 percentile lowest hourly temperature since Jan. 1, 2000 in favor of something closer to the PUCT standard, i.e., either an average lowest ambient temperature (at the 95th or even 99th percentile) over a specified number of hours (e.g., 12 hours, 24 hours, 72 hours, etc.) since a specified date (e.g., Jan. 1, 2000) or a standard based on actual operations (for existing resources) or design specifications (for new or existing resources). If the SDT were to redefine "Extreme Cold Weather Temperature" to incorporate an average lowest ambient temperature, then the NERC guide for Calculating Extreme Cold Weather Temperature would also need to be modified to develop a methodology for calculating that temperature, or alternatively, the balancing authority for each region (e.g., ERCOT for the TRE region) could be responsible for publishing the applicable average temperatures on some periodicity (e.g., every five years). It may be preferable to have the balancing authority publish that data periodically, since that provides a common reference point for all resources operating in the region.

The definition of "Generator Cold Weather Reliability Event" also should be clarified in a couple of ways. First, the phrase that begins "for which the apparent cause(s)" should be moved up to clarify that it modifies all three paragraphs of the definition (i.e., relating to (1) derates, (2) start-up failures, and (3) forced outages), rather than appearing directly at the end of paragraph (3) without any paragraph break, which could provide the impression that it only modifies that last paragraph. In addition, the definition for paragraph (2) (relating to start-up failures) should be modified to clarify that the term "start-up failure" will have the same meaning that it does for purposes of Generating Availability Data System (GADS) reporting. For instance, the definition could be modified to state that "Generator Cold Weather Reliability Event" means:

"One of the following events, if the apparent cause(s) of that event(s) is due to freezing of equipment within the Generator Owner's control and the dry bulb temperature at the time of the event was at or above the Extreme Cold Weather Temperature:

(1) a forced derate of more than 10% of the total capacity of the unit and exceeding 20 MWs for longer than four hours in duration;

(2) a start-up failure where the unit fails to synchronize within a specified start-up time, as defined in the instructions for mandatory reporting of startup failures in the Generating Availability Data System; or

(3) a Forced Outage.

Likes 0	
Dislikes 0	

Response

Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	No
Document Name	
Comment	

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for question #2.

Likes 0	
Dislikes 0	
Response	

James Baldwin - Lower Colorado River Authority - 1	
Answer	No
Document Name	
Comment	

LCRA provides the following comments:

The Extreme Cold Weather Temperature definition differs from the language/method in the Public Utility Commission of Texas Project No. 53401 to define the minimum temperature at which a resource is reasonably expected to ensure sustained operation.

LCRA offers the following revisions to events 1 and 2 of the Generator Cold Weather Reliability Event definition:

(1) a forced derate of more than 10 of the seasonally adjusted High Sustainable Limit (HSL) of the unit and exceeding 20 MWs for longer than four hours in duration;

(2) a start-up failure where the unit fails to synchronize within the Balancing Authority's specified start-up time; or"

Likes 0	
Dislikes 0	
Response	

Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	

We are concerned that the definition of Extreme Cold Weather Temperature will not capture the lower temperatures experienced in February 2021 (the Event). Even if the temperatures experienced during the Event are considered outliers, we do not believe that they should be removed from the dataset. The frequency or intensity of these extreme temperatures occurring in the future may be probabilistically low, but cannot be discounted. If NERC wants the new Standard to address temperatures like those experienced in February 2021, the ECWT definition must yield a result lower than the current definition.

Likes 0	
Dislikes 0	

Response

Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC

Answer	No
Document Name	

Comment

For Generator Cold Weather Reliability Event, PNM recommends adding to (1) the cause of derate is within the "freezing of equipment within the Generator Owner's control". This would be similar to the statement in (3).

Likes 0	
Dislikes 0	

Response

Tony Skourtas - Los Angeles Department of Water and Power - 3

Answer	No
Document Name	

Comment

LADWP proposes the following recommendations for the definitions of "Generator Cold Weather Critical Component" and "Generator Cold Weather Reliability Event".

- For the definition of "Generator Cold Weather Critical Component" LDWP proposes to update the definition as seen below. This revision provides a concise and objective definition.

"Any generating unit component or associated fixed fuel supply component, that is under the Generator Owner's control and is susceptible to freezing issues. the occurrence of which would likely lead to a Generator Cold Weather Reliability Event.

- Provide clarification for the definition of "Generator Cold Weather Reliability Event" specifically for event 3. As currently written the definition implies the time of the event would be at the temperature of Extreme Cold Temperature or warmer. If event 3 is referring to freezing temperatures meaning colder than the Extreme Cold Weather Temperature, event 3 under this definition should be revised as follows:

"(3) a Forced Outage, for which the apparent cause(s) is due to freezing of equipment within the Generator Owner's control and the dry bulb temperature at the time of the event was at or above below the Extreme Cold Weather Temperature."

Likes 0	
Dislikes 0	

Response

Sheila Suurmeier - Black Hills Corporation - 1,3,5,6	
Answer	No
Document Name	

Comment

BHC agrees with comments submitted by EEI & NAGF

Likes 0	
Dislikes 0	

Response

Micah Runner - Black Hills Corporation - 1	
Answer	No
Document Name	

Comment

BHC agrees with comments submitted by EEI & NAGF.

Likes 0	
Dislikes 0	

Response

Josh Combs - Black Hills Corporation - 3	
Answer	No
Document Name	

Comment

BHC agrees with comments submitted by EEI & NAGF.

Likes 0	
Dislikes 0	

Response

Claudine Bates - Black Hills Corporation - 6

Answer	No
Document Name	

Comment

BHC agrees with comments submitted by EEI & NAGF.

Likes 0	
Dislikes 0	

Response

Patricia Lynch - NRG - NRG Energy, Inc. - 5

Answer	No
Document Name	

Comment

Generator Cold Weather Critical Component

The definition of Generator Cold Weather Critical Component does not line up with the team's responses to comments. The proposed definition in the standard is open to interpretation and inconsistent application because it can be read to include equipment that is not listed in the response to comments. NRG proposes the SDT include the list of equipment in the standard definition.

Extreme Cold Weather Temperature

NRG is grateful the SDT simplified the ability for generators to meet these requirements with the latest definition of Extreme Cold Weather Temperature.

However, NRG understands that to meet and validate the Extreme Cold Weather Temperature (ECWT), some units will be required to perform a full reverse-engineering of identified critical systems. This would essentially require removing existing cold weather protection then installing new enhanced protection on these systems to meet the new requirements. The incremental cost differential by doing this instead of simply adding protection onto existing equipment could be cost prohibitive at some sites.

The definition does not include clarification on accepted data sources for determining extreme temperature. NRG suggests this should be extracted from the newly developed guidance document and inserted into the standard.

NRG believes that this minimum temperature level should be based upon historical operational performance or design criteria.

NRG would accept the proposed ECWT definition provided technical, commercial, and operational constraints are accepted under R7.

Generator Cold Weather Reliability Event

The definition of Generator Cold Weather Reliability Event is not clear regarding what constitutes an apparent cause. Is this due only to freezing equipment at the generator site? There are many other actual causes for generator derates or start-up failures where freezing equipment may not be the actual cause or simply play a limited role. This should be clarified.

Likes 0	
Dislikes 0	

Response

Martin Sidor - NRG - NRG Energy, Inc. - 6

Answer	No
Document Name	

Comment

Generator Cold Weather Critical Component

The definition of Generator Cold Weather Critical Component does not line up with the team's responses to comments. The proposed definition in the standard is open to interpretation and inconsistent application because it can be read to include equipment that is not listed in the response to comments. NRG proposes the SDT include the list of equipment in the standard definition.

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Likes 0	
Dislikes 0	

Response

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer	No
Document Name	

Comment

“Generator Cold Weather Critical Component” introduces more confusion than it alleviates. For example, what is the definition of “associated fixed fuel supply components”?

“Extreme Cold Weather Temperature” introduces unnecessary complexity and undue administrative burdens that do not lead to improved reliability. Reclamation recommends the initial proposal of using the coldest temperature back to 1/1/1975 was less confusing and less of an administrative burden than requiring entities to calculate the lowest .2 percentile of hourly temperatures. For example, climatological data from NOAA can only be processed 10 years at a time. For this timeframe, the file is over 55MB in size. Reclamation observed that following the NERC instructions and using a 10-year period of data took over an hour to filter and get the required data. Additionally, the data for several facilities only goes back to 2005, which will limit how much data some facilities can obtain and will automatically result in non-compliance with the proposed required analysis. Other searches yielded a longer period of available data, but from NOAA stations that were not near the facility in question (e.g., 100 miles away) or included major elevation changes (e.g., over 3000 feet and different weather patterns). These discrepancies will result in inaccurate data affecting the relevance of the calculations and again call into question the complicated structure of the proposed calculation method. Reclamation recommends the SDT account for these impacts to reliability as well as the ability to comply with the proposed requirements.

“Generator Cold Weather Reliability Event” introduces unnecessary complexity and provides loopholes for entities to circumvent solutions to the root causes of the cold weather problem FERC is attempting to solve. Reclamation recommends the specification of “10% of total capacity” is unnecessary. The focus should be on whether the derate aggregates to a total exceeding the MW threshold.

Likes 0	
Dislikes 0	

Response

Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County

Answer	No
Document Name	

Comment

While CHPD recognizes the merits of allowing the percentile method, we would recommend adding language to recognize and allow use of minimum temperature data from daily, monthly, or yearly weather record summaries, rather than prescriptively requiring a certain percentile of hourly data. Additionally it should also be noted that some weather station data will not go back to the required 2000 date and therefore language should be added to allow for flexibility in those instances. Furthermore,

some generating plants do not have weather data directly available at the plant, but this data is available at a nearby location. The proximity of the weather site location to the generating plant should be addressed so this aspect is clear to the Generator Owner.

Likes 0	
Dislikes 0	

Response

Lenise Kimes - City and County of San Francisco - 1,5 - WECC

Answer	No
Document Name	

Comment

For Generator Cold Weather Critical Component definition, please see modification (italicized - text in brackets describes recommended change) as follows:

Any generating unit component or associated fixed fuel supply component, that is under the Generator Owner's *control* [recommend replacing "control" with "ownership"] ***ownership*** and that is susceptible to freezing issues, the occurrence of which would likely lead to a generating unit(s): (1) forced derate of more than 10% of the total capacity of the unit and exceeding 20 MWs for longer than four hours in duration, (2) a start-up failure where the unit fails to synchronize within a specified start-up time, or (3) a Forced Outage.

Likes 0	
Dislikes 0	

Response

Devin Shines - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company

Answer	No
Document Name	

Comment

LouisvilleG&E/KU support EEI's comments.

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	No
Document Name	

Comment	
Dominion Energy supports comments submitted by EEI proposing revisions to the proposed definitions.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
In regards to the definition of the term “Generator Cold Weather Reliability Event”, the text “for which the apparent cause(s) is due to freezing of equipment within the Generator Owner’s control and the dry bulb temperature at the time of the event was at or above the Extreme Cold Weather Temperature” is provided *after* the text for (3), which gives the impression (likely unintentional) that it only applies to (3) rather that to (1), (2), and (3) collectively. AEP recommends moving the text so that it instead proceeds (1), (2), and (3), and adding text to make it clear that it indeed applies to all of them collectively. The definition of Generator Cold Weather Critical Component is somewhat circular, as it specifically references the word “component” multiple times, yet it does not clearly state what a “component” itself actually is. The definition could benefit from this added clarity, perhaps similar to that provided in the definition of “Protection System” in the NERC Glossary of Terms. This might be considered either now or in future phases of this project.	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	No
Document Name	
Comment	
PG&E supports the proposed definitions for Phase One (this version) of the Cold Weather project and agrees with the input by EEI and the NAGF that additional clarity is needed which should be completed during Phase Two of the project. Our input of NO for the comment is related to the additional work needed in Phase Two.	
Likes 0	
Dislikes 0	

Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3, Group Name OGE Energy	
Answer	No
Document Name	
Comment	
OG&E supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Joe Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	No
Document Name	
Comment	
Xcel Energy supports comments from EEI.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren agrees with the EEI and the NAGF comments.	
Likes 0	
Dislikes 0	
Response	

Mark Spencer - LS Power Development, LLC - 5	
Answer	No
Document Name	
Comment	

Extreme Cold Weather Temperature ("ECWT"): We do not agree that this definition adds clarity. Temperature, wind velocity, precipitation, and duration are inseparable when evaluating freeze protection measures. The SDT attempts to create a synthetic condition that has not occurred in nature. As we describe below, we think a more logical approach would be to select the duration and frequency of occurrence. This procedure links all variables as the naturally exist to establish models that set reliability standards. Setting the temperature first provides little predictive power in a generator's ability to perform under extreme cold weather events. As an example, if the ECWT were 15 degrees at a particular location and had to meet the duration standard for new generators, 12 hours, our analysis shows that the observed temperatures dip below the ECWT for some or all of the duration in almost all scenarios. In many cases, the dip is significant. Therefore, if a generator plans to perform for 12 hours *at the ECWT* it may fail. Additionally, we asked whether the SDT performed analysis to confirm whether an assumed 20 mph wind coincident with the duration was reasonable. The SDT replied that it was a reasonable assumption based on the group's experience. We analyzed the weather data for 27 locations from California to Massachusetts and North Dakota to Florida. In only one location (Boston) did wind and temperatures at or below the ECWT appear correlated.

Rather than specifying a temperature and a duration independently, the better approach would be to allow the Balancing Authorities (BA) to specify the weather scenarios that they use in their planning scenarios. Alternatively, if NERC were to set the standard, a better approach for establishing a continent-wide standard would be to start with a loss-of-load-expectation (LOLE) and work backwards to the combination of temperature, duration, wind, and (perhaps) precipitation that yield the criteria LOLE. As an example, select a reasonable duration – e.g., 12 hours, etc., then calculate the temperature that yields the selected LOLE memorialized in the reliability standard ("Historical Event(s)"). Fiftieth percentile wind speed coincident with these Historical Event(s) are then a derivative of this calculation. Because the effects of precipitation are much more subjective and difficult to quantify, the standard should require generator owners to examine historical precipitation coincident with the Historical Event(s) and document that they have considered the effects of the precipitation and modified their cold weather preparedness plans accordingly. We offer a proposed alternate definition:

*"**Extreme Cold Weather Event Standard –** An(a) observed event(s) with a duration of no less than 12 hours, such that the combination of observed hourly dry bulb temperatures and 50th percentile wind speeds yield a once in XX year probability of occurring at the generator's location based on a review of the historical weather from the period January 1, 2000 through the date the temperature is calculated."*

Generator Cold Weather Critical Component ("Component"): The benefit of defining specific components within a generator that may be susceptible to freezing are evident, but the benefit of applying a MW threshold at the component level is not. This definition does not expressly define a MW threshold but engages a threshold through the definition's reference to a "Generator Cold Weather Reliability Event." In our experience if a component is so fundamental to the operation of the facility that its loss could cause a derate, then it is critical. Additionally, setting a MW threshold may be counter-productive. As an illustrative example, say a coal plant has six coal mills and only needs five to obtain full output – i.e., the loss of any one mill would not "likely" lead to a derate, so a generator owner could logically conclude that all coal mills could be excluded from the Component definition. Redundant instrumentation, conveyors, etc. may also be excused using similar logic. We propose the following definition:

*"**Generator Cold Weather Critical Component** – Any generating unit component or associated fixed fuel supply component that are under the Generator Owner's control and are susceptible to freezing, the occurrence of which would likely lead to a forced outage, derate, failed start or the reliance on redundant or back-up components to maintain output."*

Generator Cold Weather Reliability Event ("Event"): We do not have any comments to this definition at this time.

Likes 0	
Dislikes 0	

Response	
Scott Kinney - Avista - Avista Corporation - 3	
Answer	No
Document Name	
Comment	

Avista supports all three definitions for this first phase, but we also propose additional revisions to the Generator Cold Weather Critical Supply Component and the Cold Weather Reliability Event because additional clarity is needed and that can be addressed during the next phase of this project. (See below)

Generator Cold Weather Critical Supply Component: Use of the undefined term "fixed fuel supply component" within the proposed definition of Generator Cold Weather Critical Component creates confusion. While we support the explanation provided by the SDT in the Technical Rationale, the Technical Rationale has no standing as a compliance document. For this reason, we ask the SDT to consider defining this term within the framework of the next phase of this project. We suggest the following for SDT consideration:

Fixed Fuel Supply Component: Are non-mobile equipment that support the reliable delivery of fuel to the generating unit and under the control the Generator Owner at a plant site. Gaseous, liquid, or solid fuel handling components that are installed on site as fixed parts of the fuel delivery system that are under the Generator Owner's control would be included. Components that would not be included would be mobile equipment such as trains, bulldozers, or other equipment that are not fixed in one location.

Generator Cold Weather Reliability Event: EEI is concerned with the use of the term "specified", as it relates to the start-up time of a generator during cold weather events, because it is unclear clear who would be responsible for specifying the start-up time. Results Based Standards should "define a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome." (NERC Results Based Standards – Performance Based; https://www.nerc.com/pa/Stand/Pages/ResultsBasedStandards.aspx#:~:text=Results%20based%20standards%20are%20standards,the%20NERC%20Standard%20Processes%20Manual.)

Likes 0	
Dislikes 0	
Response	
Brooke Jockin - Portland General Electric Co. - 1, Group Name Portland General Electric Co.	
Answer	No
Document Name	
Comment	

Portland General Electric Company supports the survey response provided by EEI.

Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	

Answer	No
Document Name	

Comment

Avista supports all three definitions for this first phase, but we also propose additional revisions to the Generator Cold Weather Critical Supply Component and the Cold Weather Reliability Event because additional clarity is needed and that can be addressed during the next phase of this project. (See below)

Generator Cold Weather Critical Supply Component: Use of the undefined term “fixed fuel supply component” within the proposed definition of Generator Cold Weather Critical Component creates confusion. While we support the explanation provided by the SDT in the Technical Rationale, the Technical Rationale has no standing as a compliance document. For this reason, we ask the SDT to consider defining this term within the framework of the next phase of this project. We suggest the following for SDT consideration:

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Generator Cold Weather Reliability Event: EEI is concerned with the use of the term “specified”, as it relates to the start-up time of a generator during cold weather events, because it is unclear clear who would be responsible for specifying the start-up time. Results Based Standards should “define a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome.” (NERC Results Based Standards – Performance Based;

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

ECWT source data not clearly defined. This could be anything from an employee logging a thermometer value to downloading incomplete data from NOAA. Plus, data may be available and adequate for some generating stations, but for other remote generating station the search for historical data has produced incomplete and/or missing data. Maintaining a rolling minimum value of the lowest winter temperatures (3 months) from 1/1/2000 to current is excessive, especially for 20+ year old plants. Ten years of data from the commercial operation date or ten years ending on the date of adoption of EOP-012-1 would seem sufficient.

Likes 0	
Dislikes 0	

Response

Brian Evans-Mongeon - Utility Services, Inc. - 4	
Answer	No
Document Name	
Comment	
It is unclear why the word “apparent” is used in the definition for Generator Cold Weather Reliability Event. Based on the time-lines provided for the development of a CAP (up to 150 days) there is sufficient time to make a determination of the cause of a Generator Cold Weather Reliability Event. Additionally, without determining the actual cause of an event it would be imposible to develop an effective CAP. The use of a subjective term like “apparent” opens up all events to interpretation during compliance review and should be removed from the definition.	
Likes 1	Illinois Municipal Electric Agency, 4, Todd Mary Ann
Dislikes 0	
Response	

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	

Consider modifying the following term definitions:

-Extreme Cold Weather Temperature:

- Change “Extreme Cold Weather Temperature” to “Extreme Cold Weather Target Temperature” to discern between the lowest extreme cold weather temperature and the extreme cold weather temperature adjusted for the lowest 0.2 percentile of the hourly temperatures.

-Generator Cold Weather Critical Component:

- Change “Any generating unit component or associated fixed fuel supply component…” to “Any component or associated fixed fuel supply component…” to recognize non-traditional units (e.g., solar) that do not have traditional electrical generators and to capture unit auxiliary components.

-Generator Cold Weather Reliability Event:

- Suggestion #1: (2) a start-up failure where the unit fails to synchronize within a specified start-up time:

o Define specified start-up time duration that constitutes a start-up failure.

o Define the entity that would determine the start-up time duration and failure.

- Suggestion #2: (3) a Forced Outage”,”:

o Change comma to a semi-colon.

o Note: As written, the paragraph that follows “(3) a Forced Outage” appears to be uniquely linked to Event (3) rather than representing language specified for Events (1), (2) and (3).

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	No
Document Name	

Comment

The phrase from #3 from the Generator Cold Weather Reliability Event defintion – " for which the apparent cause(s) is due to freezing of equipment within the Generator Owner's control and the dry bulb temperature at the time of the event was at or above the Extreme Cold Weather Temperature" seems to apply to points #1 and #2 and therefore should be included in these or moved to the opening statement 'One of the following events for which the apparent cause…'

Also, within the same highlighted phrase, 'freezing of equipment' is specified, but not freezing of onsite fuel supplies or process fluids? Is fuel exempt? Lube oil? Ammonia? If these are included, this should be stated and further clarification/extension of the term 'freezing' may also be warranted to state something to the effect of 'changing fuel or process fluid properties such that critical processes are limited'.

FE also supports EEI's comments on the proposed definitions.

EEI supports all three definitions for this first phase, but we also propose additional revisions to the Generator Cold Weather Critical Component and the Cold Weather Reliability Event because additional clarity is needed and that can be addressed during the next phase of this project. (See below.)

Generator Cold Weather Critical Component: Use of the undefined term "fixed fuel supply component" within the proposed definition of Generator Cold Weather Critical Component creates confusion. While we support the explanation provided by the SDT in the Technical Rationale, the Technical Rationale has no standing as a compliance document. For this reason, we recommend defining this term within the framework of the next phase of this project. We suggest the following:

Fixed Fuel Supply Component: Are non-mobile equipment that support the reliable delivery of fuel to the generating unit and under the control the Generator Owner at a plant site. Gaseous, liquid, or solid fuel handling components that are installed on site as fixed parts of the fuel delivery system that are under the Generator Owner's control would be included. Components that would not be included would be mobile equipment such as trains, bulldozers, or other equipment that are not fixed in one location.

Generator Cold Weather Reliability Event: EEI is concerned with the use of the term "specified", as it relates to the start-up time of a generator during cold weather events, because it is unclear clear who would be responsible for specifying the start-up time. Results Based Standards should "define a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome."

Likes 0	
Dislikes 0	

Response

Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6

Answer	No
Document Name	

Comment	
Talen Energy Marketing LLC supports Talen Generation's comments.	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Tri-State mostly agrees however, the concept of mobile vs. fixed fuel should be incorporated into the Generator Cold Weather Critical Component definition.	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	

Talen Energy supports in large part the inputs of the NAGF on this topic, and goes further by recommending that the, "Extreme Cold Weather Temperature," should be the historical worst-case temperature (WCT, or DBT-plus-20 mph, as described above). Setting a statistical cutoff for winterization (proposed in Rev. 2 of EOP-012-1 to be the 0.2 percentile of the winter season) is fundamentally unsuitable.

EOP-012-1 in its present form implies that the blackouts, deaths and damage caused by Winter Storm Uri are acceptable, so long as they are experienced only during the coldest 43 hours per decade (or much longer, due to the time needed to troubleshoot, thaw and restart units with freeze-up forced outages). This is precisely when BES reliability is most important, however, becoming a life-or-death matter.

Where will the power come from during those 43 (or more) hours? The answer presently is that it will be supplied by older generation plants, designed to operate through all winter storms and not just some of them. As the years pass and these facilities are replaced by 0.2 percentile units, however, occasional devastating blackouts will become the norm, not as a ghastly error but according to plan.

The argument that some EPC firms use the 0.2 percentile cutoff has no validity. This is the cause of the problem, not the cure. One must not depend on old-reliable units to save the day and allow cutting corners in the quest to become the low bidder. It is NERC's job to put a halt to such practices, not enshrine them as the law of the land.

It is impossible moreover to slice matters so finely as a fraction of a percentile, since freeze protection is subject to great uncertainty due to frequent design and installation errors by contractors. Protection that is thought to address all weather except the coldest 43 hours per decade might in fact allow freeze-up for a much longer duration. Nor is there need for extreme exactitude, since the cost difference between designing for the 0.2 percentile temperature and historical worst-case conditions is negligible in comparison to the harm being prevented.

The DBT-plus-20 mph approach proposed above provides a simple alternative for GOs having difficulty identifying the worst-historical WCT. This would not be an excessively conservative criterion, since winter storms that cause grid emergencies tend to be by those combining low DBT values with high wind speed. Also, in our experience heat tracing/insulation systems rarely provide the specified protection, much less containing enough safety margin to cover 0.19 percentile-and-lower events. In summary:

{C}- The mission of Project 2021-07 is to ensure BES reliability during ALL credible winter storm conditions.

{C}- Historical worse-case conditions are credible; they happened before, so they can happen again.

{C}- Therefore the design criterion must be the historical worst-case weather conditions, which to be meaningful must be wind and temperature-based (WCT) and relying soly on temperature (DBT).

The definition of Generator Cold Weather Critical Components and the way in which this term is used in R1 and R3 indicate an obligation to list freeze-susceptible equipment at the component level and identify their individual temperature capabilities. Doing so for every outdoors pipe and tube containing water or steam (even large-bore systems can freeze if left static for too long during downtime periods), plus their associated instruments and equipment, would be extremely and unnecessarily burdensome. It should be sufficient to address elements at the system level, where freeze protections was implemented on this basis. That is, only a single entry would be needed for all outdoors water and steam piping if it was heat-traced and insulated under a single contact, using conditions of X degrees F DBT and Y mph wind speed.

The Generator Cold Weather Reliability Event definition should be revised and Guidance material should be added, as shown below. There are presently many forced outages under part 3 of this currently proposed definition (and EOP-012-1 in its present form will not prevent them), because the vulnerability being discussed is related to WCT for conventional plants, not DBT.

Generator Cold Weather Reliability Event

(1) a forced derate of more than 10% of the total capacity of the plant and exceeding 20 MW for the plant, for longer than four hours in duration, due to freezing of equipment within the Generator Owner’s control.

or

(2) a start-up failure in which the unit fails to synchronize within the extreme cold weather start-up time declared for R3.5 [add this to R3.5, there is presently no target in this respect], due to freezing of equipment within the Generator Owner’s control.

Guidance: “Precautionary derates, e.g. ramping-down CTGs to minimum load during blizzards to help avoid clogging the inlet air filters, are not counted as forced derates so long as this limitation has been documented in accordance with R3.5 of EOP-012-1.”

Likes 0	
Dislikes 0	

Response

Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric

Answer	No
Document Name	

Comment

DTE Electric supports NAGF comments provided for this project

Likes 0	
Dislikes 0	
Response	

Diana Torres - Imperial Irrigation District - 6

Answer	No
Document Name	
Comment	

IID disagrees that the 0.2 percentile is not overly conservative, IID recommends to use 0.5 or 1.0.

Likes 0	
Dislikes 0	
Response	

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer	No
Document Name	
Comment	

The current definitions as written leave ample room for interpretation. While this is often desired, we believe that in this instance they do not provide enough clarity to the requirements of EOP-012. The specific concerns with the current verbiage are as follows:

Generator Cold Weather Critical Component: While the open-endedness of “any generating unit component” is desired as it allows the Generator Owner to identify critical components on a per-unit basis, it does not appear to include any “common” equipment shared between units. Examples would include service water, instrument air, ammonia, ash handling, common bus isolation breakers/switches, etc. The proposed modification to the definition is: “Any generating unit component or associated fixed fuel supply component, to include any critical equipment shared between multiple units (i.e. Balance of Plant (BOP) and/or Common equipment), that is under the Generator Owner’s control and is susceptible to freezing issues, the occurrence of which would likely lead to a Generator Cold Weather Reliability Event.”

Extreme Cold Weather Temperature: If the current method to calculate is implemented, NERC should consider coordinating with the National Oceanic and Atmospheric Administration to ensure dry bulb temperature data is available from 1/1/2000 through an indefinite future date. As currently written the requirement to use “the hourly temperatures measured” seems a bit excessive. Given the inherent difficulty of compiling a dataset containing > 49,000 data points and then calculating the lowest 0.2 percentile, we recommend modifying the definition to include daily minimum temperatures from the same time period. This modification would reduce the size of the dataset significantly (down to ~2076 total days) and should not change the resulting Extreme Cold Weather Temperature by any significant statistical margin given that the daily minimum will contain the hourly minimums.

Lastly, the requirement to use a fixed data start date of 01/01/2000 means the dataset will grow by approximately 2,160 data points if using the hourly metric while only 90 data points if using the daily minimum metric. Therefore, it is our recommendation to use a 20-year rolling time period if staying with the hourly metric.

If the hourly metric is to remain, a proposed modification to the definition would be: “The temperature equal to the lowest 0.2 percentile of the actual hourly temperatures measured in

December, January, and February from the previous 20 years immediately prior to the date the temperature is calculated.“

The preferred modification would be to abandon the hourly metric in favor of the daily minimum metric. This proposed modification to the definition is: “The temperature equal to the lowest 0.2 percentile of the actual daily minimum temperatures measured in December, January, and February from 1/1/2000 through the date the temperature is calculated.”

Generator Cold Weather Reliability Event: Pertaining to event type 2 that may constitute a Generator Cold Weather Reliability Event:
2. “A start-up failure where the unit fails to synchronize within a specified start-up time”: Who specifies the start-up time? Per the draft Technical Rationale and Justification for EOP-012-1, start-up failures are defined using a modified version of the GADS definition in order to ensure consistency across all jurisdictions for this standard. Our concern stems from the language in R2 that references the GADS definition of “specified start-up time” without providing the additional clarification found in the 2022 GADS Data Reporting Instructions. Our recommendation is to modify this subsection as follows: “A start-up failure where the unit fails to synchronize within a specified start-up time. The specified start-up time period for each unit is determined by the GO/GOP based on the condition of the unit at the time of start-up.”

In addition this defined term is not clear in relation to what constitutes “apparent cause(s) is due to freezing of equipment” in the draft definition. AECI urges the standard drafting team to consider removing the word “apparent” from the definition as the apparent cause may not be the actual cause after further investigation.

Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	No
Document Name	
Comment	

This standard should be clearly targeted to those entities not designed to run in below freezing conditions, that operate in those areas where it is possible to have freezing events. Those entities operating in environments where freezing is a yearly expectation, and where they are designed to operate in freezing weather should be exempt. We feel that, due to poor performance of certain generators in specific areas, the whole fleet of generators is being targeted for this poor performance. This comes at a significant cost and effort by smaller organizations who do not have these risks.

Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

LaKenya VanNorman - LaKenya VanNorman On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name Florida Municipal Power Agency (FMPA)

Answer	Yes
Document Name	

Comment

We agree with the new proposed definitions, but still believe the definition of Generator Cold Weather Reliability Event should either remove the phrase “apparent cause(s)” or reword it to be “for which the apparent cause(s), as determined by the entity during RCA or internal investigation, is due to…”. Without definition, the term “apparent” is subjective and open to different interpretations. It should be removed, or clarified that it is as defined by the entity.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	Yes
Document Name	

Comment

Exelon agrees with the proposed definitions. Exelon supports EEI's comments regarding the benefit of making clarifying enhancements to the definitions during the next phase of this project.

Submitted on behalf of Exelon, Segments 1 & 3

Likes 0	
Dislikes 0	

Response

Selene Willis - Edison International - Southern California Edison Company - 5

Answer	Yes
Document Name	

Comment	
“Please see comments submitted by the Edison Electric Institute”	
Likes 0	
Dislikes 0	
Response	
Alison Mackellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation specifically notes support for the use of percentiles in the definition of Extreme Cold Weather Temperature, and support for the use of the term "apparent" in the definition Generator Cold Weather Reliability Event. Kimberly Turco, on behalf of Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation specifically notes support for the use of percentiles in the definition of Extreme Cold Weather Temperature, and support for the use of the term "apparent" in the definition Generator Cold Weather Reliability Event. Kimberly Turco, on behalf of Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	

To clarify the definition of "Generator Cold Weather Reliability Event", we recommend the language "for which the apparent cause(s) is due to freezing of equipment within the Generator Owner's control and the dry bulb temperature at the time of the event was at or above the Extreme Cold Weather Temperature" be moved to the beginning of the definition to clarify that it applies to derates, start-up failures, AND forced outages.

Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	

The SDT intended for the "Extreme Cold Weather Temperature" to be recorded at or near the plant site, but the location is not included in the definition. We suggest the SDT consider enhancing the definition (incorporating a location) such as the following:

Extreme Cold Weather Temperature – The temperature equal to the lowest 0.2 percentile of the hourly temperatures neasured in December, January, and February from 1/1/2000 through the date the temperature is calculated at one of the following locations:

a. At the generating plant site (preferred location).

b. At the closest official meterological location.

c. At an official weather recording site within the generating plant surrounding area.

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	

Southern Company aligns with EEI's comments an offers some suggestions for additional clarity. For Generator Cold Weather Critical Component, we suggest clarification would be beneficial to specifically state in the definition that it includes equipment for which the GO has responsibility to provide freeze protection.

Southern also proposes modifying the definition of Generator Cold Weather Reliability Event to be when the dry-bulb temperature was above the generator's stated minimum operating temperature in R3 and not at or above the Extreme Cold Weather Temperature. Requiring a CAP for freezing issues below an already stated capability would only create additional administrative burden with no reliability benefit.

Likes 0	
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group

Answer	Yes
Document Name	

Comment

We agree with the definitions and our program will inform the correct action to maintain reliability at Extreme Cold Weather Temperature, prepare for a Cold Weather Event and identify Cold Weather Critical Components. We can communicate our concerns for generator availability using the communication requirements.

Likes 0	
Dislikes 0	

Response

John Liang - Snohomish County PUD No. 1 - 6

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

Gerry Adamski - Cogentrix Energy Power Management, LLC - 5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Scott McGough - Georgia System Operations Corporation - 3

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Donna Johnson - Oglethorpe Power Corporation - 5

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	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glenn Pressler - CPS Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Michael Watt - Oklahoma Municipal Power Authority - 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

Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 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	

Kristine Ward - Seminole Electric Cooperative, Inc. - 1

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Julie Hall - Entergy - 6, Group Name Entergy

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

3. Is the revised Applicability Section language clear? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6

Answer	No
Document Name	

Comment

The applicabilty should exempt those generation facilities that are designed and operated in below freezing weather, or that employ technology that is not affected by extreme cold weather.

Likes 0	
Dislikes 0	

Response

Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric

Answer	No
Document Name	

Comment

DTE Electric supports NAGF comments provided for this project

Likes 0	
Dislikes 0	

Response

Donald Lock - Talen Generation, LLC - 5

Answer	No
Document Name	

Comment

The Applicability section is clear, but insufficient. There cannot be meaningful progress on enhancing BES wintertime reliability without proper Planning Assessments and real-time resource adequacy evaluations, and these goals cannot be achieved if RCs, BAs and TOPs continue to use a DBT yardstick for WCT-related phenomena.

The DBT-based databases presently being used create a false sense of resource adequacy, as was demonstrated during Winter Storm Uri. It may not be possible for EOP-012-1 to set requirements for RCs, BAs and TOPs, since they were omitted from the SAR, but NERC should launch a parallel project so that they use accurate, WCT-based temperature capability data (or DBT-plus-20 mph), and EOP-012-1 should set the stage by manfdating collection of this information.

Likes 0	
Dislikes 0	

Response

Donna Wood - Tri-State G and T Association, Inc. - 1

Answer	No
Document Name	

Comment

a. 4.2.1.1 That commits or is obligated to serve a Balancing Authority load pursuant to an Open Access Transmission Tariff (OATT) or other contractual arrangement; This should not be included in the Applicability section as per FAC-001-3, R4.3, all BES generators must be within a BA metered boundary.

b. The inclusion of blackstart resources is redundant with the inclusion I3 of the BES definition and therefore should be removed.

c. The cold weather exclusion should be removed from the applicability section and instead a requirement should be added to require the GO to prove operability in cold weather through analysis/studies.

Likes 0	
Dislikes 0	

Response

Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6

Answer	No
Document Name	

Comment

Talen Energy Marketing LLC supports Talen Generation's comments.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	No

Document Name	
Comment	

FE supports EEI comments on the proposed changes to Functional Entities and fully support removing the phrase “pursuant to an Open Access Transmission Tariff (OATT) or other contractual arrangement”. The proposed edits read:

Applicability:

4.1 Functional Entities:

4.1.1. Generator Owner

4.1.2. Generator Operator

4.2. Facilities: The term “generating unit” subject to these requirements means:

4.2.1. A Bulk Electric System generating unit that commits or is obligated to serve a Balancing Authority load excluding a Bulk Electric System generating unit that is not committed or obligated to operate at or below thirty-two (32) degrees Fahrenheit (zero degrees Celsius) for any continuous run of more than four hours. The exclusion continues to apply should when such BES generator be called upon to operate for more than four hours in order to assist in the mitigation of BES Emergencies, Capacity Emergencies, or Energy Emergencies during periods at or below 32 degrees Fahrenheit.

4.2.2. That is identified as a Blackstart Resource.

Likes 0	
Dislikes 0	
Response	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	No
Document Name	
Comment	

We recommend the SDT consider establishing a defined winter season under 4.2.1.1.1 or placing responsibility for defining a winter season on the Balancing Authority rather than relying on the “typically not available at or below thirty-two degrees” language.

Likes 0	
Dislikes 0	
Response	
Brian Evans-Mongeon - Utility Services, Inc. - 4	
Answer	No

Document Name	
Comment	

The Applicability is unnecessarily complicated.

section 4.2.1.2: Is it the intent to not automatically include generators that meet the BES definition Inclusions I2 and I4? Blackstart Resources (I5) are already included as BES Generators per the definition of the BES and it is redundant and/or confusing to call them out specifically.

Section 4.2.1.1.1 uses the term "typically" which is subjective and unclear. If this is going to be used as an exclusion to the standard it should be definitive. Alternatively, the limited generators that this will be applicable to can utilize this type of exclusionary languge in their Cold Weather Prep Plan and as justification for not implementing a CAP to address issues as necessary.

Likes 1	Illinois Municipal Electric Agency, 4, Todd Mary Ann
Dislikes 0	
Response	

Mark Spencer - LS Power Development, LLC - 5

Answer	No
Document Name	
Comment	

The proposed definition of a BES generating unit is one "[t]hat commits or is obligated to serve a Balancing Authority load pursuant to an Open Access Transmission Tariff (OATT) or other contractual arrangements." This definition assumes that an obligation "to serve" exists. The majority of generating assets in the United States are located in regions overseen by Independent System Operators or Regional Transmission Operators and do not have obligations "to serve," unless pursuant to a state contract or stretching the definition – a Reliability Must Run contract. They may have an obligation to supply energy under specified rules on a seasonal or annual basis if they clear a capacity auction. If the intent of this rule is to apply only to generation owned by a vertically integrated utility subject to federal and/or state laws that obligate the utility to provide service, to a publicly owned generator subject to municipal rules regarding an obligation to serve, or to a generating unit that has contractually committed to supply energy for a long term period to a Balancing Authority or through state and or/federal contract, the definition may not be infirm. However, we encourage the SDT to clarify the purpose and intent of this section.

With regard to R4.1.1.1, we note that, as drafted, a generator that is typically unavailable above 32 degree Fahrenheit – e.g., a mothballed unit in south Florida – would be required to comply with the standard. The first criteria should be whether a location experiences sufficient freezing conditions to warrant applicability. If it does not, then there is no compliance obligation – e.g., San Diego. If it does, then the availability criteria should apply. We also recommend replacing "typical" with the ECWT to create bright line criteria. In addition, we do not understand the need to specify the duration of a dispatch schedule. In our experience, failures of peaking resources are more likely to occur during start-up than during operations. BAs typically dispatch peaking plants after the nadir of the local temperature in the overnight hours – i.e., morning ramp, thus we recommend SDT change the definition to:

"The term excludes a Bulk Electric System generating unit that is: (i) in a location where the Extreme Cold Weather Temperature is calculated to be greater than 32 degree Fahrenheit (0 degree Celsius) or (ii) in a location where the Extreme Cold Weather Temperature is calculated to be lower than or equal to 32 degree Fahrenheit (0 degree Celsius) and the unit is typically not available in these freezing conditions."

Likes 0	
Dislikes 0	

Response

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments

Answer	No
Document Name	

Comment

PG&E supports the comments provided by EEI and the NAGF, and has the following additional concern and recommendations related to NAGF's second input;

The currently proposed wording in Section 4.2.1.1.1 is not clear what is required if a Generator Owner's calculated Extreme Cold Weather Temperature is above 32 degrees Fahrenheit. To address this concern, PG&E recommends the addition of "or a generator that has determined its Extreme Cold Weather Temperature be above 32 degrees" in the first sentence of 4.2.1.1.1 to help correct this issue.

Likes 0	
Dislikes 0	

Response

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer	No
Document Name	

Comment

Reclamation disagrees with 4.2.1.1 and disagrees with the exclusion in 4.2.1.1.1. Reclamation disagrees with narrowing the scope of applicability based on entity choice of units that operate. Generating units that have no potential to freeze, e.g., hydroelectric plants that are housed indoors in climate-controlled buildings, should be excluded. Generating units that may be called on to assist in the mitigation of any Emergency should not be excluded because the failure of these units to operate properly in an Emergency exacerbates the Emergency. Reclamation asserts that exempting these units is a clear loophole in the intent of ensuring reliability during cold weather. Both exclusions will decrease BES reliability.

Likes 0	
Dislikes 0	

Response

Martin Sidor - NRG - NRG Energy, Inc. - 6

Answer	No
Document Name	

Comment	
A clear statement also needs to be made that this standard is not applicable to a generator with the Extreme Cold Weather temperature above 32 degrees.	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	
A clear statement also needs to be made that this standard is not applicable to a generator with the Extreme Cold Weather temperature above 32 degrees	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
BHC still needs clarity on what the SDT is attempting to say by the 4.2.1.1 BA portion.	
Likes 0	
Dislikes 0	
Response	
Josh Combs - Black Hills Corporation - 3	
Answer	No
Document Name	
Comment	

BHC still needs clarity on what the SDT is attempting to say by the 4.2.1.1 BA portion.

Likes 0	
Dislikes 0	

Response

Micah Runner - Black Hills Corporation - 1

Answer	No
Document Name	

Comment

BHC still needs clarity on what the SDT is attempting to say by the 4.2.1.1 BA portion.

Likes 0	
Dislikes 0	

Response

Sheila Suurmeier - Black Hills Corporation - 1,3,5,6

Answer	No
Document Name	

Comment

BHC still needs clarity on what the SDT is attempting to say by the 4.2.1.1 BA portion.

Likes 0	
Dislikes 0	

Response

Tony Skourtas - Los Angeles Department of Water and Power - 3

Answer	No
Document Name	

Comment

LDWP recommends this requirement to be region specific applicable only to areas that are susceptible to Extreme Cold Weather. In addition, require Generator Owners that plan to operate generating units in areas susceptible to Extreme Cold Weather to specify the need for continuous operation at or below the Extreme Cold Weather Temperature.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
In order to capture the comparable OATT in non-US jurisdictions, we suggest revising 4.2.1.1 as follows: That commits or may be committed or is obligated to serve a Balancing Authority load pursuant to an Open Access Transmission Tariff (OATT) or other contractual arrangement or rules; The IESO strongly believes that the standard should apply to all the generating units whose capacity is being counted on, including those providing sufficient reserve to withstand a cold weather event. The IESO suggests considering the concept of requiring the GO to declare to the BA/RC a unit will not run during the winter, unless the BA/RC requests it to run during an emergency.	
Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1	
Answer	No
Document Name	
Comment	
In Section 4.2.1.1.1 the language ‘typically not available’ is subjective and unclear. If an exclusion is allowed, the Balancing Authority should determine which resources are excluded from the EOP-012 standard and requirements. Further, excluding resources from NERC reliability standards but allowing those same resources to be dispatched in the conditions (below 32 degrees) which this standard addresses, is contrary to the purpose of this exact NERC standard.	
Likes 0	

Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	No
Document Name	
Comment	
In Section 4.2.1.1.1 the language 'typically not available' is subjective and unclear. If an exclusion is allowed, the Balancing Authority should determine which resources are excluded from the EOP-012 standard and requirements. Further, excluding resources from NERC reliability standards but allowing those same resources to be dispatched in the conditions (below 32 degrees) which this standard addresses, is contrary to the purpose of this exact NERC standard.	
Likes 0	
Dislikes 0	
Response	
Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	
AES Clean Energy supports comments submitted by NAGF.	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
The NAGF has two concerns with the applicability section. The first concern is that the language used in section 4.2.1.1 is unclear as to the meaning. Every generator has an interconnection agreement with their Transmission Owner (and possibly other third parties) which is under the OATT. The NAGF is concerned that the lack of clarity in this statement will	

lead to assumptions that differ across the registered entities and the regulators. Clarity would be provided by clearly stating that this standard is applicable to generators that are accepted in a capacity market rather than the vague wording used in the current draft.

The second concern is that it is not clear what is required of a Generator Owner if the calculated Extreme Cold Weather Temperature is above 32 degrees Fahrenheit. To address this concern, a clear statement that this standard is not applicable to a generator with the Extreme Cold Weather Temperature above 32 degrees is needed. The addition of “or a generator that has determined its Extreme Cold Weather Temperature to be above 32 degrees” in the first sentence of 4.2.1.1.1 will correct this issue.

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 believes that if the GOs are left to their own declaration of being “typically” available and/or if they are required to upgrade a unit or facility with freeze protection, this could create an unfair market advantage to those entities that choose not to freeze protect their units and facilities for “commercial” reasons. During extreme weather events markets may account for these situations reflected in the real-time prices. Thus, ISO-NE suggests the SDT consider the concept of requiring the GO to declare to the BA/RC a unit will not run during the winter so the GO cannot take advantage of high prices unless the BA/RC requests it to run during an emergency.

Likes 0	
Dislikes 0	

Response

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4

Answer	No
Document Name	

Comment

Alliant Energy supports the comments submitted by the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	

The Applicability Section in the revised standard seems to indicate applicability to individual generating units. During the Q&A session of the WebEx presentation held on 8/16/22, a question was asked that led to discussion around this term, and it was indicated that the requirements, when considering I4 generating facilities, should be applied to entire wind farm (time mark 1:48:14 in the August 16, 2022 webinar recording). Considering this discrepancy, the MRO NSRF requests the Standard Drafting Team provide clarifying language in the Applicability Section of the Standard.

Proposed language:

4.2 Facilities: : For purposes of this standard, the term “generating unit” subject to
these requirements means:
4.2.1 For generating facilities included in the BES under:
4.2.1.1 Inclusion I2, an individual generating unit
4.2.1.2 Inclusion I3, any Blackstart Resources identified in the Transmission Operator’s restoration plan.
4.2.1.3 Inclusion I4, the aggregated dispersed power producing resources with a total capacity of 75 MVA or greater.
and
4.2.2 That commits or is obligated to serve a Balancing Authority load
pursuant to an Open Access Transmission Tariff (OATT) or other
contractual arrangement;
4.2.3 The term excludes a Bulk Electric System generating unit that
is typically not available at or below thirty-two (32) degrees
Fahrenheit (zero degrees Celsius) for any continuous run of
more than four hours. The exclusion applies even when such
BES generator has been called to assist in the mitigation of
BES Emergencies, Capacity Emergencies, or Energy
Emergencies during periods at or below 32 degrees
Fahrenheit.

Likes 0	
Dislikes 0	
Response	

Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	No
Document Name	
Comment	

MidAmerican Energy supports the MRO NSRF comments for this question.

Likes 0	
Dislikes 0	
Response	
Steven Sconce - EDF Renewable Energy - 5	
Answer	No
Document Name	
Comment	
EDF supports the comments submitted by NAGF.	
Likes 0	
Dislikes 0	
Response	
Imane Mrini - Austin Energy - 6	
Answer	No
Document Name	
Comment	
As this is written, it says that a "generation unit" is a BES unit that is committed/obligated AND is identified as a blackstart resource. Because 4.2.1 doesn't indicate that the unit be "one of the following" and because there's no OR between 4.2.1.1 and 4.2.1.2, there is an implied AND. This suggests that, for the purpose of this standard, only blackstart units need to winterize. We suspect that this is not the intent of the document, so we would recommend changing 4.2.1 to say "A Bulk Electric System generating unit that conforms to either 4.2.1.1 or 4.2.1.2 below:". I would also move 4.2.1.1.1 to become 4.2.2. so that it doesn't impede or obscure the either/or choice of 4.2.1.1/4.2.1.2.	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
MISO supports the comments submitted by the ISO/RTO Council Standards Review Committee (IRC SRC) except where noted.	

Likes 0	
Dislikes 0	

Response

Shannon Ferdinand - Decatur Energy Center LLC - 5

Answer	No
Document Name	

Comment

Capital Power supports the North American Generators Forum (NAGF) response to this question.

Likes 0	
Dislikes 0	

Response

Ronald Bauer - MGE Energy - Madison Gas and Electric Co. - 3

Answer	No
Document Name	

Comment

Madison Gas and Electric supports the comments from the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Adam Lee - MGE Energy - Madison Gas and Electric Co. - 4

Answer	No
Document Name	

Comment

Madison Gas and Electric supports the comments of the MRO NSRF

Likes 0	
Dislikes 0	

Response	
Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations	
Answer	No
Document Name	
Comment	
In regards to the proposed Section 4.2 Facilities definition: In order to ensure a reliable response from generators that may be called upon by the Balancing Authorities during Capacity and Energy Emergencies, we recommend eliminating the exception for generators that do not operate during the winter season except when called upon by the Balancing Authority to be available during Capacity Emergencies or Energy Emergencies. Our recommended change to the language would be "The term excludes those generators that are not normally expected to operate during the winter season under normal and/or emergency conditions."	
Likes 0	
Dislikes 0	
Response	
Colin Chilcoat - Invenergy LLC - 6	
Answer	No
Document Name	
Comment	
The revised Applicability Section is less clear than the version presented for the first ballot. Specifically, it is not clear what BES generating units the SDT intends to include with respect to the load-serving requirement and listed contractual qualifiers in Section 4.2.1.1. Invenergy recommends that the Applicability be returned to the language used for the first ballot.	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	No
Document Name	
Comment	
Acciona Energy supports Midwest Reliability Organization's (MRO) NERC Standards Review Forum's (NSRF) comments on this question.	

Likes 0	
Dislikes 0	

Response

Whitney Wallace - Calpine Corporation - 5 - WECC,Texas RE,NPCC,SERC,RF

Answer	No
Document Name	

Comment

WGRs may not meet the requirements of 4.2.1.1.1 if ambient dry bulb air temperature is below 32 degrees Fahrenheit and wet precipitation (i.e., rain) is being deposited on the turbine blades. Additionally, it is not clear why certain types of units would be exempt from the Standard. NERC should clearly specify the types of units that it intends exempt from this Standard and explain why exempting these units is not unduly discriminatory.

Likes 0	
Dislikes 0	

Response

Russell Noble - Cowlitz County PUD - 3

Answer	No
Document Name	

Comment

Cowlitz agrees with comments proviced by North American Generator Forum and Utility Services.

Likes 0	
Dislikes 0	

Response

Deanna Carlson - Cowlitz County PUD - 5

Answer	No
Document Name	

Comment

Agree with comments provided by Russell Noble.

Likes 0	

Dislikes 0	

Response

Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)

Answer	No
Document Name	

Comment

The SRC supports the addition of Part 4.2.1.1, as the language provides a clear and measurable criteria. However, the SRC believes it could be improved. Specifically, Section 4.2.1.1 refers to a unit *obligated to serve a BA load pursuant to an Open Access Transmission Tariff (OATT) or other contractual arrangement*. Specifically, an OATT does not define capacity obligations of units in RTO regions. Those obligations appear in: (i) other agreements approved by FERC; (ii) state law in states with vertically integrated utilities (such as the requirement for the state PUC to find units receiving rate base treatment “used and useful”); or (iii) market rules. As written, the Standard’s language would override (or, at best, conflict with) those other requirements. As a result, to avoid that problem the SRC recommends revising the language as follows (to cover RTOs, ERCOT and Canadian entities):

That commits or may be committed or is obligated to serve Balancing Authority load pursuant to a tariffed obligation, state requirement as defined by relevant electric regulatory authority, other contractual arrangement, rules or regulations;

Section 4.2.1.1.1 goes on to inadvertently undo the sweep of Section 4.2.1.1 by stating the Standard, “...excludes a [BES] generating unit... typically not available at or below thirty-two (32) degrees...for any continuous run of more than four hours [and] applies even when such BES generator has been called to assist in the mitigation of BES Emergencies, Capacity Emergencies, or Energy Emergencies during periods at or below 32 degrees Fahrenheit.” To correct this drafting issue, the SRC recommends adding the following language at the beginning of Section 4.2.1.1.1:

“For any generating unit not covered by Section 4.2.1.1,…”

Within Section 4.2.1.1.1, using the phrase "typically not available at or below thirty-two degrees…" allows a GO to self-proclaim a unit not "typically" available in the winter. The SRC believes the SDT should revisit this language and provide more measurable parameters. Otherwise, a GO could make itself available one day and not the next. It also provides no parameters for what constitutes “typical;” *i.e.*, more than 50% of the time, 25%, etc.? As written, a Regional Entity could not audit a unit exemption.

[GOs should not be able to choose to not weatherize a unit and then choose to offer that unit to take advantage of high prices during the winter season. Thus, the SRC suggests the SDT consider the concept of requiring the GO to declare to the BA/RC a unit will not run during the winter so the GO cannot take advantage of high prices *unless* the BA/RC requests it to run during an emergency.] *****

**** Please note:*** *MISO is not a party to this paragraph in response to this Question. PJM also has concerns with this response.*

Likes 0	
Dislikes 0	

Response

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1

Answer	No
Document Name	

Comment	
AEPC has signed on to ACES comments, please see their responses.	
Likes 0	
Dislikes 0	
Response	
Rhonda Jones - Invenergy LLC - 5	
Answer	No
Document Name	
Comment	
The revised Applicability Section is less clear than the version presented for the first ballot. Specifically, it is not clear what BES generating units the SDT intends to include with respect to the load-serving requirement and listed contractual qualifiers in Section 4.2.1.1. Invenergy recommends that the Applicability be returned to the language used for the first ballot.	
Likes 0	
Dislikes 0	
Response	
LaKenya VanNorman - LaKenya VanNorman On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name Florida Municipal Power Agency (FMPA)	
Answer	No
Document Name	
Comment	
The applicability will not be consistently applied due to references to contracts for serving load that are not related to NERC standards (i.e. 4.2.1.1 “That commits or is obligated to serve a Balancing Authority load pursuant to an Open Access Transmission Tariff (OATT) or other contractual arrangement.”). In addition, the use of the phrase “not typically available at or below thirty-two (32) degrees” in 4.2.1.1.1 is highly subjective and open to interpretation.	
Likes 0	
Dislikes 0	
Response	

Natalie Johnson - Enel Green Power - 5	
Answer	No
Document Name	
Comment	
The term “generating unit” causes confusion in how the standard applies to renewable resources. Although an attempt to clarify is provided, the term “generating unit” is often interpreted to refer to individual turbines or invertors and not the aggregate facility. Enel therefore supports the MRO NSRF proposed language to further clarify section 4.2. In particular, Enel supports the MRO NSRF suggestion to clarify that the term “generating unit” refers to Inclusion I4, the aggregated dispersed power producing resources with a total capacity of 75 MVA or greater. In addition, Enel also recommends that this clarification be consistent with how this issue was addressed in other standards such as PRC-024.	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	Yes
Document Name	
Comment	
In regards to the proposed Section 4.2 Facilities definition: In order to ensure a reliable response from generators that may be called upon by the Balancing Authorities during Capacity and Energy Emergencies, we recommend eliminating the exception for generators that do not operate during the winter season except when called upon by the Balancing Authority to be available during Capacity Emergencies or Energy Emergencies. Our recommended change to the language would be “The term excludes those generators that are not normally expected to operate during the winter season under normal and/or emergency conditions.”	
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

Southern Company agrees that the Applicability Section language is clear.

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	Yes
Document Name	

Comment

None.

Likes 0	
Dislikes 0	

Response

Glen Farmer - Avista - Avista Corporation - 5

Answer	Yes
Document Name	

Comment

While Avista supports the Applicability Section, it is overly complicated and offer the following non-substantive changes for consideration:

4.2 Facilities: The term “generating unit” subject to these requirements means:

4.2.1 Bulk Electric System (BES) generating unit(s) that commit or are obligated to serve a Balancing Authority load pursuant to an Open Access Transmission Tariff (OATT) or other contractual arrangement, excluding BES generating unit(s) that are that are not committed or obligated to operate at or below thirty-two (32) degrees Fahrenheit (zero degrees Celsius) for any continuous run of more than four hours. The exclusion applies even when such BES generating unit(s) have been called to assist in the mitigation of BES Emergencies, Capacity Emergencies, or Energy Emergencies during periods at or below thirty-two (32) degrees Fahrenheit (zero degrees Celsius).

4.2.2 Blackstart Resource(s) that are identified in the Transmission Operator's system restoration plan.

Likes 0	
Dislikes 0	

Response

Brooke Jockin - Portland General Electric Co. - 1, Group Name Portland General Electric Co.

Answer	Yes
Document Name	

Comment

Portland General Electric Company supports the survey response provided by EEI.

Likes 0	
Dislikes 0	

Response

Scott Kinney - Avista - Avista Corporation - 3

Answer	Yes
Document Name	

Comment

While Avista supports the Applicability Section, it is overly complicated and offer the following non-substantive changes for consideration:

4.2 Facilities: The term "generating unit" subject to these requirements means:

4.2.1 Bulk Electric System (BES) generating unit(s) that commit or are obligated to serve a Balancing Authority load pursuant to an Open Access Transmission Tariff (OATT) or other contractual arrangement, excluding BES generating unit(s) that are that are not committed or obligated to operate at or below thirty-two (32) degrees Fahrenheit (zero degrees Celsius) for any continuous run of more than four hours. The exclusion applies even when such BES generating unit(s) have been called to assist in the mitigation of BES Emergencies, Capacity Emergencies, or Energy Emergencies during periods at or below thirty-two (32) degrees Fahrenheit (zero degrees Celsius).

4.2.2 Blackstart Resource(s) that are identified in the Transmission Operator's system restoration plan.

Likes 0	

Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Ameren agrees with the EEI and the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Joe Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Xcel Energy supports comments from EEI.	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3, Group Name OGE Energy	
Answer	Yes
Document Name	
Comment	
OG&E supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
AEP would like to express its support of EEI's response to this question and adds supportive comments below. AEP believes the Applicability section could be improved by making it clear that a Blackstart Resource, for purposes of this standard, are *only* those resources identified as such by the RTO (serving as the BA). 4.2.1.1.1 states that "The term excludes a Bulk Electric System generating unit that is typically not available…", however we believe the phrase "typically not available" is ambiguous. Rather, we believe a threshold should be established in this section, similar to that provided in MOD-026 and MOD-027. We believe clarity is also needed within 4.2.1 to make it clear if the bullets are to be collectively considered as an "and" or as an "or" clause.	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Dominion Energy supports the EEI comments and recommend modifications to the proposed Applicability section.	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company	
Answer	Yes
Document Name	
Comment	

LouisvilleG&E/KU support EEI's comments.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	Yes
Document Name	

Comment

Constellation has no additional comments.

Kimberly Turco, on behalf of Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Alison Mackellar - Constellation - 5

Answer	Yes
Document Name	

Comment

Constellation has no additional comments.

Kimberly Turco, on behalf of Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC

Answer	Yes

Document Name

Comment

PNM supports EEI’s comments.

Likes 0

Dislikes 0

Response

Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster

Answer Yes

Document Name

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for question #3.

Likes 0

Dislikes 0

Response

Dan Roethemeyer - Vistra Energy - 5

Answer Yes

Document Name

Comment

Vistra has no comments on the Applicability Section language.

Likes 0

Dislikes 0

Response

Daniel Gacek - Exelon - 1

Answer Yes

Document Name

Comment

Exelon agrees the Applicability Section language is clear, we do also support the enhancements proposed by the EEI.

Submitted on behalf of Exelon, Segments 1 & 3

Likes 0	
Dislikes 0	

Response

Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF

Answer	Yes
Document Name	

Comment

SIGE agrees with the changes to the revised Applicability Section.

Likes 0	
Dislikes 0	

Response

Stewart Rake - Luminant Mining Company LLC - 7

Answer	Yes
Document Name	

Comment

Vistra has no comments on the Applicability Section language.

Likes 0	
Dislikes 0	

Response

Michelle Amarantos - APS - Arizona Public Service Co. - 5

Answer	Yes
Document Name	

Comment

APS agrees with EEI's recommendation to remove references to the OATT and "other contractual agreement" language as it introduces complexity with little value. We agree with EEI's proposed revisions to the Applicability section.

Likes 0	
Dislikes 0	

Response

Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	

Comment

While Avista supports the Applicability Section, it is overly complicated and offer the following non-substantive changes for consideration:

4.2 Facilities: The term "generating unit" subject to these requirements means:

4.2.1 Bulk Electric System (BES) generating unit(s) that commit or are obligated to serve a Balancing Authority load pursuant to an Open Access Transmission Tariff (OATT) or other contractual arrangement, excluding BES generating unit(s) that are that are not committed or obligated to operate at or below thirty-two (32) degrees Fahrenheit (zero degrees Celsius) for any continuous run of more than four hours. The exclusion applies even when such BES generating unit(s) have been called to assist in the mitigation of BES Emergencies, Capacity Emergencies, or Energy Emergencies during periods at or below thirty-two (32) degrees Fahrenheit (zero degrees Celsius).

4.2.2 Blackstart Resource(s) that are identified in the Transmission Operator's system restoration plan.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	

Comment

EEI recommends the references to the OATT and "other contractual arrangement" language be removed because such language adds little to the requirement from results-based Reliability Standard standpoint. Additionally, while EEI supports the Applicability Section, it is overly complicated and offer the following non-substantive changes for consideration:

Applicability:

4.1 Functional Entities:

4.1.1. Generator Owner

4.1.2. Generator Operator

4.2. Facilities: The term “generating unit” subject to these requirements means:

4.2.1. A Bulk Electric System (BES) generating unit **t**hat commits or is obligated to serve a Balancing Authority load exclud**ing** a BES generating unit **that is not committed or obligated to operate** at or below thirty-two (32) degrees Fahrenheit (zero degrees Celsius) for any continuous run of more than four hours. The exclusion **continues to apply should** such BES generating unit be called **upon** to **operate for more than four hours in order to** assist in the mitigation of BES Emergencies, Capacity Emergencies, or Energy Emergencies during periods at or below 32 degrees Fahrenheit.

4.2.2. That is identified as a Blackstart Resource.

Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
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	
Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 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	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Watt - Oklahoma Municipal Power Authority - 4	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glenn Pressler - CPS Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Lenise Kimes - City and County of San Francisco - 1,5 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Johnson - Oglethorpe Power Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott McGough - Georgia System Operations Corporation - 3	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Ruskamp - Lincoln Electric System - 6, Group Name LES	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Young - Tenaska, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Foung Mua, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Wei Shao, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; - Tim Kelley, Group Name SMUD / 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	
John Liang - Snohomish County PUD No. 1 - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response
Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE understands the intent of the SDT to include generation units that operate in different types of market structures, including the ERCOT region. Texas RE recommends, however, clarifying Section 4.2.1.1, as it could benefit additional detail and clarity. The use of the term "to serve BA load" could lead to confusion for how the standard applies to generation-only BAs in the Eastern or Western interconnection as well as to ancillary services.

Texas RE recommends the type of market structure be removed from the Facilities section and the applicability focus on the reliability need.

Texas RE suggests the following proposed language, which focuses on the reliability needs that the generation units provide:

4.2.1 A Bulk Electric System generating unit:

4.2.1.1 That commits, or is committed by the BA, to provide energy to serve BA load, or;

4.2.1.2 That commits, or is committed by the BA or Reserve Sharing Group, to provide ancillary services to the BA or RSG for frequency control, frequency response, voltage control, or Operating Reserves, or;

4.2.1.3 That commits, or is committed by the BA or Reserve Sharing Group, to maintain BES elements within System Operating Limits, or;

4.2.1.4 Is identified as a Blackstart Resource.

4.2.2 The term excludes ….. (may want to include an example, such as a unit that is in a seasonal mothball status and only runs during summer months)

If the SDT feels that it is critical to maintain the market structure within the applicability section, Texas RE proposes the following language:

4.2.1 A Bulk Electric System generating unit:

4.2.1.1 That commits, or is committed by the BA, to provide energy under market processes, or;

4.2.1.2 That commits, or is committed by the BA or Reserve Sharing Group, to provide ancillary services to the BA or RSG for frequency control, voltage control, or Operating Reserves, or;

4.2.1.3 Is obligated to serve a Balancing Authority load pursuant to an Open Access Transmission Tariff (OATT) or other contractual arrangement, or;

4.2.1.4 Is identified as a Blackstart Resource.

4.2.2 The term excludes …..

Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
“Please see comments submitted by the Edison Electric Institute”	
Likes 0	
Dislikes 0	
Response	

4. Do you support the SDT proposed 12-hour timeframe to require new Generation units to be capable of performing at or below the Extreme Cold Weather Temperature? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Rhonda Jones - Invenergy LLC - 5

Answer	No
Document Name	

Comment

Invenergy recommends striking "continuous" from the requirement to reflect the fact that certain generation technologies, including wind and solar generators, have variable, not continuous output.

Even with the recommended edit above, the capability requirement does not account for all relevant circumstances. Two examples illustrate the issue: (1) Solar generators are not capable of operating in a 12-hour period that extends beyond daylight hours. (2) The capability of storage generators is constrained by their duration.

Further, the performance expectations of all generators should be the same, and the separate performance criteria proposed for new and existing generating units in R1 and R2 respectively set precedents for the unequitable treatment of Generator Owners based on a fluid effective date of the Standard.

If the SDT decides to regulate new and existing generators differently, then the SDT should establish a definition for new and existing units not based on the effective date of the Requirement, but rather the age of the generating unit.

Likes 0	
Dislikes 0	

Response

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1

Answer	No
Document Name	

Comment

AEPC has signed on to ACES comments, please see their responses.

Likes 0	
Dislikes 0	

Response

Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)

Answer	No
Document Name	

Comment

The proposed Standard requires generating units to perform at or below the ECWT for twelve hours. The SRC does not think this language, as written, suffices because it limits a unit's obligation to winterize to run for only a twelve-hour period. For example, in PJM, units with capacity obligations are required to perform whenever called upon by PJM during a declared system emergency and are subject to very high penalties if they do not perform during the hours when they can be called upon. Yet, as written, the standard would potentially erode if not create an ambiguity with that requirement by requiring a lesser only 12 hour run requirement.

The SRC recognizes this issue needs further discussion and is willing to coordinate with the SDT to address the issue.

Likes 0	
Dislikes 0	

Response

Deanna Carlson - Cowlitz County PUD - 5

Answer	No
Document Name	

Comment

Agree with comments provided by Russell Noble.

Likes 0	
Dislikes 0	

Response

Russell Noble - Cowlitz County PUD - 3

Answer	No
Document Name	

Comment

Cowlitz is concerned how this will be demonstrated by compliance documentation short of actual performance, although the intent is reasonable. The requirement should recognize good faith effort in design, but clearly define the action the responsible entity should take if the design proves inadequate in during operations.

Likes 0	
Dislikes 0	

Response	
Whitney Wallace - Calpine Corporation - 5 - WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
R1 requires the GO to operate for no less than 12 continuous hours at the ECW Temperature with wind speeds up to 20 mph. First, wind speed should be specified as "sustained wind speed". Second, ***this question infers GOs will be required to operate reliably below the ECW Temperature***. That is not the R1 requirement. R1 does not require operating at below the ECW. Furthermore, consistent with the comment in Response 3, NERC should clearly specify the types of units that it intends to exempt from this Standard and explain why exempting these units is not unduly discriminatory.	
Likes 0	
Dislikes 0	
Response	
Colin Chilcoat - Invenergy LLC - 6	
Answer	No
Document Name	
Comment	
Invenergy recommends striking "continuous" from the requirement to reflect the fact that certain generation technologies, including wind and solar generators, have variable, not continuous output. Even with the recommended edit above, the capability requirement does not account for all relevant circumstances. Two examples illustrate the issue: (1) Solar generators are not capable of operating in a 12-hour period that extends beyond daylight hours. (2) The capability of storage generators is constrained by their duration. Further, the performance expectations of all generators should be the same, and the separate performance criteria proposed for new and existing generating units in R1 and R2 respectively set precedents for the unequitable treatment of Generator Owners based on a fluid effective date of the Requirement. If the SDT decides to regulate new and existing generators differently, then the SDT should establish a definition for new and existing units not based on the effective date of the Requirement(s), but rather the age of the generating unit.	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations	

Answer	No
Document Name	
Comment	

It is our recommendation that wind should not be included in the design criteria for new Generation units unless added to ECWT definition. The reasoning behind this recommendation is due to the inconsistencies between R1 and R3. The language in R1 states that the GO *shall* include a concurrent 20 MPH wind speed in the design criteria for new generating units. Whereas the language in R3 states that the cold weather preparedness plan *may* include measures used to reduce the cooling effects of wind. Is the GO required to include wind in their calculations for all stations and all scenarios? If not, then what is the benefit for including this in the design criteria for new generating units?

Furthermore, the 20 MPH value seems to be somewhat arbitrary. Please provide additional clarification as to how this value was derived and the rationale behind this derivation.

Likes 0	
Dislikes 0	
Response	

Bobbi Welch - Midcontinent ISO, Inc. - 2

Answer	No
Document Name	
Comment	

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

Likes 0	
Dislikes 0	
Response	

Steven Sconce - EDF Renewable Energy - 5

Answer	No
Document Name	
Comment	

EDF believes that it is extremely difficult to apply a “one-size-fits-all” strategy to the timeframe. As an example, the R1 definition refers to twelve (12) continuous hours which is unrealistic during winter period (in cold climates) for inverter based resources (Photovoltaic – PV and Battery Energy Storage System – BESS), i.e., 12 hours of sunlight are not available for PV generation, and many BESS units are only rated for 4 hours. PV and BESS would be producing less than 12 hours during these months on a normal basis. Wind resource, unlike PV and BESS, is unpredictable and we cannot guarantee 12 hours, since the production time will depend of wind availability. We recommend defining a timeframe based on conventional and another for renewables (wind may need to be separate from solar and battery storage)

Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	No
Document Name	
Comment	
For some Canadian entites, units already operate in cold weather annually from November to March. These requirements represent and added administrative burden.	
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 believes that new generation units be capable of performing “Continuously” at the ECWT. The requirement should also include the 20 mph wind speed on exposed critical equipment.	
Likes 0	
Dislikes 0	
Response	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	No
Document Name	
Comment	
Cold weather performance needs to be sustained for the duration of a weather event. Historically, extreme weather events have lasted more than 12 hours. Hence, equipment should be expected to operate continuously at a stated level, albeit at a level below nameplate. Operating for 12 hours only delays onset of problems without ensuring mitigation of reliability impacts.	

Likes 0	
Dislikes 0	
Response	
Stewart Rake - Luminant Mining Company LLC - 7	
Answer	No
Document Name	
Comment	

As a general principle, Vistra believes that the requirements for existing and new resources should be substantively similar, such that neither has a material cost burden or advantage over the other. With that said, the 12-hour standard is not inherently unreasonable, in itself, ***if*** the term "Extreme Cold Weather Temperature" is defined in a less conservative manner, such as the 99th percentile minimum average ambient temperature over some timeframe (e.g., 12 to 72 hours) since a specified date (e.g., Jan. 1, 2000) at the nearest weather station. However, based on the current, very conservative proposed definition of Extreme Cold Weather Temperature, which effectively equates to a 99.8th percentile lowest hourly temperature recorded at the nearest weather station since Jan. 1, 2000, it may not be economically feasible for a new Generation unit to achieve 12-hours of sustained operations at that temperature, based on current design specifications for the particular type of resource. The costs of achieving 12-hours of sustained operations at a 1-hour 99.8th percentile standard could be cost-prohibitive and cause investors to cancel planned investments, which, in turn, would be detrimental to resource adequacy, as described in response to Question 2. If a 12-hour operations standard will be required, then the definition of Extreme Cold Weather Temperature should also be tied to historical temperatures over at least a continuous 12-hour timeframe. The Extreme Cold Weather Temperature definition, as currently framed, looks only at a single hourly temperature in the lowest 0.2 percentile since Jan. 1, 2000 and then requires a new resource to prove that it can operate at that temperature for at least 12 hours *and* at 20 mph winds. As noted under Question 2, in the draft Technical Requirements document, the example 0.2 percentile temperature had only ever occurred in 11 separate hours since 2000. Thus, there is no basis under the historical data underlying that definition of Extreme Cold Weather Temperature to require a new resource to prove it can operate for 12 consecutive hours at a temperature that apparently has not occurred in the past 22 years for 12 consecutive hours. Thus, as described under Question 2, Vistra would recommend using an average temperature over a period of hours that at least matches (if not exceeds) the required hours for which the resource must sustain operations at that temperature (and would recommend setting the percentile at something less conservative than the lowest 0.2 percentile/99.8th percentile). If the Extreme Cold Weather Temperature definition is not changed as proposed, then new resources should not be required to prove sustained operations at that temperature for more than one hour.

In addition, Requirement R1 allows a new resource to submit a declaration if it cannot satisfy the 12-hour operation requirement, but it is not clear what happens in that instance. The standard should clarify what standard will be imposed if a new resource declares that it cannot meet the standard in the requirement (e.g., 12 hours). Will the resource be held to a lower standard consistent with its design specifications? Will that lower standard relate to the applicable cold weather temperature at which the resource must sustain operations or the number of hours for which the resource must sustain operations or both? Will the Technical Feasibility Exception process be used?

Likes 0	
Dislikes 0	
Response	
Dan Roethemeyer - Vistra Energy - 5	
Answer	No
Document Name	

Comment	

As a general principle, Vistra believes that the requirements for existing and new resources should be substantively similar, such that neither has a material cost burden or advantage over the other. With that said, the 12-hour standard is not inherently unreasonable, in itself, ***if*** the term "Extreme Cold Weather Temperature" is defined in a less conservative manner, such as the 99th percentile minimum average ambient temperature over some timeframe (e.g., 12 to 72 hours) since a specified date (e.g., Jan. 1, 2000) at the nearest weather station. However, based on the current, very conservative proposed definition of Extreme Cold Weather Temperature, which effectively equates to a 99.8th percentile lowest hourly temperature recorded at the nearest weather station since Jan. 1, 2000, it may not be economically feasible for a new Generation unit to achieve 12-hours of sustained operations at that temperature, based on current design specifications for the particular type of resource. The costs of achieving 12-hours of sustained operations at a 1-hour 99.8th percentile standard could be cost-prohibitive and cause investors to cancel planned investments, which, in turn, would be detrimental to resource adequacy, as described in response to Question 2. If a 12-hour operations standard will be required, then the definition of Extreme Cold Weather Temperature should also be tied to historical temperatures over at least a continuous 12-hour timeframe. The Extreme Cold Weather Temperature definition, as currently framed, looks only at a single hourly temperature in the lowest 0.2 percentile since Jan. 1, 2000 and then requires a new resource to prove that it can operate at that temperature for at least 12 hours *and* at 20 mph winds. As noted under Question 2, in the draft Technical Requirements document, the example 0.2 percentile temperature had only ever occurred in 11 separate hours since 2000. Thus, there is no basis under the historical data underlying that definition of Extreme Cold Weather Temperature to require a new resource to prove it can operate for 12 consecutive hours at a temperature that apparently has not occurred in the past 22 years for 12 consecutive hours. Thus, as described under Question 2, Vistra would recommend using an average temperature over a period of hours that at least matches (if not exceeds) the required hours for which the resource must sustain operations at that temperature (and would recommend setting the percentile at something less conservative than the lowest 0.2 percentile/99.8th percentile). If the Extreme Cold Weather Temperature definition is not changed as proposed, then new resources should not be required to prove sustained operations at that temperature for more than one hour.

In addition, Requirement R1 allows a new resource to submit a declaration if it cannot satisfy the 12-hour operation requirement, but it is not clear what happens in that instance. The standard should clarify what standard will be imposed if a new resource declares that it cannot meet the standard in the requirement (e.g., 12 hours). Will the resource be held to a lower standard consistent with its design specifications? Will that lower standard relate to the applicable cold weather temperature at which the resource must sustain operations or the number of hours for which the resource must sustain operations or both? Will the Technical Feasibility Exception process be used?

Likes 0	
Dislikes 0	

Response

Tony Skourtas - Los Angeles Department of Water and Power - 3

Answer	No
Document Name	

Comment

LDWP recommends this requirement to be region specific applicable only to areas that are susceptible to Extreme Cold Weather. In addition, require Generator Owners that plan to operate generating units in areas susceptible to Extreme Cold Weather to specify the need for continuous operation at or below the Extreme Cold Weather Temperature.

Likes 0	
Dislikes 0	

Response

Sheila Suurmeier - Black Hills Corporation - 1,3,5,6	
Answer	No
Document Name	
Comment	

BHC does not feel 12 hours is an adequate amount of time once a new unit has gone commercial, dependent upon when that commercial date was achieved. Hypotehtically, if the unit achieved commercial operation during spring/summer, therefore, the unit may not have had a chance for capability testing during winter/extreme temperatures.

Likes 0	
Dislikes 0	
Response	

Micah Runner - Black Hills Corporation - 1	
Answer	No
Document Name	
Comment	

BHC does not feel 12 hours is an adequate amount of time once a new unit has gone commercial, dependent upon when that commercial date was achieved. Hypothetically, if the unit achieved commercial operation during spring/summer, therefore, the unit may not have had a chance for capability testing during winter/extreme temperatures.

Likes 0	
Dislikes 0	
Response	

Josh Combs - Black Hills Corporation - 3	
Answer	No
Document Name	
Comment	

BHC does not feel 12 hours is an adequate amount of time once a new unit has gone commercial, dependent upon when that commercial date was achieved. Hypothetically, if the unit achieved commercial operation during spring/summer, therefore, the unit may not have had a chance for capability testing during winter/extreme temperatures.

Likes 0	

Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
BHC does not feel 12 hours is an adequate amount of time once a new unit has gone commercial, dependent upon when that commercial date was achieved. Hypothetically, if the unit achieved commercial operation during spring/summer, therefore, the unit may not have had a chance for capability testing during winter/extreme temperatures.	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	
The 12-hour timeframe imposes a larger performance burden on new fossil generation since many renewable technologies are unlikely to meet this benchmark in the winter period as the nature of their operation is less than 12 continuous hours. In addition, renewable technology such as wind turbines cannot operate in certain winter conditions (freezing precipitation, high winds) allowing for technical exemptions. Since these IRRs could potentially be exempted under a technical exception, this creates a disadvantage for new thermal generators further slants the market playing field by giving one type of technology a competitive advantage over another type of technology. *NRG* also *has concerns with the language around the exclusion for technical, operational, and commercial reasons. Clarity is needed as to what are acceptable criteria for these exclusions as this will be subject to interpretation.*	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	No
Document Name	

Comment

The 12-hour timeframe imposes a larger performance burden on new fossil generation since many renewable technologies are unlikely to meet this benchmark in the winter period as the nature of their operation is less than 12 continuous hours. In addition, renewable technology such as wind turbines cannot operate in certain winter conditions (freezing precipitation, high winds) allowing for technical exemptions. Since these IRRs could potentially be exempted under a technical exception, this creates a disadvantage for new thermal generators further slanting the market playing field by giving one type of technology a competitive advantage over another type of technology.

NRG also *has concerns with the language around the exclusion for technical, operational, and commercial reasons. Clarity is needed as to what are acceptable criteria for these exclusions as this will be subject to interpretation.*

Likes 0	
Dislikes 0	

Response

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer	No
Document Name	

Comment

Reclamation does not agree with the fine-toothed level of specificity that is proposed. A standard that is too specific only sets up entities for compliance failure and does not improve reliability. Creating overly-specific requirements and allowing exemptions creates loopholes in the solution, which ultimately sabotages reliability. Reclamation recommends the applicability be targeted to specific geographic region(s) or specific types of generating units that are the root causes of the cold weather problems FERC is attempting to solve. Mandatory compliance for these units should not be diminished in any way.

Likes 0	
Dislikes 0	

Response

Mark Spencer - LS Power Development, LLC - 5

Answer	No
Document Name	

Comment

We note that the proposed standard requires performance at the ECWT, yet the question asks whether we support an open-ended requirement below the ECWT. We do not.

Likes 1	Vistra Energy, 5, Roethemeyer Dan
Dislikes 0	

Response	
Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 1	
Answer	No
Document Name	
Comment	
We do not have a concern where viable technical solutions exist but do have a concern where installing such measures would void manufacturer warranties and increase the risk of equipment failure. Additionally, renewable generation (Solar or Wind) is only capable of performing if the resource is available.	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	No
Document Name	
Comment	
Talen Energy Marketing supports Talen Generation's comments.	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
The equations in IEEE-515, IEEE Standard for the Testing, Design, Installation, and Maintenance of Electrical Resistance Trace Heating for Industrial Applications, have a steady-state basis. Granting an exception for inadequately protected equipment so long as it takes a long time to freeze would put the BES at risk and is not in accordance with industry practice. There is also no apparent basis for a figure of 12 hours as representing the maximum duration of a weather emergency. The historical worst-case winter storm in our area produced freeze protection-challenging cold weather (-15 F WCT or lower) for approx. 30 consecutive hours.	

Additionally, freeze protection margins cannot be reliably sliced so thin – there is great uncertainty in protecting a plant, due to frequent design and installation errors by heat tracing and insulation contractors. There is also no big-picture incentive to do so. The cost difference between a steady-state design and one with a survival limit of 12 hours is negligible in comparison to the cost to society of inadequate protection and the cost to GOs if finding that their forecasts are off and R6 retrofits are needed.	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	No
Document Name	
Comment	
Entergy agrees with the statement "at the Extreme Cold Weather Temperature" but does not agree with "or below".	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	No
Document Name	
Comment	
This is an arbitrary timeframe with an arbitrary assumption. I don't see a good technical basis established regarding this requirement.	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the language proposed in Requirement R1, which if approved, would require new generation to have the capability to operate for a period of not less than 12 hours at the Extreme Cold Weather Temperature for the unit, but we do not agree that the unit needs to be capable of operating below the Extreme Cold Weather Temperature for 12 hours, as indicated in this question.	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Avista supports the language proposed in Requirement R1, which if approved, would require new generation to have the capability to operate for a period of not less than 12 hours at the Extreme Cold Weather Temperature for the unit, but we do not agree that the unit needs to be capable of operating below the Extreme Cold Weather Temperature for 12 hours, as indicated in this question. There should be an allowance for act of god situations which a plant can not reasonably account for.	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	Yes
Document Name	
Comment	

Acciona Energy has no comments.	
Likes 0	
Dislikes 0	
Response	
Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	Yes
Document Name	
Comment	
Capital Power supports the North American Generators Forum (NAGF) response to this question.	
Likes 0	
Dislikes 0	
Response	
Imane Mrini - Austin Energy - 6	
Answer	Yes
Document Name	
Comment	
The last sentence of M1 is incomplete and therefore confusing. Is it supposed to be part of the sentence prior?	
Likes 0	
Dislikes 0	
Response	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	Yes
Document Name	
Comment	
MidAmerican Energy supports the MRO NSRF comments for this question.	

Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	

While the NAGF agrees with the proposal as being reasonable, there are still concerns related to this proposal. Those concerns include the expectation that this proposal will not protect against another event like Uri, and that the Extreme Cold Weather Temperature is not addressing wind and moisture. With this said, the proposal is considered by most to be clear and enforceable and provides clear guidance and expectations to design future generators to meet a design criterion.

The NAGF does have concern with the language around the exclusion for technical operational and commercial reasons. This language essentially makes this requirement optional to anyone that does not want to meet the design requirement. While we recognize the reasoning for the exemption language, we feel it makes the standard unenforceable by NERC.

Instead of creating the optional requirement, a more immediate impact would be seen by ensuring that Balancing Authorities and others are using information detailing generator capabilities when performing their planning processes to reduce the expectation of unplanned outages due to the lack of appropriate planning. This would allow the appropriate entities, including regulatory officials, to identify where issues might arise and how to best address the issue rather than creating optional requirements.

Likes 0	
Dislikes 0	
Response	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	

SIGE supports EEI’s comment for Question 4 and agrees with the language of R1 for new generations units to implement freeze protection measures that provide capability to operate for a period of not less than twelve (12) continuous hours at the Extreme Cold Weather Temperature if the constraint exemption (bullet 2) remains in the requirement.

Likes 0	
Dislikes 0	
Response	

Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon concurs with EEI's comment to Question 4. Submitted on behalf of Exelon, Segments 1 & 3	
Likes 0	
Dislikes 0	
Response	

Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	Yes
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for question #4.	
Likes 0	
Dislikes 0	
Response	

Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	
PNM supports EEI’s comments.	
Likes 0	
Dislikes 0	
Response	

Alison Mackellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco, on behalf of Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco, on behalf of Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Devin Shines - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company	
Answer	Yes
Document Name	
Comment	
LouisvilleG&E/KU support EEI's comments.	

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	Yes
Document Name	

Comment

AEP supports the proposed 12-hour timeframe in the current draft, however we disagree with Q4's inference that the unit needs to be capable of performing *below* the Extreme Cold Weather Temperature for 12 hours.

AEP interprets the text proposed in the final bullet of R1 as allowing a declaration to be used as an exception based on operational restrictions outside of the Generator Owner's control such as environmental permit limits for a new installation.

Likes 0	
Dislikes 0	

Response

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments

Answer	Yes
Document Name	

Comment

PG&E supports the requirement for a new generator to operate for a period not less than 12 hours as noted in the Requirement.

PG&E also supports the comments supplied by EEI that is not a 12-hour timeframe as indicated in this question and the concerns indicated in the NAGF comments regarding the Standard being unenforceable by the ERO and NAGF's input on addressing the optional requirement language.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	Yes

Document Name	
Comment	
Please see Texas RE's answer to #5.	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3, Group Name OGE Energy	
Answer	Yes
Document Name	
Comment	
OG&E supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Joe Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Xcel Energy supports comments from EEI.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	

Ameren agrees with the EEI and the NAGF comments.

Likes 0	
Dislikes 0	

Response

Scott Kinney - Avista - Avista Corporation - 3

Answer	Yes
Document Name	

Comment

Avista supports the language proposed in Requirement R1, which if approved, would require new generation to have the capability to operate for a period of not less than 12 hours at the Extreme Cold Weather Temperature for the unit, but we do not agree that the unit needs to be capable of operating below the Extreme Cold Weather Temperature for 12 hours, as indicated in this question.

There should be an allowance for act of god situations which a plant can not reasonably account for.

Likes 0	
Dislikes 0	

Response

Brooke Jockin - Portland General Electric Co. - 1, Group Name Portland General Electric Co.

Answer	Yes
Document Name	

Comment

Portland General Electric Company supports the survey response provided by EEI.

Likes 0	
Dislikes 0	

Response

Glen Farmer - Avista - Avista Corporation - 5

Answer	Yes
Document Name	

Comment

Avista supports the language proposed in Requirement R1, which if approved, would require new generation to have the capability to operate for a period of not less than 12 hours at the Extreme Cold Weather Temperature for the unit, but we do not agree that the unit needs to

be capable of operating below the Extreme Cold Weather Temperature for 12 hours, as indicated in this question.

There should be an allowance for act of god situations which a plant can not reasonably account for.

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	Yes
Document Name	

Comment

None.

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

Southern Company agrees with the 12-hour continuous hours as proposed in R1.

Likes 0	
Dislikes 0	

Response

Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric

Answer	Yes

Document Name	
Comment	

DTE Electric supports NAGF comments provided for this project

Likes 0	
Dislikes 0	
Response	

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer	Yes
Document Name	
Comment	

It is our recommendation that wind should not be included in the design criteria for new Generation units unless added to Extreme Cold Weather Temperature definition. The rationale is due to the inconsistencies between R1 and R3. The language in R1 states that the GO shall include a concurrent 20 MPH wind speed in the design criteria for new generating units. Whereas the language in R3 states that the cold weather preparedness plan may include measures used to reduce the cooling effects of wind. Is the GO required to include wind in their calculations for all stations and all scenarios? If not, then what is the benefit for including this in the design criteria for new generating units?

Furthermore, the 20 MPH value seems to be somewhat arbitrary. Please provide additional clarification as to how this value was derived and the rationale behind this derivation.

Lastly, the standard drating team should consider how commercial constraints are referenced in R1. As written a declaration for a commercial constraint as defined by the Generator Owner could preclude the ability to implement appropriate freeze protection measures to provide capability of operating for twelve (12) hours at the documented Extreme Cold Weather Temperature. A commercial constraint could be defined by the Generator Owner to include the lack of budget allocated for winterization projects. This approach seems to not align with the purpose of this standard, "To address the effects of operating in extreme cold weather by ensuring each Generator Owner has developed and implemented plan(s) to mitigate the reliability impacts of extreme cold weather on its generating units."

Likes 0	
Dislikes 0	
Response	

Natalie Johnson - Enel Green Power - 5

Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
LaKenya VanNorman - LaKenya VanNorman On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name Florida Municipal Power Agency (FMPA)	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Liang - Snohomish County PUD No. 1 - 6	
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

Michelle Amarantos - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Foung Mua, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Wei Shao, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; - Tim Kelley, Group Name SMUD / BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Adam Lee - MGE Energy - Madison Gas and Electric Co. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ronald Bauer - MGE Energy - Madison Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Young - Tenaska, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Ruskamp - Lincoln Electric System - 6, Group Name LES	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruchi Shah - AES - AES Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott McGough - Georgia System Operations Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Johnson - Oglethorpe Power Corporation - 5	
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	
James Baldwin - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Lenise Kimes - City and County of San Francisco - 1,5 - WECC	
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	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Glenn Pressler - CPS Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Watt - Oklahoma Municipal Power Authority - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Brian Evans-Mongeon - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lindsey Mannion - ReliabilityFirst - 10	
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	

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	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
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	
Diana Torres - Imperial Irrigation District - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
"Please see comments submitted by the Edison Electric Institute"	
Likes 0	
Dislikes 0	
Response	

5. Do you support the SDT proposed 1-hour timeframe to allow existing Generation units to demonstrate their performance at or below the Extreme Cold Weather Temperature? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	No
Document Name	
Comment	
This continues to put an unnecessary burden on those generators that operate in freezing environments. This one hour timeline is arbitrary and doesn't seem to have any technical justification for the timeline.	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	No
Document Name	
Comment	
Entergy agrees with the statement “at the Extreme Cold Weather Temperature” but does not agree with “or below”.	
Likes 0	
Dislikes 0	
Response	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
DTE Electric supports NAGF comments provided for this project	
Likes 0	
Dislikes 0	

Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Tri-State feels that a 1-hour is too short of a time frame for reliability, instead we recommend the time frame of 4-hours.	
Likes 0	
Dislikes 0	
Response	
Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 1	
Answer	No
Document Name	
Comment	
Need the ability to explain in a declaration, technical, commercial or operational constraints for existing units (as is proposed for new units under Requirement R1). We do not have a concern where viable technical solutions exist but do have a concern where installing such measures would void manufacturer warranties and increase the risk of equipment failure. Requiring a Corrective Action Plan (CAP) under Requirement R2 may not be feasible for certain generation, as the needed technological advancement may be delayed beyond the proposed implementation period or may never be achieved. Additionally, renewable generation (Solar or Wind) is only capable of performing if the resource is available.	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
How will it be proven that you've provided enough protection to sustain the minimum 1-hour capability during ECWT? It is still not clear why there is a different requirement for generating units existing prior to the effective date of the requirement. Shouldn't all generators have the same requirement of 12 hours while also allowing existing generatios to submit a corrective action plan?	
Likes 0	

Dislikes 0	
Response	
Mark Spencer - LS Power Development, LLC - 5	
Answer	No
Document Name	
Comment	

We note that the proposed standard requires performance at the ECWT, yet the question asks whether we support an open-ended requirement below the ECWT. We do not. Additionally, we do not support disparate treatment of resource types that are otherwise similarly situated, and new versus existing creates disparate treatment. If the SDT selected 12 hours because they thought is was the duration necessary to enhance reliability, then it should apply to all generators. During the deliberation process, certain SDT team members were concerned a rigorous standard may cause "premature retirements." We understand that the sole reason that the existing generator standard differs from new is to mitigate the "premature retirements." Section 1341 of the Energy Policy Act of 2005, which was affirmed by the Commission in its Order 672, supports cost recovery for all costs prudently incurred to comply with the Reliability Standards, and it does not limit this consideration to specific types of units or circumstances, e.g., whether because of their "newness," or retirement considerations.

Additionally, the SDT assumes that good historical performance assures good future performance. A permissive prescriptive standard may not result in this outcome. We agree with the SDT that many generators have performed well in the past and may have operated at or below their ECWT for extended durations. However, the proposed standard will only allow cost recovery for meeting the exact requirements of the standard and no more. If a generator owner elects to replace robust freeze protections that have demonstrated superlative performance with in-kind components at the end of their service life or after a major outage, the generator owner may not be able to recover the full cost of such replacement. In fact, ratemaking proceedings may expressly disallow costs incremental to meeting the one-hour standard. For these reasons, we do not support different standards between new and existing.

Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	No
Document Name	
Comment	

PG&E agrees with the input provided by the NAGF that the 1-hour timeframe will not make an improvement in performance during an extreme event and supports the NAGF recommendation on how to decide on the adequacy of the proposed timeframe.

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Dominion Energy strongly advocates for and supports appropriately addressing the reliability issues identified in the joint FERC/NERC report related to winter storm Uri in a non-arbitrary and cost-effective manner under the Federal Power Act. Accordingly, Dominion Energy recommends rather than a universal requirement to retrofit exiting generation to operate to an arbitrary temperature requirement that may be beyond its current design capabilities, a requirement to communicate the generating units' extreme cold weather operating capabilities to the RC and BA and a corresponding requirement to develop a corrective action plan to continue to operate to those capabilities if the unit fails to do so due to freezing. Dominion Energy is of the opinion that this modification will accomplish the reliability goal identified in the FERC/NERC report.	
Likes 0	
Dislikes 0	
Response	

Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation does not agree with the fine-toothed level of specificity that is proposed. The proposed calculations required to comply or determine whether compliance is required are unnecessary administrative and resource-intensive burdens that will not improve reliability and will detract from entities' ability to comply with the standard.	
Likes 0	
Dislikes 0	
Response	

Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
BHC agrees with comments submitted by EEI.	

Likes 0	
Dislikes 0	

Response

Josh Combs - Black Hills Corporation - 3

Answer	No
Document Name	

Comment

BHC agrees with comments submitted by EEI.

Likes 0	
Dislikes 0	

Response

Micah Runner - Black Hills Corporation - 1

Answer	No
Document Name	

Comment

BHC agrees with comments submitted by EEI.

Likes 0	
Dislikes 0	

Response

Sheila Suurmeier - Black Hills Corporation - 1,3,5,6

Answer	No
Document Name	

Comment

BHC agrees with comments submitted by EEI

Likes 0	
Dislikes 0	

Response	
Tony Skourtas - Los Angeles Department of Water and Power - 3	
Answer	No
Document Name	
Comment	
The requirement should be for continuous operation. The capability of the unit operating for 1 hour under Extreme Cold Weather, does not mean the generating unit will be reliable in Extreme Cold Weather..	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	No
Document Name	
Comment	
PNM has concern regarding how the acceptable evidence outline in M2 [Identification of generating units minimum temperature per Part 3.5.2 which is equal to or less than the unit's Extreme Cold Weather Temperature, documentation of freeze protection measures, Facility cold weather preparedness plan, and CAP(s)] demonstrates the capability to operate a generating unit for a period of not less than one (1) hour at the unit(s) Extreme Cold Weather Temperature.	
Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1	
Answer	No
Document Name	
Comment	
It is more appropriate to have a temperature profile for unit operation.	
Likes 0	
Dislikes 0	

Response	
Dan Roethemeyer - Vistra Energy - 5	
Answer	No
Document Name	
Comment	

The 1-hour timeframe, in itself, can be a reasonable standard. However, as discussed at length under Question 2, the term “Extreme Cold Weather Temperature” also must be defined in a similarly reasonable manner. As discussed under Question 2, Vistra proposes modifications to the definition of “Extreme Cold Weather Temperature” to make it more in line with the standards under consideration by the PUCT and to make it more economically feasible to meet.

In addition, Requirement R2 should expressly clarify that an existing resource will be deemed to have satisfied the requirements of R2 at its respective Extreme Cold Weather Temperature and that no new or modified freeze protection measures will be required if the Generator Owner: (i) has actual operating data demonstrating continuous operations for at least one hour at that plant’s Extreme Cold Weather Temperature (as cacluated under NERC’s Calculating Extreme Cold Weather Temperature guide), or (ii) in the absence of such data, can show that the plant is capable of sustained operations for one hour at that temperature based on design temperature or engineering analysis. Only if the plant cannot demonstrate (i) or (ii) above should the Generator Owner be required to implement a CAP to develop new or modified freeze protections to meet R2.

In addition, the language of R2 should make clear that the requirement is a weather preparedness standard, rather than a performance standard, and thus should avoid use of the word “ensure.”

The language of R2 could be modified as follows:

R2. For each generating unit(s) in commercial operation prior to [Effective Date of this requirement], the Generator Owner shall prepare its generating unit(s) by adding new or modifying existing freeze protection measures as needed to provide the capability to operate for a period of not less than one (1) hour at the unit(s) Extreme Cold Weather Temperature. If a Generator Owner provides evidence that it has operated for at least one hour at or below its Extreme Cold Weather Temperature, or if the Generator Owner provides design specification information or other data (e.g., an engineering report) as detailed in M2 showing that it can operate for at least one hour at or below its Extreme Cold Weather Temperature, then the Generator Owner will be deemed to have met this Requirement R2, and need not implement new or additional freeze protection measures. Generating unit(s) that are not capable of operating for one (1) hour at its Extreme Cold Weather Temperature shall develop a Corrective Action Plan (CAP) for the identified issues, including identification of any needed modifications to the cold weather preparedness plan required under Requirement R3. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]

M2. Each Generator Owner will have dated evidence that demonstrates it has freeze protection measures for its unit(s) in accordance with R2, or it has developed a CAP for the identified issues. Acceptable evidence may include the following (electronic or hardcopy format): Identification of generating units minimum temperature per Part 3.5.2 which is equal to or less than the unit’s Extreme Cold Weather Temperature, documentation of freeze protection measures, cold weather preparedness plan, engineering study, historical data demonstrating one hour of sustained operations by the unit(s) at the applicable Extreme Cold Weather Temperature, and CAP(s).

Further, the SDT should consider adding a definition of “freeze protection measures” (applicable to all of EOP-012 and not just to R2) to clarify what those measures could entail and, importantly, to make clear that those measures do not have to include capital expenditures for redesign or retrofitting. For example, it should be clarified that “freeze protection measures” include temporary equipment like wind barriers. A new definition could be added as follows:

Freeze protection measures include permanent or temporary equipment, procedures, or other measures reasonably targeted to contribute to sustained operation by an existing unit(s) for the timeframe in R1 or R2, as applicable, at the Extreme Cold Weather Temperature.

Likes 0	
Dislikes 0	

Response

Teresa Krabe - Lower Colorado River Authority - 5

Answer	No
Document Name	

Comment

It is more appropriate to have a temperature profile for unit operation.

Likes 0	
Dislikes 0	

Response

LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6

Answer	No
Document Name	

Comment

How does an existing unit "ensure" operation for one hour at a temperature that only occurs during an extreme cold weather event? This creates a liability for post event non-performance while doing little to maximize the possibility the unit will perform during such events.

In addition, this imposes additional documentation and expense on entities with units that have demonstrated performance during actual events.

Finally, there is no value "ensuring" capability to operate for 1 hour during an extreme event since performance needs to be maintained for the duration of the event, not just one hour.

Likes 0	

Dislikes 0	

Response

Ruchi Shah - AES - AES Corporation - 5

Answer	No
Document Name	

Comment

AES Clean Energy supports comments submitted by NAGF. AES Clean Energy agrees with NAGF that the 1-hour timeframe will not make a significant difference in performance improvement during an extreme cold weather event and that a better approach that relies on data should be employed in setting the time requirement.

Likes 0	
Dislikes 0	

Response

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	No
Document Name	

Comment

While providing a clear expectation for Generator Owners to meet a performance level, the 1-hour timeframe to meet the Extreme Cold Weather Temperature has not been shown to make any level of improvement of performance during an extreme event such as Uri. The NAGF notes that the weather in Dallas was at or below the ECWT for over 50 hours straight and the Houston area met or exceeded the ECWT for 30 hours or more. The SDT has also not shown that the ECWT would address the issue the Joint Report mentioned multiple times related to generators failing prior to reaching their minimum design temperature. The NAGF recommends that a comparison of these units' failure point and the ECWT be provided to industry before a determination is made as to the adequacy of the proposal.

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 believes that Generators will have difficulty creating the needed conditions to “demonstrate” performance for 1-hour at or below the ECWT absent historical data. How is this enforceable if a Unit can not demonstrate the performance.

ISO-NE recommends that existing units be required to demonstrate through historical information or through design specifications (equipment ratings, etc.) the capability to operate continuously at the Extreme Cold Weather Temperature for the unit(s), assuming a concurrent twenty (20) mph wind speed on any exposed Generator Cold Weather Critical Components;

Likes 0	
Dislikes 0	

Response

Carl Pineault - Hydro-Qu?bec Production - 1,5

Answer	No
Document Name	

Comment

Requirement R4 appears to already fullfill the requirement of R2. The 2 requirements should be merged into one.

Likes 0	
Dislikes 0	

Response

Steven Sconce - EDF Renewable Energy - 5

Answer	No
Document Name	

Comment

Please refer to our comments in Question #3. In addition, the delta between R1 requesting 12 hours and R2 requesting 1 hour does not make sense short term / long term. Is it the intent of the SDT to converge to the same amount of time on the long term?

Likes 0	
Dislikes 0	

Response

Bobbi Welch - Midcontinent ISO, Inc. - 2

Answer	No
Document Name	

Comment

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

Likes 0	
Dislikes 0	

Response

Shannon Ferdinand - Decatur Energy Center LLC - 5

Answer	No
Document Name	

Comment

Capital Power supports the North American Generators Forum (NAGF) response to this question.

Likes 0	
Dislikes 0	

Response

Colin Chilcoat - Invenergy LLC - 6

Answer	No
Document Name	

Comment

Invenergy believes the performance expectations of all generators should be the same, and the separate performance criteria proposed for new and existing generating units in R1 and R2 respectively set precedents for the unequitable treatment of Generator Owners based on a fluid effective date of the Requirement.

If the SDT decides to regulate new and existing generators differently, then the SDT should establish a definition for new and existing units not based on the effective date of the Requirement(s), but rather the age of the generating unit.

Likes 0	
Dislikes 0	

Response

Gerry Adamski - Cogentrix Energy Power Management, LLC - 5

Answer	No

Document Name	
Comment	
There should be more clarity for existing generation units to meet compliance for the 1 hr capability either in the requirement, Measure, or technical rational for the standard	
Likes 0	
Dislikes 0	
Response	
Whitney Wallace - Calpine Corporation - 5 - WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
R2 requires the GO to operate for no less than 1 continuous hour at the ECW Temperature. First, wind speed should be specified here as in R1; the wind speed should be classified as "sustained wind speed," and the "sustained wind speed" should be designated as 20 mph (greater sustained wind speeds exceed the ECW). Second, ***this question infers GOs will be required to operate reliably below the ECW Temperature***. That is not the R1 requirement or the R2 requirement.	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	No
Document Name	
Comment	
While in agreement there should be an allowance for existing generation to demonstrate performance, 1-hour may be too lenient to cover the reliability gap.	
Likes 0	
Dislikes 0	
Response	
Deanna Carlson - Cowlitz County PUD - 5	

Answer	No
Document Name	
Comment	

Agree with comments provided by Russell Noble.

Likes 0	
Dislikes 0	
Response	

Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)

Answer	No
Document Name	
Comment	

While the SRC generally supports the idea of making existing generators demonstrate they can operate at the ECWT (with the proposed revision in Question 2) for at least one hour, that language does not require adding a 20 mph wind, which differs from the requirement for new generation. The SRC believes the BES will be more resilient if *all* generators must demonstrate the ability to operate at the ECWT *plus* a 20 mph wind.

The SRC believes Generators will have difficulty creating the needed conditions to demonstrate performance for one hour at or below the ECWT absent historical data. Thus, the SRC recommends the Standard require existing units to demonstrate - through historical information or design specifications (equipment ratings, *etc*.) - the capability to operate continuously at the ECWT for the unit(s), assuming a concurrent twenty (20) mph wind speed on any exposed Generator Cold Weather Critical Components.

Likes 0	
Dislikes 0	
Response	

Rhonda Jones - Invenergy LLC - 5

Answer	No
Document Name	
Comment	

Invenergy believes the performance expectations of all generators should be the same, and the separate performance criteria proposed for new and existing generating units in R1 and R2 respectively set precedents for the unequitable treatment of Generator Owners based on a fluid effective date of the Standard.

If the SDT decides to regulate new and existing generators differently, then the SDT should establish a definition for new and existing units not based on the effective date of the Requirement, but rather the age of the generating unit.

Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 6	
Answer	Yes
Document Name	
Comment	
Agree, but this could become problematic because there is no time period mentioned. How long is a historical run able to be used as meeting the requirement?	
Likes 0	
Dislikes 0	
Response	

Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	

Talen Energy supports the comments of the NAGF on this topac, and adds that a one-hour period is appropriate since the variability of weather conditions often makes a longer demonstration impossible. This is not the end of the matter, however; this achievement should be based for conventional plants on WCT (or DBT-plus-20 mph), not DBT alone.

The lack of credibility of DBT-based achievements can be seen in reviewing the events of January 2014 for our area. No problems were encountered on 1/4/2014 at -4 F DBT and a 4.6 mph wind (-14.6 F WCT). EOP-012-1 in its present form says that all plants online at that time had a proven DBT capability of at least -4 F. Many of these facilities were knocked offline three days later, however, when the Polar Vortex of 2014 bottomed-out at 0 F with a 21.9 mph wind (-22.8 WCT).

More importantly, R2 should allow declaring R3.5.2 WCT capability values as an alternative to retrofits, and EOP-012-1 should also permit R6 CAPS that consist of revising these inputs instead of modifying equipment. Existing facilities were built in accordance with all regulatory and market rules in place at the time, and it would be wrong to order them in ex post facto fashion to become something significantly different. The lack of winterization rules to-date is not a failing of GO/GOPs, so they should not be subjected to punitive measures.

RC/BA/TOP planning based on GO/GOP temperature capability inputs hasn't worked in the past, but only due to these entities insisting on an incorrect basis (DBT only) plus failing to differentiate between temperature-caused and precipitation-caused outages. Planning Assessments and real-time reserve margin forecasts should be highly accurate once EOP-012-1 puts an end to this confusion.

Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	

Talen Energy Marketing LLC supports Talen Generation's 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

Southern Company agrees with the 1-hour timeframe to allow existing Generation units to demonstrate their performance as proposed in R2.

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	Yes
Document Name	

Comment

None.

Likes 0	
Dislikes 0	

Response

Glen Farmer - Avista - Avista Corporation - 5

Answer	Yes
Document Name	

Comment

Avista supports the proposed R2 language that requires GOs of existing Generating units ensure new or modify existing freeze protection measures provide the capability to operate for a period of not less than one (1) hour at the unit(s) Extreme Cold Weather Temperature.

Likes 0	
Dislikes 0	

Response

Scott Kinney - Avista - Avista Corporation - 3

Answer	Yes
Document Name	

Comment

Avista supports the proposed R2 language that requires GOs of existing Generating units ensure new or modify existing freeze protection measures provide the capability to operate for a period of not less than one (1) hour at the unit(s) Extreme Cold Weather Temperature.

Likes 0	
Dislikes 0	

Response

Joe Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC

Answer	Yes
Document Name	

Comment

Xcel Energy can support the 1-hour time frame for existing units, predicated on the ability that R2 is tied to R6 and, subsequently, R7. The ability to declare qualifying units as unable to implement corrective actions is a required element for Xcel Energy to support R2 of the Standard.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	Yes
Document Name	

Comment

AEP supports the proposed 1-hour timeframe in the current draft, however we disagree with Q5's inference that the unit needs to be capable of operating *below* the Extreme Cold Weather Temperature for 1 hour.

Likes 0	
Dislikes 0	

Response

Devin Shines - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company

Answer	Yes
Document Name	

Comment

LG&E/KU supports the SDT proposed 1-hour timeframe.

Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco, on behalf of Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Alison Mackellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco, on behalf of Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	Yes

Document Name

Comment

Currently this draft requires Generator Owners to retrofit their units to meet the newly defined Extreme Weather temperature levels. NRG understands that to invoke any technical, operational, or commercial exclusions clauses (such as units designed above 32 F) that each facility would require development of a CAP which may not be able to be executed under R7. It would be more prudent to include a provision in R2 to allow generators to provide these exclusions and associated justifications upfront.

NRG believes that R2 should not require existing Generators to retrofit but rather report their extreme cold weather operating parameters to the appropriate parties and only require a CAP if they fail to meet their operating parameters as communicated to the appropriate entities. This will allow the appropriate entities to identify where issues might arise and how to best address the issue rather than placing an unreasonable reliability requirement on all Generator Owners. The weatherization requirements, as currently drafted without cost recovery mechanisms in place, may exacerbate current difficulties for independent generators to cover costs and earn a return overall. The potential cost implications may result in generators either retiring or opting out of the winter season through seasonal mothballing.

Likes 0

Dislikes 0

Response

Patricia Lynch - NRG - NRG Energy, Inc. - 5

Answer Yes

Document Name

Comment

Currently this draft requires Generator Owners to retrofit their units to meet the newly defined Extreme Weather temperature levels. NRG understands that to invoke any technical, operational, or commercial exclusions clauses (such as units designed above 32 F) that each facility would require development of a CAP which may not be able to be executed under R7. It would be more prudent to include a provision in R2 to allow generators to provide these exclusions and associated justifications upfront.

NRG believes that R2 should not require existing Generators to retrofit but rather report their extreme cold weather operating parameters to the appropriate parties and only require a CAP if they fail to meet their operating parameters as communicated to the appropriate entities. This will allow the appropriate entities to identify where issues might arise and how to best address the issue rather than placing an unreasonable reliability requirement on all Generator Owners. The weatherization requirements, as currently drafted without cost recovery mechanisms in place, may exacerbate current difficulties for independent generators to cover costs and earn a return overall. The potential cost implications may result in generators either retiring or opting out of the winter season through seasonal mothballing.

Likes 0

Dislikes 0

Response

Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	Yes
Document Name	
Comment	
While Evergy supports EEI's comments in our responses, in an effort to answer the specific question from the SDT, Evergy holds no concerns with the 1-hour timeframe. Evergy agrees with the concerns about retrofits to existing resources with future transition plans but maintains that the SDT does not hold the authority to address the retrofit concern.	
Likes 0	
Dislikes 0	
Response	

Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	

SIGE supports the proposed 1-hour timeframe in R2; however, for clarity and consistency, SIGE recommends modifying R2 to mirror R1:

For each generating unit(s) in commercial operation prior to [Effective Date of this requirement], the Generator Owner shall:

- *Ensure its generating unit(s) add new or modify existing freeze protection measures as needed to provide the capability to operate for a period of not less than one (1) hour at the unit(s) Extreme Cold Weather Temperature. Generator Owner shall develop a Corrective Action Plan (CAP) for the identified issues, including identification of any needed modifications to the cold weather preparedness plan required under Requirement R3; or*
- ***Explain in a declaration, any technical, commercial, or operational constraints as defined by the Generator Owner that preclude the ability to implement appropriate freeze protection measures to provide capability of operating for a period of not less than one (1) hour at the unit(s) Extreme Cold Weather Temperature.***

Likes 0	
Dislikes 0	
Response	

Stewart Rake - Luminant Mining Company LLC - 7	
Answer	Yes
Document Name	
Comment	

The 1-hour timeframe, in itself, can be a reasonable standard. However, as discussed at length under Question 2, the term "Extreme Cold Weather Temperature" also must be defined in a similarly reasonable manner. As discussed under Question 2, Vistra proposes modifications to the definition of "Extreme Cold Weather Temperature" to make it more in line with the standards under consideration by the PUCT and to make it more economically feasible to meet.

In addition, Requirement R2 should expressly clarify that an existing resource will be deemed to have satisfied the requirements of R2 at its respective Extreme Cold Weather Temperature and that no new or modified freeze protection measures will be required if the Generator Owner: (i) has actual operating data demonstrating continuous operations for at least one hour at that plant's Extreme Cold Weather Temperature (as cacluated under NERC's Calculating Extreme Cold Weather Temperature guide), or (ii) in the absence of such data, can show that the plant is capable of sustained operations for one hour at that temperature based on design temperature or engineering analysis. Only if the plant cannot demonstrate (i) or (ii) above should the Generator Owner be required to implement a CAP to develop new or modified freeze protections to meet R2.

In addition, the language of R2 should make clear that the requirement is a weather preparedness standard, rather than a performance standard, and thus should avoid use of the word "ensure."

The language of R2 could be modified as follows:

R2. For each generating unit(s) in commercial operation prior to [Effective Date of this requirement], the Generator Owner shall prepare its generating unit(s) by adding new or modifying existing freeze protection measures as needed to provide the capability to operate for a period of not less than one (1) hour at the unit(s) Extreme Cold Weather Temperature. If a Generator Owner provides evidence that it has operated for at least one hour at or below its Extreme Cold Weather Temperature, or if the Generator Owner provides design specification information or other data (e.g., an engineering report) as detailed in M2 showing that it can operate for at least one hour at or below its Extreme Cold Weather Temperature, then the Generator Owner will be deemed to have met this Requirement R2, and need not implement new or additional freeze protection measures. Generating unit(s) that are not capable of operating for one (1) hour at its Extreme Cold Weather Temperature shall develop a Corrective Action Plan (CAP) for the identified issues, including identification of any needed modifications to the cold weather preparedness plan required under Requirement R3. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]

M2. Each Generator Owner will have dated evidence that demonstrates it has freeze protection measures for its unit(s) in accordance with R2, or it has developed a CAP for the identified issues. Acceptable evidence may include the following (electronic or hardcopy format): Identification of generating units minimum temperature per Part 3.5.2 which is equal to or less than the unit's Extreme Cold Weather Temperature, documentation of freeze protection measures, cold weather preparedness plan, engineering study, historical data demonstrating one hour of sustained operations by the unit(s) at the applicable Extreme Cold Weather Temperature, and CAP(s).

Further, the SDT should consider adding a definition of "freeze protection measures" (applicable to all of EOP-012 and not just to R2) to clarify what those measures could entail and, importantly, to make clear that those measures do not have to include capital expenditures for redesign or retrofitting. For example, it should be clarified that "freeze protection measures" include temporary equipment like wind barriers. A new definition could be added as follows:

Freeze protection measures include permanent or temporary equipment, procedures, or other measures reasonably targeted to contribute to sustained operation by an existing unit(s) for the timeframe in R1 or R2, as applicable, at the Extreme Cold Weather Temperature.

Likes 0	
Dislikes 0	

Response

George Brown - Acciona Energy North America - 5	
Answer	Yes
Document Name	

Comment	
Acciona Energy has no comments.	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Avista supports the proposed R2 language that requires GOs of existing Generating units ensure new or modify existing freeze protection measures provide the capability to operate for a period of not less than one (1) hour at the unit(s) Extreme Cold Weather Temperature.	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
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	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Evans-Mongeon - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Michael Watt - Oklahoma Municipal Power Authority - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brooke Jockin - Portland General Electric Co. - 1, Group Name Portland General Electric Co.	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Glenn Pressler - CPS Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Donna Johnson - Oglethorpe Power Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott McGough - Georgia System Operations Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Ruskamp - Lincoln Electric System - 6, Group Name LES	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamison Cawley - Nebraska Public Power District - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Mark Young - Tenaska, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Imane Mrini - Austin Energy - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ronald Bauer - MGE Energy - Madison Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Adam Lee - MGE Energy - Madison Gas and Electric Co. - 4	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Foung Mua, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Wei Shao, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; - Tim Kelley, Group Name SMUD / BANC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 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	
John Liang - Snohomish County PUD No. 1 - 6	
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	

LaKenya VanNorman - LaKenya VanNorman On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name Florida Municipal Power Agency (FMPA)

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Natalie Johnson - Enel Green Power - 5

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3, Group Name OGE Energy

Answer	
Document Name	
Comment	

OG&E supports the comments submitted by EEI.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE does not agree the proposed 1-hour timeframe in Requirement R2 is sufficient to allow existing Generation units to demonstrate their performance at or below the Extreme Cold Weather Temperature. Historical events in 2011, 2014, 2018, and 2021, have instances in which it has taken at least 6-12 hours for freezing issues to appear, depending on the unit status. During the South Central United States cold weather BES event in January 2018, for example, cold weather was sustained for two days. Between January 15 and January 17, 2018, generation resources experienced various outages, derates, or failures to start. Similarly, for over two days in February 2021, ERCOT averaged 34,000 MW of generation outages. The SDT should consider a longer duration to demonstrate performance at or below the Extreme Cold Weather Temperature based on historic events.

Likes 0	
Dislikes 0	

Response

Lenise Kimes - City and County of San Francisco - 1,5 - WECC

Answer	
Document Name	

Comment

Difficult to answer yes or no... the 1-hour timeframe for demonstrating (which we interpret to mean testing) a Generation unit's performance sounds reasonable, however, if operating at or below the Extreme Cold Weather Temperature, you would not be in a testing state, you would be in an *actual* Extreme Cold Weather Temperature state.

Likes 0	
Dislikes 0	

Response

Selene Willis - Edison International - Southern California Edison Company - 5

Answer	

Document Name	
Comment	
“Please see comments submitted by the Edison Electric Institute”	
Likes 0	
Dislikes 0	
Response	

6. Do you support the addition of a 20 megawatt minimum (corresponding to the definition of a BES impacting generating unit) for requiring CAPS for derates? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Natalie Johnson - Enel Green Power - 5	
Answer	No
Document Name	
Comment	
Please refer to comments in question 2.	
Likes 0	
Dislikes 0	
Response	

Rhonda Jones - Invenergy LLC - 5	
Answer	No
Document Name	
Comment	
Invenergy supports the addition of a megawatt minimum for requiring CAPs for derates. However, Invenergy believes the minimum could be better aligned with NERC's BES criteria by establishing a minimum of 20 MVA for individual generating units identified under Inclusion I2 of the BES definition, or a minimum of 75 MVA for generating units identified under Inclusion I4 of the BES definition.	
Likes 0	
Dislikes 0	
Response	

Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)	
Answer	No
Document Name	
Comment	
The SRC supports the addition of a 20 MW minimum to align with the BES definition of a generating unit. That said, we do not support the corresponding limitations on Corrective Action Plans (CAPs) in the Generator Cold Weather Reliability Event (GCWRE) definition. As written, when taking the proposed GCWRE definition in conjunction with Requirement 6, a GO must develop a CAP if a unit experiences, "a forced derate of *more than 10% of the total capacity* of the unit, ***and*** *exceeding 20 MWs*, for longer than four hours in duration…." The SRC believes this language could be	

interpreted to exclude all units rated at 200 MWs or less. Specifically, for 10% of unit capacity to exceed 20 MWs, the unit must have nameplate capacity of at least 201 MWs (*i.e.,* 10% of 201 MWs = 20.1 MWs).

The SRC cannot support such a broad carve out of applicability. The SRC recommends the SDT revise the GCWRE definition to make clear a *plant* or *facility* consisting of individual units less than 200 MW must aggregate the derate to apply to the entire plant/facility to reach the 10% and 20 MW threshold; *i.e.*, the GO of a plant consisting of five 190 MW units (950 MW) each experiencing a 10% derate (19 MWs) would aggregate the unit derates to determine whether the 20 MW threshold is met (19 MWs times 5 units = 95 MWs; because 95 MWs > 20 MWs, the Standard would apply).

Likes 0	
Dislikes 0	

Response

Whitney Wallace - Calpine Corporation - 5 - WECC,Texas RE,NPCC,SERC,RF

Answer	No
Document Name	

Comment

The definition should be clarified. Is it 10% of the unit or 10% of the power block? In addition, as written, it is interpreted that it is only reportable if the impact is 10% of the unit capacity and exceeds 20 MW. The definition is not written as “or” as implied in the question.

Further, there is no tie for the derate to be the result of a GCWRE. For example, a failed thermocouple on a duct burner runner in a heat recovery steam generator will require a CAP under this proposed language. However, thermocouples are consumable components that are replaced routinely due to the cyclic nature of duct burner operation in combined cycle power plants. Besides clarifying the definition of GCWRE to pertain only to GCWCC, NERC should consider implementing tiered limits (e.g., 50 MW for 500 MW or more, 25 MW for less than 500 MW, etc.). This type of tiering system would alleviate potentially excessive administrative burdens on plant staff associated with CAPs. For smaller units (less than 20 MWs), a CAP should not be required.

Likes 0	
Dislikes 0	

Response

George Brown - Acciona Energy North America - 5

Answer	No
Document Name	

Comment

Acciona Energy supports Midwest Reliability Organization’s (MRO) NERC Standards Review Forum’s (NSRF) comments on this question.

Likes 0	
Dislikes 0	

Response	
Colin Chilcoat - Invenergy LLC - 6	
Answer	No
Document Name	
Comment	
Invenergy supports the addition of a megawatt minimum for requiring CAPs for derates. However, Invenergy believes the minimum could be better aligned with NERC's BES criteria by establishing a minimum of 20 MVA for individual generating units identified under Inclusion I2 of the BES definition, or a minimum of 75 MVA for generating units identified under Inclusion I4 of the BES definition.	
Likes 0	
Dislikes 0	
Response	
Adam Lee - MGE Energy - Madison Gas and Electric Co. - 4	
Answer	No
Document Name	
Comment	
Madison Gas and Electric supports the comments of the MRO NSRF	
Likes 0	
Dislikes 0	
Response	
Ronald Bauer - MGE Energy - Madison Gas and Electric Co. - 3	
Answer	No
Document Name	
Comment	
Madison Gas and Electric supports the comments from the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	

Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
MISO supports the comments submitted by the ISO/RTO Council Standards Review Committee (IRC SRC).	
Likes 0	
Dislikes 0	
Response	
Steven Sconce - EDF Renewable Energy - 5	
Answer	No
Document Name	
Comment	
The 20MW value is reasonable; however, for solar and wind generation, the term generating unit needs further definition for aggregate production (total-plant) vs. individual generator/inverter-based resource. EDF supports the comments submitted by Talen Generation.	
Likes 0	
Dislikes 0	
Response	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	No
Document Name	
Comment	
MidAmerican Energy supports the MRO NSRF response to this question, referring to the answer to question 2 regarding the Generator Cold Weather Reliability Event definition.	
Likes 0	
Dislikes 0	
Response	

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
Please refer to comments provided by the MRO NSRF for the Generator Cold Weather Reliability Event definition, in question 2.	
Likes 0	
Dislikes 0	
Response	

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	No
Document Name	
Comment	
Alliant Energy supports the comments submitted by the MRO NSRF.	
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 believes the term Generating unit is vague and is open to interpretation. Does this mean each generating unit or is it an entire facility. Depending on the interpretation of unit by a GO, they could declare each unit separate in the large plant with many separate units which could preclude them from the applicability section of this standard as well as exempt form the CAP requirements outlined in Requirement 6.	
Likes 0	
Dislikes 0	
Response	

LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	

Answer	No
Document Name	
Comment	
This language exempts distributed generation, which is trending upward and is becoming a larger percentage of total generation, and creates a "perverse incentive" to implement multiple small units to avoid requirements. This subverts the purpose of mitigating reliability impacts during extreme cold weather.	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation does not agree with the fine-toothed level of specificity that is proposed. Too much effort is required to be spent determining whether or not the requirements apply or if they can be avoided. Reclamation recommends the standard be written in a plain and straightforward set of requirements. Please refer to the proposal submitted in Reclamation's comments to Draft 1 Question 4.	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
All generation, regardless of size, needs to be reliable for the range of conditions the industry agrees to.	
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	
In the definition of Generator Cold Weather Reliability Event, Tacoma Power recommends changing "total capacity of the unit" to "facility rating of the unit." Tacoma Power is concerned with the regulatory burden of trying to document the total capacity of a unit that is seasonally dependent/variable. By changing to "facility rating", this would ensure a fixed and predictable number that constitutes the 10% value.	
Likes 1	LS Power Development, LLC, 5, Spencer Mark
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	No
Document Name	
Comment	
Talen Energy Marketing supports Talen Generation's comments.	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
The value of 20 MW is suitable, but it needs to be applied for EOP-012-1 in plant-total fashion, not per generation unit as in the presently proposed definition of a Generator Cold Weather Reliability Event. A criterion of 20 MW per wind turbine would be meaningless.	
Likes 1	LS Power Development, LLC, 5, Spencer Mark
Dislikes 0	
Response	

Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	No
Document Name	
Comment	
We see no technical justification for the 20 MW threashold. How will this apply to Hydro resouces that are run-of-the-river where their capacity may diminish, but due to water flow (low fuel), they would never be able to generate to thier capacity?	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes

Document Name	
Comment	

EEI supports the addition of a 20 megawatt minimum, as proposed in the definition for a "Generator Gold Weather Event", however, Question 6 and language contained in the Technical Rationale (see page 8, Requirement R6), raises an important question about the intended alignment of the minimum value (as described in the definition of Generator Cold Weather Reliability Event) with the BES definition. If this threshold is intended to align with the BES definition, then the threshold should be adjusted to consider the differences between conventional and distributed/IBR resources. While the 20 MW value aligns with the BES definition for the minimum individual conventional generating resources, (see Inclusion I2); the threshold for Inverter Based Resources (i.e., dispersed power producing resources/Inclusion I4) is measure by the aggregated capacity of a plant resulting in a minimum value of 75 MW. For this reason, EEI asks for additional clarification whether the minimum threshold value is to be aligned with the BES definition, or not.

Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	

Avista supports the addition of a 20 megawatt minimum with the proposed Generator Cold Weather Reliability Event and its impact on GO responsibilities as it relates to CAPS within Requirement R6.

Likes 0	
Dislikes 0	
Response	
Deanna Carlson - Cowlitz County PUD - 5	
Answer	Yes
Document Name	
Comment	

Deanna Carlson, Cowlitz PUD, 5, 9/1/22

Likes 0	
Dislikes 0	
Response	

Michelle Amarantos - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
APS supports the addition of a 20 megawatt minimum as proposed in the definition of a "Generator Cold Weather Reliability Event." Additionally, APS echoes EEI's comments questioning the intended alignment of the minimum value described in the "Generator Cold Weather Reliability Event" definition with the BES definition. If the threshold is intended to align with the BES definition, then it should be adjusted to consider the differences between conventional and inverter-based resources. While the 20 MW value aligns with the BES definition for the minimum individual conventional generating resources, (see Inclusion I2); the threshold for Inverter Based Resources (i.e., dispersed power producing resources/Inclusion I4) is measure by the aggregated capacity of a plant resulting in a minimum value of 75 MW.	
Likes 0	
Dislikes 0	
Response	
Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	Yes
Document Name	
Comment	
Capital Power supports the North American Generators Forum (NAGF) response to this question.	
Likes 0	
Dislikes 0	
Response	
Mark Young - Tenaska, Inc. - 5	
Answer	Yes
Document Name	
Comment	
As long as the 10% is an additional criteria, e.g. 10% AND 20 MW. We do not support just a 20 MW derate alone.	
Likes 0	
Dislikes 0	

Response	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	Yes
Document Name	
Comment	
Yes, the addition of a 20 megawatt minimum component to the 10% minimum adequately addresses the reliability need while uniformly applying the derate threshold to generating units regardless of total capacity or fuel source.	
Likes 0	
Dislikes 0	
Response	
Stewart Rake - Luminant Mining Company LLC - 7	
Answer	Yes
Document Name	
Comment	
Vistra has no comments on this proposed change.	
Likes 0	
Dislikes 0	
Response	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
SIGE does not oppose the 20 megawatts minimum; however, SIGE does have recommendations for how it is currently addressed in the Generator Cold Weather Reliability Event definition. See SIGE's response to Question 2.	
Likes 0	
Dislikes 0	
Response	

Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon concurs with EEI's comment to Question 6. Submitted on behalf of Exelon, Segments 1 & 3	
Likes 0	
Dislikes 0	
Response	
Dan Roethemeyer - Vistra Energy - 5	
Answer	Yes
Document Name	
Comment	
Vistra has no comments on this proposed change.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	Yes
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for question #6.	
Likes 0	
Dislikes 0	

Response	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	
PNM supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Alison Mackellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco, on behalf of Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco, on behalf of Segments 5 and 6	

Likes 0	
Dislikes 0	

Response

Devin Shines - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company

Answer	Yes
Document Name	

Comment

LouisvilleG&E/KU support EEI's comments.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	Yes
Document Name	

Comment

With reference to the definition of a “Generator Cold Weather Reliability Event” we believe the 20 MW minimum should apply not only to (1), but (2) and (3) as well. Having said that however, it is not clear how this 20 MW minimum would apply to dispersed generation, either collectively (say, in the case of a wind farm) or to their individual units. Various interpretations of its application are possible, and the requirement would benefit by including text which clearly shows exactly how the minimum would be applied to dispersed units.

Likes 0	
Dislikes 0	

Response

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments

Answer	Yes
Document Name	

Comment

PG&E supports the addition of the 20 MW minimum, and supports the input provided by EEI on additional clarification on aligning the minimum threshold value with the BES Definition.

Likes 0	
Dislikes 0	

Response

Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3, Group Name OGE Energy

Answer	Yes
Document Name	

Comment

OG&E supports the comments submitted by EEI.

Likes 0	
Dislikes 0	

Response

Joe Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC

Answer	Yes
Document Name	

Comment

Xcel Energy supports comments from EEI.

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 3

Answer	Yes
Document Name	

Comment

Ameren agrees with the EEI and the NAGF comments.

Likes 0	
Dislikes 0	
Response	
Mark Spencer - LS Power Development, LLC - 5	
Answer	Yes
Document Name	
Comment	

We support the 20 megawatt threshold with the following caveats. We recommend that the SDT couple the MW threshold with a narrow dead band to the ECWT. If a generator is experiencing *any* derate due to a freezing issue, a minor derate may be signaling a potential weak link in its freeze protection measures. This derate would be particularly worrisome if the derate occurred at a temperature well exceeding the ECWT.

Additionally, the proposed draft allows for an exemption from developing a CAP only if the derate is less than four hours, yet the proposed standard for existing generators is one hour. Clearly, a four hour derate is longer than the one hour standard, so what would be the CAP for a derate of less than 20 MW and greater than four hours (particularly if the derate started in the 2nd hour)? What would be the CAP for a derate of greater than 20 MW but starting in hour two? Would the CAPs simply state that the generator met the reliability standard and no further action is required?

Likes 1	Vistra Energy, 5, Roethemeyer Dan
Dislikes 0	
Response	
Scott Kinney - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	

Avista supports the addition of a 20 megawatt minimum with the proposed Generator Cold Weather Reliability Event and its impact on GO responsibilities as it relates to CAPS within Requirement R6.

Likes 0	
Dislikes 0	
Response	
Brooke Jockin - Portland General Electric Co. - 1, Group Name Portland General Electric Co.	
Answer	Yes

Document Name	
Comment	
Portland General Electric Company supports the survey response provided by EEI.	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Avista supports the addition of a 20 megawatt minimum with the proposed Generator Cold Weather Reliability Event and its impact on GO responsibilities as it relates to CAPS within Requirement R6.	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
None.	
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	

Southern Company agrees that the 20 MW minimum is appropriate.	
Likes 0	
Dislikes 0	
Response	
LaKenya VanNorman - LaKenya VanNorman On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name Florida Municipal Power Agency (FMPA)	
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	
John Liang - Snohomish County PUD No. 1 - 6	
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	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Foung Mua, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Wei Shao, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; - Tim Kelley, Group Name SMUD / BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Imane Mrini - Austin Energy - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Eric Ruskamp - Lincoln Electric System - 6, Group Name LES	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Ruchi Shah - AES - AES Corporation - 5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Scott McGough - Georgia System Operations Corporation - 3

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Donna Johnson - Oglethorpe Power Corporation - 5

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	
James Baldwin - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Tony Skourtas - Los Angeles Department of Water and Power - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Josh Combs - Black Hills Corporation - 3	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County	
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	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Glenn Pressler - CPS Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Watt - Oklahoma Municipal Power Authority - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Brian Evans-Mongeon - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lindsey Mannion - ReliabilityFirst - 10	
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	
Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
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	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	
Comment	
No Comment	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
“Please see comments submitted by the Edison Electric Institute”	
Likes 0	
Dislikes 0	
Response	

Lenise Kimes - City and County of San Francisco - 1,5 - WECC	
Answer	
Document Name	
Comment	
This does not apply to HHWP, so we choose to not weigh-in regarding this.	
Likes 0	
Dislikes 0	
Response	

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	
Yes, AECI supports the suggested approach.	
Likes 0	
Dislikes 0	
Response	

7. The SDT believes that with the proposed modifications to EOP-012-1, the initial proposed implementation plan is appropriate with one change. The 18-month implementation time frame is for all revised and new requirements in EOP-012-1, except Requirements R1 and R2 which have a 60-month implementation time frame, and R4 which has a 78-month implementation time frame. Do you agree with this implementation time frame? If you think an alternate timeframe is needed, please propose an alternate implementation plan and time period, and provide a detailed explanation of actions planned to meet the implementation deadline.

Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6

Answer	No
Document Name	

Comment

This implementation is so extended, that these requirements will not be in force when the next Texas winter weather event occures.

Likes 0	
Dislikes 0	

Response

Donald Lock - Talen Generation, LLC - 5

Answer	No
Document Name	

Comment

The implementation plan must be reconsidered in light of the the changes recommended in these comments.

Likes 0	
Dislikes 0	

Response

Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6

Answer	No
Document Name	

Comment

Talen Energy Marketing supports Talen Generation's comments.

Likes 0	
Dislikes 0	

Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation supports the 18-month implementation time frame. Reclamation disagrees with the 60-month and 78-month implementation time frames. A 5-6 year implementation period is inconsistent with the expedited time frame that has been applied to the standards development process. Reclamation recommends the time would be better spent to conscientiously develop a workable standard than to expedite a defective standard and provide 5-6 years to try to make it work.	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	No
Document Name	
Comment	
Excluding the concerns raised in previous questions, these proposed implementation times are reasonable except for R7. Since R1 and R2 are not enforceable until 60 months, then a CAP implementation for R7 identified under R2 should follow this, not precede this time interval.	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	
Excluding the concerns raised in previous questions, these proposed implementation times are reasonable except for R7. Since R1 and R2 are not enforceable until 60 months, then a CAP implementation for R7 identified under R2 should follow this, not precede this time interval.	
Likes 0	

Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	

We recommend a twelve month implementation time frame for all revised and new requirements; and a three year implementation time frame for EOP-012-1 Requirements R1 and R2 as this seems to be a sufficient amount of time to become compliant given that the new requirements were included in The Joint Inquiry Report published on November 18, 2021, the additional year for standard development and regulatory review requirements.   A twelve month implementation would only miss implementation for one winter (2023-2024).

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 reiterates its comments regarding the implementation plan from the Round 1 Comments.

ISO-NE believes the proposed 18 months for the implementation is excessive due to the fact that the first requirements that become effective with this 18 months are carried over from EOP-011-2 R7 & R8 into EOP-012-1 R3 and R5. These requirements are already due to be effective April 1, 2023. These "new" requirements in EOP-012-1 have been written to provide further details required for a previously written Generator Cold Weather Preparedness Plan, and changed Training to Annual Training. Also, based on the CAP requirements in R6 and R7, "*A CAP shall be written within 150 days or by July 1st, whichever is earlier*" already provides some additional time from the original effective date for Generators that actually experience a trip attrinuted to freezing under the Standard. Determined by the NERC Board approval date, an effective date of 12 months will potentially include the majority of the Winter Season of 2023-2024 under R3 and R5 instead of pushing the Standard off for another winter season, which was a concern for the EOP-011-2 implementation plan.

Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	No

Document Name	
Comment	
MISO supports the comments submitted by the ISO/RTO Council Standards Review Committee (IRC SRC).	
Likes 0	
Dislikes 0	
Response	
Whitney Wallace - Calpine Corporation - 5 - WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
No for R6 only. R6 should read, "a [GO] that experiences a Generator Cold Weather Reliability Event shall develop a CAP, ***no longer than July 1….***" This will ensure that sufficient time is allotted for corrective actions to be developed that may take many months to plan and implement effectively in accordance with all design and code requirements. The primary focus of the GO if a GCWRE should occur should be to first implement immediate corrective actions that will allow the forced outage to be ended and the generating unit to be returned to service as safely and quickly as possible during an extreme cold weather event, and then develop long term corrective actions. Allowing for additional time for development of a CAP will allow for improved engineering solutions since more planning and engineering resources can be allocated to developing and implementing the correction actions(s). Additionally, the implementation of a CAP should be for up to 24 months due to supply chain challenges that the industry continues to experience.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)	
Answer	No
Document Name	
Comment	
The proposed implementation plan provides up to sixty months to implement the standard for individual units (eighteen months to identify the ECWT and develop a winterization plan and forty-two months to meet the reporting requirements), which could deter earlier compliance. Specifically, many units compete in wholesale markets and a unit owner may refrain from spending capital dollars (driving up its costs and thus its market bids) earlier than its competitors who delay compliance to later dates. In this way, the timeline works as a disincentive to early compliance. The SRC understands the need to recognize the complexities of winterization for different technologies and individual unit characteristics, but to avoid creating disincentives to earlier compliance, the SRC recommends a shorter period of twelve months to identify the ECWT and develop a winterization plan and an additional twenty-four months for all units (new and old) to comply with the winterization requirements and adding an exception process to	

the extent a GO can document compliance will take longer due to an individual unit's characteristics. The GO should have to document unit-specific exceptions and make the documentation available for review and audit.

The SRC believes an implementation plan with an early, but realistic, compliance date that allows for reasonable exceptions avoids the disincentive created by a lengthy process that would allow even units facing minimal winterization requirements to refrain from complying earlier.

Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	

DTE Electric supports NAGF comments provided for this project

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

Southern Company agrees with EEI and supports the proposed implementation plan.

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	Yes
Document Name	

Comment

None.

Likes 0	
Dislikes 0	

Response

Glen Farmer - Avista - Avista Corporation - 5

Answer	Yes
Document Name	

Comment

Avista supports the proposed Implementation Plan.

Likes 0	
Dislikes 0	
Response	
Scott Kinney - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Avista supports the proposed Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Mark Spencer - LS Power Development, LLC - 5	
Answer	Yes
Document Name	
Comment	
We appreciate the SDT's consideration of industry comments and the modifications to the implementation timeline.	
Likes 1	Vistra Energy, 5, Roethemeyer Dan
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Ameren agrees with the EEI and the NAGF comments.	
Likes 0	
Dislikes 0	

Response

Joe Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC

Answer	Yes
Document Name	

Comment

Xcel Energy supports comments from EEI.

Likes 0

Dislikes 0

Response

Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3, Group Name OGE Energy

Answer	Yes
Document Name	

Comment

OG&E supports the comments submitted by EEI.

Likes 0

Dislikes 0

Response

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments

Answer	Yes
Document Name	

Comment

PG&E believes the implementation timeframes are reasonable. PG&E agrees with the concerns raised by EEI and NAGF that are noted in the input to the earlier questions.

Likes 0

Dislikes 0

Response

Devin Shines - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company	
Answer	Yes
Document Name	
Comment	
LouisvilleG&E/KU support EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco, on behalf of Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Alison Mackellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco, on behalf of Segments 5 and 6	

Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	
PNM supports the Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Dan Roethemeyer - Vistra Energy - 5	
Answer	Yes
Document Name	
Comment	
The implementation timeline seems reasonable if the adopted standards are modified as recommended in these comments.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon supports the proposed implementation plan. Submitted on behalf of Exelon, Segments 1 & 3	

Likes 0	
Dislikes 0	
Response	
Stewart Rake - Luminant Mining Company LLC - 7	
Answer	Yes
Document Name	
Comment	
The implementation timeline seems reasonable if the adopted standards are modified as recommended in these comments.	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
Excluding the concerns raised in previous questions, the NAGF believes that the proposed implementation times are reasonable.	
Likes 0	
Dislikes 0	
Response	
Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	Yes
Document Name	
Comment	
Capital Power supports the North American Generators Forum (NAGF) response to this question.	
Likes 0	
Dislikes 0	

Response	
Colin Chilcoat - Invenergy LLC - 6	
Answer	Yes
Document Name	
Comment	
Invenergy supports the proposed implementation time frame.	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	Yes
Document Name	
Comment	
Acciona Energy has no comments.	
Likes 0	
Dislikes 0	
Response	
Deanna Carlson - Cowlitz County PUD - 5	
Answer	Yes
Document Name	
Comment	
Deanna Carlson, Cowlitz PUD, 5, 9/1/22	
Likes 0	
Dislikes 0	
Response	

Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Avista supports the proposed Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Rhonda Jones - Invenergy LLC - 5	
Answer	Yes
Document Name	
Comment	
Invenergy supports the proposed implementation time frame.	
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 Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 6	
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	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
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	
Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 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	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Brian Evans-Mongeon - Utility Services, Inc. - 4

Answer	Yes
Document Name	

Comment

Likes 0

Dislikes 0

Response

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

Answer	Yes
Document Name	

Comment

Likes 0

Dislikes 0

Response

Michael Watt - Oklahoma Municipal Power Authority - 4

Answer	Yes
Document Name	

Comment

Likes 0

Dislikes 0

Response

Brooke Jockin - Portland General Electric Co. - 1, Group Name Portland General Electric Co.

Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glenn Pressler - CPS Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 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	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lenise Kimes - City and County of San Francisco - 1,5 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Josh Combs - Black Hills Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sheila Suurmeier - Black Hills Corporation - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tony Skourtas - Los Angeles Department of Water and Power - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
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

Teresa Krabe - Lower Colorado River Authority - 5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Donna Johnson - Oglethorpe Power Corporation - 5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Scott McGough - Georgia System Operations Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ruchi Shah - AES - AES Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Eric Ruskamp - Lincoln Electric System - 6, Group Name LES	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jamison Cawley - Nebraska Public Power District - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Sconce - EDF Renewable Energy - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Young - Tenaska, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Imane Mrini - Austin Energy - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ronald Bauer - MGE Energy - Madison Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Adam Lee - MGE Energy - Madison Gas and Electric Co. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Foung Mua, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Wei Shao, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; - Tim Kelley, Group Name SMUD / BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
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	
John Liang - Snohomish County PUD No. 1 - 6	
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	

LaKenya VanNorman - LaKenya VanNorman On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name Florida Municipal Power Agency (FMPA)	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Natalie Johnson - Enel Green Power - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	
Yes, AECI supports the suggested approach.	
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 make the implementation plan more clear by adding a graphic with the various effective and compliance dates. Texas RE is concerned, however, with the 60-month timeframe to comply with Requirements R1 and R2. Texas RE believes this poses a reliability risk and that entities should implement freeze protection measures and provide the capability to operated for at least one hour at the unit(s) Extreme Cold Weather Temperature as soon as possible in order to ensure there is no reliability gap. In the ERCOT region, generation entities were not given five years to comply with weather emergency preparedness rules and required to complete winter weather emergency preparation measures by December 1, 2021. These measures included winterization, operation readiness, structural preparations, enclose sensors for cold weather critical components, address cold weather critical components failures that occurred between November 30, 2020, and March 1, 2020, provide training on winter weather preparations, and determine minimum design temperature or minimum experienced operating temperature, among other items. Texas RE understands the intent of compliance various thresholds set forth in both Requirements R1 and R2 is to recognize that existing generation resources may find it more difficult to retrofit appropriate freeze protection measures. Texas RE understand the technical rationale for requiring existing units to ensure capability of operating for at least one hour at the Extreme Cold Weather Temperature (R2) whereas new generation should be able to demonstrate it can operate for 12 hours at the Extreme Cold Weather Temperature given the putative differences between newer and older generating units. While Texas RE notes that the recently implemented Texas rules do not recognize this distinction between new and existing resources, Texas RE believes that the current proposed EOP-012-1 R1 and R2 define the scope of "existing" resources too broadly by appearing to connect the definition of "existing" resources to the effective date of the standard requirement. Instead, Texas RE recommends the language in Requirements R1 and R2 reference the effective date of the governmental authority's order approving EOP-012-1. The effective date of the FERC order puts new and existing generating entities on notice that they will need to comply with the standard by the compliance date, obviating the need to extend the lower R2 compliance thresholds for "existing" resources to units constructed following the effective date of the FERC order. Otherwise, generating units built as much as 60 months from the FERC order date will be treated as "existing" units subject to the lower R2 requirements. As Texas RE stated above, entities should not have five years to comply with these requirements, but at a minimum, resources constructed within this five-year window should not be treated as "existing" resources, but rather be required to meet the 12-hour requirements for new generation resources. Finally, Texas RE recommends clarifying the first section of the graphic to say that it is the Effective date of the Governmental Authorities' approval of EOP-012-1 and the implementation plan. This is consistent with the language in the paragraph below regarding the effective date of EOP-012-1. Texas RE furthermore recommends that the Standard EOP-012-1 section on page 4 specify that the effective date of the standard applies to all requirements unless specified for a different compliance date or initial performance date.

Likes 0	
Dislikes 0	

Response

Selene Willis - Edison International - Southern California Edison Company - 5

Answer	
Document Name	
Comment	
"Please see comments submitted by the Edison Electric Institute"	
Likes 0	
Dislikes 0	
Response	

8. The SDT proposes that the modifications in the proposed EOP-012-1 meet the key recommendations in The Report 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.	
LaKenya VanNorman - LaKenya VanNorman On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name Florida Municipal Power Agency (FMPA)	
Answer	No
Document Name	
Comment	
R3.2 and R3.3 are unnecessary from a performance-based standard perspective. Requiring a CAP for any failure to run or any derate from a cold weather event is sufficient to provide performance under the standard. However, requiring the creation of lists of equipment and protective measures, while good engineering practice, are not good compliance activities. This results in administrative burden for administration's sake. In addition, the standard is full of subjective, ambiguous, and in-auditable language. Phrases like "typically available", and provisions that allow for any "technical, commercial or operational constraints" as defined by the GO are subjective and open to interpretation, and will compliance certainty difficult for entities. This includes referencing non-NERC contracts such as OATTs or "other contracactual arrangement[s]" in the Applicability language. All of these factors will result in a high compliance burden and risk of fines and significant capital spends on upgrades due to standard uncertainty and ambiguity.	
Likes 0	
Dislikes 0	
Response	
Rhonda Jones - Invenergy LLC - 5	
Answer	No
Document Name	
Comment	
For EOP-012-1, Invenergy is unable to quantify the overall costs and benefits to arrive at a definitive conclusion about the cost effectiveness of the current draft. However, as noted in Invenergy's previous responses, the current proposal yields an arbitrarily stringent standard that could impose more onerous requirements than are necessary to ensure generator availability during the prolonged extreme cold events – occurring over multiple hours or days – that this Standard is intended to address. The alternative approach Invenergy suggests would reasonably be expected to yield a more cost-effective approach to meeting the key recommendations in the Joint Inquiry Report. Invenergy also remains concerned that certain generating units, including independent power producers, may be required to bear significant incremental costs to comply with the standard without a corresponding mechanism for recovering those costs.	
Likes 0	

Dislikes 0	

Response

Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)

Answer	No
Document Name	

Comment

The SRC believes the proposed revisions do not meet the key recommendations, regardless of whether they are "cost effective" (based on our comments, above). If the goal of this Standard is to ensure generators ride-through extreme weather events, the SDT should draft a Standard to accomplish that goal. NERC should leave the issue of compensation to FERC and other regulators to determine how to compensate GOs for the cost of winterization and freeze protection measures (*e.g.*, areas of the country using cost-based rates could include the cost of upgrades in the rate base to establish customer pricing; parts of the country with wholesale markets can develop market tools to provide compensation to generators who upgrade resources). *See*, Key Recommendation 2 in the Joint Report.

Likes 0	
Dislikes 0	

Response

Deanna Carlson - Cowlitz County PUD - 5

Answer	No
Document Name	

Comment

Agree with comments provided by Russell Noble.

Likes 0	
Dislikes 0	

Response

Russell Noble - Cowlitz County PUD - 3

Answer	No
Document Name	

Comment

Cowlitz agrees with comments provided by the North American Generator Forum.

Likes 0	
Dislikes 0	

Response

Whitney Wallace - Calpine Corporation - 5 - WECC,Texas RE,NPCC,SERC,RF

Answer	No
Document Name	

Comment

No for R5 only. The R5 requirement should focus on the content of the training to be given, the desired audience of that training, and the completion date. Requiring identification of the entity responsible for actually giving the training in the requirement will not increase the efficacy of the training material. It simply creates an administrative item to be tracked that adds nothing to generating unit reliability. Content, audience and completion of the required training accomplish that, not the denotation of who will be performing the training.

Likes 0	
Dislikes 0	

Response

Colin Chilcoat - Invenergy LLC - 6

Answer	No
Document Name	

Comment

For EOP-012-1, Invenergy is unable to quantify the overall costs and benefits to arrive at a definitive conclusion about the cost effectiveness of the current draft.

However, as noted in Invenergy's previous responses, the current proposal yields an arbitrarily stringent standard that could impose more onerous requirements than are necessary to ensure generator availability during the prolonged extreme cold events – occurring over multiple hours or days – that this Standard is intended to address. The alternative approach Invenergy suggests would reasonably be expected to yield a more cost-effective approach to meeting the key recommendations in the Joint Inquiry Report.

Invenergy also remains concerned that certain generating units, including independent power producers, may be required to bear significant incremental costs to comply with the standard without a corresponding mechanism for recovering those costs.

Likes 0	
Dislikes 0	

Response

Shannon Ferdinand - Decatur Energy Center LLC - 5

Answer	No
Document Name	
Comment	
Capital Power supports the North American Generators Forum (NAGF) response to this question.	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
MISO supports the comments submitted by the ISO/RTO Council Standards Review Committee (IRC SRC).	
Likes 0	
Dislikes 0	
Response	
Mark Young - Tenaska, Inc. - 5	
Answer	No
Document Name	
Comment	
This is essentially a return on investment question. It is difficult to answer this question until there is an understanding of total cost recovery required to implement this design standard for the entire BES. The Report's #2 recommendation was for markets or consumers to provide cost recovery. While NERC cannot mandate cost recovery, NERC can provide exemptions for compliance until markets and regulatory agencies determine the need and the method of compensating Generator Owners for their investment in winter weatherization.	
Likes 0	
Dislikes 0	
Response	
Steven Sconce - EDF Renewable Energy - 5	

Answer	No
Document Name	
Comment	
EDFR supports the comments submitted by NAGF.	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	No
Document Name	
Comment	
For Canadian entites, the necessary cold weather practices are already in place. The administrative burden associated to the tasks being required in the standards outweigh the reliability benefits, as we already have a good handle on planning, operations and maintenance activites in cold (and even extreme cold) weather.	
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 supports the comments of the SRC that cost recovery mechanism be left to FERC and the Industry to determine how to compensate GOs for any upgrades if needed.	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	

Answer	No
Document Name	

Comment
The NAGF does not agree that the draft EOP-012 addresses the concerns from the Report in a cost-effective manner. The NAGF is concerned that the proposal, while a great improvement from the initial posting, fails to address the concerns from the Report in several areas. These areas include: • The proposed standard does not require significant changes beyond calculating the Extreme Cold Weather Temperature and listing components susceptible to the cold weather. • The design requirements only require the Generator Owner to identify why nothing was done, not make changes to the design to make the generator more reliable during winter. As the SDT is trying to address the issue of retrofit without being able to address the compensation issue, we understand why this compromise is being proposed. • The Report states that many units failed before reaching their minimum design criteria. The proposed standard does not require a CAP if this occurs. The CAP is only required if a failure occurs above the ECWT, which has no significant meaning to a generator's design capability. This feature also appears to undermine the requirement to provide the BA, TOP and RC with a minimum operating temperature to be used during the planning process. • The proposed standard does require generators to address the conditions seen, specifically temperature, wind and moisture combined. For example, a wind turbine is likely able to operate to a minimum temperature of 20 degrees Fahrenheit if it is dry but will have blade icing occur at 32 degrees Fahrenheit if there is moisture. If the ECWT for that site is 25, a CAP will be required for blade icing, but not if the nacelle ices at 22 degrees due to failure to close vents.

Likes 0	
Dislikes 0	

Response

Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	

Comment
AES Clean Energy supports comments submitted by NAGF.

Likes 0	
Dislikes 0	

Response

Stewart Rake - Luminant Mining Company LLC - 7	
Answer	No
Document Name	

Comment

The modifications in proposed EOP-012-1 continue to raise cost effectiveness concerns, because the standards are tied to a very conservative temperature standard of the 0.2 percentile lowest hourly temperature experienced at the closest weather station since Jan. 1, 2000. Generators in the TRE region have no mechanism for cost recovery for any capital expenditures or other expenses they incur to implement the new standards. Generators in other reliability regions similarly may not have the ability to recover costs to implement weather preparedness standards, especially if they are not rate regulated companies. If the standards are revised as recommended throughout Vistra's comments (and the comments being filed by Texas Competitive Power Advocates, of which Vistra is a member), then the standard would meet the key recommendations in The Report in a cost-effective manner. However, if the standard is adopted as currently proposed, there would be serious questions regarding the cost-effectiveness of the standard, and it could even lead to early retirements or cancellations or delays of new resources.

Likes 0	
Dislikes 0	
Response	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	No
Document Name	
Comment	
Refer to above comments	
Likes 0	
Dislikes 0	
Response	
Dan Roethemeyer - Vistra Energy - 5	
Answer	No
Document Name	
Comment	

The modifications in proposed EOP-012-1 continue to raise cost effectiveness concerns, because the standards are tied to a very conservative temperature standard of the 0.2 percentile lowest hourly temperature experienced at the closest weather station since Jan. 1, 2000. Generators in the TRE region have no mechanism for cost recovery for any capital expenditures or other expenses they incur to implement the new standards. Generators in other reliability regions similarly may not have the ability to recover costs to implement weather preparedness standards, especially if they are not rate regulated companies. If the standards are revised as recommended throughout Vistra's comments (and the comments being filed by Texas Competitive Power Advocates, of which Vistra is a member), then the standard would meet the key recommendations in The Report in a cost-effective manner. However, if the standard is adopted as currently proposed, there would be serious questions regarding the cost-effectiveness of the standard, and it could even lead to early retirements or cancellations or delays of new resources.

Likes 0	
Dislikes 0	

Response	
Sheila Suurmeier - Black Hills Corporation - 1,3,5,6	
Answer	No
Document Name	
Comment	
BHC agrees with the first statement but cannot determine cost effectiveness and offers no comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	No
Document Name	
Comment	
BHC agrees with the first statement but cannot determine cost effectiveness and offers no comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Josh Combs - Black Hills Corporation - 3	
Answer	No
Document Name	
Comment	
BHC agrees with the first statement but cannot determine cost effectiveness and offers no comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	

Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
BHC agrees with the first statement but cannot determine cost effectiveness and offers no comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	
The recommendations are inherently not cost-effective for Generator Owners, so changing the standard language will not make them so.	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	No
Document Name	
Comment	
The recommendations are inherently not cost-effective for Generator Owners, so changing the standard language will not make them so.	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No

Document Name	
Comment	

Reclamation observes that the SDT has asserted that it has the support of industry except for minor details in the standard and is promising improvements in "Phase 2" of this project. Reclamation can identify no basis for this assertion based on the failure of the previous ballot and the refusal of this SDT and other SDTs to modify "legacy" language in subsequent standards modification projects once language has been approved. Reclamation asserts that a two-phase approach to developing standards that inherently requires re-versioning Phase 1 standards in Phase 2 is not cost effective. Reclamation recommends a good approach to promulgating quality standards is not to force a defective product through the system but rather to spend the necessary time to make the product right the first time. Reclamation observes that many entities have provided direct suggestions for improvement starting with Draft 1 of this project, but the SDT took neither the time nor the effort to properly consider them.

Likes 0	
Dislikes 0	
Response	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	No
Document Name	
Comment	

Dominion Energy is of the opinion that the recommended alternative for Requirement 2 discussed previously in response to Question 5 is a more cost-effective manner to address the reliability concerns of generation not operating as planned during extreme cold weather.

Likes 0	
Dislikes 0	
Response	

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments

Answer	No
Document Name	
Comment	

At this time PG&E cannot determine if the proposed modifications are cost effective.

Likes 0	
Dislikes 0	
Response	

Mark Spencer - LS Power Development, LLC - 5	
Answer	No
Document Name	
Comment	

Most BAs in the US are summer peaking systems (the seasonal spread increases to the south), and a significant fraction of generation is located in the RTOs with annual capacity markets that offer no distinction between summer peaking generators and all others generators. Consequently, the proposed standard will impose a requirement on a significant number of generators that are not needed to meet the winter load. Moreover, generators that historically have not been needed to serve winter load typically do not procure firm transportation rights or forward contract for fuel. This forces generators that may or may not be able to obtain fuel and have historically not been needed to serve winter load to incur the cost of compliance. Regardless whether these costs are born by the ratepayer or absorbed by the generator owner, this is not a cost effective outcome. A cost effective approach, while enhancing reliability, would be to procure the exact quantity, and no more, of reliable generation necessary to prevent wide-scale manual load shedding.

We reiterate that the BAs are best positioned to quantify their needs under a range of weather scenarios aligned with their Emergency Operating Plans, to specify an absolute performance requirement (inclusive of weather, fuel, environmental restrictions, etc.), and levy penalties for non-performance in the most cost effective manner. As an example, if a BA procured sufficient weatherized winter supply backed by certain fuel, the SDT's concern of "premature retirements" would be moot. Additionally, the Regional Entities' would have bright line criteria to apply to determine whether generator owners are complying with any commitments made to their BAs.

Likes 1	Vistra Energy, 5, Roethemeyer Dan
Dislikes 0	
Response	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	No
Document Name	
Comment	

Without a definition of "commercial constraints" it is difficult to know how R1 and R7 should be evaluated for compliance. We recommend the Standard Drafting Team make it clear in the standard that "commercial constraint" is limited to the inability to obtain necessary equipment or services after reasonable efforts due to supply issues or unavailability of services. Without this limitation, "commercial constraints" could be interpreted to mean cost prohibitions or economic pressures on the commercial profitability of a unit. It is our understanding that cost prohibitions or economic pressures are not intended to be acceptable justifications for not implementing freeze protection measures.

Likes 1	LS Power Development, LLC, 5, Spencer Mark
Dislikes 0	
Response	
Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 1	

Answer	No
Document Name	
Comment	
NextEra Energy is not supplying a position or comment on the cost effectiveness of these proposed changes.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
We believe that establishing a new Extreme Cold Weather Temperature may result in the need for costly upgrades to coal handling facilities, which may only become apparent during the implementation period. Generator Owners will be reluctant to make these costly investments unless and until the need for them is proven.	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	No
Document Name	
Comment	
Talen Energy Marketing supports Talen Generation's comments.	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	No

Document Name	

Comment

The cost-effective sequence of events for bolstering generation plant cold weather protection is to firstly obtain valid capability data (based on WCT or DBT-plus-20 mph, not DBT alone), then have RCs, BAs and TOPs identify their true reserve margins for extreme cold weather events. These parties can then adopt the appropriate market solutions – incentivizing upgrades where shortages are predicted, and accepting the status quo where no action is needed.

EOP-012-1 presently takes an extremely non-cost-effective approach, immediately leaping to a draconian and unnecessary requirement for retrofitting of existing units. This problem is exacerbated by using an incorrect basis for Extreme Cold Weather Temperature (DBT only, instead of WCT or DBT-plus-20 mph) and an incorrect protect-to target (0.2 percentile instead of historical worst-case weather). GOs can thereby be lured into installing inadequate protection, setting them up for immense market losses for 43 hours per decade (or more) if sold-ahead and, due to freeze-up, having to buy power on the spot market at prices that can reach $1000/MWh or higher (large units can lose $1MM per hour in this fashion). This situation also paves the way for having to tear-out marginal, EOP-012-1-based heat tracing/insulation systems that fail to protect as hoped and start over as an R6 CAP.

It also bears mentioning that the ultimate, “low hanging fruit,” for enhancing BES wintertime reliability is to put additional generation units online out-of-merit when an extreme storm is impending, since it is far easier to keep a unit running during severe weather than it is to start-up under such circumstances. EOP-012-1 may not be the place to address this issue, but until NERC acts in this respect, or at least encourages ISOs to act, it is not apparent that a sincere effort is being made regarding cost effectiveness.

Likes 0	
Dislikes 0	

Response

Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric

Answer	No
Document Name	

Comment

DTE Electric supports NAGF comments provided for this project

Likes 0	
Dislikes 0	

Response

Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6

Answer	No
Document Name	

Comment

The modifications continue to burden small utilities who already operate in sub-freezing weather. These requirments put significant burden on staff unnecessarily, and expose the parent company to administrative penalties, not performance penalties.

Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brooke Jockin - Portland General Electric Co. - 1, Group Name Portland General Electric Co.	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Avista supports the proposed change to the standard.	
Likes 0	

Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	Yes
Document Name	
Comment	
Acciona Energy supports Midwest Reliability Organization's (MRO) NERC Standards Review Forum's (NSRF) comments on this question.	
Likes 0	
Dislikes 0	
Response	
Adam Lee - MGE Energy - Madison Gas and Electric Co. - 4	
Answer	Yes
Document Name	
Comment	
Madison Gas and Electric supports the comments of the MRO NSRF	
Likes 0	
Dislikes 0	
Response	
Ronald Bauer - MGE Energy - Madison Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Madison Gas and Electric supports the comments from the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	

Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	Yes
Document Name	
Comment	
MidAmerican Energy supports the MRO NSRF comments for this question.	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
The MRO NSRF agrees EOP-012-1 meets the key recommendations in The Report in a cost effective manner. The sum of all the components of the proposed Standard as written create a balanced approach between the need to improve grid reliability and resiliency during cold weather events and the need to participate in a competitive market.	
Likes 0	
Dislikes 0	
Response	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Alliant Energy supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	

Jamison Cawley - Nebraska Public Power District - 1	
Answer	Yes
Document Name	
Comment	

NPPD agrees EOP-012-1 meets the key recommendations in The Report in a cost effective manner. The sum of all the components of the proposed Standard as written create a balanced approach between the need to improve grid reliability and resiliency during cold weather events and the need to participate in a competitive market.

Likes 0	
Dislikes 0	
Response	

Alison Mackellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	

EOP-012 achieves a cost effective solution because of the exemptions built in R7 for technical, commercial, or operational constraints that may apply to a particular generator. Constellation notes, however, that the standard could provide greater clarification that lack of cost recovery is a commercial constraint to implementation of Requirement R1 and any Corrective Action Plan (CAP) under Requirement R2 or exception under Requirement R7. It is critical that any adopted weatherization requirements clearly ensure that lack of cost recovery is included under the qualified “commercial” constraints listed in Requirements R1, R2 and R7 and specifically outline how determinations for each category of constraint will be decided. In addition, under Requirement R2, Generator Owners should have the option to develop and implement a CAP or be allowed to explain in a declaration why corrective actions are not being implemented due to any technical, commercial, or operational constraints as defined by the Generator Owner. These options should not be across two separate Requirements (R2 and R7) within the draft standard. Streamlining R2 and R7 into one Requirement will create efficiencies in compliance for Generator Owners and in compliance monitoring reviews for the NERC Regional Entities.

Kimberly Turco, on behalf of Segments 5 and 6

Likes 0	
Dislikes 0	
Response	

Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	

EOP-012 achieves a cost effective solution because of the exemptions built in R7 for technical, commercial, or operational constraints that may apply to a particular generator. Constellation notes, however, that the standard could provide greater clarification that lack of cost recovery is a commercial constraint to implementation of Requirement R1 and any Corrective Action Plan (CAP) under Requirement R2 or exception under Requirement R7. It is critical that any adopted weatherization requirements clearly ensure that lack of cost recovery is included under the qualified “commercial” constraints listed in Requirements R1, R2 and R7 and specifically outline how determinations for each category of constraint will be decided. In addition, under Requirement R2, Generator Owners should have the option to develop and implement a CAP or be allowed to explain in a declaration why corrective actions are not being implemented due to any technical, commercial, or operational constraints as defined by the Generator Owner. These options should not be across two separate Requirements (R2 and R7) within the draft standard. Streamlining R2 and R7 into one Requirement will create efficiencies in compliance for Generator Owners and in compliance monitoring reviews for the NERC Regional Entities.

Kimberly Turco, on behalf of Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Joe Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC

Answer	Yes
Document Name	

Comment

Xcel Energy can support the cost-effectiveness of implementing this Standard, predicated on the ability that R2 is tied to R6 and, subsequently, R7. The ability to declare qualifying units as unable to implement corrective actions is a required element for Xcel Energy to support the implementation of this Standard in a cost-effective manner.

Likes 0	
Dislikes 0	

Response

Scott Kinney - Avista - Avista Corporation - 3

Answer	Yes
Document Name	

Comment

Avista supports the proposed change to the standard.

Likes 0	
Dislikes 0	

Response

Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Avista supports the proposed change to the standard.	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
None.	
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	
Southen Company agrees that the proposed requirements are cost effective assuming the exceptions provided in R1 and R7 remain the same.	
Likes 0	
Dislikes 0	
Response	
Natalie Johnson - Enel Green Power - 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	
John Liang - Snohomish County PUD No. 1 - 6	
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	
Michelle Amarantos - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Foung Mua, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Wei Shao, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; - Tim Kelley, Group Name SMUD / BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Eric Ruskamp - Lincoln Electric System - 6, Group Name LES	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Scott McGough - Georgia System Operations Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Donna Johnson - Oglethorpe Power Corporation - 5	
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	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Tony Skourtas - Los Angeles Department of Water and Power - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Glenn Pressler - CPS Energy - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Watt - Oklahoma Municipal Power Authority - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Evans-Mongeon - 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	

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	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Kristine Ward - Seminole Electric Cooperative, Inc. - 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

Diana Torres - Imperial Irrigation District - 6

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	
Document Name	
Comment	
CEPM believes that as an IPP (non-Utility) there needs to be better defined means for IPPs to recoup costs for modification of existing units to operate to the minimum operating temerpature prior to R2 becoming enforcable. We believe the SDT does have an obligation with support of these approaches along with the GO and ISO/RTO.	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	
Comment	

No Comment

Likes 0	
Dislikes 0	

Response

Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF

Answer	
Document Name	

Comment

At this time, SIGE is unable to quantify if the modifications will be cost-effective.

Likes 0	
Dislikes 0	

Response

Selene Willis - Edison International - Southern California Edison Company - 5

Answer	
Document Name	

Comment

“Please see comments submitted by the Edison Electric Institute”

Likes 0	
Dislikes 0	

Response

Lenise Kimes - City and County of San Francisco - 1,5 - WECC

Answer	
Document Name	

Comment

Difficult to weigh-in since actual potential costs are unknown at this time.

Likes 0	
Dislikes 0	

Response

Devin Shines - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company

Answer	
Document Name	

Comment

LouisvilleG&E/KU support EEI's comments.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE recommends the SDT consider including parameters or examples for when the use of a technical, commercial, or operational constraint is justifiable for not implementing a CAP in Requirement R7. The use of the phrase “as defined by the Generator Owner” is broad and could lead to reliability gaps.

Likes 0	
Dislikes 0	

Response

Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3, Group Name OGE Energy

Answer	
Document Name	

Comment

OG&E supports the comments submitted by EEI.

Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	
Yes, AECI supports the suggested approach.	
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.

Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	
Document Name	
Comment	
The focus needs to be on those entities who have failed to perform during cold weather, and should not impact those who operate facilities located and operated in cold climates where freezing temperatures are common. The standard and VSLs all point to admistrative activities and not performance activities. This creates a nighmare during audits and exposure to many companies who should not be considered risks.	
Likes 0	
Dislikes 0	
Response	

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	
AECI has 2 additional comments for this standard not covered in the previous comment sections. These comments are specific to R5 and R6 respectively. R5: In regards to the proposed verbiage requiring “generating unit-specific training”, it is our opinion that this could be overly burdensome for stations with multiple units; particular for those stations with multiple units of a similar design (a.k.a. “sister” units). Recommend modifying this requirement to require station-specific training in lieu of generating unit-specific training. It is our opinion that this modification will allow the GO/GOP the flexibility to develop their training modules with an appropriate level of detail so as to sufficiently train station personnel without requiring them to create multiple modules with similar or identical content. R6: Concerning the proposed timeline for the development of a CAP, it is our recommendation that the July 1st date be removed from this requirement. The rationale for this recommendations is thus: 150 days prior to July 1st is Feb 1st for non-leap years and Feb 2nd for leap years. Moreover, the July 1st timeline is further condensed if a Generator Cold Weather Reliability Event (GCWRE) occurs in March or April. Lastly, the stated intent of the timeframe options within the Technical Rationale is to allow GO’s to review multiple events holistically following a winter season. In certain areas of the country, a GCWRE could realistically occur as early as late-October. In this instance, the latest possible date for the development of a CAP would be March 30th. Given that it is also realistic for a GCWRE to occur in March, 150 days seems a reasonable number of days to cover all but the most extreme scenarios. Therefore, we recommend removing the hard deadline of July 1st.	

Thank you for the opportunity to comment. AECI thanks the standard drafting team for their diligence and commitment to improve system reliability with an expedited timeline.	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	
Document Name	
Comment	
General area aspects have not been captured to help determine the extreme weather temperature aspect. Geographic guidance from the BA could be beneficial. From a technical view should we have some type of forwarding looking element.	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 6	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	
Document Name	
Comment	

DTE Electric supports NAGF comments provided for this project	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	
Document Name	
Comment	

Talen Energy supports the supplemental comments of the NAGF, and adds those presented below.

{C}1. {C}R1 says that GO/GOPs must, "Explain in a declaration, any technical, commercial, or operational constraints," but there is no mechanism for these inputs to be conveyed to RCs, BAs and TOPs. Such limitations should be declared in R3.5 of EOP-012-1, and R3.5 should be amended to require that data be sent to RCs, BAs and TOPs.

{C}2. {C}The exceptions of the second bullet point of R1 should be revised to disallow failure to winterize new units simply because the owners don't feel like spending the money. Reliability standards should set the rules for being allowed to sit at the table. Perhaps the expression, "preclude the ability," was not meant to grant carte blanche in this respect, but if so it is an example of the need for use of clear language in reliability standards.

If there is an implied regulatory hurdle to be cleared in this respect, as opposed to relying solely on the judgment of GOs, guidance is required in EOP-012-1 for emerging technologies such as preventing ice accumulation on wind turbine blades. It may not be possible to set firm rules in such cases, but NERC should create incentives to advance the state of the art (the "best available technology") rather than permanent loopholes.

{C}3. {C}The "demonstrates" of M1 should be limited to major freeze prevention measures, such as heat tracing/insulation systems and wind turbine nacelle heating. GOs should not have to obtain design calculations for every lube/seal oil reservoir heater, building heater, enclosure heater and other minor winterization measure for plants built many decades ago, especially since there are no calculations for wind barriers, CTG inlet air heaters and the like.

{C}4. {C}The entry, "features. Any," in M1 should be, "features, any."

{C}5. {C}The, "add new or modify," language of R2 should be expunged, as well as the percentile based performance criterion of the Extreme Cold Weather Temperature definition, for the reasons given earlier in these comments. The CAPs of R2 should allow revising the capability declaration of R3.5.2 in lieu of modifying the facility, again as explained earlier.

{C}6. {C}The Extreme Cold Weather Temperature criterion should be replaced in R3.1, and everywhere else it is used in EOP-012-1, with the historical worst-case WCT (or DBT-with-20 mph wind value), as mentioned previously. The only calculations then required involve converting DBT+wind values to WCT, which is so simplistic that there's no need to document the math as compliance evidence.

{C}7. {C}The Guidance section of EOP-012-1 should explain that the high level of uncertainty inherent in winterization makes it unnecessary to seek perfection in compiling weather data for R3 of EOP-012-1. Readings from the nearest airport are acceptable, and in fact are often more accurate than plant measurements. Non-official sources of weather data are acceptable so long as they have a reputable basis, e.g. extremeweatherwatch.com draws its information from the NOAA database.

{C}8. {C}Revise or eliminate R3.2, “Documentation identifying the Generator Cold Weather Critical Components,” as discussed earlier in these comments.

{C}9. {C}Revise R3.3 in accordance with our earlier comments, i.e.

{C}- include congealing when defining the term “freezing”

{C}- have precipitation stand separate from temperature/wind-related considerations

{C}- differentiate between principal and secondary winterization measures

{C}- cover temperature and wind in a combined fashion (WCT, or DBT-plus-20 mph)

Regarding the last of these points, DBT and wind speed are inputs to a single heat transfer calculation, ref. the formulae in IEEE-515, and must therefore be handled together. Calling for identification of DBT capability and, separately, “the cooling effects of wind,” is like identifying the load capability of a generator in terms of voltage, with separate consideration of the effect of current.

{C}10. {C}R3.5 is unchanged from EOP-011-2 and might therefore be thought to be noncontroversial, but this earlier standard is not yet enforceable, so no case law has been developed to bring its ambiguities and omissions into focus. These gaps should be closed in the Guidance section of EOP-012-1 as follows:

{C}a. “Capability” in the present context means real and reactive power output. That is, NERC is seeking information regarding factors that could limit output during winter storms below the values that grid operators are expecting. “Availability” refers to ability to start-up and remain online

{C}b. The word, “concerns,” in R3.5.1.2 pertains to fuel supply and inventory issues known to GO/GOPs or reasonably expected, not speculations about what might go wrong. Known inability of a NG pipeline company to support all plants on their system at maximum load during extended periods of peak demand would be reportable, for example, but GO/GOPs are not expected to evaluate fuel suppliers’ pipelines, compression/pumping equipment, contract terms or other matters over which generation entities have no control. Also, do not provide non-actionable inputs such as, “Fuel contracts contain a force majeure clause,” or, “Can’t get fuel oil deliveries if the roads are closed.”

{C}c. The term, “Environmental constraints,” in R3.5.1.4 pertains to maximum output. Narrowing of the max-to-min load environmentally compliant turndown range as the weather gets colder, as may be experienced by some combustion turbine generator units with dry low-NOx combustors, need not be reported.

{C}d. Cold-startup times for extreme winter weather conditions should be added to R3.5.1, given the use of this criterion in defining the term, “Generator Cold Weather Reliability Event”

{C}e. The need to provide evidence for the design temperature option of R3.5.2 should be limited to major freeze prevention elements, as was mentioned earlier in these comments. A unit with heat tracing and insulation designed for -25 F DBT and a 10 mph wind (-47 F WCT) may report a value of -19 F (-47 F WCT with a 20 mph wind), for example, without confirming that the lube oil heater has the same capability. This approach is especially important for peaking units that were built long ago and run primarily in the summer, not winter. They may not have the one-hour proof of R2, and design information for minor freeze prevention elements simply doesn’t exist. Demanding that such equipment be reverse-engineered would be unreasonable.

{C}f. A look-back period should be specified for the historical operating temperature option of R3.5.2. We suggest the shorter of five years and the time that the unit has been in service, with going back to the most recent extreme cold weather event being preferred for units old enough to do so.

{C}g. A requirement to report data to the RC, BA and TOP should be added to R3.5. They need to use these inputs, but there’s presently no requirement that they be reported to them.

{C}11. {C}R4 should be deleted. Plants must perform pre-winter preparations annually, and these activities should include updating for the past year the cold weather capability and other information communicated under R3.5 to the RC, BA and TOP. There is no benefit from endlessly repeating analyses, especially after implementing the changes recommended above.

{C}12. {C}The term, “unit-specific,” in R5 should be changed to, “plant-specific.” A facility with three fossil units, for example, should cover any individual-unit idiosynchrosies, but it does not need three different training courses.

{C}13. {C}The Guidance section of the standard should make it clear that annual training of maintenance and operations personnel for R5 should include on-condition activities in addition to the the NERC cold weather preparedness plan. That is, R3.4 establishes that the measures covered by EOP-012-1 are limited to those performed prior to winter in once-and-done fashion, and plants also have tasks to be performed as real-time weather conditions dictate, such as enhanced operator rounds, call-outs, and cycling mechanical-draft cooling tower fans to prevent excessive ice formation. The Guidance section of the standard should also advise that training may be split into a generic freeze prevention course and a supplemental, plant-specific module.

{C}14. {C}R6.3 does not identify the level of performance to be achieved by CAPs. It should be revised to explicitly say that it can consist of equipment modifications or adjustments to the cold weather capability declared for R3.5.2. If for example a plant with heat tracing and insulation designed for -20 F with a 20 mph wind incurs a freeze-related forced outage it can revise the R3.5.2 value or, as a market decision, add-to or modify equipment.

{C}15. {C}Regarding our earlier comments on historical worst-case temperature vs the present basis of the Extreme Cold Weather Temperature definition, R6 presently says that forced outages, derates and failures to start must be corrected if occurring during 0.2 percentile-and-up conditions, but for the coldest 43 hours per decade freeze-up instances and the blackouts, deaths and damage they cause, are acceptable – no corrective action is needed. How can this be called a “reliability” standard?

{C}16. {C}Having R6 require CAPs and R7 provide a no-limits offramp (“technical, commercial, or operational constraints”) is strange and ineffective. PRC-004 has been cited as establishing a precedent in this respect, but this is not the case. R5 of PRC-004-6 says that entities must establish a CAP or state a valid technical (not commercial) justification for not doing so (“beyond the entity’s control or would not improve BES reliability”), then R6 says that CAPs developed in R5 must be implemented.

R7.1 should be amended to simply require implementation of the CAP, given the R6.3 changes requested above (modification of R3.5.2 capability declarations is sufficient). Justifications are not then required. The present R6-R7 combination seems to says that GO/GOPs must identify solutions to freeze-up problems, then they have the option of doing nothing, but if they choose this alternative it remains an open compliance issue forever.

Likes 0	
Dislikes 0	

Response

Donna Wood - Tri-State G and T Association, Inc. - 1

Answer	
Document Name	

Comment

The cold weather exclusion should be removed from the Applicability section and instead a requirement should be added to require the GO to prove operability in cold weather through analysis/studies. This is a common practice among standards that apply to a subset of BES Elements or Facilities. Tri-State suggests that the SDT look at similar standards/requirements such as TPL-007-4, R5, PRC-023-4 R6, and PRC-002-2 R1.

The Applicability section is not auditable and leaving the exception within that section could allow for entities to incorrectly exclude their units with no repercussions. This in turn could cause a reduction in grid reliability as Generator Owners continue to be unprepared for cold weather events.

Likes 0	
Dislikes 0	

Response

Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6

Answer	
Document Name	

Comment

Talen Energy Marketing supports Talen Generation's additional comments.

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

Southern Company would suggest the SDT include additional language in R1 to strengthen expectations that a generator that is committed or contractually obligated to serve a BA load per Appicablility section 4.2.1 will design and plan to operate under the conditions described in R1. The "Or" clause in R1, currently in this version, leaves too much latitude for generators not to perform prior to actually experiencing a Generator Cold Weather Reliability Event.

Southern Company suggests the following language to be added to R1:

- "If the generating unit(s) are contractually obligated to operate in the aforementioned conditions, and any technical, commercial, or operational constraint is identified by the Generator Owner, the Generator Owner shall notify their applicable Generator Operator, Transmission Operator, Balancing Authority and Reliability Coordinator in a timely manner. The Generator Owner shall specify the anticipated time required for mitigation and identify an approximate return to service date."

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	
Document Name	

Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
FE requests clarification on the following two points : 1. Is bidding in a Unit as 'must run' for freeze protection of itself or neighboring Units (whether for radiant heat to a building, aux steam for heat or startup, or circulation of at-risk systems/fluids) an acceptable freeze protection measure? If entering a Unit 'must run' for freeze protection cannot be relied upon as an available measure, then the implementation/compliance most likely cannot be achieved in many cases in a 'cost effective manner' 2. If all Units at a specific location/plant were in reserve and none permitted to start ahead of extreme cold weather conditions, would a failure to start in extreme conditions be considered a qualifying event?	
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	
Document Name	
Comment	
For EOP-012-1 R6, Tacoma Power recommends deleting the "or by July 1, whichever is earlier" language. If a cold weather event occurred in late Spring or early Summer (i.e. April through June), an entity would have less than 150 days to holistically review the event and develop a CAP.	
Likes 0	
Dislikes 0	
Response	

Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 1	
Answer	
Document Name	
Comment	
NextEra Energy supports a weatherization framework that provides flexibility for generators to adopt new effective, commercially viable and proven technologies, but cautions against requiring the adoption of unproven technology that could damage equipment or otherwise reduce the operating life and void warranties, thereby reducing overall reliability.	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	
Document Name	
Comment	
None at this time.	
Likes 0	
Dislikes 0	
Response	

Lindsey Mannion - ReliabilityFirst - 10	
Answer	
Document Name	
Comment	
We request the SDT confirm in a Consideration of Comments that only one of the three bullets under 3.5.2 is required for a given generating unit. We recommend the SDT consider whether the proposed interaction between R2/R4/R6 and R7 will cause GOs needing to take the declaration in 7.1 an R2/R4/R6 noncompliance based on the Glossary of Terms definition of Corrective Action Plan. R7.1 allows an entity with an appropriate justification to declare that a CAP will not be implemented, but developing a CAP requires both developing a list of actions AND extablishing an associated timetable for implementation. As a timetable for implementation is not reasonable to require for corrective actions a GO is constrained from implementing, we recommend replacing “CAP” with “list of corrective actions” in R2/R4/R6 and changing R7 part 7.1 to “Create and Implement one or more Corrective Action Plans addressing each corrective action identified pursuant to Requirements R2, R4, or R6, or explain in a declaration why one or more identified corrective actions will not be implemented due to technical, commercial, or operational constraints as defined by the Generator Owner.”	
Likes 0	
Dislikes 0	
Response	

Brian Evans-Mongeon - Utility Services, Inc. - 4	
Answer	
Document Name	
Comment	
We understand R1 and R2 as requiring GOs to implement freeze control measures that they reasonably believe, based on good engineering judgment and their experience with their particular units and weather patterns, will result in the unit being able to operate continuously for the applicable time at the Extreme Cold Weather Temperature. Our understanding of the proposed requirements is that if a new or existing unit experiences a Forced Outage as a result of a Generator Cold Weather Reliability Event, even if the Forced Outage occurs after less than twelve hours (for a new generator) or one hour (for an existing generator) of continuous operations, the Forced Outage will not constitute evidence of noncompliance with R1 or R2. Instead, the GO will develop and implement a CAP pursuant to R6 and R7, as it would in response to any Generator Cold Weather Reliability Event. The contrary interpretation—that R1 and R2 require freeze protection measures that are 100% guaranteed to work—would require a level of certainty that simply does not exist. Generators are complex machines; they sometimes fail in unforeseen ways. This problem is only compounded by the fact that, as noted by multiple panelists at the April 27-28, 2022 FERC, NERC, and Regional Entities Technical Conference on Improving Winter-Readiness of Generating Units, a cold weather event cannot be simulated ahead of time to allow functional testing of a unit’s set of winterization measures. Finding a GO noncompliant with R1 or R2 based on the failure in a particular instance of winterization measures it reasonably believed, based on the information available to it prior to the cold weather event, would be adequate, would not enhance reliability. We read R2 as providing that, where an existing unit is *not* capable of operating continuously for one hour at the Extreme Cold Weather Temperature, the method by which the GO “ensure[s] its generating unit(s) add new or modify existing freeze protection measures as needed” is the development of a CAP pursuant to R2. In other words, a GO demonstrates compliance with R2 by demonstrating either that it has implemented appropriate freeze protection measures, or that it has developed a CAP[A1] .	

Suggested edit to Requirement R2 (making the 2 sentences in the Requirement 'or' statements):

R2. For each generating unit(s) in commercial operation prior to [Effective Date of this requirement], the Generator Owner shall ensure its generating unit(s):

· Add new or modify existing freeze protection measures as needed to provide the capability to operate for a period of not less than one (1) hour at the unit(s) Extreme Cold Weather Temperature; or

· If generating unit(s) are not capable of operating for one (1) hour at its Extreme Cold Weather Temperature, shall develop a Corrective Action Plan (CAP) for the identified issues, including identification of any needed modifications to the cold weather preparedness plan required under Requirement R3.

Suggested edit to Measure M2 (add the clause "ability to operate for 1 hour at"):

M2. Each Generator Owner will have dated evidence that demonstrates it has freeze protection measures for its unit(s) in accordance with R2, or it has developed a CAP for the identified issues. Acceptable evidence may include the following (electronic or hardcopy format): Identification of generating units ability to operate for 1 hour at the minimum temperature per Part 3.5.2 which is equal to or less than the unit's Extreme Cold Weather Temperature, documentation of freeze protection measures, cold weather preparedness plan, and CAP(s).

Likes 1	Illinois Municipal Electric Agency, 4, Todd Mary Ann
Dislikes 0	

Response

Michael Watt - Oklahoma Municipal Power Authority - 4

Answer	
Document Name	

Comment

OMPA agrees with the TAPs comments below:

We understand R1 and R2 as requiring GOs to implement freeze control measures that they reasonably believe, based on good engineering judgment and their experience with their particular units and weather patterns, will result in the unit being able to operate continuously for the applicable time at the Extreme Cold Weather Temperature. Our understanding of the proposed requirements is that if a new or existing unit experiences a Forced Outage as a result of a Generator Cold Weather Reliability Event, even if the Forced Outage occurs after less than twelve hours (for a new generator) or one hour (for an existing generator) of continuous operations, the Forced Outage will not constitute evidence of noncompliance with R1 or R2. Instead, the GO will develop and implement a CAP pursuant to R6 and R7, as it would in response to any Generator Cold Weather Reliability Event. The contrary interpretation—that R1 and R2 require freeze protection measures that are 100% guaranteed to work—would require a level of certainty that simply does not exist. Generators are complex machines; they sometimes fail in unforeseen ways. This problem is only compounded by the fact that, as noted by multiple panelists at the April 27-28, 2022 FERC, NERC, and Regional Entities Technical Conference on Improving Winter-Readiness of Generating Units, a cold weather event cannot be simulated ahead of time to allow functional testing of a unit's set of winterization measures. Finding a GO noncompliant with R1 or R2 based on the failure in a particular instance of winterization measures it reasonably believed, based on the information available to it prior to the cold weather event, would be adequate, would not enhance reliability.

We read R2 as providing that, where an existing unit is *not* capable of operating continuously for one hour at the Extreme Cold Weather Temperature, the method by which the GO "ensure[s] its generating unit(s) add new or modify existing freeze protection measures as needed" is the development of a

CAP pursuant to R2. In other words, a GO demonstrates compliance with R2 by demonstrating either that it has implemented appropriate freeze protection measures, or that it has developed a CAP.

The SDT has indicated that it plans to revisit the language of EOP-012-1 as part of Phase 2 of this project. Although we believe that our readings of the requirements, as outlined above, are consistent with the SDT's intent, we strongly recommend that Phase 2 clarify the language of R1 and R2 on these issues. Expressing the SDT's intent more clearly would reduce the risk of confusion and conflicting interpretations.

Likes 1	Illinois Municipal Electric Agency, 4, Todd Mary Ann
Dislikes 0	

Response

Glen Farmer - Avista - Avista Corporation - 5

Answer	
Document Name	

Comment

Avista recommends some reconsideration as to the applicability of the EOP 12-2 as it relates to ALL BES generating facilities. Both the letter and intent of the draft standard appear to be related specifically to thermal or steam process plants that use a Rankin cycle to generate electricity, and their susceptibility for freezing during cold weather. Can the permit team under Part 2 reconsider the applicability of facilities to consider to just those facilities related to the Rankin cycle that use steam as a means of generating electricity. Many facilities such as hydroelectric facilities internal combustion generation, wind turbine generators, and are much less susceptible to extreme cold weather and should not be treated the same regarding compliance requirements of such a standard.

Likes 0	
Dislikes 0	

Response

Brooke Jockin - Portland General Electric Co. - 1, Group Name Portland General Electric Co.

Answer	
Document Name	

Comment

Portland General Electric Company supports the survey response provided by EEI.

Likes 0	
Dislikes 0	

Response

Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	
Document Name	
Comment	

We understand R1 and R2 as requiring GOs to implement freeze control measures that they reasonably believe, based on good engineering judgment and their experience with their particular units and weather patterns, will result in the unit being able to operate continuously for the applicable time at the Extreme Cold Weather Temperature. Our understanding of the proposed requirements is that if a new or existing unit experiences a Forced Outage as a result of a Generator Cold Weather Reliability Event, even if the Forced Outage occurs after less than twelve hours (for a new generator) or one hour (for an existing generator) of continuous operations, the Forced Outage will not constitute evidence of noncompliance with R1 or R2. Instead, the GO will develop and implement a CAP pursuant to R6 and R7, as it would in response to any Generator Cold Weather Reliability Event. The contrary interpretation—that R1 and R2 require freeze protection measures that are 100% guaranteed to work—would require a level of certainty that simply does not exist. Generators are complex machines; they sometimes fail in unforeseen ways. This problem is only compounded by the fact that, as noted by multiple panelists at the April 27-28, 2022 FERC, NERC, and Regional Entities Technical Conference on Improving Winter-Readiness of Generating Units, a cold weather event cannot be simulated ahead of time to allow functional testing of a unit's set of winterization measures. Finding a GO noncompliant with R1 or R2 based on the failure in a particular instance of winterization measures it reasonably believed, based on the information available to it prior to the cold weather event, would be adequate, would not enhance reliability.

We read R2 as providing that, where an existing unit is *not* capable of operating continuously for one hour at the Extreme Cold Weather Temperature, the method by which the GO "ensure[s] its generating unit(s) add new or modify existing freeze protection measures as needed" is the development of a CAP pursuant to R2. In other words, a GO demonstrates compliance with R2 by demonstrating either that it has implemented appropriate freeze protection measures, or that it has developed a CAP.

The SDT has indicated that it plans to revisit the language of EOP-012-1 as part of Phase 2 of this project. Although we believe that our readings of the requirements, as outlined above, are consistent with the SDT's intent, we strongly recommend that Phase 2 clarify the language of R1 and R2 on these issues. Expressing the SDT's intent more clearly would reduce the risk of confusion and conflicting interpretations.

Likes 0	
Dislikes 0	
Response	

Scott Kinney - Avista - Avista Corporation - 3	
Answer	
Document Name	
Comment	

Avista recommends some reconsideration as to the applicability of the EOP 12-2 as it relates to ALL BES generating facilities. Both the letter and intent of the draft standard appear to be related specifically to thermal or steam process plants that use a Rankin cycle to generate electricity, and their susceptibility for freezing during cold weather. Can the permit team under Part 2 reconsider the applicability of facilities to consider to just those facilities related to the Rankin cycle that use steam as a means of generating electricity. Many facilities such as hydroelectric facilities internal combustion generation, wind turbine generators, and are much less susceptible to extreme cold weather and should not be treated the same regarding compliance requirements of such a standard.

Likes 0	

Dislikes 0	

Response

Mark Spencer - LS Power Development, LLC - 5

Answer	
Document Name	

Comment

The SDT states that "cost recovery" is outside the scope of its work, yet wades into economic regulation by i) applying different standards to new and existing generators and ii) offering a "commercial constraint" exemption. In the former instance, the only justification the SDT offered is that a more stringent standard could create premature retirements. This is despite the plain language requirement of the statute that all prudent and necessary costs to comply with the reliability standards shall be recoverable. If generator owners are held harmless from the cost of compliance, then why would a rigorous standard drive retirements? In the latter case, the commercial constraint would violate NERC Market Principles. As an illustrative example, if two generators, A and B, were participating in the same market, owner of Generator A declared its intention to retire "soon" and declared a "commercial constraint" exemption from compliance. Generator A is not saddled with the compliance costs because of its "constraint," while Generator B has compliance costs; yet both generators compete in the same market in the same interval. We cannot think of a clearer example of a reliability standard creating an unfair competitive advantage.

Additionally, the SDT's attempt at economic regulation is producing a diluted reliability standard that could actually reduce reliability. Our analysis demonstrates that all locations that experience freezing temperatures experienced multiple events that lasted more than one hour at or below their respective ECWT. As we describe above, we are concerned that fleet performance will regress towards the new 1-hour standard, even for existing generators that may have had historically good performance. This would reduce reliability. Additionally, setting a 12-hour duration for new resources would take decades to have any meaningful reliability impact as new generators replace existing. For these reasons, we urge the SDT to set a common standard for existing and new that will meaningfully enhance reliability.

We also urge the SDT to eliminate the "commercial constraint" exemption. We are not aware of a similar provision in any other approved NERC reliability standard, and this provision may create unwanted debate regarding other reliability standards. First, it leaves it to the generator owner's discretion to determine whether it is exempt from compliance, which favors states and merchant generators to rely on the most liberal interpretation of the exemption that achieves the lowest cost. This is extremely bad precedent. Second, the vaguely defined exemption will create inevitable disagreements between generator owners and auditors that may only be raised at the time of the audit. Third, it raises the question that if a retirement decision is a valid exemption then why should a generator that is "due to retire soon" be required to comply with *any* NERC reliability standard? This is bad precedent. Finally, a generator owner could make an argument that if its tariff does not allow cost recovery that too is a commercial constraint and merits an exemption. Unlike the regulated markets, this is particularly worrisome for the organized markets where cost recovery is not guaranteed before an investment is made.

We are also concerned NERC may not have the authority under the Federal Power Act to impose the proposed standard. NERC cites the definition of "reliability standard" as its authority to impose requirements on existing generators. The definition from the statute is replicated below:

"*The term 'reliability standard' means a requirement, approved by the Commission under this section, to provide for reliable operation of the bulk-power system. The term includes requirements for the operation of existing bulk-power system facilities, including cybersecurity protection, and the design of* *planned additions or modifications to such facilities to the extent necessary to provide for reliable operation of the bulk-power system, but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity."*

However, the statute also defines the term "reliable operations":

"The term 'reliable operation' means 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."

The term 'reliable operations' is expressly limited to items that cause "sudden disturbances, including a cybersecurity incident" or an "unanticipated failure of system elements." "[U]nanticipated failure" is not a failure of a generator at a temperature below its cold weather rating. Thus, it appears that mandating expanded performance obligations directly on existing generators through a reliability standard is outside the scope of this definition. Additionally, we are not aware of any approved reliability standard mandating generators install components for an expanded range of services.

For these reasons, we encourage NERC to reconsider its approach. We offer an alternative approach that would require the BAs to procure this expanded service and harmonize it with attributes in addition to freeze protection – e.g., fuel, environmental limitations, etc. Relying on BAs to procure their reliability needs is a more defensible and economically efficient approach to enhancing reliability. It is also an approach that eliminates the need for a "commercial constraint" exemption and permits for a more robust reliability standard. However, if NERC does not consider this alternate, we recommend that the Commission hold the compliance date in abeyance until cost recovery has been properly addressed. As background, in the ISO New England CIP IROL proceeding certain generators were designated IROL facilities, were promised that they would have an opportunity to recover their costs, and incurred substantial compliance costs. Unfortunately, the ISO's filing was after many generators incurred the costs and thus the Commission found that recovery of costs prior to the filing would violate the filed rate doctrine, and rejected recovery of those pre-filing costs.

Likes 1	Vistra Energy, 5, Roethemeyer Dan
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 3

Answer	
Document Name	

Comment

Ameren agrees with the EEI and the NAGF comments.

Likes 0	
Dislikes 0	

Response

Joe Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC

Answer	
Document Name	

Comment

Xcel Energy supports comments from EEI.

Likes 0	
Dislikes 0	

Response

Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3, Group Name OGE Energy

Answer	
Document Name	

Comment

OG&E supports the comments submitted by EEI.

Likes 0	
Dislikes 0	

Response

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments

Answer	
Document Name	

Comment

PG&E thanks the SDT's for their effort to address the industry's concerns regarding the proposed Standard, the effort it has taken to complete the work up to this point, and the work necessary to complete the modifications in Phase Two of the project.

PG&E also supports the additional input provided by EEI related to Requirement R2, and the NAGF concerns related to retrofitting and compensation on those retrofits. This includes the NAGF input that the Requirements in EOP-011 which is enforceable on 4/1/2023 should be allowed to take effect and determine if they are sufficient to address cold weather operations. PG&E also supports the NAGF proposed language if NERC wishes to add in the reliability requirements language.

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	
Document Name	

Comment

As stated above, Dominion Energy remains concerned with the requirement to retrofit or otherwise improve an existing generator's cold weather performance capability and proposes the drafting team consider the more cost-effective option of requiring generators to communicate their extreme cold weather operating capabilities to the BA and RC. Communicating operating capabilities and failing to meet them during an event would result in the CAP as outlined in R6. This option allows the BA and RC to appropriately plan for extreme cold weather events without placing a potentially unnecessary burden to retrofit existing generators and require them to perform beyond established designed operating parameters.

Dominion Energy is of the opinion that ensuring operating parameters for extreme cold weather are communicated and understood by the appropriate entities is more beneficial to reliability during these events than a blanket retrofit requirement.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	
Document Name	

Comment

AEP recognizes the importance of this project, and the priority which it has been given. Having said that, AEP hopes that industry's outstanding concerns (those not currently met in the current draft) will be fully addressed in a Phase II of this project. In addition, we recommend that industry be allowed the customary time period to develop comments and cast ballots at that time.

Likes 0	
Dislikes 0	

Response

Devin Shines - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company

Answer	

Document Name	

Comment
LouisvilleG&E/KU support EEI's comments.

Likes 0	
Dislikes 0	

Response

Lenise Kimes - City and County of San Francisco - 1,5 - WECC	
Answer	
Document Name	

Comment
No additional comments.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6	
Answer	
Document Name	

Comment
One of the most important aspects of this Phase 1 EOP-12 and existing EOP-11-2 is the communication of limiting temperatures to the BA/TOP via IRO-010 and TOP-003. Although how the BA/TOP will use the temperature information is outside the scope of these efforts, BA/TOP knowledge of limiting operating temperature and Extreme Cold Weather Temperature (ECWT), and the expected dialogue between GO/GOPs and BA/TOPs, is expected to result in more robust, realistic cold weather resource planning. ..... Two editorial comments on the Technical Rationale doc: 1) The last two bullet points supporting R6 in the Technical Rationale document should be reworded, perhaps with examples. That is, the current bullet point language that the use of the ECWT instead of minimum operating temperature removes incentives and disincentives is confusing, and the two appear to be addressing the same issue, just coming from different perspectives. 2) Also in the same section is the capitalization of Generator Unit Minimum Temperature. Recommend a check be made to ensure this is an official definition. Kimberly Turco, on behalf of Segments 5 and 6

Likes 0	
Dislikes 0	

Response
Alison Mackellar - Constellation - 5

Answer	
Document Name	

Comment

One of the most important aspects of this Phase 1 EOP-12 and existing EOP-11-2 is the communication of limiting temperatures to the BA/TOP via IRO-010 and TOP-003. Although how the BA/TOP will use the temperature information is outside the scope of these efforts, BA/TOP knowledge of limiting operating temperature and Extreme Cold Weather Temperature (ECWT), and the expected dialogue between GO/GOPs and BA/TOPs, is expected to result in more robust, realistic cold weather resource planning. ..... Two editorial comments on the Technical Rationale doc: 1) The last two bullet points supporting R6 in the Technical Rationale document should be reworded, perhaps with examples. That is, the current bullet point language that the use of the ECWT instead of minimum operating temperature removes incentives and disincentives is confusing, and the two appear to be addressing the same issue, just coming from different perspectives. 2) Also in the same section is the capitalization of Generator Unit Minimum Temperature. Recommend a check be made to ensure this is an official definition

Kimberly Turco, on behalf of Segments 5 and 6

Likes 0	
Dislikes 0	

Response
Richard Jackson - U.S. Bureau of Reclamation - 1

Answer	
Document Name	

Comment

Reclamation is providing the language it proposed for EOP-012 in Draft 1 here for convenience:

Reclamation recommends rewriting the requirements of EOP-012-1 as follows:

R1. *use existing language from Draft 1 EOP-012-1 R1.1* with the following corrections:

Each Generator Owner shall design new and maintain existing generating units to be capable of continuous operations at the documented minimum hourly temperature experienced at each unit's location since 1/1/1975 or a lesser period if reliable data is not available to 1975.

R2. *use existing language from Draft 1 EOP-012-1 R1* with the following corrections:

Each Generator Owner shall implement new or modify existing protection based on the documented minimum hourly temperature for its generating units including the following minimum criteria:

R2.1. the cooling effect of wind; and

R2.2. impacts on equipment operation due to precipitation (e.g., sleet, snow, ice, and freezing rain).

R3. *use existing language from Draft 1 EOP-012-1 R1.4* with the following corrections:

For each existing generating unit that requires new or modified protection based on the documented minimum hourly temperature, the Generator Owner shall develop and implement a Corrective Action Plan (CAP) or, where deemed appropriate by the Generator Owner based on the review of parts R3.1.1 through R3.1.3., declare that no corrective actions will be taken.

R3.1. A CAP shall contain the following minimum information:

R3.1.1. Corrective action(s) for the affected unit(s).

R3.1.2. Any temporary operating limitations that would apply until the corrective actions are implemented.

R3.1.3. A schedule for implementing the corrective action(s).

R3.2. A declaration shall document any technical, commercial, or operational constraints of each affected unit, as defined by the Generator Owner, in support of the declaration.

R4. *use existing language from Draft 1 EOP-012-1 R2* with the following corrections:

Each Generator Owner that does not implement new or modify existing protection based on the documented minimum hourly temperature in accordance with R2 due to technical, commercial, or operational constraints, as defined by the Generator Owner, shall:

R4.1. Document its determination and the constraints; and

R4.2. Review its determination every five calendar years to determine whether the constraints remain applicable.

R5. *use existing language from Draft 1 EOP-012-1 R3*

R6. *use existing language from Draft 1 EOP-012-1 R4, update Part numbers as necessary*

R7. *use existing language from Draft 1 EOP-012-1 R5* with the following corrections:

Each Generator Owner, in conjunction with its Generator Operator, shall ensure generating unit-specific cold weather preparedness plan training is provided to its personnel responsible for implementing cold weather preparedness plans.

R7.1. The Generator Owner and Generator Operator shall identify the entity responsible for providing the training.

R7.2. The Generator Owner and Generator Operator shall ensure the training is provided to personnel responsible for implementing cold weather preparedness plans upon entrance on duty and annually thereafter.

R8. *use existing language from Draft 1 EOP-012-1 R6* with the following corrections:

Each Generator Owner that owns a generating unit that experiences an event resulting in a derate of more than 10% of the total capacity of the unit for longer than four hours in duration, a start-up failure where the unit fails to synchronize within a specified start-up time, or a Forced Outage for which (i) the apparent cause(s) of the event is due to extreme cold weather effects within the Generator Owner’s control to protect against, and (ii) the ambient conditions at the site at the time of the event are at or above the temperature documented in Part 3.4.2 shall:

R8.1. No later than 150 days subsequent to the event or by July 1 that follows the event, whichever is ***later***, develop a CAP; or

R8.2. Declare, where deemed appropriate by the Generator Owner based on review of Parts 8.3.1. through 8.3.5, that no revisions to the cold weather preparedness plan are required and that no further corrective actions will be taken.

R8.3. At a minimum, a CAP shall contain:

R8.3.1. A summary of the identified cause(s) ***of*** the equipment ***derate, failure to start, or Forced Outage***, and any relevant associated data.

8.3.2 use existing 6.2.1. language

8.3.3. use existing 6.2.2. language

8.3.4. (modified 6.2.3.) Specific corrective action(s) for the affected unit(s) and identified similar units, including:

8.3.4.1. (modified 6.2.3.) any necessary modifications to the Generator Owner's cold weather preparedness plan(s); and

8.3.4.2. (modified 6.2.4.) consideration of any technical, commercial, or operational constraints, as defined by the Generator Owner.

8.3.5. A ***schedule*** for implementing the corrective actions.

R8.4. At a minimum, a declaration shall document technical, commercial, or operational constraints, as defined by the Generator Owner, as support for the declaration.

Reclamation recommends the timeframe for developing a CAP be 150 days subsequent to the event or by July 1 that follows the event, whichever is ***later***. Using whichever is earlier could subject an entity to an unreasonably short deadline depending on when the event occurs.

Reclamation recommends moving the language pertaining to the cold weather preparedness plans from the original R1 to the original R3 (new R5 based on Reclamation's proposed renumbering in the above comments). Modifications to the cold weather preparedness plan should relate back to the CAP, if necessary, not the CAP requirements relating forward to the cold weather preparedness plan.

Reclamation recommends not limiting the training on cold weather preparedness plans to "maintenance or operations" personnel, as other personnel may also be responsible for implementing cold weather preparedness plans and should not be excluded from the training. Reclamation recommends the annual cold weather preparedness plan training be contained in PER-006 instead of EOP-012.

Reclamation supports the retention and reuse of pertinent information from the Draft 1 Measures.

Likes 0	
Dislikes 0	

Response

Martin Sidor - NRG - NRG Energy, Inc. - 6

Answer	
Document Name	

Comment

NRG agrees with the NAGF that communicating operating parameters for extreme cold weather that are understood by the appropriate entities is more appropriate and beneficial to reliability during these events rather than a blanket retrofit requirement to operate to a defined condition.

We realize NERC cannot address the compensation issue for required improvements, but unless there is agreement from and with parties that can provide compensation for upgrades, this standard becomes an unfunded mandate on Generator Owners.

Likes 0	
Dislikes 0	

Response

Romel Aquino - Edison International - Southern California Edison Company - 3

Answer	
Document Name	

Comment

Please see comments submitted by the Edison Electric Institute

Likes 0	
Dislikes 0	

Response

Patricia Lynch - NRG - NRG Energy, Inc. - 5

Answer	
Document Name	

Comment

NRG agrees with the NAGF that communicating operating parameters for extreme cold weather that are understood by the appropriate entities is more appropriate and beneficial to reliability during these events than a blanket retrofit requirement to operate to a defined condition.

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Likes 0	
Dislikes 0	

Response

Selene Willis - Edison International - Southern California Edison Company - 5

Answer	
Document Name	

Comment	
"Please see comments submitted by the Edison Electric Institute"	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	
Document Name	
Comment	
PNM supports EEI's comments regarding modification of Requirement R2 to link with Requirement R7.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	
Document Name	
Comment	

The IESO reiterates its comment for Draft 1, where it requested that removal of the 'commercial' reference in Requirements 1 and 7.1 as this language is vague, creates an ambiguity as to the obligation otherwise provided for in the standard, and a review of commercial issues is not within NERC's domain and expertise.

In the Reliability Standard CIP-014 – Physical Security, NERC recognized that it does not have the physical security expertise to appropriately evaluate the risk assessment performed by the Transmission Owner. As such, CIP-014 requires an unaffiliated third party with the appropriate expertise to verify it.

Given that NERC's purview is reliability of the bulk power system, and not commercial matters, the SRC proposes that NERC adopt a similar approach for the proposed standard. Should a Generator Owner opt out of a Corrective Action Plan for commercial constraints, an unaffiliated third party should verify the finanacial assessment performed by the Generator Owner. The third party should have financial analysis experience, such as an auditing/accounting firm.

We also suggest that NERC develop clear boundaries regarding the use of commercial constraints to opt out of a CAP, such as:

- the investment in freezing protection measures is cost prohibitive due to new technology not yet advanced (i.e., economies of scale to yet reached) or
- the investment is below the registered entity's rate of return.

We recognize that cost recovery for generators is also not within the purview of NERC. Cost recovery for generators usually falls within state/provincial purview, and through market mechanisms. The SRC proposes that NERC consider adding a stakeholder process in the proposed requirement, similar to that in Reliability Standard TPL-001 – Transmission Planning on use of planned consequential load loss. An open stakeholder process that ensures state/provincial agencies are aware of the need for freeze protection measures to meet the reliability requirements in the proposed standard will allow affected parties to assess the cost recovery issues.

Likes 0	
Dislikes 0	

Response

Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster

Answer	
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for question #9.

Likes 0	
Dislikes 0	

Response

Dan Roethemeyer - Vistra Energy - 5

Answer	
Document Name	

Comment

Vistra has additional recommendations/requested clarifications on the proposed requirements described below:

The NERC Calculating Extreme Cold Weather Temperature guide should be modified to address circumstances where National Oceanic and Atmospheric Administration (NOAA) data dating back to January 1, 2000 does not exist for the particular location. For example, NOAA has weather data for Andrews, Texas dating back only to 2014, and there are no other representative NOAA locations in the dataset. There may be other instances of rural airports or other NOAA weather data locations that do not have data going back to 2000. The Guide should specify an alternate source(s) of acceptable weather data for calculation of the Extreme Cold Weather Temperature in instances where NOAA data does not exist back to 2000, as well as how to select the location for the substitute temperature data, how to input that substitute data into the NOAA dataset, and how to treat missing temperature data (blanks) when the NOAA report is run.

Proposed R3.1 requires that a Generator Owner include in its cold weather preparedness plan the “Extreme Cold Weather Temperature for their unit(s) including the calculation date and source of temperature data.” If the Technical Requirements document titled “Calculating Extreme Cold Weather Temperature” is intended to provide the source of temperature data for all Generator Owners, then this language should be modified to state “Extreme Cold Weather Temperature for their unit(s) including the calculation date using NERC’s guide for Calculating Extreme Cold Weather Temperature.” Otherwise, the standard should be modified to clarify what sources of data are permissible, including data provided by the balancing authority (as noted in response to Question 2).

Proposed R3.5.1.2 requires Generator Owners to include within their cold weather preparedness plans “Generating unit(s) cold weather data, to include: … Fuel supply and inventory concerns.” This language should be revised to clarify that the Generator Owner is only responsible for fuel supply and inventory within its control and knowledge, as Generator Owners do not always own the source or transportation for their fuel supply and thus cannot always identify or anticipate fuel supply and inventory concerns. For example, the requirement could be modified to read: “Generating unit(s) cold weather data, to include: … Fuel supply and inventory concerns, to the extent known to the Generator Owner.”

Proposed R4 should clarify that a redesign of the unit(s) will not be required every five years. The standard requires that a Generator Owner calculate a new Extreme Cold Weather Temperature and update its cold weather preparedness plan and freeze protection measures as needed, or else, develop a Corrective Action Plan (CAP). As drafted, the standard could be interpreted as potentially requiring a redesign or retrofitting of a unit every 5 years. Vistra recommends that, in conjunction with adding a definition of “freeze protection measures” that includes procedures and temporary equipment among those measures (as recommended under Question 5), R4.3 could be modified to add the following sentence at the end: “If a CAP is required under this Requirement R4, the CAP cannot require a Generator Owner to redesign or retrofit its unit to meet the requirements in R1 or R2, as applicable, at the updated Extreme Cold Weather Temperature for the unit(s).”

Proposed R5 should clarify that the required training will be site-specific, rather than unit-specific: “Each Generator Owner in conjunction with its Generator Operator shall identify the entity responsible for providing the generating unit-site specific training, and that identified entity shall provide annual training at each site to its maintenance or operations personnel responsible for implementing the cold weather preparedness plan(s) at that site developed pursuant to Requirement R3.”

Proposed R6 should require a CAP to be developed within 150 days, rather than the earlier of 150 days or July 1. If a Generator Cold Weather Reliability Event occurs at the end of the winter season (or during a freak winter-like storm in March or April), a Generator Owner could have significantly fewer than 150 days to develop a CAP if the standard is based on the earlier of July 1 or 150 days. At the same time, even if an event occurred as late as early April, the 150 day standard would still require that the CAP be developed in advance of the next winter season (e.g., 150 days, or roughly 5 months, after April would still be in September). Thus, R6 should strike the alternative reference to July 1.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	
Document Name	

Comment	
Exelon concurs with EEI's comment to Question 9 Submitted on behalf of Exelon, Segments 1 & 3	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	
Document Name	
Comment	
Nothing additional to add at this time.	
Likes 0	
Dislikes 0	
Response	
Donna Johnson - Oglethorpe Power Corporation - 5	
Answer	
Document Name	
Comment	
For R5: In regards to the proposed verbiage requiring "generating unit-specific training", it is OPC's opinion that this could be overly repetitious for stations that have multiple units, which are considered sister units and hence would have the same generator protection measures in place. We recomenend modifying this requirement to require station-specitic training in lieu of generating unit-specific training. In cased where there are different freeze protection measures for unit(s), those measures would be defined within the training anyway since it covers freeze protection for all units at a station.	
Likes 0	
Dislikes 0	
Response	

Scott McGough - Georgia System Operations Corporation - 3	
Answer	
Document Name	
Comment	

For **R5:** In regards to the proposed verbiage requiring "generating unit-specific training", it is OPC's opinion that this could be overly repetitious for stations that have multiple units, which are considered sister units and hence would have the same generator protection measures in place. We recommend modifying this requirement to require station-specific training in lieu of generating unit-specifc training. In cases where there are different freeze protection measures for unit(s), those measures would be defined within the training anyway since it covers freeze protection for all units at a station.

Likes 0	
Dislikes 0	
Response	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	
Document Name	
Comment	

The industry already voted other requirements into standards, and now the SDT is expanding the requirements to a new standard which is unnecessary. These requirements are not an emergency operations standard as written. If such standards are needed, they constitute a facilities standard (as in Facilities Design, Connections, and Maintenance).

Likes 0	
Dislikes 0	
Response	
Stewart Rake - Luminant Mining Company LLC - 7	
Answer	
Document Name	
Comment	

Vistra has additional recommendations/requested clarifications on the proposed requirements described below:

The NERC Calculating Extreme Cold Weather Temperature guide should be modified to address circumstances where National Oceanic and Atmospheric Administration (NOAA) data dating back to January 1, 2000 does not exist for the particular location. For example, NOAA has weather data for Andrews, Texas dating back only to 2014, and there are no other representative NOAA locations in the dataset. There may be other instances of rural airports or other NOAA weather data locations that do not have data going back to 2000. The Guide should specify an alternate source(s) of acceptable weather data for calculation of the Extreme Cold Weather Temperature in instances where NOAA data does not exist back to 2000, as well as how to select the location for the substitute temperature data, how to input that substitute data into the NOAA dataset, and how to treat missing temperature data (blanks) when the NOAA report is run.

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Proposed R3.5.1.2 requires Generator Owners to include within their cold weather preparedness plans “Generating unit(s) cold weather data, to include: … Fuel supply and inventory concerns.” This language should be revised to clarify that the Generator Owner is only responsible for fuel supply and inventory within its control and knowledge, as Generator Owners do not always own the source or transportation for their fuel supply and thus cannot always identify or anticipate fuel supply and inventory concerns. For example, the requirement could be modified to read: “Generating unit(s) cold weather data, to include: … Fuel supply and inventory concerns, to the extent known to the Generator Owner.”

Proposed R4 should clarify that a redesign of the unit(s) will not be required every five years. The standard requires that a Generator Owner calculate a new Extreme Cold Weather Temperature and update its cold weather preparedness plan and freeze protection measures as needed, or else, develop a Corrective Action Plan (CAP). As drafted, the standard could be interpreted as potentially requiring a redesign or retrofitting of a unit every 5 years. Vistra recommends that, in conjunction with adding a definition of “freeze protection measures” that includes procedures and temporary equipment among those measures (as recommended under Question 5), R4.3 could be modified to add the following sentence at the end: “If a CAP is required under this Requirement R4, the CAP cannot require a Generator Owner to redesign or retrofit its unit to meet the requirements in R1 or R2, as applicable, at the updated Extreme Cold Weather Temperature for the unit(s).”

Proposed R5 should clarify that the required training will be site-specific, rather than unit-specific: “Each Generator Owner in conjunction with its Generator Operator shall identify the entity responsible for providing the generating unit-site specific training, and that identified entity shall provide annual training at each site to its maintenance or operations personnel responsible for implementing the cold weather preparedness plan(s) at that site developed pursuant to Requirement R3.”

Proposed R6 should require a CAP to be developed within 150 days, rather than the earlier of 150 days or July 1. If a Generator Cold Weather Reliability Event occurs at the end of the winter season (or during a freak winter-like storm in March or April), a Generator Owner could have significantly fewer than 150 days to develop a CAP if the standard is based on the earlier of July 1 or 150 days. At the same time, even if an event occurred as late as early April, the 150 day standard would still require that the CAP be developed in advance of the next winter season (e.g., 150 days, or roughly 5 months, after April would still be in September). Thus, R6 should strike the alternative reference to July 1.

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Proposed R3.5.1.2 requires Generator Owners to include within their cold weather preparedness plans “Generating unit(s) cold weather data, to include: … Fuel supply and inventory concerns.” This language should be revised to clarify that the Generator Owner is only responsible for fuel supply and inventory within its control and knowledge, as Generator Owners do not always own the source or transportation for their fuel supply and thus cannot always identify or anticipate fuel supply and inventory concerns. For example, the requirement could be modified to read: “Generating unit(s) cold weather data, to include: … Fuel supply and inventory concerns, to the extent known to the Generator Owner.”

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Proposed R4 should clarify that a redesign of the unit(s) will not be required every five years. The standard requires that a Generator Owner calculate a new Extreme Cold Weather Temperature and update its cold weather preparedness plan and freeze protection measures as needed, or else, develop a Corrective Action Plan (CAP). As drafted, the standard could be interpreted as potentially requiring a redesign or retrofitting of a unit every 5 years. Vistra recommends that, in conjunction with adding a definition of “freeze protection measures” that includes procedures and temporary equipment among those measures (as recommended under Question 5), R4.3 could be modified to add the following sentence at the end: “If a CAP is required under this Requirement R4, the CAP cannot require a Generator Owner to redesign or retrofit its unit to meet the requirements in R1 or R2, as applicable, at the updated Extreme Cold Weather Temperature for the unit(s).”

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Likes 0	
Dislikes 0	

Response

Ruchi Shah - AES - AES Corporation - 5

Answer	
Document Name	

Comment

AES Clean Energy agrees with the comments submitted by NAGF.

Likes 0	
Dislikes 0	

Response

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	
Document Name	

Comment

NAGF membership is concerned with the requirement to retrofit or otherwise improve an existing generator's cold weather performance capability without NERC having the ability to address the compensation issue identified in the Joint Inquiry Report under Key Recommendation 2. There is also concern that the proposed design requirements are not sufficient to protect against another event like Uri. Until industry addresses the compensation issue, it is unreasonable to adopt a design requirement for existing generating units.

While the NAGF supports efforts for generators to take reasonable steps to provide reliable service through cold weather events, a mandatory requirement without reasonable compensation puts some generators at an unfair and potentially fatal disadvantage, which is detrimental for the electric industry. It has also been noted that some generators are unable to meet the design requirements due to technological issues or availability. With the efforts made by the drafting team to address these conflicting issues, the proposed requirements are optional at best and therefore unlikely to provide improved reliability.

Given all of the challenges that we are seeing across the different regions regarding infrastructure issues , the creation of more uncertainty in the generation arena has the potential to further aggravate the situation rather than improve it. NAGF members support ensuring generator operating parameters are communicated to, understood, and used in the planning processes by the appropriate entities is more appropriate and beneficial to reliability during these events than a blanket retrofit requirement to operate to an arbitrary condition.

The NAGF believes that the existing requirements in EOP-011 that are to be implemented no later than April 1, 2023, should be used first to determine if these proposed requirements are warranted. Until such time as these requirements become effective, NERC and FERC do not know where the need for further improvements exist.

To the extent that NERC and FERC wish to add to the reliability requirements related to cold weather operation, the NAGF proposes the following language:

“Generator Owners shall identify their minimum operating temperature based on operating history. This information shall include lowest temperature operated to, lowest wind chill temperature operated to, and the lowest temperature during which precipitation was occurring, if possible. These numbers shall be reviewed once each year to determine if new limits have been determined. “

Likes 0	
Dislikes 0	

Response

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1

Answer	
Document Name	

Comment

For all above questions,we are agaisnt this standard as for some Canadian entites, units already operate in cold weather annually from November to March. These requirements represent an added administrative burden.

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

ISO-NE appreciates the efforts of the SDT however, as an ISO acting as the RC and BA for our area ISO has some concerns as described in the above comments as well as in the comments provided by the SRC. It appears that the Standard as written will ensure continued reliable operation of the BES under normal cold weather conditions, but would have limited effect on “Extreme” cold weather conditions such as those experienced during the 2014 Polar Vortex, the 2021 Storm Uri, or the 1994 North American cold wave (January 18-22). ISO-NE recommends that the Standard address at a minimum the extreme cold temperatures and duration experienced during the 2021 Storm Uri which has been the primary example as the need for this new Standard.

ISO-NE Supports the Comments Provided by the SRC.

Likes 0	
Dislikes 0	

Response

Jamison Cawley - Nebraska Public Power District - 1	
Answer	
Document Name	
Comment	

NPPD suggests removing the 'July 1' requirement for the deadline in generating a corrective action plan and making the deadline a straight 150 days from the event. If an event occurs in early March an entity might only have approx. 110 days to generate the corrective action plan. With a straight 150 days, an entity can still create the CAP before the next winter season.

We believe the timeframe for development of Corrective Action Plans (CAP) in R2 and R4.3 is unclear. The glossary definition of CAP is A list of actions and an associated timetable for implementation to remedy a specific problem. While the language is clear that CAPs are to be developed within the Requirements, it is not clear how long an entity has to develop the CAP.

Proposed language:

R2: "…shall develop a Corrective Action Plan (CAP) within 150 days for the identified issues…"

R4.3: "…and if not develop a CAP within 150 days for the identified issues…"

R6: "…shall develop a CAP, within 150 days that contains at a minimum:"

NPPD would like to propose the following language modification for Requirement R3.4:

Existing language "Annual inspection and maintenance of generating unit(s)…"

Proposed language "Annual inspection and maintenance *as determined by the results of the inspection,* of generating unit(s)…"

Likes 0	
Dislikes 0	
Response	

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	
Document Name	
Comment	

Alliant Energy supports the comments submitted by the MRO NSRF.

Likes 0	
Dislikes 0	
Response	

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	

Requirement R1

The MRO NSRF is concerned about Requirement R1, Bullet 1 as it relates to a “concurrent twenty (20) mph wind speed”. The MRO NSRF believes that 20 mph is an arbitrary velocity that will not capture the actual conditions based on the geographic location of the generating unit, unnecessarily raise the operational cost of the generating unit and not increase the reliability of the generating unit, as the fixed velocity may be too low/high for the geographical location. Rather than used a fixed velocity the MRO NSRF would like to suggest allowing the Generator Owner to calculate the appropriate wind speed using a statical methodology similar to how the Extreme Cold Weather Temperature is calculated. Entity B would like to suggest the following Requirement R1 language modification and §6. Definitions Used in this proposed standard:

R1, Bullet 1: “… assuming a Concurrent Wind Speed on any exposed Generator Cold Weather Critical Components; or”

Concurrent Wind Speed – The wind speed equal to the highest X percentile of the hourly wind speeds for the geographic location of the generating unit, measured in December, January and February for the previous 30 years through the date the temperature is calculated.

Proposed language modifications:

The MRO NSRF would like to propose the following language modification for Requirement R3.4:

Existing language “Annual inspection and maintenance of generating unit(s)…”
Proposed language “Annual inspection and maintenance, as determined by the results of the inspection, of generating unit(s)…”

The MRO NSRF would like to propose the following language modification for Requirement R4:

Existing language “Once every five calendar years, each Generator Owner shall for each generating unit:”

Proposed language “Once every five calendar years, with a calendar year starting on the first day of a new year (January 1) after an activity pursuant to the subparts below has been completed, each Generator owner shall for each generating unit:”

The MRO NSRF believes defining the calendar year, as it is in NERC Reliability Standard PRC-005-6, will provide added confines to when the five year cycle begins and does not leave interpretation for it to be a 60-month cycle.

The MRO NSRF would like to propose the following language modification for Requirement R6:

Existing language: “…experiences a Generator Cold Weather Reliability Event shall develop a CAP, within 150 days or by July 1, whichever is earlier, that contains at a minimum…”

Proposed language: “…experiences a Generator Cold Weather Reliability Event shall develop a CAP, within 150 calendar days, that contains at a minimum…”

We believe that 150 calendar days after a Generator Cold Weather Reliability Event should be the standard to develop a CAP. If the generating unit experiences a Generator Cold Weather Reliability Event on February 28, a Generator Owner will only have 120 days to develop a CAP. Since CAPs may take additional resources to analyze and develop, 150 calendar days provides the same amount of time for Generator Owners to develop a CAP regardless of when during the winter season a Generator Cold Weather Reliably Event occurs. In addition, to align with the language in NERC Reliability Standard PRC-004-6, Entity B is recommending the inclusion of the word “calendar”. Also please consdier adding timeframe requirements for the development of Corrective Action Plans (CAP) in R2 and R4.3. The glossary definition of CAP is “A list of actions and an associated timetable for implementation to remedy a specific problem". While the language is clear that CAPs are to be developed within the Requirements, it is not clear how long an entity has to develop the CAP. Proposed language:

R2: "…shall develop a Corrective Action Plan (CAP) within 150 days for the identified issues…"

R4.3: "…and if not develop a CAP within 150 days for the identified issues…"

Likes 0	
Dislikes 0	

Response

Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3

Answer	
Document Name	

Comment

MidAmerican Energy supports both the MRO NSRF and EEI comments for this section.

Likes 0	
Dislikes 0	

Response

Michele Richmond - Texas Competitive Power Advocates - NA - Not Applicable - Texas RE

Answer	
Document Name	TCPA Comments on Revised NERC Weatherization Proposal - Filed 9-1-22.docx

Comment

Please see attached comments

Likes 0	
Dislikes 0	

Response

Steven Sconce - EDF Renewable Energy - 5

Answer	
Document Name	

Comment

Note – From a design/development perspective, inverter-based generation resources are mostly operating to -25C for utility scale application. Any temperature below this would force the inverters to stop producing.

Likes 0	
Dislikes 0	

Response

Mark Young - Tenaska, Inc. - 5

Answer	
Document Name	EOP-012-1 Second Draft - Tenaska Comments Rev 4 final.docx

Comment

See attached comments document

Likes 0	
Dislikes 0	

Response

Bobbi Welch - Midcontinent ISO, Inc. - 2

Answer	
Document Name	

Comment

MISO supports the comments submitted by the ISO/RTO Council Standards Review Committee (IRC SRC). In addition, we are submitting comments on behalf of MISO as an individual entity.

Guidance should be provided as to what is "economically feasible" so a consistent approach is used to assess "commercial constraints." (Part 7.1)

With respect to Part 7.1, which states:

"Each Generator Owner shall implement each CAP developed pursuant to Requirements R2, R4, or R6, or explain in a declaration why corrective actions are not being implemented due to any technical, *commercial*, or operational constraints as defined by the Generator Owner"

MISO observes that "commercial" aspects are typically outside of NERC's purview which raises the question: how will this provision be monitored and enforced without pre-defined criteria? Therefore, MISO asks the SDT to set guidance as to what is "economically feasible." Without meaningful guidance, providing a broad commercial "out" could encourage generators to elect this option as opposed to making improvements, particularly if a neighboring generator does likewise, thereby leaving the BES no more reliable than before the standard was drafted.

Finally, MISO acknowledges it is important to get this standard "right," particularly in light of the changing resource mix. As traditional resources retire and are replaced with intermittent resources, it will be important to have design criteria, such as the Extreme Cold Weather Temperature definition, set appropriately to ensure reliability benefits are achieved and maintained over time.

Likes 0	
Dislikes 0	

Response

Imane Mrini - Austin Energy - 6

Answer	
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Shannon Ferdinand - Decatur Energy Center LLC - 5

Answer	
Document Name	

Comment

Capital Power supports the North American Generators Forum (NAGF) response to this question.

Likes 0	
Dislikes 0	

Response

Ronald Bauer - MGE Energy - Madison Gas and Electric Co. - 3

Answer	
Document Name	

Comment

Madison Gas and Electric supports the comments from the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Adam Lee - MGE Energy - Madison Gas and Electric Co. - 4	
Answer	
Document Name	
Comment	
Madison Gas and Electric supports the comments of the MRO NSRF	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations	
Answer	
Document Name	
Comment	

We have 2 additional comments for this standard not covered in the previous comment sections. These comments are specific to R5 and R6 respectively.

R5: In regards to the proposed verbiage requiring "generating unit-specific training", it is our opinion that this could be overly burdensome for stations with multiple units; particular for those stations with multiple units of a similar design (a.k.a. "sister" units). Recommend modifying this requirement to require station-specific training in lieu of generating unit-specific training.

It is our opinion that this modification will allow the GO/GOP the flexibility to develop their training modules with an appropriate level of detail so as to sufficiently train station personnel without requiring them to create multiple modules with similar or identical content.

R6: Concerning the proposed timeline for the development of a CAP, it is our recommendation that the July 1st date be removed from this requirement. The rationale for this recommendations is thus: 150 days prior to July 1st is Feb 1st for non-leap years and Feb 2nd for leap years. Moreover, the July 1st timeline is further condensed if a Generator Cold Weather Reliability Event (GCWRE) occurs in March or April. Lastly, the stated intent of the timeframe options within the Technical Rationale is to allow GO's to review multiple events holistically following a winter season. In certain areas of the country, a GCWRE could realistically occur as early as late-October. In this instance, the latest possible date for the development of a CAP would be March 30th.

Given that it is also realistic for a GCWRE to occur in March, 150 days seems a reasonable number of days to cover all but the most extreme scenarios. Therefore, we recommend removing the hard deadline of July 1st.

Further, ACES has one member with the the following comments we would like to capture:

- It should be noted that wind turbines are also highly susceptible to cold weather events. Ignoring wind units at a time when the grid is using them more and more may have long lasting consequences.
- Finally, extreme weather should include calm cloudy days. The standard is targeted to units that are being retired more and more from the grid. Piling on additional compliance burdens will only hasten these units departures. The SDT should consider targeted reliability standards that require intermittent resources to run, ride through, and in general operate more reliably. Intermittent resources no longer operate on the periphery, they are a core component of the functional power grid.

Thank you for the opportunity to comment.

Likes 0	
Dislikes 0	

Response

Colin Chilcoat - Invenergy LLC - 6

Answer	
Document Name	

Comment

Invenergy appreciates the SDT's time and work on this important project, and would like to offer the below additional comments.

Invenergy recommends the following change to R2 to better align it with R1:

For each generating unit(s) in commercial operation prior to [Effective Date of this requirement], the Generator Owner shall:

- *Add new or modify existing freeze protection measures as needed to provide the capability to operate for a period of not less than one (1) hour at the unit(s) Extreme Cold Weather Temperature.*

Generating unit(s) that are not capable of operating for one (1) hour at its Extreme Cold Weather Temperature shall:

- *Develop a Corrective Action Plan (CAP) for the identified issue(s), including identification of any needed modifications to the cold weather preparedness plan required under Requirement R3;* ***or***
- *Explain in a declaration, any technical, commercial, or operational constraints as defined by the Generator Owner that preclude any ability to implement or modify appropriate freeze protection measures to provide capability of operating for one (1) hour at the documented Extreme Cold Weather Temperature.*

Corresponding changes to other sections of the standard that flow from this section should be made as well. In particular, the Violation Severity Level table for R2 should be edited to match those for R1.

Additionally, the SDT should consider adding language relieving Generator Owners of the need to develop CAPs for Generator Cold Weather Critical Components for which a technical, commercial, or operational constraint has already been declared.

Lastly, the SDT should clarify how a Generator Owner is expected to incorporate the wind speed criterion in R1 ("...assuming a concurrent twenty (20) mph wind speed on any exposed Generator Cold Weather Critical Components;") into their design. Specifically, is it purely a design consideration, or is it meant to be factored into the calculation of the Extreme Cold Weather Temperature?

Likes 0	

Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	
Comment	
If "commercial" limitations can be defined by the GO, the auditor will have to respect and accept any commercial limitation which would allow the GO to exclude any unit.	
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 Regional Standards Committee	
Answer	
Document Name	
Comment	
Evidence Retention should contain the words "since the last audit". The draft primarily has "…data or evidence to show compliance for three years". This standard is geared towards GO's. GO's at NPCC are normally on a six-year audit cycle.	
Likes 0	
Dislikes 0	
Response	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	

Response

George Brown - Acciona Energy North America - 5	
Answer	
Document Name	
Comment	
Acciona Energy supports Midwest Reliability Organization's (MRO) NERC Standards Review Forum's (NSRF) comments on this question.	
Likes 0	
Dislikes 0	
Response	

Whitney Wallace - Calpine Corporation - 5 - WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
Calpine notes that most Independent System Operators (ISOs) are currently undertaking regulatory or stakeholder processes to examine improving reliability related to extreme weather events. These processes include a review of current and potential future planning standards, determining appropriate capacity accreditation for different resources, including fuel security considerations, as well as potentially differentiated levels of capacity compensation for resources providing different levels of reliability. As a result, any further cold weather standards should be developed by the ISOs as part of these regional processes. Additionally, because compliance with the proposed Standard could result in a significant cost burden for GOs, the proposed Standard should be revised to clearly state that GOs must have a mechanism to recover costs incurred to comply with this Standard. The Standard contemplates that a GO may not be able to comply with the Standard due to "technical, commercial or operational constraints" but does not specifically provide that lack of cost recovery is a commercial constraint that provides an exception to implementation of a CAP. The proposed Standard should be revised to make this clear.	
Likes 0	
Dislikes 0	
Response	

Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	
Document Name	
Comment	

Request the following language change for requirement R3.5.2 Generating Unit(s) minimum: Design temperature; ***OR***. Note the addition of the word "or".

Likes 0	
Dislikes 0	

Response

John Liang - Snohomish County PUD No. 1 - 6	
Answer	
Document Name	

Comment
Request the following language change for requirement R3.5.2 Generating unit(s) minimum: Design temperature; ***OR***. Note the addition of the word "OR".

Likes 0	
Dislikes 0	

Response

Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)	
Answer	
Document Name	

Comment

The SRC appreciates the efforts of the SDT and realizes it has the unenviable task of balancing the competing interests of many stakeholder groups. Nonetheless, as ISO and RTOs, we, as Balancing Authorities and Reliability Coordinators, have a great stake in ensuring BES reliability. As independent operators and planners, we neither own, operate nor maintain generation assets; we must rely on the GOs' and GOPs' cooperation and response to meet interconnected reliability requirements with limited authority. Consequently, the SRC has an obligation to bring to the SDT's attention the comments mentioned above and the following additional comments.

A. **Align Requirement 1 and Part 7.1 with FERC-NERC joint report Key Recommendation 1f to require operation at the Extreme Cold Weather Temperature (ECWT).**

To recap, the second bullet in Requirement 1 states a GO must:

Explain in a declaration, any technical, commercial, or operational constraints as defined by the Generator Owner that preclude the ability to *implement appropriate freeze protection measures* to provide capability of operating for twelve (12) hours at the documented Extreme Cold Weather Temperature. (see Recommendation #2)

Additionally, Requirement 7, Part 7.1, requires a GO to implement each CAP, "or explain in a declaration why corrective actions are not being implemented due to any technical, commercial, or operational constraints as defined by the Generator Owner."

The SRC identified several issues with the proposed language regarding declarations:

(1) Key Recommendation 1f from the Joint Report states the NERC Reliability Standards should be revised to, “require GOs to retrofit existing generating units, and when building new generating units, to design them, *to operate to a specified ambient temperature and weather conditions* (*e.g*., wind, freezing precipitation).”

That language is quite prescriptive and does not provide for a technical, commercial or operational “out” (as currently contained in the draft Standard). The concern with providing a broad commercial "out" is it could encourage generators to elect this option as opposed to making improvements, particularly if a neighboring competitor chooses to do likewise, thereby leaving the BES no more resilient than before the Standard was drafted.

(2) The Standard does not identify to whom the GO provides the declaration. The SRC recommends the GO provide declarations to the RC and BA.

(3) Using the phrase "as defined by the Generator Owner" gives the GO absolute discretion to determine what constraints are valid. The SRC believes the standard should require documentation demonstrating the GO cannot comply with the Standard (such as an engineering analysis) to make it “auditable” by a Regional Entity.

B. **Align wind speed requirements for new (R1) and existing (R2) generating units.** Requirement 2 requires an existing unit to demonstrate it can, "...operate for a period of not less than one (1) hour at the unit(s) Extreme Cold Weather Temperature."

Requirement 1 indicates new units must operate at the ECWT, “assuming a concurrent twenty (20) mph wind speed.” The SRC believes Requirement 2 should also include a twenty (20) mph wind speed on any exposed Generator Cold Weather Critical Components.

C. **Revise Part 7.1 to align with FERC-NERC joint report Key Recommendation 1d by requiring implementation of a CAP for identified equipment.** Collectively, Requirements 2, 6 and 7 require development and implementation of a CAP.

Key Recommendation 1d. in the Joint Report states the GO should implement a CAP for the identified equipment, ***and*** evaluate whether a CAP applies *to similar equipment for its other units* and: (i) either revise its cold weather preparedness plan or (ii) explain in a declaration why no revisions to the cold weather preparedness plan are appropriate.

The intent of this language is not to allow the GO to use a declaration to avoid implementing a CAP for *the equipment that **actually experienced** the forced outage, derate or failure to start.* Rather, the intent of the “declaration option” is to provide some leeway and flexibility to the GO when determining whether the CAP should also apply to *similar equipment for other generating units* the GO owns). Therefore, the SRC does not support the current language that would allow generating units that **actually experienced** an outage, derate or failure to start to avoid implementing a CAP by providing a declaration regarding the unit that experienced the GCWRE.

Additionally, Key Recommendation 1d. from the Joint Report states a new Standard should, “specify the specific timing for the CAP to be developed and implemented…but the CAP should be developed as quickly as possible, and *be completed by no later than the beginning of the next winter season*.” As written, the Standard does not contain a requirement to develop a CAP “as quickly as possible” and ensure the CAP is completed “no later than the beginning of the next winter season.” The SRC recommends adding language to address timing in the standard.

Finally, the Standard contains no criteria regarding the quality of a CAP (*e.g*., review/approval by another entity). The SRC believes the Standard should require an unaffiliated, qualified third-party to review and approve a proposed CAP similar to the requirement in CIP-014.

D. **Require unaffiliated third-parties to review and approve proposed measures (akin to CIP-014).** Requirement 3.3 provides cold weather preparedness plans must include (among other things):

Documentation of freeze protection measures implemented on Generator Cold Weather Critical Components which may include measures used to reduce the cooling effects of wind determined necessary by the Generator Owner to protect against heat loss, and where applicable, the effects of freezing precipitation (e.g., sleet, snow, ice, and freezing rain) Instead of saying "which *may* include measures," the requirement should read, "which *shall* include measures…." Further, referring to the measures as "determined necessary by the GO" gives the GO absolute discretion to determine what measures to apply. The SRC proposes replacing "determined necessary" with "where applicable" as in the latter half of the requirement if the intent is to provide flexibility for generators with fully enclosed facilities (*e.g.*, those in the north that may not have to reduce the cooling effects of wind). In addition, the SRC believes some other entity should have the authority to review/approve appropriate measures. One possibility is to employ language like that used in CIP-014 in which an unaffiliated third-party verifies the work product. E. **Additional Comments.** The SRC makes the following comments it considers less critical than those mentioned above yet still worthy of consideration. (1) The definition of GCWRE (in sub-section (2)) includes, "a start-up failure where the unit fails to synchronize *within a specified start-up time*." The definition does not make clear how to determine the appropriate start-up time. The SRC proposes replacing "***a*** specified start-up time" with "its specified longest start-up time: (i) pursuant to its design specifications, (ii) communicated to its BA or (iii) pursuant to its agreement to serve load." (2) The definition of GCWRE applies to events, "for which the apparent cause(s) is due to freezing of equipment within the Generator Owner's control and…." That wording indicates the event must be "apparently" due to freezing (with no way to determine whether freezing "apparently" caused the event). Thus, the SRC proposes replacing that phrase with "due to failure of equipment within the Generator Owner's control when..." (3) As written, the Generator Cold Weather Critical Component includes the phrase "which would likely lead to a Generator Cold Weather Reliability Event." That phrase includes subjective language ("would likely lead to") open to differing interpretations by different people. The SRC recommends revising the definition to read: "Any generating unit component or associated fixed fuel supply component, under the Generator Owner's control, susceptible to extreme cold weather that could cause a Generator Cold Weather Reliability Event." (4) The first bullet in Requirement 1 includes, "assuming a concurrent twenty (20) mph wind speed on any exposed Generator Cold Weather Critical Components." The SRC believes GOs should have to take into account the wind effect on the *entire facility* (not just Cold Weather Critical Components). Thus, the SRC believes that phrase should read simply, "assuming a concurrent twenty (20) mph wind." The SRC wishes to express our sincere gratitude to the Project's Standard Drafting Team Members and supporting roles. We understand the many work hours needed in developing multiple documents, as well as responding to comments. Please know we appreciate your hard work and dedication to this Project.	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	
AEPC has signed on to ACES comments, please see their responses.	

Thank you for the opportunity to comment.

Likes 0	
Dislikes 0	

Response

Mike Magruder - Avista - Avista Corporation - 1

Answer	
Document Name	

Comment

Avista recommends some reconsideration as to the applicability of the EOP 12-2 as it relates to ALL BES generating facilities. Both the letter and intent of the draft standard appear to be related specifically to thermal or steam process plants that use a Rankin cycle to generate electricity, and their susceptibility for freezing during cold weather. Can the permit team under Part 2 reconsider the applicability of facilities to consider to just those facilities related to the Rankin cycle that use steam as a means of generating electricity. Many facilities such as hydroelectric facilities internal combustion generation, wind turbine generators, and are much less susceptible to extreme cold weather and should not be treated the same regarding compliance requirements of such a standard.

Likes 0	
Dislikes 0	

Response

Rhonda Jones - Invenergy LLC - 5

Answer	
Document Name	

Comment

Invenergy appreciates the SDTs time and work on this important project, and would like to offer the below additional comments.

Invenergy recommends the following change to R2 to better align it with R1:

For each generating unit(s) in commercial operation prior to [Effective Date of this requirement], the Generator Owner shall:

- Add new or modify existing freeze protection measures as needed to provide the capability to operate for a period of not less than one (1) hour at the unit(s) Extreme Cold Weather Temperature.

Generating unit(s) that are not capable of operating for one (1) hour at its Extreme Cold Weather Temperature shall:

- Develop a Corrective Action Plan (CAP) for the identified issue(s), including identification of any needed modifications to the cold weather preparedness plan required under Requirement R3; **or**

- Explain in a declaration, any technical, commercial, or operational constraints as defined by the Generator Owner that preclude any ability to implement or modify appropriate freeze protection measures to provide capability of operating for one (1) hour at the documented Extreme Cold Weather Temperature.

Corresponding changes to other sections of the standard that flow from this section should be made as well. In particular, the Violation Severity Level table for R2 should be edited to match those for R1.

Additionally, the SDT should consider adding language relieving Generator Owners of the need to develop CAPs for Generator Cold Weather Critical Components for which a technical, commercial, or operational constraint has already been declared.

Lastly, the SDT should clarify how a Generator Owner is expected to incorporate the wind speed criterion in R1 ("...assuming a concurrent twenty (20) mph wind speed on any exposed Generator Cold Weather Critical Components;") into their design. Specifically, is it purely a design consideration, or is it meant to be factored into the calculation of the Extreme Cold Weather Temperature?

Likes 0	
Dislikes 0	

Response

LaKenya VanNorman - LaKenya VanNorman On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name Florida Municipal Power Agency (FMPA)

Answer	
Document Name	

Comment

FMPA also supports the comments of the Transmission Access Policy Study Group (TAPS), which are as follows:

We understand R1 and R2 as requiring GOs to implement freeze control measures that they reasonably believe, based on good engineering judgment and their experience with their particular units and weather patterns, will result in the unit being able to operate continuously for the applicable time at the Extreme Cold Weather Temperature. Our understanding of the proposed requirements is that if a new or existing unit experiences a Forced Outage as a result of a Generator Cold Weather Reliability Event, even if the Forced Outage occurs after less than twelve hours (for a new generator) or one hour (for an existing generator) of continuous operations, the Forced Outage will not constitute evidence of noncompliance with R1 or R2. Instead, the GO will develop and implement a CAP pursuant to R6 and R7, as it would in response to any Generator Cold Weather Reliability Event. The contrary interpretation—that R1 and R2 require freeze protection measures that are 100% guaranteed to work—would require a level of certainty that simply does not exist. Generators are complex machines; they sometimes fail in unforeseen ways. This problem is only compounded by the fact that, as noted by multiple panelists at the April 27-28, 2022 FERC, NERC, and Regional Entities Technical Conference on Improving Winter-Readiness of Generating Units, a cold weather event cannot be simulated ahead of time to allow functional testing of a unit's set of winterization measures. Finding a GO noncompliant with R1 or R2 based on the failure in a particular instance of winterization measures it reasonably believed, based on the information available to it prior to the cold weather event, would be adequate, would not enhance reliability.

We read R2 as providing that, where an existing unit is *not* capable of operating continuously for one hour at the Extreme Cold Weather Temperature, the method by which the GO "ensure[s] its generating unit(s) add new or modify existing freeze protection measures as needed" is the development of a CAP pursuant to R2. In other words, a GO demonstrates compliance with R2 by demonstrating either that it has implemented appropriate freeze protection measures, or that it has developed a CAP.

The SDT has indicated that it plans to revisit the language of EOP-012-1 as part of Phase 2 of this project. Although we believe that our readings of the requirements, as outlined above, are consistent with the SDT's intent, we strongly recommend that Phase 2 clarify the language of R1 and R2 on these issues. Expressing the SDT's intent more clearly would reduce the risk of confusion and conflicting interpretations.

Likes 0	
Dislikes 0	

Response

Natalie Johnson - Enel Green Power - 5	
Answer	
Document Name	2021-07_Unofficial_Comment_Form_second ballot_082022 (Enel 9-1-2022).docx

Comment
Enel would like clarifications included that criteria applies only to available capacity as indicated by the forecasted power curve. Intermittent resources may not be available due to low wind or irradiance. Another example would be a planned outage for maintenance. It should be clarified that criteria applies to available capacity and not nameplate for intermittent resources. Enel suggests this clarification could be added with an accompanying footnote in the appropriate places. Enel also suggests that R2 adds the following clarifying language: Generating unit(s) that are not capable of operating for one (1) hour at its Extreme Cold Weather Temperature shall develop a Corrective Action Plan (CAP), ***according to R7,*** for the identified issues, including identification of any needed modifications to the cold weather preparedness plan required under Requirement R3. Additionally, Enel suggests that the language for CAPS only refer to 150 days for a deadline without the July 1 reference for clarity and fairness so everyone gets the same deadline. Enel agrees with MRO NSRF's concern regarding the concurrent twenty (20) mph wind speed.

Likes 0	
Dislikes 0	

Response

Consideration of Comments

Project Name:	2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Draft 2
Comment Period Start Date:	8/3/2022
Comment Period End Date:	9/1/2022
Associated Ballots:	2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination EOP-012-1 | Non-binding Poll AB 2 NB 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination EOP-012-1 AB 2 ST 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination Implementation Plan AB 2 OT

There were 100 sets of responses, including comments from approximately 237 different people from approximately 158 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, 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 the Vice President of Engineering and Standards, Howard Gugel (via email) or at (404) 446-9693.

Questions

1. The SDT is proposing three new definitions from the initial posting of EOP-012. Does adding definitions of Extreme Cold Weather Temperature, Generator Cold Weather Critical Component, and Generator Cold Weather Reliability Event provide additional clarity to the requirements of EOP-012? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

2. Do you agree with the proposed definitions of Extreme Cold Weather Temperature, Generator Cold Weather Critical Component, and Generator Cold Weather Reliability Event? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

3. Is the revised Applicability Section language clear? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

4. Do you support the SDT proposed 12-hour timeframe to require new Generation units to be capable of performing at or below the Extreme Cold Weather Temperature? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

5. Do you support the SDT proposed 1-hour timeframe to allow existing Generation units to demonstrate their performance at or below the Extreme Cold Weather Temperature? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

6. Do you support the addition of a 20 megawatt minimum (corresponding to the definition of a BES impacting generating unit) for requiring CAPS for derates? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

7. The SDT believes that with the proposed modifications to EOP-012-1, the initial proposed implementation plan is appropriate with one change. The 18-month implementation time frame is for all revised and new requirements in EOP-012-1, except Requirements R1 and R2 which have a 60-month implementation time frame, and R4 which has a 78-month implementation time frame. Do you agree with this implementation time frame? If you think an alternate timeframe is needed, please propose an alternate implementation plan and time period, and provide a detailed explanation of actions planned to meet the implementation deadline.

8. The SDT proposes that the modifications in the proposed EOP-012-1 meet the key recommendations in The Report 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.

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
DTE Energy - Detroit Edison Company	Adrian Raducea	5		DTE Energy - DTE Electric	Karie Barczak	DTE Energy - Detroit Edison Company	3	RF
					Adrian Raducea	DTE Energy - Detroit Edison	5	RF
					patricia ireland	DTE Energy	4	RF
Portland General Electric Co.	Brooke Jockin	1		Portland General Electric Co.	Brooke Jockin	Portland General Electric	1	WECC
					Dan Mason	Portland General Electric	6	WECC
					Ryan Olson	Portland General Electric	5	WECC
					Adam Menendez	Portland General Electric Co.	3	WECC
WEC Energy Group, Inc.	Christine Kane	3		WEC Energy Group	Christine Kane	WEC Energy Group	3	RF
					Matthew Beilfuss	WEC Energy Group, Inc.	4	RF

					Clarice Zellmer	WEC Energy Group, Inc.	5	RF
					David Boeshaar	WEC Energy Group, Inc.	6	RF
PPL - Louisville Gas and Electric Co.	Devin Shines	3,5,6	RF,SERC	Louisville Gas and Electric Company and Kentucky Utilities Company	Charles Freibert	PPL - Louisville Gas and Electric Co.	3	SERC
					JULIE HOSTRANDER	PPL - Louisville Gas and Electric Co.	5	SERC
					Linn Oelker	PPL - Louisville Gas and Electric Co.	6	SERC
OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove	3		OGE Energy	Donald Hargrove	OGE Energy - Oklahoma Gas and Electric Co.	3	MRO
					Terri Pyle	OGE Energy - Oklahoma Gas and Electric Co.	1	MRO
					Patrick Wells	OGE Energy - Oklahoma Gas and Electric Co.	5	MRO
					Ashley Stringer	OGE Energy - Oklahoma Gas	6	MRO

							and Electric Co.		
Elizabeth Davis	Elizabeth Davis			RF,SERC	ISO/RTO Council (IRC) Standards Review Committee (SRC)	Mike Del Viscio	PJM	2	RF
						Becky Davis	PJM	2	RF
						Gregory Campoli	New York Independent System Operator	2	NPCC
						Charles Yeung	Southwest Power Pool, Inc. (RTO)	2	MRO
						Helen Lainis	IESO	2	NPCC
						Bobbi Welch	Midcontinent ISO, Inc.	2	RF
						Kathleen Goodman	ISO-NE	2	NPCC
						Nathan Bigbee	ERCOT	2	Texas RE
						Ali Miremadi	California ISO	2	WECC
Lincoln Electric System	Eric Ruskamp	6			LES	Eric Ruskamp	Lincoln Electric System	6	MRO
						Dan Pudenz	Lincoln Electric System	1	MRO

					Jason Fortik	Lincoln Electric System	3	MRO
					Kayleigh Wilkerson	Lincoln Electric System	5	MRO
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
					Marc Donaldson	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
ACES Power Marketing	Jodirah Green	6	MRO,NA - Not Applicable,RF,SERC,Texas RE,WECC	ACES Standard Collaborations	Bob Solomon	Hoosier Energy Rural Electric	1	SERC

						Cooperative, Inc.		
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					Scott Berry	Wabash Valley Power Association	3	RF
					Nick Fogleman	Prairie Power, Inc.	1	SERC
					Ryan Strom	Buckeye Power, Inc.	5	RF
					Ellen Watkins	Sunflower Electric Power Corporation	1	MRO
					Patti Metro	National Rural Electric Cooperative Association	3	NA - Not Applicable
					Patti Metro	National Rural Electric Cooperative Association	3	NA - Not Applicable

Entergy	Julie Hall	6		Entergy	Oliver Burke	Entergy - Entergy Services, Inc.	1	SERC
					Jamie Prater	Entergy	5	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
					LaTroy Brumfield	American Transmission Company, LLC	1	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
					David Heins	Omaha Public Power District	1,3,5,6	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
Duke Energy	Kim Thomas	1,3,5,6	FRCC,RF,SERC,Texas RE	Duke Energy	Laura Lee	Duke Energy	1	SERC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF

LaKenya VanNorman	LaKenya VanNorman		SERC	Florida Municipal Power Agency (FMPA)	Chris Gowder	Florida Municipal Power Agency	5	SERC
					Dan O'Hagan	Florida Municipal Power Agency	4	SERC
					Carl Turner	Florida Municipal Power Agency	3	SERC
					Jade Bulitta	Florida Municipal Power Agency	6	SERC
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
					Tricia Bynum	FirstEnergy - FirstEnergy Corporation	6	RF
					Mark Garza	FirstEnergy- FirstEnergy	4	RF

Public Utility District No. 1 of Chelan County	Meaghan Connell	5		PUD No. 1 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
					Glen Pruitt	Public Utility District No. 1 of Chelan County	6	WECC
					Meaghan Connell	Public Utility District No. 1 Chelan County	5	WECC
Michael Johnson	Michael Johnson		WECC	PG&E All Segments	Marco Rios	Pacific Gas and Electric Company	1	WECC
					Sandra Ellis	Pacific Gas and Electric Company	3	WECC
					James Mearns	Pacific Gas and Electric Company	5	WECC
Southern Company - Southern	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern	1	SERC

Company Services, Inc.						Company Services, Inc.		
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
					Jim Howell	Southern Company - Southern Company Services, Inc. - Gen	5	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC Regional Standards Committee	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Glen Smith	Entergy Services	4	NPCC

					Alan Adamson	New York State Reliability Council	7	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Harish Vijay Kumar	IESO	2	NPCC
					David Kiguel	Independent	7	NPCC
					Nick Kowalczyk	Orange and Rockland	1	NPCC
					Joel Charlebois	AESI - Acumen Engineered Solutions International Inc.	5	NPCC
					Mike Cooke	Ontario Power Generation, Inc.	4	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Shivaz Chopra	New York Power Authority	5	NPCC

					Deidre Altobell	Con Ed - Consolidated Edison	4	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Cristhian Godoy	Con Ed - Consolidated Edison Co. of New York	6	NPCC
					Nurul Abser	NB Power Corporation	1	NPCC
					Randy MacDonald	NB Power Corporation	2	NPCC
					Michael Ridolfino	Central Hudson Gas and Electric	1	NPCC
					Vijay Puran	NYSPS	6	NPCC
					ALAN ADAMSON	New York State Reliability Council	10	NPCC

					Sean Cavote	PSEG - Public Service Electric and Gas Co.	1	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					John Pearson	ISONE	2	NPCC
					Nicolas Turcotte	Hydro-Qu?bec TransEnergie	1	NPCC
					Chantal Mazza	Hydro-Quebec	2	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	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
Western Electricity Coordinating Council	Steven Rueckert	10		WECC Entity Monitoring	Steve Rueckert	WECC	10	WECC
					Phil O'Donnell	WECC	10	WECC
Tim Kelley	Tim Kelley		WECC	SMUD / 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
					Stephen Pogue	M and A Electric Power Cooperative	3	SERC
					William Price	M and A Electric Power Cooperative	1	SERC
					Peter Dawson	Sho-Me Power Electric Cooperative	1	SERC
					Mark Ramsey	N.W. Electric Power Cooperative, Inc.	1	NPCC
					John Stickley	NW Electric Power	3	SERC

						Cooperative, Inc.		
					Tony Gott	KAMO Electric Cooperative	3	SERC
					Micah Breedlove	KAMO Electric Cooperative	1	SERC
					Kevin White	Northeast Missouri Electric Power Cooperative	1	SERC
					Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	3	SERC
					Ryan Ziegler	Associated Electric Cooperative, Inc.	1	SERC
					Brian Ackermann	Associated Electric Cooperative, Inc.	6	SERC
					Brad Haralson	Associated Electric Cooperative, Inc.	5	SERC

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

1. The SDT is proposing three new definitions from the initial posting of EOP-012. Does adding definitions of Extreme Cold Weather Temperature, Generator Cold Weather Critical Component, and Generator Cold Weather Reliability Event provide additional clarity to the requirements of EOP-012? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	No
Document Name	
Comment	
These definitions continue to add an administrative burden on those entities who operate, and are designed to operate in cold climates. Specifically, many hydro projects in northern climates that operate in sub-zero weather have dealt with extreme temperature operations successfully. How much more planning and preparation must be made when we already operate to -28 F during the winter? We may see seasons with more river ice, but that is not unusual. Months of preplanning will not prevent river icing, or the work that must be done to mitigate the effects.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT had numerous discussions regarding this point during the Standard Development process and due to the comments received by industry in the initial and second ballot being split on this matter, the SDT elects to not make the proposed change at this time.	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	

The proposed definitions are insufficient; another is needed for temperature. The issue at hand cannot be addressed using only readings from thermometers (dry bulb temperature, DBT). Generic references to, “the temperature,” as in the Extreme Cold Weather Temperature definition, therefore degrade clarity due to lack of specificity.

The parameter of interest for conventional generation plants is the wind chill temperature (WCT), combining the effects of DBT and wind speed in causing heat transfer. Winter Storm Uri, the Polar Vortex of 2014, and the 2011 Southwest Cold Weather Event all achieved an “extreme” classification by virtue of involving high winds, and any standard on the subject must explicitly address this point. RCs, BAs and TOPs cannot adequately plan for winter storm-related threats to the BES if using DBT-based generation plant capability data for an inherently WCT-based phenomenon.

Some manufacturers of wind turbines offer winterization packages based on DBT, however, so it may be necessary for EOP-012-1 to say that WCT or DBT is to be used as applicable for the generation technology at hand. An alternative, universal approach is to say that “temperature” in the present context means DBT plus a 20 mph wind, this being a typical sustained wind condition for the worst hours of the aforementioned grid emergencies.

The Guidance section of EOP-012-1 should then explain that the WCT scale is to be used for transposing capability data. A conventional plant that is protected to -10 F DBT with a 5 mph wind (-22 F WCT), for example, is to state its EOP-012-1 capability as being 0 F DBT (-22 F WCT when combined with a 20 mph wind).

A definition is also needed for freezing, and it should clarify how precipitation fits into the picture. We propose, “The transition of water to ice, or congealing of fluids to the point of affecting operations (e.g. for lube oil, fuel oil and water treatment chemicals). The effects of precipitation stand separate from freezing.” The Guidance section of the standard should add, “A unit having a freeze prevention capability of -15 F DBT with a 20 mph wind, for example, might be forced offline by a snow or ice storm at 30 F.”

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT had numerous discussions regarding this point during the Standard Development process and due to the comments received by industry in the initial and second ballot being split on this matter, the SDT elects to not make the proposed change at this time. The SDT also notes that the Standard Processes Manual, section 5.1, states that “If a term is used in a Reliability Standard

according to its common meaning (as found in a collegiate dictionary), the term shall not be proposed for addition to the Glossary of Terms", therefore, the SDT does not agree with developing definitions for temperature and freezing.	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	No
Document Name	
Comment	
Talen Marketing LLC supports Talen Generation's comments.	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation disagrees that the proposed Glossary Terms provide clarity for the proposed requirements of EOP-012. The most significant issues are what is meant by "susceptible to freezing issues" and "fuel supply component." The phrase "susceptible to freezing" is not relevant for solar and wind. While this equipment may have frozen precipitation on them, the component itself is not frozen. The phrase "fuel supply component" is not relevant for hydro, solar, and wind. Exempting components located inside temperature controlled buildings that are not susceptible to freezing would allow entities to focus on components that actually pose a risk to the BES. This seems to be the intent of the SDT, but needs to be clearly written in the standard.	

A reliability standard should be applicable to specific reliability functions (e.g., Generator Owner, Generator Operator), specific geographic locations (e.g., south of 35 degrees latitude), and/or specific equipment (e.g., gas, solar, wind). Reclamation observes that undue effort is being spent on precisely identifying the specific cold weather conditions under which the standard applies. Reclamation asserts this effort will result in a disservice to the intent of ensuring electric reliability during cold weather because the narrow applicability will allow critical electrical infrastructure to be exempt from the proposed requirements. Reclamation observes that many of the issues the SDT appears to be trying to address and that entities have commented about would be better addressed in a forum outside of electric reliability standards, e.g., marketing issues. It appears that the electric industry is being inappropriately tasked with solving a problem the root cause of which may not be within its purview.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT may consider your comments during phase two of the Extreme Cold Weather Standard Development project.	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	No
Document Name	
Comment	
The definitions do not meet their objective as described in question 2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT had numerous discussions regarding this point during the Standard Development process and due to the comments received by industry in the initial and second ballot being split on this matter, the SDT elects to not make the proposed change at this time.	

Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	No
Document Name	
Comment	
Capital Power supports the North American Generators Forum (NAGF) response to this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to NAGF.	
Whitney Wallace - Calpine Corporation - 5 - WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
Outages on GO controlled transmission lines caused by ice storms should not be included in a Generator Cold Weather Reliability Event (GCWRE). Also, GOs should be exempted from including forced outages as GCWREs if the forced outage was caused by a loss of offsite power caused by a BES grid event (e.g., load shed, low frequency, sub-synchronous resonance, etc.) or other transmission events unrelated to the GO Operation. In addition, GO operators should be exempted from including forced outages due to loss of fuel supply for any reason outside of the GO's control. For these events, the exemption should apply to not only the time of the event, but also to any recovery time required to implement corrective actions needed as a direct result of the causal event.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. Please note that the definition of Generator Cold Weather critical component starts with "Any generating unit component or associated fixed fuel supply that is under the Generator Owner's control and is susceptible to freezing issues". The SDT's intent would be that all of the instances cited above would fall out of scope for the new proposed standard based on this definition. The SDT has provided further clarity in the Technical Rationale and may consider your comments in phase two.	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
The proposed definitions for Extreme Cold Weather Temperature, Generator Cold Weather Critical Component, and Generator Cold Weather Reliability Event provide needed additional clarity to the requirements for EOP-012. However, we have some concerns with the proposed definition of Generator Cold Weather Critical Component and Generator Cold Weather Reliability Event.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The SDT had numerous discussions regarding this point during the Standard Development process and due to the comments received by industry in the initial and second ballot being split on this matter, the SDT elects to not make the proposed change at this time.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company agrees that the addition of these key terms provide additional clarity to the proposed standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	

The SDT appreciates your review.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Avista agrees that the proposed definitions for Extreme Cold Weather Temperature, Generator Cold Weather Critical Component, and Generator Cold Weather Reliability Event provide needed clarity to the requirements for EOP-012-1. However, we recommend additional revisions to the definitions of Generator Cold Weather Critical Component and Generator Cold Weather Reliability Event to provide enhanced clarity, to be addressed during the 2nd phase of this project. (See our response to Question 2)	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT may consider your comments during phase two of the Extreme Cold Weather Standard Development project.	
Brooke Jockin - Portland General Electric Co. - 1, Group Name Portland General Electric Co.	
Answer	Yes
Document Name	
Comment	
Portland General Electric Company supports the survey response provided by EEI.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. Please see response to EEI.	
Scott Kinney - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Avista agrees that the proposed definitions for Extreme Cold Weather Temperature, Generator Cold Weather Critical Component, and Generator Cold Weather Reliability Event provide needed clarity to the requirements for EOP-012-1. However, we recommend additional revisions to the definitions of Generator Cold Weather Critical Component and Generator Cold Weather Reliability Event to provide enhanced clarity, to be addressed during the 2nd phase of this project. (See our response to Question 2)	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT may consider your comments during phase two of the Extreme Cold Weather Standard Development project.	
Mark Spencer - LS Power Development, LLC - 5	
Answer	Yes
Document Name	
Comment	
We agree appropriately formed definitions would provide additional clarity if the comments below are addressed.	
Likes 1	Vistra Energy, 5, Roethemeyer Dan
Dislikes 0	

Response	
Thank you for your comment.	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Ameren agrees with the EEI and the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI and NAGF.	
Joe Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Xcel Energy supports comments from EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI.	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3, Group Name OGE Energy	

Answer	Yes
Document Name	
Comment	
OG&E supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI.	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	Yes
Document Name	
Comment	
PG&E agrees to the proposed definitions and the recommendations supplied by EEI on additional revisions during Phase Two of the Cold Weather project.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI.	
Thomas Foltz - AEP - 5	
Answer	Yes

Document Name	
Comment	
AEP would like to express its support of EEI's response to this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI.	
Devin Shines - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company	
Answer	Yes
Document Name	
Comment	
LouisvilleG&E/KU support EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI.	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	

Constellation has no additional comments. Kimberly Turco, on behalf of Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Alison Mackellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco, on behalf of Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes

Document Name	
Comment	
"Please see comments submitted by the Edison Electric Institute"	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI.	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	
PNM agrees that the proposed definitions for Extreme Cold Weather Temperature, Generator Cold Weather Critical Component, and Generator Cold Weather Reliability Event. PNM also supports the comments provided by EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT may consider your comments during phase two of the Extreme Cold Weather Standard Development project. Please see response to EEI.	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	Yes

Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for question #1.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to EEI.	
Dan Roethemeyer - Vistra Energy - 5	
Answer	Yes
Document Name	
Comment	
Adding the proposed defined terms provides additional clarity to the requirements of EOP-012, and Vistra supports inclusion of definitions for those terms in the Reliability Standard. However, Vistra recommends refinements to the definitions as described below under Question 2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT may consider your comments during phase two of the Extreme Cold Weather Standard Development project.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	

Comment	
Exelon agrees that the proposed definitions provide additional clarity to EOP-012-1. Submitted on behalf of Exelon, Segments 1 & 3	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Southern Indiana Gas & Electric Company (SIGE) agrees the added definitions of Extreme Cold Weather Temperature, Generator Cold Weather Critical Component, and Generator Cold Weather Reliability Event provide additional clarity to the requirements of EOP-012. However, similar to EEI, SIGE also has concerns with the proposed definition of Generator Cold Weather Critical Component and Generator Cold Weather Reliability Event – as addressed in SIGE's response to Question 2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT may consider your comments during phase two of the Extreme Cold Weather Standard Development project. Please see response to EEI.	

Stewart Rake - Luminant Mining Company LLC - 7

Answer	Yes
Document Name	
Comment	
Adding the proposed defined terms provides additional clarity to the requirements of EOP-012, and Vistra supports inclusion of definitions for those terms in the Reliability Standard. However, Vistra recommends refinements to the definitions as described below under Question 2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT may consider your comments during phase two of the Extreme Cold Weather Standard Development project.	

Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen

Answer	Yes
Document Name	
Comment	
ISO-NE agrees that for the context of the new EOP-012 Standard these definitions are needed for clarification purposes, however some modifications to those definitions may be needed as described in Question 2 Comments by the SRC and ISO-NE.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT may consider your comments during phase two of the Extreme Cold Weather Standard Development project.	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	Yes
Document Name	
Comment	
Yes, the addition of the definitions provides additional clarity to the requirements. The proposed definitions as stand-alone items in the NERC Glossary of Terms will also help to provide uniformity across future Standards dealing with extreme weather such as TPL-001 recently focused on by a FERC NOPR.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Alliant Energy supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. Please see response to MRO NSRF.

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Yes, the addition of the definitions provides additional clarity to the requirements. The MRO NSRF would like to suggest that the three proposed Terms (Generator Cold Weather Critical Component, Extreme Cold Weather Temperature & Generator Cold Weather Reliability Event) be placed in a new section, §6. Definitions Used in this proposed standard, similar to NERC Reliability Standard PRC-005-6 Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance, rather than the NERC Glossary of Terms. The proposed definitions are dependent on NERC Reliability Standard EOP-012-1 – Extreme Cold Weather Preparedness and Operations, §4.2 term “generating unit” to ensure a comprehensive and complete definition. As such, placing the three proposed terms into the NERC Glossary of Terms would prevent them from being fully defined as intended by the Standards Drafting Team and subject to unintentional misinterpretation. The MRO NSRF suggests consideration be given to including these definitions in the NERC Glossary of Terms during future revisions.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT may consider your comments during phase two of the Extreme Cold Weather Standard Development project.	

Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	Yes
Document Name	
Comment	
MidAmerican Energy supports the MRO NSRF as well as EEI comments for this question.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to MRO NSRF and EEI.	
Imane Mrini - Austin Energy - 6	
Answer	Yes
Document Name	
Comment	
The definition of Generator Cold Weather Reliability Event, item 1 is not entirely clear. Is the intent to exclude derates equal to 20MW (if they are more than 10%) or equal to 10% of total unit capacity (when more than 20MW)? Suggest rewording to : a forced derate exceeding 10% of the total capacity of the unit but no less than 20 MW for longer than four hours in duration;"	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has made some clarifying changes to the Standard to address this concern and may consider your other comments during phase two of the Extreme Cold Weather Standard Development project.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	
MISO supports the comments submitted by the ISO/RTO Council Standards Review Committee (IRC SRC). In addition, we are submitting comments on behalf of MISO as an individual entity.	

MISO thanks the Standard Drafting Team (SDT) for adopting the recommendation in MISO's comments from **Project 2019-06: Cold Weather** to develop a "cold weather" definition. Having a national reference will drive consistency of application across the NERC footprint.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT had numerous discussions regarding this point during the Standard Development process and due to the comments received by industry in the initial and second ballot being split on this matter, the SDT elects to not make the proposed change at this time. The SDT also notes that the Standard Processes Manual, section 5.1, states that "If a term is used in a Reliability Standard according to its common meaning (as found in a collegiate dictionary), the term shall not be proposed for addition to the Glossary of Terms", therefore, the SDT does not agree with developing a definition of cold weather.	
Ronald Bauer - MGE Energy - Madison Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Madison Gas and Electric supports the comments from the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to MRO NSRF.	
Adam Lee - MGE Energy - Madison Gas and Electric Co. - 4	
Answer	Yes
Document Name	

Comment	
Madison Gas and Electric supports the comments of the MRO NSRF	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to MRO NSRF.	
Colin Chilcoat - Invenergy LLC - 6	
Answer	Yes
Document Name	
Comment	
The defined terms do make the proposed requirements clearer. However, there are still areas of ambiguity that Invenergy recommends be addressed. Those recommendations can be found in our response to Question 2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT may consider your comments during phase two of the Extreme Cold Weather Standard Development project.	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	Yes
Document Name	
Comment	

We agree the definitions would provide additional clarity.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
George Brown - Acciona Energy North America - 5	
Answer	Yes
Document Name	
Comment	
Acciona Energy supports Midwest Reliability Organization's (MRO) NERC Standards Review Forum's (NSRF) comments on this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to MRO NSRF.	
Deanna Carlson - Cowlitz County PUD - 5	
Answer	Yes
Document Name	
Comment	
Deanna Carlson, Cowlitz PUD, 5, 9/1/22	
Likes 0	

Dislikes 0	
Response	
The SDT appreciates your review.	
Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)	
Answer	Yes
Document Name	
Comment	
The ISO/RTO Council (IRC) Standards Review Committee (SRC) supports the addition of definitions for Extreme Cold Weather Temperature, Generator Cold Weather Critical Component, and Generator Cold Weather Reliability Event.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Avista agrees that the proposed definitions for Extreme Cold Weather Temperature, Generator Cold Weather Critical Component, and Generator Cold Weather Reliability Event provide needed clarity to the requirements for EOP-012-1. However, we recommend additional revisions to the definitions of Generator Cold Weather Critical Component and Generator Cold Weather Reliability Event to provide enhanced clarity, to be addressed during the 2nd phase of this project. (See our response to Question 2)	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT may consider your comments during phase two of the Extreme Cold Weather Standard Development project.	
Rhonda Jones - Invenergy LLC - 5	
Answer	Yes
Document Name	
Comment	
The defined terms do make the proposed requirements clearer. However, there are still areas of ambiguity that Invenergy recommends be addressed. Those recommendations can be found in our response to Question 2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT may consider your comments during phase two of the Extreme Cold Weather Standard Development project.	
Natalie Johnson - Enel Green Power - 5	
Answer	Yes
Document Name	
Comment	
Yes, the addition of the definitions provides additional clarity to the requirements. However, Enel agrees with the MRO NSRF comments that these definitions should also be added to the NERC Glossary of Terms.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT may consider your comments during phase two of the Extreme Cold Weather Standard Development project. Please see response to MRO NSRF. The definitions will be added to the NERC Glossary of Terms.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI agrees that the proposed definitions for Extreme Cold Weather Temperature, Generator Cold Weather Critical Component, and Generator Cold Weather Reliability Event provide additional clarity to the requirements for EOP-012-1. However, we recommend additional revisions to the definitions of Generator Cold Weather Critical Component and Generator Cold Weather Reliability Event to provide enhanced clarity, that can be addressed during the 2nd phase of this project. (See our response to Question 2)	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT may consider your comments during phase two of the Extreme Cold Weather Standard Development project.	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Diana Torres - Imperial Irrigation District - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
The SDT appreciates your review.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	

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	
The SDT appreciates your review.	
Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Brian Evans-Mongeon - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

The SDT appreciates your review.	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Michael Watt - Oklahoma Municipal Power Authority - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Glenn Pressler - CPS Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Lenise Kimes - City and County of San Francisco - 1,5 - WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Josh Combs - Black Hills Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
The SDT appreciates your review.	
Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Sheila Suurmeier - Black Hills Corporation - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Tony Skourtas - Los Angeles Department of Water and Power - 3	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
James Baldwin - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
The SDT appreciates your review.	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Donna Johnson - Oglethorpe Power Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Scott McGough - Georgia System Operations Corporation - 3	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Ruchi Shah - AES - AES Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

The SDT appreciates your review.	
Eric Ruskamp - Lincoln Electric System - 6, Group Name LES	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Steven Sconce - EDF Renewable Energy - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Mark Young - Tenaska, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Foung Mua, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Wei Shao, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; - Tim Kelley, Group Name SMUD / BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Michelle Amarantos - APS - Arizona Public Service Co. - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
The SDT appreciates your review.	
John Liang - Snohomish County PUD No. 1 - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
LaKenya VanNorman - LaKenya VanNorman On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4,	

6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name Florida Municipal Power Agency (FMPA)	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	

2. Do you agree with the proposed definitions of Extreme Cold Weather Temperature, Generator Cold Weather Critical Component, and Generator Cold Weather Reliability Event? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

EEI supports all three definitions for this first phase, but we also propose additional revisions to the Generator Cold Weather Critical Component and the Cold Weather Reliability Event because additional clarity is needed that can be addressed during the next phase of this project. (See below.)

Generator Cold Weather Critical Component: Use of the undefined term “fixed fuel supply component” within the proposed definition of Generator Cold Weather Critical Component creates confusion. While we support the explanation provided by the SDT in the Technical Rationale, the Technical Rationale has no standing as a compliance document. For this reason, we recommend defining this term within the framework of the next phase of this project. We suggest the following:

Fixed Fuel Supply Component: Are non-mobile equipment that support the reliable delivery of fuel to the generating unit and under the control the Generator Owner at a plant site. Gaseous, liquid, or solid fuel handling components that are installed on site as fixed parts of the fuel delivery system that are under the Generator Owner’s control would be included. Components that would not be included would be mobile equipment such as trains, bulldozers, or other equipment that are not fixed in one location.

Generator Cold Weather Reliability Event: EEI is concerned with the use of the term "specified", as it relates to the start-up time of a generator during cold weather events, because it is unclear who would be responsible for specifying the start-up time. Results Based Standards should "define a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome." (NERC Results Based Standards – Performance Based; https://www.nerc.com/pa/Stand/Pages/ResultsBasedStandards.aspx#:~:text=Results%20based%20standards%20are%20standards,the%20NERC%20Standard%20Processes%20Manual.)

Likes 0	
Dislikes 0	

Response
Thank you for your comment. The SDT may consider your comments during phase two of the Extreme Cold Weather Standard Development project.

Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)

Answer	No
Document Name	IRC SRC supporting tabled temperatures.pdf

Comment
The SRC believes two definitions require revising, specifically: 1. **Extreme Cold Weather Temperature (ECWT)**: The SRC evaluated this temperature and found it is not low enough to capture the critical hours during cold weather periods, such as Winter Storm Uri, The South Central United States Cold Weather Event of January 17, 2018, The 2014 Polar Vortex, the February 2011 Southwest Cold Weather Event and the Cold Wave in January 1994. The following information supports the request to lower the ECWT and cover events such as Winter Storm Uri.

The SDT apparently chose a “look back” date of the year 2000 based on statements on the NOAA website indicating it made some improvements in weather infrastructure around that time. That reason does not justify limiting the look back to 1/1/2000 and misinterprets the NOAA website language. The NOAA website notes it completed its “Modernization and Associated Restructuring” (MAR) effort in 2000. That effort, as the website describes, “modernized” its surface observational infrastructure by incorporating more automation. However, nothing in that effort changed the availability or quality of previous temperature data of NOAA (and its predecessor the National Weather Bureau).

During the NERC presentation on 8/16/22, the Standard Drafting Team (SDT) presented the ECWT for the Dallas, Texas area (12°F). The actual temperature in the Dallas area during Winter Storm Uri was -2°F.

Next, the PJM region experienced extremely cold conditions with a direct impact on reliability (through freezing of coal piles, canal locks and natural gas infrastructure) in 1994. The conditions at that time were the type of conditions the standard should address as they parallel those experienced during Winter Storm Uri. However, limiting the look back to the year 2000 would ignore even this relatively recent (1994) experience for determining ECWT in the PJM region.

The attached chart compares the impact of the proposed ECWT in the PJM region and illustrates how much the 0.2 percentile factor moves the requirement for winterization away from the actual temperature experienced. The results call into question the value of the 0.2 percentile factor.

Some examples included in the chart (please reference additional data and details via the attached file) - all temperatures in degrees Farenheit:

Weather Station = Allentown Lehigh Valley International Airport; Minimum Temp = -9.75; 0.2 Percentile = -0.75; 0.02 Percentile = -6.00; and average lowest temperature over a six hour period = -7.50

Weather Station = Atlantic City International Airport; Minimum Temp = -12.50; 0.2 Percentile = 0.00; 0.02 Percentile = -7.50; and average lowest temperature over a six hour period = -8.33

Weather Station = Chicago O'Hare International Airport; Minumum Temp = -26.00; 0.2 Percentile = -14.00; 0.02 Percentile = -23.00; and average lowest temperature over a six hour period = -24.33

Further, MISO examined two cities in its footprint - Lake Charles, Louisiana (LCH) and Little Rock, Arkansas (LIT) - adversely affected during the February, 2021 event. For LCH, the proposed ECWT would be 24.98° F. When reviewing the hourly data from December 1991 to February

2022, 206 hours meet or fall below that ECWT over thirty-eight days and twenty-five events. LCH also had sixteen hours during Winter Storm Uri the proposed ECWT would exclude.

The proposed ECWT for LIT is 12.92° F. In the hourly data from December 1991 to February 2022, 183 hours meet or fall below that ECWT over thirty-two days and twenty-one events. LIT also had fifty-seven hours during Winter Storm Uri the proposed ECWT would exclude.

In light of the foregoing, the SRC recommends using a fifty year look back period (replacing the year 2000 with the year 1972). The SRC also recommends striking the 0.2 percentile entirely or, at least, changing it to the 0.**02** percentile so the resulting ECWT more accurately reflects actual cold temperatures.

As an alternative to the addition of a percentile adjustment while avoiding requiring winterization to one extremely cold anomalous hour, the SRC recommends the SDT consider, as a viable alternative, defining the ECWT as a period of sustained cold temperatures (*e.g.*, the average of the lowest recorded six hours at a given location). In short, the day would be divided into six hour blocks (e.g. midnight to 6AM, 6AM to noon, noon to 6PM and 6PM to midnight) with the average coldest temperature during those six hour blocks determine the ECWT. The table attached demonstrates the results for all these options. The SDT may need to do additional work in this area, however, the SRC has seen insufficient justification for using the proposed 0.2 percentile factor.

Please note: *The Public Utility Commission of Texas is currently working on a proposed rule establishing a cold weather temperature standard. Accordingly, ERCOT does not support or oppose the SRC's comments on the Extreme Cold Weather Temperature definition.*

2. **Generator Cold Weather Reliability Event (GCWRE)**: The SRC believes the terms "generating unit" or "unit" does not make it clear the Standard applies to an entire *facility/plant*. The NERC Glossary does not define generation "unit," but many industry people consider an individual turbine/generator a *unit* (*e.g.*, a plant may have four quick start Combustion Turbine *units* and one combined cycle *unit*). The SDT should review and revise the "Applicability" section of EOP-012-2 to clearly identify how the standard applies to dispersed generation resources. This is not a new concept and is supported by the work previously completed under Project 2014-01: Standards Applicability for Dispersed Generation Resources.

The NERC Glossary defines a *Facility* as "a set of electrical equipment that operates as a single Bulk Electric System Element (*e.g.*, a line, a generator, a shunt compensator, transformer, *etc*.)" and an *Element* as, "any electrical device with terminals that may be connected to other electrical devices...." Those definitions do not, however, clearly indicate whether "generator" includes *all* the associated equipment/components the Standard seeks to cover. By way of example, other NERC Glossary definitions use "generating unit" and/or "generating facility" but not always in the same way, for example:

- Blackstart Resource ("A generating unit(s) and its associated set of equipment….")

- Cranking Path ("A portion of the electric system that can be isolated and then energized to deliver electric power from a generation source to enable the startup of one or more other generating units")

- Economic Dispatch ("The allocation of demand to individual generating units on line to effect the most economical production of electricity")

- Forced Outage ("1. The removal from service availability of a generating unit…for emergency reasons….")

- Frequency Measurable Event ("…a cumulative change in generating unit/ generating facility, DC tie and/or firm load pre-perturbation megawatt value to post-perturbation megawatt value absolute deviation greater than 550 MW….")

Thus, referring to the NERC Glossary does not provide an easy solution for this issue. The SRC believes the SDT should include a standard-only definition of *generating unit* or *generating facility*, particularly to ensure it captures dispersed resources adequately. A Standard-only definition could include, for example, "the technology used to convert a primary fuel into electricity including generators, inverters, associated control systems, valves, actuators, other mechanical and electrical components, *etc*." Such an approach would capture PV, wind, natural gas, nuclear, hydro, fuel oil, biomass, *etc*. and ensure the rule covers individual parts of facilities.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The SDT may consider your comment on the Cold Weather Reliability Event definition during phase two of the Extreme Cold Weather Standard Development project. The SDT had numerous discussions regarding the Extreme Cold Weather Temperature definition during the Standard Development process and due to the comments received by industry in the initial and second ballot being split on this matter, the SDT disagrees with making the proposed change at this time.

Natalie Johnson - Enel Green Power - 5

Answer	No
Document Name	
Comment	

Extreme Cold Weather Temperature: On a positive note, Enel prefers the updated criteria. It is a clearer criteria to assess and apply, especially with the focus on December to January months. Enel does support the MRO NSRF comments that industry meteorological experts (i.e NOAA, NWS) should be consulted and involved in this process.

Generator Cold Weather Reliability Event: Enel would like to recommend a few additional edits to the Generator Cold Weather Reliability Event definition. The additional criteria is a step in the right direction but could still lead to undue administrative burden without a corresponding reliability benefit. The 10% of the total capacity and exceeding 20MW is still far too low and could cause Corrective Action Plans for events that do not impact the Bulk Electric System resulting in substantial and unnecessary burdens. Enel suggests again that NERC adopt the same approach used in PRC-004, where misoperations that affect an aggregate nameplate rating of less than or equal to 75MVA of BES facilities **are excluded**. For this reason Enel agrees with the MRO NSRF comments on this defined term. In addition, Enel would like to ensure that criteria is applied to “available” capacity as indicated by the forecasted power curve. Renewables cannot generate during low wind or solar conditions and therefore criteria should not be applied to unavailable capacity or nameplate.

Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT may consider your comments during phase two of the Extreme Cold Weather Standard Development project.

Rhonda Jones - Invenergy LLC - 5

Answer	No
Document Name	
Comment	

Invenergy does not agree with the definitions as currently drafted and offers the following recommendations.

Generator Cold Weather Reliability Event:

As noted below in response to Question 6, Invenergy recommends setting the forced derate threshold in a manner consistent with NERC's BES criteria, using a minimum of 20 MVA for individual generating units and a minimum of 75 MVA for dispersed power producing resources.

Invenergy proposes the following change to condition (1) of the definition:

(1) A forced derate of:

- More than 10% of the total capacity of the unit and exceeding 20 MVA for generating units identified under Inclusion I2 of the BES definition; or
- More than 10% of the total capacity of the generating facility and exceeding 75 MVA for generating units identified under Inclusion I4 of the BES definition.

Additionally, Invenergy recommends removing the word "apparent" from the definition.

Extreme Cold Weather Temperature:

The proposed definition improves on the previous draft by using a percentile instead of the single minimum hourly temperature and data starting on 1/1/2000 rather than 1/1/1975.

As Invenergy did in response to the first ballot, we propose that the methodology use a multi-day average temperature rather than hourly temperatures, and a reliability analysis-based percentile rather than the 0.2 proposed in the latest draft. Without endorsing the exact values proposed, we note the proposal by Commission Staff at the Public Utility Commission of Texas (see Project No. 53401, Electric Weather Preparedness Standards-Phase II, Memorandum and Proposal for Publication dated May 19, 2022) would be expected to yield a more reasonable requirement: "…the lesser of the minimum ambient temperature at which the resource has experienced sustained operations or the 95th percentile minimum average 72-hour temperature reported in ERCOT's historical weather study…for the weather zone in which the resource is located." (Emphasis added.)

To demonstrate the need for this alternative approach, consider solar generators. Under the SDT's proposal, the calculation of the Extreme Cold Weather Temperature will be heavily influenced by colder nighttime temperatures, when there is no solar generation. Using a multi-day period would more reasonably set the minimum temperature standard for these facilities. Finally, Generator Owners need additional detail on the mechanics of calculating the Extreme Cold Weather Temperature as it is presently defined. For example, if hourly temperature data back to 1/1/2000 at a Generator Owner's nearest weather station(s) are unavailable, should the Generator Owner use only the data available at that station, or use an alternative station regardless of the distance from the facility? What fraction of the data from the nearest station must be missing before an alternative station is used?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT may consider your comment on the Cold Weather Reliability Event definition during phase two of the Extreme Cold Weather Standard Development project. The SDT had numerous discussions regarding the Extreme Cold Weather Temperature definition during the Standard Development process and due to the comments received by industry in the initial and second ballot being split on this matter, the SDT disagrees with making the proposed change at this time. Additionally, the SDT is using the definition of apparent as defined in the dictionary as "clear or manifest to the understanding".	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
Avista supports all three definitions for this first phase, but we also propose additional revisions to the Generator Cold Weather Critical Supply Component and the Cold Weather Reliability Event because additional clarity is needed and that can be addressed during the next phase of this project. (See below) **Generator Cold Weather Critical Supply Component:** Use of the undefined term "fixed fuel supply component" within the proposed definition of Generator Cold Weather Critical Component creates confusion. While we support the explanation provided by the SDT in the	

Technical Rationale, the Technical Rationale has no standing as a compliance document. For this reason, we ask the SDT to consider defining this term within the framework of the next phase of this project. We suggest the following for SDT consideration:

Fixed Fuel Supply Component: Are non-mobile equipment that support the reliable delivery of fuel to the generating unit and under the control the Generator Owner at a plant site. Gaseous, liquid, or solid fuel handling components that are installed on site as fixed parts of the fuel delivery system that are under the Generator Owner's control would be included. Components that would not be included would be mobile equipment such as trains, bulldozers, or other equipment that are not fixed in one location.

Generator Cold Weather Reliability Event: EEI is concerned with the use of the term "specified", as it relates to the start-up time of a generator during cold weather events, because it is unclear clear who would be responsible for specifying the start-up time. Results Based Standards should "define a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome." (NERC Results Based Standards – Performance Based; https://www.nerc.com/pa/Stand/Pages/ResultsBasedStandards.aspx#:~:text=Results%20based%20standards%20are%20standards,the%20NERC%20Standard%20Processes%20Manual.)

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT may consider your comments during phase two of the Extreme Cold Weather Standard Development project.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
AEPC has signed on to ACES comments, please see their responses.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to ACES.	
Deanna Carlson - Cowlitz County PUD - 5	
Answer	No
Document Name	
Comment	
Agree with comments provided by Russell Noble.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to Russell Noble - Cowlitz County PUD.	
Russell Noble - Cowlitz County PUD - 3	
Answer	No
Document Name	
Comment	
While Cowlitz appreciates the effort so far, further improvements are needed. We agree with comments provided by the North American Generator Forum.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. Please see response to NAGF’s comments.	
Michelle Amarantos - APS - Arizona Public Service Co. - 5	
Answer	No
Document Name	
Comment	
APS supports all three definitions for this phase. However, we support EEI’s proposed revisions to Generator Cold Weather Critical Component and Cold Weather Reliability Event during the next phase of the project. Specifically, APS supports EEI’s proposal to add a definition for Fixed Fuel Supply Component to eliminate confusion within the Generator Cold Weather Critical Component definition. Additionally, APS agrees that within the Generator Cold Weather Reliability definition, the use of term “specified” as it relates to the start-up time of a generator during cold weather events is ambiguous, as it unclear who would be responsible for specifying the start-up time.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT may consider this modification during phase two of the Extreme Cold Weather Standard Development project.	
Whitney Wallace - Calpine Corporation - 5 - WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	

See comment for Question 1. For Start Failure, the line should read, "a start-up failure where the unit fails to synchronize within a specified and scheduled start-up time." The addition of "**and scheduled**" makes it clear that a failed start resulting from a GO starting a unit on its own accord or during testing would not be reported as a failed start under the winterization program.

The definition of GCWRE should be clarified to state (changes are bold):

Generator Cold Weather Reliability Event: **A failure of a Generator Cold Weather Critical Component that causes** one of the following events:

(1) a forced derate of more than 10% of the total capacity of the unit and exceeding 20 MWs for longer than four hours in duration;

(2) a start-up failure where the unit fails to synchronize within a specified **and scheduled** start-up time; or

(3) a Forced Outage, for which the apparent cause(s) is due to freezing of equipment within the Generator Owner's control and the dry bulb temperature at the time of the event was at or above the Extreme Cold Weather Temperature.

Furthermore, a component failure that occurs during a cold weather event but was not caused by the cold weather event should not fall under this Standard. NERC should revise the Standard to make this clear.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT may consider this modification during phase two of the Extreme Cold Weather Standard Development project.

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Foung Mua, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Wei Shao, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; - Tim Kelley, Group Name SMUD / BANC

Answer	No
Document Name	

Comment	
The proposed definition for Cold Weather Reliability Event uses the language "total capacity of the unit" which is vague and not defined in the NERC Glossary of Terms. SMUD recommends that the language "Facility Rating of the unit" be used which is more specific and includes a NERC defined term that is referenced in other reliability standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT may consider this modification during phase two of the Extreme Cold Weather Standard Development project.	
George Brown - Acciona Energy North America - 5	
Answer	No
Document Name	
Comment	
Acciona Energy supports Midwest Reliability Organization's (MRO) NERC Standards Review Forum's (NSRF) comments on this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to Midwest Reliability Organization's (MRO).	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	No
Document Name	
Comment	

For the second item, the "specified time" is ambiguouse. If it is completely up to the generator operator, then is is not a standard. Perhaps the specified time could be required to be included in the Operating Plan or Data requirements of R3.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT may consider your comments during phase two of the Extreme Cold Weather Standard Development project.	
Colin Chilcoat - Invenergy LLC - 6	
Answer	No
Document Name	
Comment	

Invenergy does not agree with the definitions as currently drafted and offers the following recommendations.

Generator Cold Weather Reliability Event:

As noted below in response to Question 6, Invenergy recommends setting the forced derate threshold in a manner consistent with NERC's BES criteria, using a minimum of 20 MVA for individual generating units and a minimum of 75 MVA for dispersed power producing resources.

Invenergy proposes the following change to condition (1) of the definition:

(1) A forced derate of:

- More than 10% of the total capacity of the unit and exceeding 20 MVA for generating units identified under Inclusion I2 of the BES definition; **or**
- More than 10% of the total capacity of the generating facility and exceeding 75 MVA for generating units identified under Inclusion I4 of the BES definition.

Additionally, Invenergy recommends removing the word “apparent” from the definition.

Extreme Cold Weather Temperature:

The proposed definition improves on the previous draft by using a percentile instead of the single minimum hourly temperature and data starting on 1/1/2000 rather than 1/1/1975.

As Invenergy did in response to the first ballot, we propose that the methodology use a multi-day average temperature rather than hourly temperatures, and a reliability analysis-based percentile rather than the 0.2 proposed in the latest draft. Without endorsing the exact values proposed, we note the proposal by Commission Staff at the Public Utility Commission of Texas (see Project No. 53401, Electric Weather Preparedness Standards-Phase II, Memorandum and Proposal for Publication dated May 19, 2022) would be expected to yield a more reasonable requirement: “…the lesser of the minimum ambient temperature at which the resource has experienced sustained operations or **the 95th percentile minimum average 72-hour temperature** reported in ERCOT’s historical weather study…for the weather zone in which the resource is located.” (Emphasis added.)

To demonstrate the need for this alternative approach, consider solar generators. Under the SDT’s proposal, the calculation of the Extreme Cold Weather Temperature will be heavily influenced by colder nighttime temperatures, when there is no solar generation. Using a multi-day period would more reasonably set the minimum temperature standard for these facilities.

Finally, Generator Owners need additional detail on the mechanics of calculating the Extreme Cold Weather Temperature as it is presently defined. For example, if hourly temperature data back to 1/1/2000 at a Generator Owner’s nearest weather station(s) are unavailable, should the Generator Owner use only the data available at that station, or use an alternative station regardless of the distance from the facility? What fraction of the data from the nearest station must be missing before an alternative station is used?

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The SDT may consider your comment on the Cold Weather Reliability Event definition during phase two of the Extreme Cold Weather Standard Development project. The SDT had numerous discussions regarding the Extreme Cold Weather Temperature definition during the Standard Development process and due to the comments received by industry in the initial and second ballot being split on this matter, the SDT disagrees with making the proposed change at this time. Additionally, the SDT is using the definition of apparent as defined in the dictionary as “clear or manifest to the understanding”.

Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations

Answer	No
Document Name	

Comment

The current definitions as written leave ample room for interpretation. While this is often desired, we believe that in this instance they do not provide enough clarity to the requirements of EOP-012. The specific concerns with the current verbiage are as follows:

Generator Cold Weather Critical Component: While the open-endedness of “any generating unit component” is desired in that it allows the GO to identify critical components on a per-unit basis, it does not appear to include any “common” equipment shared between units. Examples would include service water, instrument air, ammonia, ash handling, common bus isolation breakers/switches, etc.

The proposed modification to the definition is: “Any generating unit component or associated fixed fuel supply component, to include any critical equipment shared between multiple units (i.e. Balance of Plant (BOP) and/or Common equipment), that is under the Generator Owner’s control and is susceptible to freezing issues, the occurrence of which would likely lead to a Generator Cold Weather Reliability Event.”

Extreme Cold Weather Temperature: The flexibility and intent behind using the “lowest 0.2 percentile” is greatly appreciated; however, the requirement to use “the hourly temperatures measured” seems a bit excessive. Given the inherent difficulty of compiling a dataset containing greater than 49,000 data points and then calculating the lowest 0.2 percentile, we recommend modifying the definition to include daily minimum temperatures from the same time period. This modification would reduce the size of the dataset significantly (down to ~2076 total days) and should not change the resulting Extreme Cold Weather Temperature by any significant statistical margin given that the daily minimum will contain the hourly minimums.

Lastly, the requirement to use a fixed data start date of 01/01/2000 means the dataset will grow by approximately 2,160 data points if using the hourly metric while only 90 data points if using the daily minimum metric. Therefore, it is our recommendation to use a 20-year rolling time period if staying with the hourly metric.

If the hourly metric is to remain, a proposed modification to the definition would be: "The temperature equal to the lowest 0.2 percentile of the actual hourly temperatures measured in December, January, and February from the previous 20 years immediately prior to the date the temperature is calculated. "

The preferred modification would be to abandon the hourly metric in favor of the daily minimum metric. Thus the *preferred* proposed modification to the definition is: "The temperature equal to the lowest 0.2 percentile of the actual daily minimum temperatures measured in December, January, and February from 1/1/2000 through the date the temperature is calculated."

Generator Cold Weather Reliability Event: Pertaining to event type 2 that may constitute a Generator Cold Weather Reliability Event (GCWE):

2. "A start-up failure where the unit fails to synchronize within a specified start-up time": Who specifies the start-up time? Per the draft Technical Rationale and Justification for EOP-012-1, start-up failures are defined using a modified version of the GADS definition in order to ensure consistency across all jurisdictions for this standard. Our concern stems from the language in R2 that references the GADS definition of "specified start-up time" without providing the additional clarification found in the 2022 GADS Data Reporting Instructions. Our recommendation is to modify this subsection as follows: "A start-up failure where the unit fails to synchronize within a specified start-up time. The specified start-up time period for each unit is determined by the GO/GOP based on the condition of the unit at the time of start-up."

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The SDT may consider your comments on both the Cold Weather Reliability Event and Generator Cold Weather Reliability Event definitions during phase two of the Extreme Cold Weather Standard Development project. The SDT had numerous discussions regarding the Extreme Cold Weather Temperature definition during the Standard Development process and due to the comments received by industry in the initial and second ballot being split on this matter, the SDT disagrees with making the proposed change at this time.

Adam Lee - MGE Energy - Madison Gas and Electric Co. - 4

Answer	No

Document Name	
Comment	
Madison Gas and Electric supports the comments of the MRO NSRF	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to Midwest Reliability Organization's (MRO).	
Ronald Bauer - MGE Energy - Madison Gas and Electric Co. - 3	
Answer	No
Document Name	
Comment	
Madison Gas and Electric supports the comments from the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to Midwest Reliability Organization's (MRO).	
Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	No
Document Name	
Comment	

Capital Power supports the North American Generators Forum (NAGF) response to this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to NAGF.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	

MISO supports the comments submitted by the ISO/RTO Council Standards Review Committee (IRC SRC). In addition, we are submitting comments on behalf of MISO as an individual entity.

In analyzing the proposed Extreme Cold Weather Temperature, MISO discovered that it doesn't go far enough to capture many of the hours in recent major cold weather events, including Winter Storm Uri (February 2021), South Central Cold Weather Event (January 2018) and the Polar Vortex (January 2014). **Without an adequate temperature definition, the standard will not achieve its intended outcome or provide a measurable reliability benefit as the balance of winterization requirements hinge upon the adequacy of this definition**.

The current **Extreme Cold Weather Temperature (ECWT)** definition sets "the temperature equal to the lowest 0.2 percentile of the hourly temperatures measured in December, January, and February from 1/1/2000 through the date the temperature is calculated."

In analyzing the proposed definition, we found that **the lowest 0.2 percentile is insufficient to capture many of the hours in past extreme events** (*see* detailed analysis below). Therefore, we recommend the SDT modify the percentile. One option is to model this threshold after an established industry percentile; e.g. the Loss of Load Expectation (LOLE) which is equivalent to one day in ten years. This equates to:

LOLE = 1 day/(10 years x 365 days/year) = 0.000274 or **0.0274 percentile** almost 10 times less than the current benchmark.

In contrast, the current 0.2 percentile in the ECWT definition equates to:

ECWT = 1 day/(0.002 x 365 days/year) = **1 day every 1.37 years** which indicates a need to plan for a loss of load expectation (LOLE) on an almost annual or yearly basis.

Planning to shed load in support of a major event on an annual basis fails to adequately address the findings from past major events and will not provide measurable reliability benefits. Therefore, **MISO recommends the SDT adopt a more stringent percentile such as that for LOLE (of 0.0274)** in determining the Extreme Cold Weather Temperature definition.

Using a smaller percentile also has the added benefit of addressing Generator Owner concerns that the definition not be based on the single coldest hour experienced; but rather a temperature for which has been realized on multiple occasions over a period of time.

MISO Temperature Analysis

To evaluate the adequacy of the Extreme Cold Weather Temperature definition, MISO examined two cities in its footprint - Lake Charles, Louisiana (LCH) and Little Rock, Arkansas (LIT) – both of which were adversely affected during the Winter Storm Uri (February 2021) event.

For LCH, the proposed ECWT would be 24.98° F. When reviewing the hourly data from December 1991 to February 2022, 206 hours meet or fall below that ECWT over thirty-eight days and twenty-five events. LCH also had sixteen hours (16) during Winter Storm Uri the proposed ECWT would exclude.

The proposed ECWT for LIT is 12.92° F. In the hourly data from December 1991 to February 2022, 183 hours meet or fall below that ECWT over thirty-two days and twenty-one events. LIT also had fifty-seven (57) hours during Winter Storm Uri the proposed ECWT would exclude.

In light of the foregoing, the SRC recommends using a fifty year look back period (replacing the year 2000 with the year 1972). The SRC also recommends striking the 0.2 percentile entirely or, at least, changing it to the 0.**02** percentile so the resulting ECWT more accurately reflects *extreme* cold temperatures.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT had numerous discussions regarding this point during the Standard Development process and due to the comments received by industry in the initial and second ballot being split on this matter, the SDT elects to not make the proposed change at this time.	
Imane Mrini - Austin Energy - 6	
Answer	No
Document Name	
Comment	
The definition of Generator Cold Weather Reliability Event, item 1 is not entirely clear. Is the intent to exclude derates equal to 20MW (if they are more than 10%) or equal to 10% of total unit capacity (when more than 20MW)? Suggest rewording to : a forced derate exceeding 10% of the total capacity of the unit but no less than 20 MW for longer than four hours in duration;"	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has made some clarifying changes to the Standard to address this concern.	
Mark Young - Tenaska, Inc. - 5	
Answer	No
Document Name	
Comment	
Generator Cold Weather Reliability Event - In (1), (2), and (3), change “unit” to “unit or combined cycle block”. The event descriptions do not specifically indicate events relating to freezing. Suggested change:	

*(1) a forced derate **due to freezing equipment**, which results in more than 10% of the total capacity of the unit and exceeding 20 MWs for longer than four hours in duration*

*(2) a start-up failure where the unit fails to synchronize within a specified start-up time **due to freezing equipment.***

On a temperature related note, unless there has been some analysis of historical data to substantiate it, imposing the 20mph wind assumption on top of the temperature requirement will likely cause plants to design for a theoretical weather condition that has never existed. Given the costs and challenges involved with this effort, we should not be basing design on arbitrary assumptions.

Also relating to temperature, “Design temperature”, “historical operating temperature”, or “current cold weather performance temperature” do not have a practical meaning for wind turbines with respect to cold weather reliability. Wind turbines are often rated to perform at extremely low temperatures. The reliability issue is icing “conditions” which usually happen at temperatures much higher than the lowest rated temperature. Icing conditions are related to a combination of temperature and moisture vs a specific low temperature. Additionally, there is no known technology that reliably mitigates all icing concerns.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The SDT may consider your comment on the Cold Weather Reliability Event definition during phase two of the Extreme Cold Weather Standard Development project. The SDT had numerous discussions regarding the Extreme Cold Weather Temperature definition and wind criteria during the Standard Development process and due to the comments received by industry in the initial and second ballot being split on this matter, the SDT disagrees with making the proposed change at this time.

Steven Sconce - EDF Renewable Energy - 5

Answer	No
Document Name	

Comment	
The term Generator is not clearly defined. Please refer to our comments in question #4 and #5. EDF supports the comments of NAGF and EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT may consider your comments during phase two of the Extreme Cold Weather Standard Development project. Also, please see the responses to NAGF and EEI comments.	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	No
Document Name	
Comment	
MidAmerican Energy supports the EEI and NSRF comments for this question. We would also expound on NSRF's comments that one location's weather data would mean over 175,000 points of data.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT may consider your comments during phase two of the Extreme Cold Weather Standard Development project. Also, please see the responses to NSRF and EEI comments.	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	No
Document Name	
Comment	

How is the BA held responsible for determining what is considered the "winter season"? EOP-012-1 section 4.2 lacks clarity and there are no requirements concerning this responsibility, nor is it mentioned in the TR.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT may consider your comments during phase two of the Extreme Cold Weather Standard Development project. Please note that the concept of the BA determining a "winter season" has been removed from the proposed Standard.	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	

- Generator Cold Weather Reliability Event

The MRO NSRF disagrees with the definition of Generator Cold Weather Reliability Event as written. We believe that 10% of the total capacity and exceeding 20MW is far too low for many generating units. The MRO NSRF appreciates the Standard Drafting Teams (SDT) adding the "and exceeding 20MW" prose for a Generator Cold Weather Reliability Event. However, we would suggest tying the magnitude back to a reliability concept such as the BES Definition: 75MVA/20MVA. The simple reasoning is that for a 100MVA facility identified under Inclusion I4 of the BES Definition, a derate of 10% (10MVA) and 20MW would not constitute a reliability concern as it does not even meet the thresholds to be BES for generation facilities identified under inclusion I4. Given that, the MRO NSRF believes the threshold for a Generator Cold Weather Reliability Event as currently proposed is adding an undue administrative burden without a clear increase in reliability.

The MRO NSRF suggests the following language modification to this Definition:

Generator Cold Weather Reliability Event - One of the following events, for which the apparent cause(s) is due to freezing of equipment within the Generator Owner's control and the dry bulb temperature at the time of the event was at or above the Extreme Cold Weather Temperature:

(1) a forced derate of:

- *10% or greater than or equal to 20MVA of the Facility Rating, whichever is greater, for generating units identified under Inclusion I2 of the BES definition*

or

- *10% or greater than or equal to 75MVA of the Facility Rating, whichever is greater, for generating units identified under Inclusion I4 of the BES definition*

for longer than four hours in duration;

(2) a start-up failure where the *generating* unit fails to synchronize within a specified start-up time;

or

(3) a Forced Outage.

If the current ballot gains approval without changes to the proposed language of the Standard, the MRO NSRF would like to suggest addressing the afforemention comments in a future phase of this project.

- Extreme Cold Weather Temperature

Regarding Extreme Cold Weather Temperature, the MRO NSRF would like to thank the SDT for the changes incorporated from Draft 1 to Draft 2. While we appreciate the effort to reduce the burden on Generator Owner and Generator Operators to evaluate the Extreme Cold Weather Temperature, we disagree with the proposed definition for several reasons. First, the MRO NSRF would suggest the SDT to work with the National Oceanic and Atmospheric Administration (NOAA), National Weather Service (NWS), team members of the FERC, NERC and Regional Entity Staff Report to develop the appropriate percentile this definition will require Generator Owners and Generator Operators to meet in Requirements R1 and R2. Within the technical rationale, the SDT states “select the 0.2 percentile of winter month temperatures since 1/1/2000 to identify a temperature which has been rarely surpassed, but which allows some margin for a Generator Owner to have previously demonstrated successful operation”. While we agree with a statistical approach, we cannot support the level of 0.2 percentile without a scientific and statistical analysis to determine if 0.2 is appropriate.

As it relates to the portion of the of the definition that states “from 1/1/2000 through the date the temperature is calculated”, the MRO NSRF suggests two items. First, confer with the members from NOAA, NWS and ECCC to confirm that keeping 1/1/2000 as the baseline date is appropriate (for example, not dropping the oldest 5 year period for each new calculation) or if it should be on a latest 15, 20, 30 winter season basis. Secondly, the way the current language is proposed, in conjunction with requirement R4, we are concerned of an overlap between the effective date of the standard and implementation date of the requirement could cause inadvertent confusion as to when to calculate the winter season temperature. For example, if the effective date of the standard is 1/1/2023, does an entity calculate the Extreme Cold Weather Temperature to 12/31/2022? Therefore, the MRO NSRF proposes to clarify “through the date the temperature is calculated” to “through the end of the previous winter season of the date the temperature is calculated”.

The MRO NSRF requests clarification on data souce location. Historical hourly temperature data for many project locations is nonexistent. Several of our members have considered National Weather Service data from small airports, but these stations can be many miles away from the project locations. The NSRF requests modification to the language in the definition to the effect of, “the closest NWS site data is adequate for calculating this temperature (ECWT)”.

Additionally, the MRO NSRF request the SDT consider changing the beginning date of records for the Extreme Cold Weather Temperature from 1/1/2000 to 1/1/2005. While there is certainly temperature data on the NOAA NCEI website for most airports located near large population centers that goes back to the 1/1/2000 date, there is abundantly more data available for some more remote areas starting in 2005. This would help entities obtain a more accurate temperature for the local area that generators may be in, which for some generation facilities such as wind or solar farms may be quite remote and several hundred miles away from any major population area.

In consideration of this data calculation, perhaps NERC can work with NOAA’s National Climatic Data Center (NCDC) on setting up this data for download for industry members. In the June 2013 issue of the Bulletin of the American Meteorological Society, “Alternative Climate Normals: Impacts to the Energy Industry”, the article states that NCDC has been expanding its “proactive engagement” with various sectors and has analyzed what data the energy sector requires for climate normals. To ensure Generator Owners and Generator Operators are using the same data, the NSRF would like to propose that NERC and NCDC develop a data set so industry members do not have to manipulate large sets of data. The winter season data set will be over 2,000 data points and currently as proposed over a 20 year span. Forward looking, this data manipulation will require an abundance of resources to complete for new and existing generation resources.

Alternative Climate Normals: Impacts to the Energy Industry in: Bulletin of the American Meteorological Society Volume 94 Issue 6 (2013) (ametsoc.org)

Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT may consider your comment on the Cold Weather Reliability Event definition during phase two of the Extreme Cold Weather Standard Development project. The SDT had numerous discussions regarding the Extreme Cold Weather Temperature definition during the Standard Development process and due to the comments received by industry in the initial and second ballot being split on this matter, the SDT disagrees with making the proposed change at this time.	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	No
Document Name	
Comment	
Alliant Energy supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to MRO NSRF comments.	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	No
Document Name	
Comment	
NPPD agrees with the definition of as proposed, with the following exceptions:	

Cold Weather Reliability Event definition: we request the definition be modified to the following: *"(1) a forced derate of more than 10% of the **Facility Rating** of the unit and exceeding 20 MWs for longer than four hours in duration;"*. We believe the basis should be the Facility Rating of the generator rather than the capacity. We believe this modification would provide additional clarity and provide for a more accurate calculation.

Extreme Cold Weather Temperature definition: historical hourly temperature data for many project locations is nonexistent. Several entities have considered National Weather Service data from small airports, but these stations can be many miles away from the facility locations. We request modification to the language in the definition to the effect of, "the closest NWS site data is adequate for calculating this temperature (ECWT)". Also, NPPD requests the SDT consider changing the beginning date of records for the Extreme Cold Weather Temperature from 1/1/2000 to 1/1/2005. While there is certainly temperature data on the NOAA NCEI website for most airports located near large population centers that goes back to the 1/1/2000 date, there is abundantly more data available for some more remote areas starting in 2005. This would help entities obtain a more accurate temperature for the local area that generators may be in, which for some facilities may be quite remote and several hundred miles away from any major population area.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The SDT may consider your comment on the Cold Weather Reliability Event definition during phase two of the Extreme Cold Weather Standard Development project. The SDT had numerous discussions regarding the Extreme Cold Weather Temperature definition during the Standard Development process and due to the comments received by industry in the initial and second ballot being split on this matter, the SDT disagrees with making the proposed change at this time.

Eric Ruskamp - Lincoln Electric System - 6, Group Name LES

Answer	No
Document Name	

Comment

The definition for Extreme Cold Weather Temperature seems overly complicated and will require a lot of data crunching to reach a number that could be attained by looking at lowest recorded temperature in each year, without having to retrieve hourly data and perform statistical analysis.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT had numerous discussions regarding this point during the Standard Development process and due to the comments received by industry in the initial and second ballot being split on this matter, the SDT elects to not make the proposed change at this time	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	No
Document Name	
Comment	
ECWT: The EOP-012 standard as written would not have mitgated much of the events that happened during Feb 2021 in the Southern US. It looks like the Standard is written to ensure that Generators are able to operate to the “normal” experienced low temperatures experienced during the winter months. The ECWT definition does not address the “Extreme” cold weather. It specifies something that sounds good, but in reality leaves the “equipment freezes” door wide open: the criterion is that fixed portions of cold-weather sensitive equipment should not freeze when exposed to 0.2% of the coldest winter hours in the past 20 years. To give an example: Dallas, TX got down to -2degF for quite a while during storm Uri – the standard requires protection down to 14degF. This means that for the Dallas area, this standard would have minimal influence during a similar extreme event. ISO-NE supports the recommendation from the SRC Comments that the Standard should consider a period of sustained cold temperatures (e.g., the average of the lowest recorded six hours at a given location) as the ECWT.	

GCWRE: Additionally, the term Generating unit is vague and is open to interpretation. Does this mean each generating unit or is it an entire facility. Depending on the interpretation of unit by a GO, they could declare each unit separate in the large plant with many units which could preclude them from the applicability section of this standard as well as exempt form the CAP requirements outlined in Requirement 6.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT may consider your comment on the term "Generating unit" during phase two of the Extreme Cold Weather Standard Development project. The SDT had numerous discussions regarding the Extreme Cold Weather Temperature definition during the Standard Development process and due to the comments received by industry in the initial and second ballot being split on this matter, the SDT disagrees with making the proposed change at this time.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	

The NAGF agrees with creation of the definitions. The NAGF has concerns with the proposed definitions as written.

- The definition of Generator Cold Weather Reliability Event is not clear. Use of the word "apparent" in the definition has the potential to cause disagreements during an audit due to the multiple meanings of the word. It would be better to use a word that has a consistent definition rather than a word with multiple different meanings. Synonyms for apparent include assumed, evident, ostensible, ostensive, presumed, prima facie, putative, reputed, seeming, supposed. Based on this list of words, if an auditor assumes that an outage was caused by freezing based on the timing of the outage the auditor would be correct to expect a CAP for that event. (As written, an auditor can take the position any outage that is assumed to be caused by freezing requires a CAP to be created. Then the CAP must either be implemented, or a declaration made that the CAP will not be implemented.) While we do not believe this is the intent of the SDT, the NAGF asks the SDT to address this potential conflict by replacing the word apparent with a word that provides clearer intent.

- The Generator Cold Weather Reliability Event uses the term "freezing of equipment" and Generator Cold Weather Critical Component uses "susceptible to freezing issue" without clearly defining what is meant. While the SDT has spent a significant amount of time discussing what they mean by freezing, that discussion does not appear to be captured well in this documentation. The NAGF recommends that this issue be clearly explained to ensure that all entities understand what issues are to be addressed.
- The SDT has used the Extreme Cold Weather Temperature in the definition of Generator Cold Weather Reliability Event which will cause a Generator Owner to do a CAP under R6. This definition should instead use the term "generator minimum operating temperature as identified in the cold weather plan" to better address reliability. The NAGF agrees with the Technical Rationale document that using the Extreme Cold Weather Temperature treats everyone equally. However, in this case, treating everyone equally does not address the reliability concerns raised in the Joint Inquiry Report. The NAGF explain this position in more detail under question 8.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT may consider your comments during phase two of the Extreme Cold Weather Standard Development project. The SDT is using the definition of apparent as defined in the dictionary as "clear or manifest to the understanding".

Ruchi Shah - AES - AES Corporation - 5

Answer	No
Document Name	

Comment

AES Clean Energy supports comments submitted by NAGF.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Please see response to NAGF.

LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	No
Document Name	
Comment	
The defined Extreme Cold Weather Temperature does not result in a temperature that would cause a Generator Cold Weather Reliability Event (as defined by this standard). It should be no higher than the lowest historically recorded temperature for the region.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT had numerous discussions regarding this point during the Standard Development process and due to the comments received by industry in the initial and second ballot being split on this matter, the SDT elects to not make the proposed change at this time.	
Stewart Rake - Luminant Mining Company LLC - 7	
Answer	No
Document Name	
Comment	
The definition of "Extreme Cold Weather Temperature"--though an improvement over the cold weather standard in the previous version of EOP-012, which required continuous operations at the documented lowest hourly temperature experienced at the particular location since Jan. 1, 1975--remains problematic and could exacerbate resource adequacy challenges facing the nation (particularly in the Texas Reliability Entity, Inc. (TRE) region), without actually improving reliability outcomes—i.e., if the costs to achieve these standards prove substantial, the adoption of the standards could contribute to early retirements or cancellations or delays of planned resources, which could harm long-term resource adequacy and thus reliability. The new proposal is still extremely conservative, effectively equating to a 99.8th percentile coldest hourly temperature experienced at the applicable weather station for a resource since 2000, during the months of December, January, and February—in other words, a temperature that is colder than the temperature experienced in 99.8 percent of the total hours studied. In the	

draft Technical Requirements document (NERC's Calculating Extreme Cold Weather Temperatures), the 0.2 percentile lowest temperature for the example weather station was 2 degrees Fahrenheit, which apparently had occurred in only 11 hours in the study period (dating back to January 1, 2000), and those 11 hours seemingly were not contiguous.

A requirement for new resources to operate for 12 consecutive hours, and existing resources to operate for 1 continuous hour, at a temperature experienced so few times in the past 22 years could require the Generator Owner to make significant capital expenditures (e.g., depending on the design specifications of the resource and depending on whether the SDT clarifies the meaning of "freeze protection measures" as recommended by Vistra under Question 5) to prepare for an extremely unlikely future occurrence, without any way for the Generator Owner to recoup the costs. The proposed definition and the accompanying standard based on that definition for new resources (R1) seems especially unworkable and unreasonable, as it would require new resources to operate for 12 consecutive hours at a temperature that would have occurred for one hour on only a handful of (apparently separate) occasions over the past two decades—in other words, new resources would be required to prove they could operate in conditions that have apparently never occurred, at least during the lookback period (i.e., while the temperature would have reached the Extreme Cold Weather Temperature for 1-hour periods at least a few times since 2000, it is unlikely that the Extreme Cold Weather Temperature would have occurred for 12 consecutive hours since 2000). In lieu of making those unrecoverable expenditures in an attempt to prepare their resource to operate in speculative future extended extreme cold temperatures, investors may forego or cancel resource additions. Similarly, an existing Generator Owner that cannot operate for one hour at its Extreme Cold Weather Temperature may decide to retire early in lieu of making significant expenditures to attempt to operate at that temperature for one hour in the future.

Notably, the new proposal is far more conservative than the proposed extreme weather standard under consideration for the TRE region, by the Public Utility Commission of Texas (PUCT). In a pending rulemaking, the PUCT has proposed an extreme cold weather standard based on sustaining operations at either the 95th percentile minimum average 72-hour temperature as published in a recurring study by the balancing authority (which will be filed every 5 years and will examine weather outcomes dating back over 100 years) or the lowest ambient temperature at which the particular resource has experienced sustained operations. While Vistra has urged the PUCT to not adopt the alternative "lowest ambient temperature" standard for a variety of reasons (notably that it may effectively override the 72-hour average standard and impose different weather standards for different resources), and while the PUCT has yet to adopt its final rule establishing its standards, Vistra believes the intent of the "lowest temperature" standard proposed by the PUCT is actually to require resources to maintain weatherization measures that go above and beyond the standard, rather than to supplant the 72-hour average standard. In any event, the PUCT's proposed "lowest temperature" standard would still be preferable to the 0.2 percentile standard proposed by the SDT, since the PUCT standard would take into account the resource's demonstrated capabilities, not require it to sustain operations at a temperature at which it has never sustained operations, and not require new resources to sustain operations at that temperature for durations and in compounding weather conditions that are extremely unlikely to have any historical precedent.

Vistra urges the SDT to reconsider the proposed 0.2 percentile lowest hourly temperature since Jan. 1, 2000 in favor of something closer to the PUCT standard, i.e., either an average lowest ambient temperature (at the 95th or even 99th percentile) over a specified number of hours (e.g., 12 hours, 24 hours, 72 hours, etc.) since a specified date (e.g., Jan. 1, 2000) or a standard based on actual operations (for existing resources) or design specifications (for new or existing resources). If the SDT were to redefine "Extreme Cold Weather Temperature" to incorporate an average lowest ambient temperature, then the NERC guide for Calculating Extreme Cold Weather Temperature would also need to be modified to develop a methodology for calculating that temperature, or alternatively, the balancing authority for each region (e.g., ERCOT for the TRE region) could be responsible for publishing the applicable average temperatures on some periodicity (e.g., every five years). It may be preferable to have the balancing authority publish that data periodically, since that provides a common reference point for all resources operating in the region.

The definition of "Generator Cold Weather Reliability Event" also should be clarified in a couple of ways. First, the phrase that begins "for which the apparent cause(s)" should be moved up to clarify that it modifies all three paragraphs of the definition (i.e., relating to (1) derates, (2) start-up failures, and (3) forced outages), rather than appearing directly at the end of paragraph (3) without any paragraph break, which could provide the impression that it only modifies that last paragraph. In addition, the definition for paragraph (2) (relating to start-up failures) should be modified to clarify that the term "start-up failure" will have the same meaning that it does for purposes of Generating Availability Data System (GADS) reporting. For instance, the definition could be modified to state that "Generator Cold Weather Reliability Event" means:

"One of the following events, if the apparent cause(s) of that event(s) is due to freezing of equipment within the Generator Owner's control and the dry bulb temperature at the time of the event was at or above the Extreme Cold Weather Temperature:

(1) a forced derate of more than 10% of the total capacity of the unit and exceeding 20 MWs for longer than four hours in duration;

(2) a start-up failure where the unit fails to synchronize within a specified start-up time, as defined in the instructions for mandatory reporting of startup failures in the Generating Availability Data System; or

(3) a Forced Outage

Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT may consider your comment on the Cold Weather Reliability Event definition during phase two of the Extreme Cold Weather Standard Development project. The SDT had numerous discussions regarding the Extreme Cold Weather Temperature definition during the Standard Development process and due to the comments received by industry in the initial and second ballot being split on this matter, the SDT disagrees with making the proposed change at this time. The SDT is using the definition of apparent as defined in the dictionary as “clear or manifest to the understanding”.	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	No
Document Name	
Comment	
The Extreme Cold Weather Temperature definition differs from the language/method in the Public Utility Commission of Texas Project No. 53401 to define the minimum temperature at which a resource is reasonably expected to ensure sustained operation. LCRA offers the following revisions to events 1 and 2 of the Generator Cold Weather Reliability Event definition: (1) a forced derate of more than 10 of the *seasonally adjusted High Sustainable Limit (HSL)* of the unit and exceeding 20 MWs for longer than four hours in duration; (2) a start-up failure where the unit fails to synchronize within *the Balancing Authority’s* specified start-up time; or”	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT may consider your comments during phase two of the Extreme Cold Weather Standard Development project.	

Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	No
Document Name	
Comment	

SIGE is requesting the Standard Drafting Team consider the following recommendations:

For **Generator Cold Weather Reliability Event**:

- As written, bullets 1 and 2 could apply at any time during the year. SIGE is proposing the addition of a qualify to define the applicability of bullets 1 and 2. Additionally, SIGE is proposing increasing 10% to 15% to allow larger units capacity for everyday variances:

Generator Cold Weather Reliability Event: One of the following events ***occurring when the ambient temperature is at or below 32 degrees****:*

(1) a forced derate of more than ***15****% of the total capacity of the unit and or exceeding 20 MWs,* ***whichever is greater****, for longer than four hours in duration;*

(2) a start-up failure where the unit fails to synchronize within a specified start-up time; or

(3) a Forced Outage, for which the apparent cause(s) is due to freezing of equipment within the Generator Owner's control and the dry bulb temperature at the time of the event was at or above the Extreme Cold Weather Temperature

- In alignment with EEI's comment, SIGE is also voicing concern that use of the term "specified" in bullet 2 is unclear as to whom is responsible or what is determining the 'specifying' of the start-up time.

For **Generator Cold Weather Critical Component**, SIGE believes that the inclusion of the phrase "fixed fuel supply component" in the proposed definition is not clear and supports EEI's proposed definition of "fixed fuel supply component".

Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT may consider your comments during phase two of the Extreme Cold Weather Standard Development project.	
Dan Roethemeyer - Vistra Energy - 5	
Answer	No
Document Name	
Comment	

The definition of "Extreme Cold Weather Temperature"--though an improvement over the cold weather standard in the previous version of EOP-012, which required continuous operations at the documented lowest hourly temperature experienced at the particular location since Jan. 1, 1975--remains problematic and could exacerbate resource adequacy challenges facing the nation (particularly in the Texas Reliability Entity, Inc. (TRE) region), without actually improving reliability outcomes—i.e., if the costs to achieve these standards prove substantial, the adoption of the standards could contribute to early retirements or cancellations or delays of planned resources, which could harm long-term resource adequacy and thus reliability. The new proposal is still extremely conservative, effectively equating to a 99.8th percentile coldest hourly temperature experienced at the applicable weather station for a resource since 2000, during the months of December, January, and February—in other words, a temperature that is colder than the temperature experienced in 99.8 percent of the total hours studied. In the draft Technical Requirements document (NERC's Calculating Extreme Cold Weather Temperatures), the 0.2 percentile lowest temperature for the example weather station was 2 degrees Fahrenheit, which apparently had occurred in only 11 hours in the study period (dating back to January 1, 2000), and those 11 hours seemingly were not contiguous.

A requirement for new resources to operate for 12 consecutive hours, and existing resources to operate for 1 continuous hour, at a temperature experienced so few times in the past 22 years could require the Generator Owner to make significant capital expenditures (e.g., depending on the design specifications of the resource and depending on whether the SDT clarifies the meaning of "freeze protection measures" as recommended by Vistra under Question 5) to prepare for an extremely unlikely future occurrence, without any way for the Generator Owner to recoup the costs. The proposed definition and the accompanying standard based on that definition for new resources (R1) seems especially unworkable and unreasonable, as it would require new resources to operate for 12 consecutive hours at a temperature that would have occurred for one hour on only a handful of (apparently separate) occasions over the past two decades—in other words, new resources would be required to prove they could operate in conditions that have apparently never occurred, at least during the lookback period (i.e., while the temperature would have reached the Extreme Cold Weather Temperature for 1-hour periods at least a few times since 2000, it is unlikely that the Extreme Cold Weather Temperature would have occurred for 12 consecutive hours since 2000). In lieu of making those unrecoverable expenditures in an attempt to prepare their resource to operate in speculative future extended extreme cold temperatures, investors may forego or cancel resource additions. Similarly, an existing Generator Owner that cannot operate for one hour at its Extreme Cold Weather Temperature may decide to retire early in lieu of making significant expenditures to attempt to operate at that temperature for one hour in the future.

Notably, the new proposal is far more conservative than the proposed extreme weather standard under consideration for the TRE region, by the Public Utility Commission of Texas (PUCT). In a pending rulemaking, the PUCT has proposed an extreme cold weather standard based on sustaining operations at either the 95th percentile minimum average 72-hour temperature as published in a recurring study by the balancing authority (which will be filed every 5 years and will examine weather outcomes dating back over 100 years) or the lowest ambient temperature at which the particular resource has experienced sustained operations. While Vistra has urged the PUCT to not adopt the alternative "lowest ambient temperature" standard for a variety of reasons (notably that it may effectively override the 72-hour average standard and impose different weather standards for different resources), and while the PUCT has yet to adopt its final rule establishing its standards, Vistra believes the intent of the “lowest temperature” standard proposed by the PUCT is actually to require resources to maintain weatherization measures that go above and beyond the standard, rather than to supplant the 72-hour average standard. In any event, the PUCT’s proposed “lowest temperature” standard would still be preferable to the 0.2 percentile standard proposed by the SDT, since the PUCT standard would take into account the resource’s demonstrated capabilities, not require it to sustain operations at a temperature at which it has never sustained operations, and not require new resources to sustain operations at that temperature for durations and in compounding weather conditions that are extremely unlikely to have any historical precedent.

Vistra urges the SDT to reconsider the proposed 0.2 percentile lowest hourly temperature since Jan. 1, 2000 in favor of something closer to the PUCT standard, i.e., either an average lowest ambient temperature (at the 95th or even 99th percentile) over a specified number of hours (e.g., 12 hours, 24 hours, 72 hours, etc.) since a specified date (e.g., Jan. 1, 2000) or a standard based on actual operations (for existing resources) or design specifications (for new or existing resources). If the SDT were to redefine “Extreme Cold Weather Temperature” to incorporate an average lowest ambient temperature, then the NERC guide for Calculating Extreme Cold Weather Temperature would also need to be modified to develop a methodology for calculating that temperature, or alternatively, the balancing authority for each region (e.g., ERCOT for the TRE region) could be responsible for publishing the applicable average temperatures on some periodicity (e.g., every five years). It may be preferable to have the balancing authority publish that data periodically, since that provides a common reference point for all resources operating in the region.

The definition of "Generator Cold Weather Reliability Event" also should be clarified in a couple of ways. First, the phrase that begins "for which the apparent cause(s)" should be moved up to clarify that it modifies all three paragraphs of the definition (i.e., relating to (1) derates, (2) start-up failures, and (3) forced outages), rather than appearing directly at the end of paragraph (3) without any paragraph break, which could provide the impression that it only modifies that last paragraph. In addition, the definition for paragraph (2) (relating to start-up failures) should be modified to clarify that the term "start-up failure" will have the same meaning that it does for purposes of Generating Availability Data System (GADS) reporting. For instance, the definition could be modified to state that "Generator Cold Weather Reliability Event" means:

"One of the following events, if the apparent cause(s) of that event(s) is due to freezing of equipment within the Generator Owner's control and the dry bulb temperature at the time of the event was at or above the Extreme Cold Weather Temperature:

(1) a forced derate of more than 10% of the total capacity of the unit and exceeding 20 MWs for longer than four hours in duration;

(2) a start-up failure where the unit fails to synchronize within a specified start-up time, as defined in the instructions for mandatory reporting of startup failures in the Generating Availability Data System; or

(3) a Forced Outage.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The SDT may consider your comment on the Cold Weather Reliability Event definition during phase two of the Extreme Cold Weather Standard Development project. The SDT had numerous discussions regarding the Extreme Cold Weather Temperature

definition during the Standard Development process and due to the comments received by industry in the initial and second ballot being split on this matter, the SDT disagrees with making the proposed change at this time. The SDT is using the definition of apparent as defined in the dictionary as "clear or manifest to the understanding".

Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for question #2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI.	
James Baldwin - Lower Colorado River Authority - 1	
Answer	No
Document Name	
Comment	
LCRA provides the following comments: The Extreme Cold Weather Temperature definition differs from the language/method in the Public Utility Commission of Texas Project No. 53401 to define the minimum temperature at which a resource is reasonably expected to ensure sustained operation. LCRA offers the following revisions to events 1 and 2 of the Generator Cold Weather Reliability Event definition:	

(1) a forced derate of more than 10 of the seasonally adjusted High Sustainable Limit (HSL) of the unit and exceeding 20 MWs for longer than four hours in duration; (2) a start-up failure where the unit fails to synchronize within the Balancing Authority's specified start-up time; or"	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT may consider your comment on the Cold Weather Reliability Event definition during phase two of the Extreme Cold Weather Standard Development project. The SDT had numerous discussions regarding the Extreme Cold Weather Temperature definition during the Standard Development process and due to the comments received by industry in the initial and second ballot being split on this matter, the SDT disagrees with making the proposed change at this time.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
We are concerned that the definition of Extreme Cold Weather Temperature will not capture the lower temperatures experienced in February 2021 (the Event). Even if the temperatures experienced during the Event are considered outliers, we do not believe that they should be removed from the dataset. The frequency or intensity of these extreme temperatures occurring in the future may be probabilistically low, but cannot be discounted. If NERC wants the new Standard to address temperatures like those experienced in February 2021, the ECWT definition must yield a result lower than the current definition.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT had numerous discussions regarding this point during the Standard Development process and due to the comments received by industry in the initial and second ballot being split on this matter, the SDT elects to not make the proposed change at this time.	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	No
Document Name	
Comment	
For Generator Cold Weather Reliability Event, PNM recommends adding to (1) the cause of derate is within the "freezing of equipment within the Generator Owner's control". This would be similar to the statement in (3).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT may consider this modification during phase two of the Extreme Cold Weather Standard Development project.	
Tony Skourtas - Los Angeles Department of Water and Power - 3	
Answer	No
Document Name	
Comment	
LADWP proposes the following recommendations for the definitions of "Generator Cold Weather Critical Component" and "Generator Cold Weather Reliability Event". • For the definition of "Generator Cold Weather Critical Component" LDWP proposes to update the definition as seen below. This revision provides a concise and objective definition.	

"Any generating unit component or associated fixed fuel supply component, that is under the Generator Owner's control and is susceptible to freezing issues. the occurrence of which would likely lead to a Generator Cold Weather Reliability Event. • Provide clarification for the definition of "Generator Cold Weather Reliability Event" specifically for event 3. As currently written the definition implies the time of the event would be at the temperature of Extreme Cold Temperature or warmer. If event 3 is referring to freezing temperatures meaning colder than the Extreme Cold Weather Temperature, event 3 under this definition should be revised as follows: "(3) a Forced Outage, for which the apparent cause(s) is due to freezing of equipment within the Generator Owner's control and the dry bulb temperature at the time of the event was at or above below the Extreme Cold Weather Temperature."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT may consider your comments during phase two of the Extreme Cold Weather Standard Development project.	
Sheila Suurmeier - Black Hills Corporation - 1,3,5,6	
Answer	No
Document Name	
Comment	
BHC agrees with comments submitted by EEI & NAGF	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI and NAGF.	
Micah Runner - Black Hills Corporation - 1	
Answer	No
Document Name	
Comment	
BHC agrees with comments submitted by EEI & NAGF.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI and NAGF.	
Josh Combs - Black Hills Corporation - 3	
Answer	No
Document Name	
Comment	
BHC agrees with comments submitted by EEI & NAGF.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI and NAGF.	

Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
BHC agrees with comments submitted by EEI & NAGF.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI and NAGF.	

Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	
Generator Cold Weather Critical Component *The definition of Generator Cold Weather Critical Component does not line up with the team's responses to comments. The proposed definition in the standard is open to interpretation and inconsistent application because it can be read to include equipment that is not listed in the response to comments. NRG proposes the SDT include the list of equipment in the standard definition.* *Extreme Cold Weather Temperature*	

NRG is grateful the SDT simplified the ability for generators to meet these requirements with the latest definition of Extreme Cold Weather Temperature. *However, NRG understands that to meet and validate the Extreme Cold Weather Temperature (ECWT), some units will be required to perform a full reverse-engineering of identified critical systems. This would essentially require removing existing cold weather protection then installing new enhanced protection on these systems to meet the new requirements. The incremental cost differential by doing this instead of simply adding protection onto existing equipment could be cost prohibitive at some sites.* *The definition does not include clarification on accepted data sources for determining extreme temperature. NRG suggests this should be extracted from the newly developed guidance document and inserted into the standard.* *NRG believes that this minimum temperature level should be based upon historical operational performance or design criteria.* *NRG would accept the proposed ECWT definition provided technical, commercial, and operational constraints are accepted under R7.* *Generator Cold Weather Reliability Event* *The definition of Generator Cold Weather Reliability Event is not clear regarding what constitutes an apparent cause. Is this due only to freezing equipment at the generator site? There are many other actual causes for generator derates or start-up failures where freezing equipment may not be the actual cause or simply play a limited role. This should be clarified.*

Likes 0	
Dislikes 0	

Response	
Thank you for your comments. The SDT may consider your comments on the Cold Weather Reliability Event and the Generator Cold Weather Critical Component definitions during phase two of the Extreme Cold Weather Standard Development project. The SDT had numerous discussions regarding the Extreme Cold Weather Temperature definition during the Standard Development process and due to the comments received by industry in the initial and second ballot being split on this matter, the SDT disagrees with making the proposed change at this time. The SDT is using the definition of apparent as defined in the dictionary as "clear or manifest to the understanding".	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	No
Document Name	
Comment	
Generator Cold Weather Critical Component *The definition of Generator Cold Weather Critical Component does not line up with the team's responses to comments. The proposed definition in the standard is open to interpretation and inconsistent application because it can be read to include equipment that is not listed in the response to comments. NRG proposes the SDT include the list of equipment in the standard definition.* ***Extreme Cold Weather Temperature*** *NRG is grateful the SDT simplified the ability for generators to meet these requirements with the latest definition of Extreme Cold Weather Temperature.* *However, NRG understands that to meet and validate the Extreme Cold Weather Temperature (ECWT), some units will be required to perform a full reverse-engineering of identified critical systems. This would essentially require removing existing cold weather protection then installing new enhanced protection on these systems to meet the new requirements. The incremental cost differential by doing this instead of simply adding protection onto existing equipment could be cost prohibitive at some sites.* *The definition does not include clarification on accepted data sources for determining extreme temperature. NRG suggests this should be extracted from the newly developed guidance document and inserted into the standard.*	

NRG believes that this minimum temperature level should be based upon historical operational performance or design criteria. *NRG would accept the proposed ECWT definition provided technical, commercial, and operational constraints are accepted under R7.* ***Generator Cold Weather Reliability Event*** *The definition of Generator Cold Weather Reliability Event is not clear regarding what constitutes an apparent cause. Is this due only to freezing equipment at the generator site? There are many other actual causes for generator derates or start-up failures where freezing equipment may not be the actual cause or simply play a limited role. This should be clarified.*	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT may consider your comments on the Cold Weather Reliability Event and the Generator Cold Weather Critical Component definitions during phase two of the Extreme Cold Weather Standard Development project. The SDT had numerous discussions regarding the Extreme Cold Weather Temperature definition during the Standard Development process and due to the comments received by industry in the initial and second ballot being split on this matter, the SDT disagrees with making the proposed change at this time.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
"Generator Cold Weather Critical Component" introduces more confusion than it alleviates. For example, what is the definition of "associated fixed fuel supply components"? "Extreme Cold Weather Temperature" introduces unnecessary complexity and undue administrative burdens that do not lead to improved reliability. Reclamation recommends the initial proposal of using the coldest temperature back to 1/1/1975 was less confusing and less of an administrative burden than requiring entities to calculate the lowest .2 percentile of hourly temperatures. For example, climatological data	

from NOAA can only be processed 10 years at a time. For this timeframe, the file is over 55MB in size. Reclamation observed that following the NERC instructions and using a 10-year period of data took over an hour to filter and get the required data. Additionally, the data for several facilities only goes back to 2005, which will limit how much data some facilities can obtain and will automatically result in non-compliance with the proposed required analysis. Other searches yielded a longer period of available data, but from NOAA stations that were not near the facility in question (e.g., 100 miles away) or included major elevation changes (e.g., over 3000 feet and different weather patterns). These discrepancies will result in inaccurate data affecting the relevance of the calculations and again call into question the complicated structure of the proposed calculation method. Reclamation recommends the SDT account for these impacts to reliability as well as the ability to comply with the proposed requirements. “Generator Cold Weather Reliability Event” introduces unnecessary complexity and provides loopholes for entities to circumvent solutions to the root causes of the cold weather problem FERC is attempting to solve. Reclamation recommends the specification of “10% of total capacity” is unnecessary. The focus should be on whether the derate aggregates to a total exceeding the MW threshold.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT may consider your comment on the Cold Weather Reliability Event definition during phase two of the Extreme Cold Weather Standard Development project. The SDT had numerous discussions regarding the Extreme Cold Weather Temperature definition during the Standard Development process and due to the comments received by industry in the initial and second ballot being split on this matter, the SDT disagrees with making the proposed change at this time.	
Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County	
Answer	No
Document Name	
Comment	
While CHPD recognizes the merits of allowing the percentile method, we would recommend adding language to recognize and allow use of minimum temperature data from daily, monthly, or yearly weather record summaries, rather than prescriptively requiring a certain percentile of hourly data. Additionally it should also be noted that some weather station data will not go back to the required 2000 date	

and therefore language should be added to allow for flexibility in those instances. Furthermore, some generating plants do not have weather data directly available at the plant, but this data is available at a nearby location. The proximity of the weather site location to the generating plant should be addressed so this aspect is clear to the Generator Owner.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT had numerous discussions regarding this point during the Standard Development process and due to the comments received by industry in the initial and second ballot being split on this matter, the SDT elects to not make some of the proposed changes at this time. However, some of your suggestions for clarification may be considered in phase two of the Extreme Cold Weather Standard Development project.	
Lenise Kimes - City and County of San Francisco - 1,5 - WECC	
Answer	No
Document Name	
Comment	
For Generator Cold Weather Critical Component definition, please see modification (italicized - text in brackets describes recommended change) as follows: Any generating unit component or associated fixed fuel supply component, that is under the Generator Owner's *control* [recommend replacing "control" with "ownership"] ***ownership*** and that is susceptible to freezing issues, the occurrence of which would likely lead to a generating unit(s): (1) forced derate of more than 10% of the total capacity of the unit and exceeding 20 MWs for longer than four hours in duration, (2) a start-up failure where the unit fails to synchronize within a specified start-up time, or (3) a Forced Outage.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT may consider this modification during phase two of the Extreme Cold Weather Standard Development project.	
Devin Shines - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company	
Answer	No
Document Name	
Comment	
LouisvilleG&E/KU support EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Dominion Energy supports comments submitted by EEI proposing revisions to the proposed definitions.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI.	

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
In regards to the definition of the term “Generator Cold Weather Reliability Event”, the text “for which the apparent cause(s) is due to freezing of equipment within the Generator Owner’s control and the dry bulb temperature at the time of the event was at or above the Extreme Cold Weather Temperature” is provided *after* the text for (3), which gives the impression (likely unintentional) that it only applies to (3) rather that to (1), (2), and (3) collectively. AEP recommends moving the text so that it instead proceeds (1), (2), and (3), and adding text to make it clear that it indeed applies to all of them collectively. The definition of Generator Cold Weather Critical Component is somewhat circular, as it specifically references the word “component” multiple times, yet it does not clearly state what a “component” itself actually is. The definition could benefit from this added clarity, perhaps similar to that provided in the definition of “Protection System” in the NERC Glossary of Terms. This might be considered either now or in future phases of this project.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT may consider this modification during phase two of the Extreme Cold Weather Standard Development project. The SDT is using the definition of apparent as defined in the dictionary as “clear or manifest to the understanding”.	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	No
Document Name	
Comment	

PG&E supports the proposed definitions for Phase One (this version) of the Cold Weather project and agrees with the input by EEI and the NAGF that additional clarity is needed which should be completed during Phase Two of the project. Our input of NO for the comment is related to the additional work needed in Phase Two.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI and NAGF.	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3, Group Name OGE Energy	
Answer	No
Document Name	
Comment	
OG&E supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI.	
Joe Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	No
Document Name	

Comment	
Xcel Energy supports comments from EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI.	
David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren agrees with the EEI and the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI and NAGF.	
Mark Spencer - LS Power Development, LLC - 5	
Answer	No
Document Name	
Comment	
Extreme Cold Weather Temperature (“ECWT”): We do not agree that this definition adds clarity. Temperature, wind velocity, precipitation, and duration are inseparable when evaluating freeze protection measures. The SDT attempts to create a synthetic condition that has not	

occurred in nature. As we describe below, we think a more logical approach would be to select the duration and frequency of occurrence. This procedure links all variables as the naturally exist to establish models that set reliability standards. Setting the temperature first provides little predictive power in a generator's ability to perform under extreme cold weather events. As an example, if the ECWT were 15 degrees at a particular location and had to meet the duration standard for new generators, 12 hours, our analysis shows that the observed temperatures dip below the ECWT for some or all of the duration in almost all scenarios. In many cases, the dip is significant. Therefore, if a generator plans to perform for 12 hours *at the ECWT* it may fail. Additionally, we asked whether the SDT performed analysis to confirm whether an assumed 20 mph wind coincident with the duration was reasonable. The SDT replied that it was a reasonable assumption based on the group's experience. We analyzed the weather data for 27 locations from California to Massachusetts and North Dakota to Florida. In only one location (Boston) did wind and temperatures at or below the ECWT appear correlated.

Rather than specifying a temperature and a duration independently, the better approach would be to allow the Balancing Authorities (BA) to specify the weather scenarios that they use in their planning scenarios. Alternatively, if NERC were to set the standard, a better approach for establishing a continent-wide standard would be to start with a loss-of-load-expectation (LOLE) and work backwards to the combination of temperature, duration, wind, and (perhaps) precipitation that yield the criteria LOLE. As an example, select a reasonable duration – e.g., 12 hours, etc., then calculate the temperature that yields the selected LOLE memorialized in the reliability standard ("Historical Event(s)"). Fiftieth percentile wind speed coincident with these Historical Event(s) are then a derivative of this calculation. Because the effects of precipitation are much more subjective and difficult to quantify, the standard should require generator owners to examine historical precipitation coincident with the Historical Event(s) and document that they have considered the effects of the precipitation and modified their cold weather preparedness plans accordingly. We offer a proposed alternate definition:

*"**Extreme Cold Weather Event Standard –** An(a) observed event(s) with a duration of no less than 12 hours, such that the combination of observed hourly dry bulb temperatures and 50th percentile wind speeds yield a once in XX year probability of occurring at the generator's location based on a review of the historical weather from the period January 1, 2000 through the date the temperature is calculated."*

Generator Cold Weather Critical Component ("Component"): The benefit of defining specific components within a generator that may be susceptible to freezing are evident, but the benefit of applying a MW threshold at the component level is not. This definition does not expressly define a MW threshold but engages a threshold through the definition's reference to a "Generator Cold Weather Reliability Event." In our experience if a component is so fundamental to the operation of the facility that its loss could cause a derate, then it is

critical. Additionally, setting a MW threshold may be counter-productive. As an illustrative example, say a coal plant has six coal mills and only needs five to obtain full output – i.e., the loss of any one mill would not "likely" lead to a derate, so a generator owner could logically conclude that all coal mills could be excluded from the Component definition. Redundant instrumentation, conveyors, etc. may also be excused using similar logic. We propose the following definition: *"**Generator Cold Weather Critical Component** – Any generating unit component or associated fixed fuel supply component that are under the Generator Owner's control and are susceptible to freezing, the occurrence of which would likely lead to a forced outage, derate, failed start or the reliance on redundant or back-up components to maintain output."* **Generator Cold Weather Reliability Event ("Event"):** We do not have any comments to this definition at this time.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT had numerous discussions regarding the ECWT during the Standard Development process and due to the comments received by industry in the initial and second ballot being split on this matter, the SDT elects to not make some of the proposed changes at this time. However, some of your suggestions for clarification regarding Extreme Cold Weather Event and Generator Cold Weather Critical Component may be considered in phase two of the Extreme Cold Weather Standard Development project.	
Scott Kinney - Avista - Avista Corporation - 3	
Answer	No
Document Name	
Comment	

Avista supports all three definitions for this first phase, but we also propose additional revisions to the Generator Cold Weather Critical Supply Component and the Cold Weather Reliability Event because additional clarity is needed and that can be addressed during the next phase of this project. (See below)

Generator Cold Weather Critical Supply Component: Use of the undefined term "fixed fuel supply component" within the proposed definition of Generator Cold Weather Critical Component creates confusion. While we support the explanation provided by the SDT in the Technical Rationale, the Technical Rationale has no standing as a compliance document. For this reason, we ask the SDT to consider defining this term within the framework of the next phase of this project. We suggest the following for SDT consideration:

Fixed Fuel Supply Component: Are non-mobile equipment that support the reliable delivery of fuel to the generating unit and under the control the Generator Owner at a plant site. Gaseous, liquid, or solid fuel handling components that are installed on site as fixed parts of the fuel delivery system that are under the Generator Owner's control would be included. Components that would not be included would be mobile equipment such as trains, bulldozers, or other equipment that are not fixed in one location.

Generator Cold Weather Reliability Event: EEI is concerned with the use of the term "specified", as it relates to the start-up time of a generator during cold weather events, because it is unclear clear who would be responsible for specifying the start-up time. Results Based Standards should "define a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome." (NERC Results Based Standards – Performance Based; https://www.nerc.com/pa/Stand/Pages/ResultsBasedStandards.aspx#:~:text=Results%20based%20standards%20are%20standards,the%20NERC%20Standard%20Processes%20Manual.)

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT may consider your comments during phase two of the Extreme Cold Weather Standard Development project.

Brooke Jockin - Portland General Electric Co. - 1, Group Name Portland General Electric Co.

Answer	No

Document Name	
Comment	
Portland General Electric Company supports the survey response provided by EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	

Avista supports all three definitions for this first phase, but we also propose additional revisions to the Generator Cold Weather Critical Supply Component and the Cold Weather Reliability Event because additional clarity is needed and that can be addressed during the next phase of this project. (See below)

Generator Cold Weather Critical Supply Component: Use of the undefined term "fixed fuel supply component" within the proposed definition of Generator Cold Weather Critical Component creates confusion. While we support the explanation provided by the SDT in the Technical Rationale, the Technical Rationale has no standing as a compliance document. For this reason, we ask the SDT to consider defining this term within the framework of the next phase of this project. We suggest the following for SDT consideration:

Fixed Fuel Supply Component: Are non-mobile equipment that support the reliable delivery of fuel to the generating unit and under the control the Generator Owner at a plant site. Gaseous, liquid, or solid fuel handling components that are installed on site as fixed parts of the

fuel delivery system that are under the Generator Owner's control would be included. Components that would not be included would be mobile equipment such as trains, bulldozers, or other equipment that are not fixed in one location. **Generator Cold Weather Reliability Event**: EEI is concerned with the use of the term "specified", as it relates to the start-up time of a generator during cold weather events, because it is unclear clear who would be responsible for specifying the start-up time. Results Based Standards should "define a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome." (NERC Results Based Standards – Performance Based;	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT may consider your comments during phase two of the Extreme Cold Weather Standard Development project.	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
ECWT source data not clearly defined. This could be anything from an employee logging a thermometer value to downloading incomplete data from NOAA. Plus, data may be available and adequate for some generating stations, but for other remote generating station the search for historical data has produced incomplete and/or missing data. Maintaining a rolling minimum value of the lowest winter temperatures (3 months) from 1/1/2000 to current is excessive, especially for 20+ year old plants. Ten years of data from the commercial operation date or ten years ending on the date of adoption of EOP-012-1 would seem sufficient.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. The SDT had numerous discussions regarding this point during the Standard Development process and due to the comments received by industry in the initial and second ballot being split on this matter, the SDT elects to not make some of the proposed changes at this time. However, some of your suggestions for clarification may be considered in phase two of the Extreme Cold Weather Standard Development project.	
Brian Evans-Mongeon - Utility Services, Inc. - 4	
Answer	No
Document Name	
Comment	
It is unclear why the word “apparent” is used in the definition for Generator Cold Weather Reliability Event. Based on the time-lines provided for the development of a CAP (up to 150 days) there is sufficient time to make a determination of the cause of a Generator Cold Weather Reliability Event. Additionally, without determining the actual cause of an event it would be imposible to develop an effective CAP. The use of a subjective term like “apparent” opens up all events to interpretation during compliance review and should be removed from the definition.	
Likes 1	Illinois Municipal Electric Agency, 4, Todd Mary Ann
Dislikes 0	
Response	
Thank you for your comment. The SDT may consider this modification during phase two of the Extreme Cold Weather Standard Development project.	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	

Consider modifying the following term definitions:

-Extreme Cold Weather Temperature:

- Change "Extreme Cold Weather Temperature" to "Extreme Cold Weather Target Temperature" to discern between the lowest extreme cold weather temperature and the extreme cold weather temperature adjusted for the lowest 0.2 percentile of the hourly temperatures.

-Generator Cold Weather Critical Component:

- Change "Any generating unit component or associated fixed fuel supply component…" to "Any component or associated fixed fuel supply component…" to recognize non-traditional units (e.g., solar) that do not have traditional electrical generators and to capture unit auxiliary components.

-Generator Cold Weather Reliability Event:

- Suggestion #1: (2) a start-up failure where the unit fails to synchronize within a specified start-up time:

o Define specified start-up time duration that constitutes a start-up failure.

o Define the entity that would determine the start-up time duration and failure.

- Suggestion #2: (3) a Forced Outage",":

o Change comma to a semi-colon.

o Note: As written, the paragraph that follows "(3) a Forced Outage" appears to be uniquely linked to Event (3) rather than representing language specified for Events (1), (2) and (3).

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT may consider your comments during phase two of the Extreme Cold Weather Standard Development project.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	

The phrase from #3 from the Generator Cold Weather Reliability Event defintion – " for which the apparent cause(s) is due to freezing of equipment within the Generator Owner's control and the dry bulb temperature at the time of the event was at or above the Extreme Cold Weather Temperature" seems to apply to points #1 and #2 and therefore should be included in these or moved to the opening statement 'One of the following events for which the apparent cause…'

Also, within the same highlighted phrase, 'freezing of equipment' is specified, but not freezing of onsite fuel supplies or process fluids? Is fuel exempt? Lube oil? Ammonia? If these are included, this should be stated and further clarification/extension of the term 'freezing' may also be warranted to state something to the effect of 'changing fuel or process fluid properties such that critical processes are limited'.

FE also supports EEI's comments on the proposed definitions.

EEI supports all three definitions for this first phase, but we also propose additional revisions to the Generator Cold Weather Critical Component and the Cold Weather Reliability Event because additional clarity is needed and that can be addressed during the next phase of this project. (See below.)

Generator Cold Weather Critical Component: Use of the undefined term "fixed fuel supply component" within the proposed definition of Generator Cold Weather Critical Component creates confusion. While we support the explanation provided by the SDT in the Technical Rationale, the Technical Rationale has no standing as a compliance document. For this reason, we recommend defining this term within the framework of the next phase of this project. We suggest the following:

Fixed Fuel Supply Component: Are non-mobile equipment that support the reliable delivery of fuel to the generating unit and under the control the Generator Owner at a plant site. Gaseous, liquid, or solid fuel handling components that are installed on site as fixed parts of the

fuel delivery system that are under the Generator Owner's control would be included. Components that would not be included would be mobile equipment such as trains, bulldozers, or other equipment that are not fixed in one location. Generator Cold Weather Reliability Event: EEI is concerned with the use of the term "specified", as it relates to the start-up time of a generator during cold weather events, because it is unclear clear who would be responsible for specifying the start-up time. Results Based Standards should "define a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT may consider your comments during phase two of the Extreme Cold Weather Standard Development project.	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	No
Document Name	
Comment	
Talen Energy Marketing LLC supports Talen Generation's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to Talen Generation's comments.	
Donna Wood - Tri-State G and T Association, Inc. - 1	

Answer	No
Document Name	
Comment	
Tri-State mostly agrees however, the concept of mobile vs. fixed fuel should be incorporated into the Generator Cold Weather Critical Component definition.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT may consider this modification during phase two of the Extreme Cold Weather Standard Development project.	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
Talen Energy supports in large part the inputs of the NAGF on this topic, and goes further by recommending that the, "Extreme Cold Weather Temperature," should be the historical worst-case temperature (WCT, or DBT-plus-20 mph, as described above). Setting a statistical cutoff for winterization (proposed in Rev. 2 of EOP-012-1 to be the 0.2 percentile of the winter season) is fundamentally unsuitable. EOP-012-1 in its present form implies that the blackouts, deaths and damage caused by Winter Storm Uri are acceptable, so long as they are experienced only during the coldest 43 hours per decade (or much longer, due to the time needed to troubleshoot, thaw and restart units with freeze-up forced outages). This is precisely when BES reliability is most important, however, becoming a life-or-death matter.	

Where will the power come from during those 43 (or more) hours? The answer presently is that it will be supplied by older generation plants, designed to operate through all winter storms and not just some of them. As the years pass and these facilities are replaced by 0.2 percentile units, however, occasional devastating blackouts will become the norm, not as a ghastly error but according to plan.

The argument that some EPC firms use the 0.2 percentile cutoff has no validity. This is the cause of the problem, not the cure. One must not depend on old-reliable units to save the day and allow cutting corners in the quest to become the low bidder. It is NERC's job to put a halt to such practices, not enshrine them as the law of the land.

It is impossible moreover to slice matters so finely as a fraction of a percentile, since freeze protection is subject to great uncertainty due to frequent design and installation errors by contractors. Protection that is thought to address all weather except the coldest 43 hours per decade might in fact allow freeze-up for a much longer duration. Nor is there need for extreme exactitude, since the cost difference between designing for the 0.2 percentile temperature and historical worst-case conditions is negligible in comparison to the harm being prevented.

The DBT-plus-20 mph approach proposed above provides a simple alternative for GOs having difficulty identifying the worst-historical WCT. This would not be an excessively conservative criterion, since winter storms that cause grid emergencies tend to be by those combining low DBT values with high wind speed. Also, in our experience heat tracing/insulation systems rarely provide the specified protection, much less containing enough safety margin to cover 0.19 percentile-and-lower events. In summary:

{C}- The mission of Project 2021-07 is to ensure BES reliability during ALL credible winter storm conditions.

{C}- Historical worse-case conditions are credible; they happened before, so they can happen again.

{C}- Therefore the design criterion must be the historical worst-case weather conditions, which to be meaningful must be wind and temperature-based (WCT) and relying soly on temperature (DBT).

The definition of Generator Cold Weather Critical Components and the way in which this term is used in R1 and R3 indicate an obligation to list freeze-susceptible equipment at the component level and identify their individual temperature capabilities. Doing so for every outdoors pipe and tube containing water or steam (even large-bore systems can freeze if left static for too long during downtime periods), plus their associated instruments and equipment, would be extremely and unnecessarily burdensome. It should be sufficient to address elements at the system level, where freeze protections was implemented on this basis. That is, only a single entry would be needed for all outdoors water and steam piping if it was heat-traced and insulated under a single contact, using conditions of X degrees F DBT and Y mph wind speed.

The Generator Cold Weather Reliability Event definition should be revised and Guidance material should be added, as shown below. There are presently many forced outages under part 3 of this currently proposed definition (and EOP-012-1 in its present form will not prevent them), because the vulnerability being discussed is related to WCT for conventional plants, not DBT. Generator Cold Weather Reliability Event (1) a forced derate of more than 10% of the total capacity of the plant and exceeding 20 MW for the plant, for longer than four hours in duration, due to freezing of equipment within the Generator Owner's control. or (2) a start-up failure in which the unit fails to synchronize within the extreme cold weather start-up time declared for R3.5 [add this to R3.5, there is presently no target in this respect], due to freezing of equipment within the Generator Owner's control. Guidance: "Precautionary derates, e.g. ramping-down CTGs to minimum load during blizzards to help avoid clogging the inlet air filters, are not counted as forced derates so long as this limitation has been documented in accordance with R3.5 of EOP-012-1."

Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT may consider your comment on the Cold Weather Reliability Event and Generator Cold Weather Critical Component definitions during phase two of the Extreme Cold Weather Standard Development project. The SDT had numerous discussions regarding the Extreme Cold Weather Temperature definition during the Standard Development process and due to the comments received by industry in the initial and second ballot being split on this matter, the SDT disagrees with making the proposed change at this time.	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	

DTE Electric supports NAGF comments provided for this project	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to NAGF's comments.	
Diana Torres - Imperial Irrigation District - 6	
Answer	No
Document Name	
Comment	
IID disagrees that the 0.2 percentile is not overly conservative, IID recommends to use 0.5 or 1.0.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT had numerous discussions regarding this point during the Standard Development process and due to the comments received by industry in the initial and second ballot being split on this matter, the SDT elects to not make the proposed change at this time.	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	No
Document Name	
Comment	

The current definitions as written leave ample room for interpretation. While this is often desired, we believe that in this instance they do not provide enough clarity to the requirements of EOP-012. The specific concerns with the current verbiage are as follows:

Generator Cold Weather Critical Component: While the open-endedness of “any generating unit component” is desired as it allows the Generator Owner to identify critical components on a per-unit basis, it does not appear to include any “common” equipment shared between units. Examples would include service water, instrument air, ammonia, ash handling, common bus isolation breakers/switches, etc. The proposed modification to the definition is: “Any generating unit component or associated fixed fuel supply component, to include any critical equipment shared between multiple units (i.e. Balance of Plant (BOP) and/or Common equipment), that is under the Generator Owner’s control and is susceptible to freezing issues, the occurrence of which would likely lead to a Generator Cold Weather Reliability Event.”

Extreme Cold Weather Temperature: If the current method to calculate is implemented, NERC should consider coordinating with the National Oceanic and Atmospheric Administration to ensure dry bulb temperature data is available from 1/1/2000 through an indefinite future date. As currently written the requirement to use “the hourly temperatures measured” seems a bit excessive. Given the inherent difficulty of compiling a dataset containing > 49,000 data points and then calculating the lowest 0.2 percentile, we recommend modifying the definition to include daily minimum temperatures from the same time period. This modification would reduce the size of the dataset significantly (down to ~2076 total days) and should not change the resulting Extreme Cold Weather Temperature by any significant statistical margin given that the daily minimum will contain the hourly minimums.

Lastly, the requirement to use a fixed data start date of 01/01/2000 means the dataset will grow by approximately 2,160 data points if using the hourly metric while only 90 data points if using the daily minimum metric. Therefore, it is our recommendation to use a 20-year rolling time period if staying with the hourly metric.

If the hourly metric is to remain, a proposed modification to the definition would be: “The temperature equal to the lowest 0.2 percentile of the actual hourly temperatures measured in December, January, and February from the previous 20 years immediately prior to the date the temperature is calculated.“

The preferred modification would be to abandon the hourly metric in favor of the daily minimum metric. This proposed modification to the definition is: “The temperature equal to the lowest 0.2 percentile of the actual daily minimum temperatures measured in December, January, and February from 1/1/2000 through the date the temperature is calculated.”

Generator Cold Weather Reliability Event: Pertaining to event type 2 that may constitute a Generator Cold Weather Reliability Event:
2. “A start-up failure where the unit fails to synchronize within a specified start-up time”: Who specifies the start-up time? Per the draft Technical Rationale and Justification for EOP-012-1, start-up failures are defined using a modified version of the GADS definition in order to ensure consistency across all jurisdictions for this standard. Our concern stems from the language in R2 that references the GADS definition of “specified start-up time” without providing the additional clarification found in the 2022 GADS Data Reporting Instructions. Our recommendation is to modify this subsection as follows: “A start-up failure where the unit fails to synchronize within a specified start-up time. The specified start-up time period for each unit is determined by the GO/GOP based on the condition of the unit at the time of start-up.”

In addition this defined term is not clear in relation to what constitutes “apparent cause(s) is due to freezing of equipment” in the draft definition. AECI urges the standard drafting team to consider removing the word “apparent” from the definition as the apparent cause may not be the actual cause after further investigation.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The SDT may consider your comment on the Cold Weather Reliability Event and Generator Cold Weather Critical Component definitions during phase two of the Extreme Cold Weather Standard Development project. The SDT had numerous discussions regarding the Extreme Cold Weather Temperature definition during the Standard Development process and due to the comments received by industry in the initial and second ballot being split on this matter, the SDT disagrees with making the proposed change at this time.

Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6

Answer	No
Document Name	
Comment	
This standard should be clearly targeted to those entities not designed to run in below freezing conditions, that operate in those areas where it is possible to have freezing events. Those entities operating in environments where freezing is a yearly expectation, and where they are designed to operate in freezing weather should be exempt. We feel that, due to poor performance of certain generators in specific areas, the whole fleet of generators is being targeted for this poor performance. This comes at a significant cost and effort by smaller organizations who do not have these risks.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT may consider this modification during phase two of the Extreme Cold Weather Standard Development project. Please note that the SDT performed spot reviews of existing fleets of generating assets that currently operate in extreme cold weather and to the extent that these units are employing current industry best practices, the SDT feels that the additional compliance documentation in meeting the proposed new standard will not be significant in either cost or effort.	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	

LaKenya VanNorman - LaKenya VanNorman On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name Florida Municipal Power Agency (FMPA)	
Answer	Yes
Document Name	
Comment	
We agree with the new proposed definitions, but still believe the definition of Generator Cold Weather Reliability Event should either remove the phrase “apparent cause(s)” or reword it to be “for which the apparent cause(s), as determined by the entity during RCA or internal investigation, is due to…”. Without definition, the term “apparent” is subjecetive and open to different interpretations. It should be removed, or clarified that it is as defined by the entity.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT may consider your comments during phase two of the Extreme Cold Weather Standard Development project.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon agrees with the proposed definitions. Exelon supports EEI's comments regarding the benefit of making clarifying enhancements to the definitions during the next phase of this project.	

Submitted on behalf of Exelon, Segments 1 & 3	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Also see response to EEI.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	
“Please see comments submitted by the Edison Electric Institute”	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to Edison Electric Institute.	
Alison Mackellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	

Constellation specifically notes support for the use of percentiles in the definition of Extreme Cold Weather Temperature, and support for the use of the term "apparent" in the definition Generator Cold Weather Reliability Event. Kimberly Turco, on behalf of Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT will note the support for both the percentile approach and the support for “apparent” in phase two ongoing discussions. The SDT is using the definition of apparent as defined in the dictionary as “clear or manifest to the understanding”.	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation specifically notes support for the use of percentiles in the definition of Extreme Cold Weather Temperature, and support for the use of the term "apparent" in the definition Generator Cold Weather Reliability Event. Kimberly Turco, on behalf of Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT will note the support for both the percentile approach and the support for “apparent” in phase two ongoing discussions. The SDT is using the definition of apparent as defined in the dictionary as “clear or manifest to the understanding”.	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
To clarify the definition of “Generator Cold Weather Reliability Event”, we recommend the language “for which the apparent cause(s) is due to freezing of equipment within the Generator Owner’s control and the dry bulb temperature at the time of the event was at or above the Extreme Cold Weather Temperature” be moved to the beginning of the definition to clarify that it applies to derates, start-up failures, AND forced outages.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT may consider this modification during phase two of the Extreme Cold Weather Standard Development project.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
The SDT intended for the “Extreme Cold Weather Temperature” to be recorded at or near the plant site, but the location is not included in the definition. We suggest the SDT consider enhancing the definition (incorporating a location) such as the following:	

Extreme Cold Weather Temperature – The temperature equal to the lowest 0.2 percentile of the hourly temperatures neasured in December, January, and February from 1/1/2000 through the date the temperature is calculated at one of the following locations:

a. At the generating plant site (preferred location).

b. At the closest official meterological location.

c. At an official weather recording site within the generating plant surrounding area.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT may consider your comments during phase two of the Extreme Cold Weather Standard Development project.

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

Answer	Yes
Document Name	

Comment

Southern Company aligns with EEI's comments an offers some suggestions for additional clarity. For Generator Cold Weather Critical Component, we suggest clarification would be beneficial to specifically state in the definition that it includes equipment for which the GO has responsibility to provide freeze protection.

Southern also proposes modifying the definition of Generator Cold Weather Reliability Event to be when the dry-bulb temperature was above the generator's stated minimum operating temperature in R3 and not at or above the Extreme Cold Weather Temperature. Requiring a CAP for freezing issues below an already stated capability would only create additional administrative burden with no reliability benefit.

Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The SDT may consider your comments during phase two of the Extreme Cold Weather Standard Development project.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
We agree with the definitions and our program will inform the correct action to maintain reliability at Extreme Cold Weather Temperature, prepare for a Cold Weather Event and identify Cold Weather Critical Components. We can communicate our concerns for generator availability using the communication requirements.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
John Liang - Snohomish County PUD No. 1 - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	

Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Scott McGough - Georgia System Operations Corporation - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Donna Johnson - Oglethorpe Power Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Sean Steffensen - IDACORP - Idaho Power Company - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Glenn Pressler - CPS Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
The SDT appreciates your review.	
Michael Watt - Oklahoma Municipal Power Authority - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
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	
The SDT appreciates your review.	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your review.	

3. Is the revised Applicability Section language clear? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	No
Document Name	
Comment	
The applicabilty should exempt those generation facilities that are designed and operated in below freezing weather, or that employ technology that is not affected by extreme cold weather.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The drafting team has added clarifying language for the final ballot.	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
DTE Electric supports NAGF comments provided for this project	
Likes 0	
Dislikes 0	
Response	

Thank you for the comment, please see response to NAGF.	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
The Applicability section is clear, but insufficient. There cannot be meaningful progress on enhancing BES wintertime reliability without proper Planning Assessments and real-time resource adequacy evaluations, and these goals cannot be achieved if RCs, BAs and TOPs continue to use a DBT yardstick for WCT-related phenomena. The DBT-based databases presently being used create a false sense of resource adequacy, as was demonstrated during Winter Storm Uri. It may not be possible for EOP-012-1 to set requirements for RCs, BAs and TOPs, since they were omitted from the SAR, but NERC should launch a parallel project so that they use accurate, WCT-based temperature capability data (or DBT-plus-20 mph), and EOP-012-1 should set the stage by manfdating collection of this information.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team will not take action on your comment but will pass your suggestion for a parallel project onto NERC for consideration. The drafting team would also remind industry that any entity or individual may propose the development of a new or modified Reliability Standard by submitting a completed SAR to the NERC Reliability Standards staff.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	

a. 4.2.1.1 That commits or is obligated to serve a Balancing Authority load pursuant to an Open Access Transmission Tariff (OATT) or other contractual arrangement; This should not be included in the Applicability section as per FAC-001-3, R4.3, all BES generators must be within a BA metered boundary. b. The inclusion of blackstart resources is redundant with the inclusion I3 of the BES definition and therefore should be removed. c. The cold weather exclusion should be removed from the applicability section and instead a requirement should be added to require the GO to prove operability in cold weather through analysis/studies.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The SDT is not making substantive changes to the applicability section but has added clarifying language that may address some of your concerns. FAC-001 concerns interconnection requirements and is not related to the commitment to run during freezing temperatures, which is part of the elements of applicability. The use of the term Blackstart Resources is for clarity notwithstanding any potential redundancies.	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	No
Document Name	
Comment	
Talen Energy Marketing LLC supports Talen Generation's comments.	
Likes 0	
Dislikes 0	
Response	

Thank you for the comment, please see response to Talen Generation.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FE supports EEI comments on the proposed changes to Functional Entities and fully support removing the phrase “pursuant to an Open Access Transmission Tariff (OATT) or other contractual arrangement”. The proposed edits read: Applicability: 4.1 Functional Entities: 4.1.1. Generator Owner 4.1.2. Generator Operator 4.2. Facilities: The term “generating unit” subject to these requirements means: 4.2.1. A Bulk Electric System generating unit that commits or is obligated to serve a Balancing Authority load excluding a Bulk Electric System generating unit that is not committed or obligated to operate at or below thirty-two (32) degrees Fahrenheit (zero degrees Celsius) for any continuous run of more than four hours. The exclusion continues to apply should when such BES generator be called upon to operate for more than four hours in order to assist in the mitigation of BES Emergencies, Capacity Emergencies, or Energy Emergencies during periods at or below 32 degrees Fahrenheit. 4.2.2. That is identified as a Blackstart Resource.	
Likes 0	
Dislikes 0	
Response	

Thank you for the comment. The drafting team has added clarifying language for the final ballot.

Lindsey Mannion - ReliabilityFirst - 10	
Answer	No
Document Name	
Comment	
We recommend the SDT consider establishing a defined winter season under 4.2.1.1.1 or placing responsibility for defining a winter season on the Balancing Authority rather than relying on the "typically not available at or below thirty-two degrees" language.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The drafting team had previously determined (based on multiple comments on Draft One) to not define the winter season or add the responsibility for the BA to determine a winter season. Therefore, the drafting team has decided to continue with the current Draft Two paradigm.	

Brian Evans-Mongeon - Utility Services, Inc. - 4	
Answer	No
Document Name	
Comment	
The Applicability is unnecessarily complicated. section 4.2.1.2: Is it the intent to not automatically include generators that meet the BES definition Inclusions I2 and I4? Blackstart Resources (I5) are already included as BES Generators per the definition of the BES and it is redundant and/or confusing to call them out specifically.	

Section 4.2.1.1.1 uses the term "typically" which is subjective and unclear. If this is going to be used as an exclusion to the standard it should be definitive. Alternatively, the limited generators that this will be applicable to can utilize this type of exclusionary langue in their Cold Weather Prep Plan and as justification for not implementing a CAP to address issues as necessary.	
Likes 1	Illinois Municipal Electric Agency, 4, Todd Mary Ann
Dislikes 0	
Response	
Thank you for the comment. The drafting team has added clarifying language for the final ballot.	
Mark Spencer - LS Power Development, LLC - 5	
Answer	No
Document Name	
Comment	

The proposed definition of a BES generating unit is one "[t]hat commits or is obligated to serve a Balancing Authority load pursuant to an Open Access Transmission Tariff (OATT) or other contractual arrangements." This definition assumes that an obligation "to serve" exists. The majority of generating assets in the United States are located in regions overseen by Independent System Operators or Regional Transmission Operators and do not have obligations "to serve," unless pursuant to a state contract or stretching the definition – a Reliability Must Run contract. They may have an obligation to supply energy under specified rules on a seasonal or annual basis if they clear a capacity auction. If the intent of this rule is to apply only to generation owned by a vertically integrated utility subject to federal and/or state laws that obligate the utility to provide service, to a publicly owned generator subject to municipal rules regarding an obligation to serve, or to a generating unit that has contractually committed to supply energy for a long term period to a Balancing Authority or through state and or/federal contract, the definition may not be infirm. However, we encourage the SDT to clarify the purpose and intent of this section.

With regard to R4.1.1.1, we note that, as drafted, a generator that is typically unavailable above 32 degree Fahrenheit – e.g., a mothballed unit in south Florida – would be required to comply with the standard. The first criteria should be whether a location experiences sufficient freezing conditions to warrant applicability. If it does not, then there is no compliance obligation – e.g., San Diego. If it does, then the availability criteria should apply. We also recommend replacing "typical" with the ECWT to create bright line criteria. In addition, we do not understand the need to specify the duration of a dispatch schedule. In our experience, failures of peaking resources are more likely to occur

during start-up than during operations. BAs typically dispatch peaking plants after the nadir of the local temperature in the overnight hours – i.e., morning ramp, thus we recommend SDT change the definition to: *“The term excludes a Bulk Electric System generating unit that is: (i) in a location where the Extreme Cold Weather Temperature is calculated to be greater than 32 degree Fahrenheit (0 degree Celsius) or (ii) in a location where the Extreme Cold Weather Temperature is calculated to be lower than or equal to 32 degree Fahrenheit (0 degree Celsius) and the unit is typically not available in these freezing conditions.”*	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The drafting team has added clarifying language for the final ballot.	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	No
Document Name	
Comment	
PG&E supports the comments provided by EEI and the NAGF, and has the following additional concern and recommendations related to NAGF’s second input; The currently proposed wording in Section 4.2.1.1.1 is not clear what is required if a Generator Owner's calculated Extreme Cold Weather Temperature is above 32 degrees Fahrenheit. To address this concern, PG&E recommends the addition of “or a generator that has determined its Extreme Cold Weather Temperature be above 32 degrees” in the first sentence of 4.2.1.1.1 to help correct this issue.	
Likes 0	
Dislikes 0	

Response	
Thank you for the comment. The drafting team has added clarifying language for the final ballot.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation disagrees with 4.2.1.1 and disagrees with the exclusion in 4.2.1.1.1. Reclamation disagrees with narrowing the scope of applicability based on entity choice of units that operate. Generating units that have no potential to freeze, e.g., hydroelectric plants that are housed indoors in climate-controlled buildings, should be excluded. Generating units that may be called on to assist in the mitigation of any Emergency should not be excluded because the failure of these units to operate properly in an Emergency exacerbates the Emergency. Reclamation asserts that exempting these units is a clear loophole in the intent of ensuring reliability during cold weather. Both exclusions will decrease BES reliability.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The drafting team believes that the exclusions as developed during team meetings is consistent with the intent stated in the Joint Report. Additionally, the drafting team has added clarifying language for the final ballot, but is not making substantive changes to the current language.	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	No
Document Name	
Comment	

A clear statement also needs to be made that this standard is not applicable to a generator with the Extreme Cold Weather temperature above 32 degrees.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The drafting team has added clarifying language for the final ballot.	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	
A clear statement also needs to be made that this standard is not applicable to a generator with the Extreme Cold Weather temperature above 32 degrees	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The drafting team has added clarifying language for the final ballot.	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	

BHC still needs clarity on what the SDT is attempting to say by the 4.2.1.1 BA portion.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The drafting team has added clarifying language for the final ballot.	
Josh Combs - Black Hills Corporation - 3	
Answer	No
Document Name	
Comment	
BHC still needs clarity on what the SDT is attempting to say by the 4.2.1.1 BA portion.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The drafting team has added clarifying language for the final ballot.	
Micah Runner - Black Hills Corporation - 1	
Answer	No
Document Name	
Comment	
BHC still needs clarity on what the SDT is attempting to say by the 4.2.1.1 BA portion.	
Likes 0	

Dislikes 0	
Response	
Thank you for the comment. The drafting team has added clarifying language for the final ballot.	
Sheila Suurmeier - Black Hills Corporation - 1,3,5,6	
Answer	No
Document Name	
Comment	
BHC still needs clarity on what the SDT is attempting to say by the 4.2.1.1 BA portion.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The drafting team has added clarifying language for the final ballot.	
Tony Skourtas - Los Angeles Department of Water and Power - 3	
Answer	No
Document Name	
Comment	
LDWP recommends this requirement to be region specific applicable only to areas that are susceptible to Extreme Cold Weather. In addition, require Generator Owners that plan to operate generating units in areas susceptible to Extreme Cold Weather to specify the need for continuous operation at or below the Extreme Cold Weather Temperature.	
Likes 0	
Dislikes 0	

Response	
Thank you for the comment. The Joint Report recommends national standards be developed on an industry-wide basis, which was the model followed in the SAR. The standard drafting team is not developing regional specific standards or applicability.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
In order to capture the comparable OATT in non-US jurisdictions, we suggest revising 4.2.1.1 as follows: That commits or may be committed or is obligated to serve a Balancing Authority load pursuant to an Open Access Transmission Tariff (OATT) or other contractual arrangement or rules; The IESO strongly believes that the standard should apply to all the generating units whose capacity is being counted on, including those providing sufficient reserve to withstand a cold weather event. The IESO suggests considering the concept of requiring the GO to declare to the BA/RC a unit will not run during the winter, unless the BA/RC requests it to run during an emergency.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The drafting team has added clarifying language for the final ballot.	
James Baldwin - Lower Colorado River Authority - 1	
Answer	No
Document Name	
Comment	

In Section 4.2.1.1.1 the language 'typically not available' is subjective and unclear. If an exclusion is allowed, the Balancing Authority should determine which resources are excluded from the EOP-012 standard and requirements. Further, excluding resources from NERC reliability standards but allowing those same resources to be dispatched in the conditions (below 32 degrees) which this standard addresses, is contrary to the purpose of this exact NERC standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The drafting team believes that the exclusions, as developed during team meetings, is consistent with the intent stated in the Joint Report. Additionally, the drafting team has added clarifying language for the final ballot, but is not making substantive changes to the current language. Your suggestion will be forwarded onto the drafting team for consideration in Phase Two.	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	No
Document Name	
Comment	
In Section 4.2.1.1.1 the language 'typically not available' is subjective and unclear. If an exclusion is allowed, the Balancing Authority should determine which resources are excluded from the EOP-012 standard and requirements. Further, excluding resources from NERC reliability standards but allowing those same resources to be dispatched in the conditions (below 32 degrees) which this standard addresses, is contrary to the purpose of this exact NERC standard.	
Likes 0	
Dislikes 0	
Response	

Thank you for the comment. The drafting team believes that the exclusions, as developed during team meetings, is consistent with the intent stated in the Joint Report. Additionally, the drafting team has added clarifying language for the final ballot, but is not making substantive changes to the current language. Your suggestion will be forwarded onto the drafting team for consideration in Phase Two.	
Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	
AES Clean Energy supports comments submitted by NAGF.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see response to NAGF.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
The NAGF has two concerns with the applicability section. The first concern is that the language used in section 4.2.1.1 is unclear as to the meaning. Every generator has an interconnection agreement with their Transmission Owner (and possibly other third parties) which is under the OATT. The NAGF is concerned that the lack of clarity in this statement will lead to assumptions that differ across the registered entities and the regulators. Clarity would be provided by clearly stating that this standard is applicable to generators that are accepted in a capacity market rather than the vague wording used in the current draft.	

The second concern is that it is not clear what is required of a Generator Owner if the calculated Extreme Cold Weather Temperature is above 32 degrees Fahrenheit. To address this concern, a clear statement that this standard is not applicable to a generator with the Extreme Cold Weather Temperature above 32 degrees is needed. The addition of "or a generator that has determined its Extreme Cold Weather Temperature to be above 32 degrees" in the first sentence of 4.2.1.1.1 will correct this issue.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team has added clarifying language for final ballot.	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	No
Document Name	
Comment	
ISO-NE believes that if the GOs are left to their own declaration of being "typically" available and/or if they are required to upgrade a unit or facility with freeze protection, this could create an unfair market advantage to those entities that choose not to freeze protect their units and facilities for "commercial" reasons. During extreme weather events markets may account for these situations reflected in the real-time prices. Thus, ISO-NE suggests the SDT consider the concept of requiring the GO to declare to the BA/RC a unit will not run during the winter so the GO cannot take advantage of high prices unless the BA/RC requests it to run during an emergency.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Additionally, the drafting team has added clarifying language for the final ballot, but is not making substantive changes to the current language. Your suggestion will be forwarded onto the drafting team for consideration in Phase Two.	

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	No
Document Name	
Comment	
Alliant Energy supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see response to MRO NSRF.	

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	

The Applicability Section in the revised standard seems to indicate applicability to individual generating units. During the Q&A session of the WebEx presentation held on 8/16/22, a question was asked that led to discussion around this term, and it was indicated that the requirements, when considering I4 generating facilities, should be applied to entire wind farm (time mark 1:48:14 in the August 16, 2022 webinar recording). Considering this discrepancy, the MRO NSRF requests the Standard Drafting Team provide clarifying language in the Applicability Section of the Standard.

Proposed language:

4.2 Facilities: : For purposes of this standard, the term “generating unit” subject to
these requirements means:
4.2.1 For generating facilities included in the BES under:

4.2.1.1 Inclusion I2, an individual generating unit 4.2.1.2 Inclusion I3, any Blackstart Resources identified in the Transmission Operator’s restoration plan. 4.2.1.3 Inclusion I4, the aggregated dispersed power producing resources with a total capacity of 75 MVA or greater. and 4.2.2 That commits or is obligated to serve a Balancing Authority load pursuant to an Open Access Transmission Tariff (OATT) or other contractual arrangement; 4.2.3 The term excludes a Bulk Electric System generating unit that is typically not available at or below thirty-two (32) degrees Fahrenheit (zero degrees Celsius) for any continuous run of more than four hours. The exclusion applies even when such BES generator has been called to assist in the mitigation of BES Emergencies, Capacity Emergencies, or Energy Emergencies during periods at or below 32 degrees Fahrenheit.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The drafting team determined that referencing “Bulk Electric System” or “BES” from the glossary of terms is sufficient to capture Inclusions I2-I4.	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	No
Document Name	
Comment	

MidAmerican Energy supports the MRO NSRF comments for this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see response to MRO NSRF.	
Steven Sconce - EDF Renewable Energy - 5	
Answer	No
Document Name	
Comment	
EDF supports the comments submitted by NAGF.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to NAGF.	
Imane Mrini - Austin Energy - 6	
Answer	No
Document Name	
Comment	
As this is written, it says that a "generation unit" is a BES unit that is committed/obligated AND is identified as a blackstart resource. Because 4.2.1 doesn't indicate that the unit be "one of the following" and because there's no OR between 4.2.1.1 and 4.2.1.2, there is an implied AND. This suggests that, for the purpose of this standard, only blackstart units need to winterize. We suspect that this is not the intent of the	

document, so we would recommend changing 4.2.1 to say "A Bulk Electric System generating unit that conforms to either 4.2.1.1 or 4.2.1.2 below:". I would also move 4.2.1.1.1 to become 4.2.2. so that it doesn't impede or obscure the either/or choice of 4.2.1.1/4.2.1.2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, the team has made clarifying changes to the final ballot.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
MISO supports the comments submitted by the ISO/RTO Council Standards Review Committee (IRC SRC) except where noted.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see response to IRC SRC.	
Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	No
Document Name	
Comment	
Capital Power supports the North American Generators Forum (NAGF) response to this question.	
Likes 0	

Dislikes 0	
Response	
Thank you for the comment, please see response to NAGF.	
Ronald Bauer - MGE Energy - Madison Gas and Electric Co. - 3	
Answer	No
Document Name	
Comment	
Madison Gas and Electric supports the comments from the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to MRO NSRF.	
Adam Lee - MGE Energy - Madison Gas and Electric Co. - 4	
Answer	No
Document Name	
Comment	
Madison Gas and Electric supports the comments of the MRO NSRF	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to MRO NSRF.	

Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations	
Answer	No
Document Name	
Comment	
In regards to the proposed Section 4.2 Facilities definition: In order to ensure a reliable response from generators that may be called upon by the Balancing Authorities during Capacity and Energy Emergencies, we recommend eliminating the exception for generators that do not operate during the winter season except when called upon by the Balancing Authority to be available during Capacity Emergencies or Energy Emergencies. Our recommended change to the language would be “The term excludes those generators that are not normally expected to operate during the winter season under normal and/or emergency conditions.”	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The drafting team has added clarifying language for the final ballot.	
Colin Chilcoat - Invenergy LLC - 6	
Answer	No
Document Name	
Comment	
The revised Applicability Section is less clear than the version presented for the first ballot. Specifically, it is not clear what BES generating units the SDT intends to include with respect to the load-serving requirement and listed contractual qualifiers in Section 4.2.1.1. Invenergy recommends that the Applicability be returned to the language used for the first ballot.	
Likes 0	

Dislikes 0	
Response	
Thank you for the comment. The drafting team determined to retain the second ballot language, but has included clarified language for the final ballot.	
George Brown - Acciona Energy North America - 5	
Answer	No
Document Name	
Comment	
Acciona Energy supports Midwest Reliability Organization's (MRO) NERC Standards Review Forum's (NSRF) comments on this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to MRO NSRF.	
Whitney Wallace - Calpine Corporation - 5 - WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
WGRs may not meet the requirements of 4.2.1.1.1 if ambient dry bulb air temperature is below 32 degrees Fahrenheit and wet precipitation (i.e., rain) is being deposited on the turbine blades. Additionally, it is not clear why certain types of units would be exempt from the Standard. NERC should clearly specify the types of units that it intends exempt from this Standard and explain why exempting these units is not unduly discriminatory.	
Likes 0	

Dislikes 0	
Response	
Thank you for the comment. The drafting team believes that the exclusions, as developed during team meetings, is consistent with the intent stated in the Joint Report. Additionally, the drafting team has added clarifying language for the final ballot, but is not making substantive changes to the current language.	
Russell Noble - Cowlitz County PUD - 3	
Answer	No
Document Name	
Comment	
Cowlitz agrees with comments proviced by North American Generator Forum and Utility Services.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see response to NAGF.	
Deanna Carlson - Cowlitz County PUD - 5	
Answer	No
Document Name	
Comment	
Agree with comments provided by Russell Noble.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment, please see response to Russell Noble.	
Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)	
Answer	No
Document Name	
Comment	

The SRC supports the addition of Part 4.2.1.1, as the language provides a clear and measurable criteria. However, the SRC believes it could be improved. Specifically, Section 4.2.1.1 refers to a unit *obligated to serve a BA load pursuant to an Open Access Transmission Tariff (OATT) or other contractual arrangement*. Specifically, an OATT does not define capacity obligations of units in RTO regions. Those obligations appear in: (i) other agreements approved by FERC; (ii) state law in states with vertically integrated utilities (such as the requirement for the state PUC to find units receiving rate base treatment “used and useful”); or (iii) market rules. As written, the Standard’s language would override (or, at best, conflict with) those other requirements. As a result, to avoid that problem the SRC recommends revising the language as follows (to cover RTOs, ERCOT and Canadian entities):

That commits or may be committed or is obligated to serve Balancing Authority load pursuant to a tariffed obligation, state requirement as defined by relevant electric regulatory authority, other contractual arrangement, rules or regulations;

Section 4.2.1.1.1 goes on to inadvertently undo the sweep of Section 4.2.1.1 by stating the Standard, “...excludes a [BES] generating unit... typically not available at or below thirty-two (32) degrees...for any continuous run of more than four hours [and] applies even when such BES generator has been called to assist in the mitigation of BES Emergencies, Capacity Emergencies, or Energy Emergencies during periods at or below 32 degrees Fahrenheit.” To correct this drafting issue, the SRC recommends adding the following language at the beginning of Section 4.2.1.1.1:

“For any generating unit not covered by Section 4.2.1.1,…”

Within Section 4.2.1.1.1, using the phrase "typically not available at or below thirty-two degrees…" allows a GO to self-proclaim a unit not "typically" available in the winter. The SRC believes the SDT should revisit this language and provide more measurable parameters. Otherwise,

a GO could make itself available one day and not the next. It also provides no parameters for what constitutes "typical;" *i.e.*, more than 50% of the time, 25%, etc.? As written, a Regional Entity could not audit a unit exemption. [GOs should not be able to choose to not weatherize a unit and then choose to offer that unit to take advantage of high prices during the winter season. Thus, the SRC suggests the SDT consider the concept of requiring the GO to declare to the BA/RC a unit will not run during the winter so the GO cannot take advantage of high prices *unless* the BA/RC requests it to run during an emergency.] ***** **** Please note:*** *MISO is not a party to this paragraph in response to this Question. PJM also has concerns with this response.*	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The drafting team has added clarifying language for the final ballot, but is not making substantive changes to the current language.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
AEPC has signed on to ACES comments, please see their responses.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see response to ACES.	
Rhonda Jones - Invenergy LLC - 5	
Answer	No

Document Name	
Comment	
The revised Applicability Section is less clear than the version presented for the first ballot. Specifically, it is not clear what BES generating units the SDT intends to include with respect to the load-serving requirement and listed contractual qualifiers in Section 4.2.1.1. Invenergy recommends that the Applicability be returned to the language used for the first ballot.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The drafting team determined to retain the second ballot language, but has included clarified language for the final ballot.	
LaKenya VanNorman - LaKenya VanNorman On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name Florida Municipal Power Agency (FMPA)	
Answer	No
Document Name	
Comment	
The applicability will not be consistently applied due to references to contracts for serving load that are not related to NERC standards (i.e. 4.2.1.1 “That commits or is obligated to serve a Balancing Authority load pursuant to an Open Access Transmission Tariff (OATT) or other contractual arrangement.”). In addition, the use of the phrase “not typically available at or below thirty-two (32) degrees” in 4.2.1.1.1 is highly subjective and open to interpretation.	
Likes 0	
Dislikes 0	

Response	
Thank you for the comment. The drafting team has added clarifying language for the final ballot.	
Natalie Johnson - Enel Green Power - 5	
Answer	No
Document Name	
Comment	
The term “generating unit” causes confusion in how the standard applies to renewable resources. Although an attempt to clarify is provided, the term “generating unit” is often interpreted to refer to individual turbines or invertors and not the aggregate facility. Enel therefore supports the MRO NSRF proposed language to further clarify section 4.2. In particular, Enel supports the MRO NSRF suggestion to clarify that the term “generating unit” refers to Inclusion I4, the aggregated dispersed power producing resources with a total capacity of 75 MVA or greater. In addition, Enel also recommends that this clarification be consistent with how this issue was addressed in other standards such as PRC-024.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The drafting team determined that referencing “Bulk Electric System” or “BES” from the glossary of terms is sufficient to capture Inclusions I2-I4.	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	Yes
Document Name	
Comment	
In regards to the proposed Section 4.2 Facilities definition: In order to ensure a reliable response from generators that may be called upon by the Balancing Authorities during Capacity and Energy Emergencies, we recommend eliminating the exception for generators that do not operate during the winter season except when called upon by the Balancing Authority to be available during Capacity Emergencies or Energy Emergencies. Our recommended change to the language would be "The term excludes those generators that are not normally expected to operate during the winter season under normal and/or emergency conditions."	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The drafting team believes that the exclusions, as developed during team meetings, is consistent with the intent stated in the Joint Report. Additionally, the drafting team has added clarifying language for the final ballot, but is not making substantive changes to the current language.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	

Comment	
Southern Company agrees that the Applicability Section language is clear.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
While Avista supports the Applicability Section, it is overly complicated and offer the following non-substantive changes for consideration:	

4.2 Facilities: The term “generating unit” subject to these requirements means: 4.2.1 Bulk Electric System (BES) generating unit(s) that commit or are obligated to serve a Balancing Authority load pursuant to an Open Access Transmission Tariff (OATT) or other contractual arrangement, excluding BES generating unit(s) that are that are not committed or obligated to operate at or below thirty-two (32) degrees Fahrenheit (zero degrees Celsius) for any continuous run of more than four hours. The exclusion applies even when such BES generating unit(s) have been called to assist in the mitigation of BES Emergencies, Capacity Emergencies, or Energy Emergencies during periods at or below thirty-two (32) degrees Fahrenheit (zero degrees Celsius). 4.2.2 Blackstart Resource(s) that are identified in the Transmission Operator’s system restoration plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The drafting team has added clarifying language for the final ballot.	
Brooke Jockin - Portland General Electric Co. - 1, Group Name Portland General Electric Co.	
Answer	Yes
Document Name	
Comment	
Portland General Electric Company supports the survey response provided by EEI.	
Likes 0	
Dislikes 0	
Response	

Thank you for the comment, please see response to EEI.	
Scott Kinney - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
While Avista supports the Applicability Section, it is overly complicated and offer the following non-substantive changes for consideration: 4.2 Facilities: The term “generating unit” subject to these requirements means: 4.2.1 Bulk Electric System (BES) generating unit(s) that commit or are obligated to serve a Balancing Authority load pursuant to an Open Access Transmission Tariff (OATT) or other contractual arrangement, excluding BES generating unit(s) that are that are not committed or obligated to operate at or below thirty-two (32) degrees Fahrenheit (zero degrees Celsius) for any continuous run of more than four hours. The exclusion applies even when such BES generating unit(s) have been called to assist in the mitigation of BES Emergencies, Capacity Emergencies, or Energy Emergencies during periods at or below thirty-two (32) degrees Fahrenheit (zero degrees Celsius). 4.2.2 Blackstart Resource(s) that are identified in the Transmission Operator’s system restoration plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The drafting team has added clarifying language for the final ballot.	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	

Ameren agrees with the EEI and the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see response to EEI and NAGF.	
Joe Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Xcel Energy supports comments from EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see response to EEI.	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3, Group Name OGE Energy	
Answer	Yes
Document Name	
Comment	
OG&E supports the comments submitted by EEI.	
Likes 0	

Dislikes 0	
Response	
Thank you for the comment, please see response to EEI.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
AEP would like to express its support of EEI’s response to this question and adds supportive comments below. AEP believes the Applicability section could be improved by making it clear that a Blackstart Resource, for purposes of this standard, are *only* those resources identified as such by the RTO (serving as the BA). 4.2.1.1.1 states that “The term excludes a Bulk Electric System generating unit that is typically not available…”, however we believe the phrase “typically not available” is ambiguous. Rather, we believe a threshold should be established in this section, similar to that provided in MOD-026 and MOD-027. We believe clarity is also needed within 4.2.1 to make it clear if the bullets are to be collectively considered as an “and” or as an “or” clause.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The drafting team has added clarifying language for the final ballot that may address some of your concerns. Blackstart Resource is a defined term in the NERC Glossary of Terms, which recognizes the TOP’s role to identify such units for its restoration plans. The drafting team believes bringing in an RTO/BA to identify what Blackstart Resources are subject to the winterization requirements adds an unwarranted complexity to the intent, and may unnecessarily constrict the applicability of the proposed standard.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	

Answer	Yes
Document Name	
Comment	
Dominion Energy supports the EEI comments and recommend modifications to the proposed Applicability section.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see response to EEI.	
Devin Shines - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company	
Answer	Yes
Document Name	
Comment	
LouisvilleG&E/KU support EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see response to EEI.	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	

Comment	
Constellation has no additional comments. Kimberly Turco, on behalf of Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Alison Mackellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco, on behalf of Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	

Answer	Yes
Document Name	
Comment	
PNM supports EEI’s comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to EEI.	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	Yes
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for question #3.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to EEI.	
Dan Roethemeyer - Vistra Energy - 5	
Answer	Yes
Document Name	

Comment	
Vistra has no comments on the Applicability Section language.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon agrees the Applicability Section language is clear, we do also support the enhancements proposed by the EEI. Submitted on behalf of Exelon, Segments 1 & 3	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see response to EEI.	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	

Comment	
SIGE agrees with the changes to the revised Applicability Section.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The drafting team has added clarifying language for the final ballot.	
Stewart Rake - Luminant Mining Company LLC - 7	
Answer	Yes
Document Name	
Comment	
Vistra has no comments on the Applicability Section language.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Michelle Amarantos - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	

APS agrees with EEI's recommendation to remove references to the OATT and "other contractual agreement" language as it introduces complexity with little value. We agree with EEI's proposed revisions to the Applicability section.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The drafting team has added clarifying language for the final ballot.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
While Avista supports the Applicability Section, it is overly complicated and offer the following non-substantive changes for consideration: 4.2 Facilities: The term "generating unit" subject to these requirements means: 4.2.1 Bulk Electric System (BES) generating unit(s) that commit or are obligated to serve a Balancing Authority load pursuant to an Open Access Transmission Tariff (OATT) or other contractual arrangement, excluding BES generating unit(s) that are that are not committed or obligated to operate at or below thirty-two (32) degrees Fahrenheit (zero degrees Celsius) for any continuous run of more than four hours. The exclusion applies even when such BES generating unit(s) have been called to assist in the mitigation of BES Emergencies, Capacity Emergencies, or Energy Emergencies during periods at or below thirty-two (32) degrees Fahrenheit (zero degrees Celsius). 4.2.2 Blackstart Resource(s) that are identified in the Transmission Operator's system restoration plan.	
Likes 0	
Dislikes 0	
Response	

Thank you for the comment. The drafting team has added clarifying language for the final ballot.

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	Yes
Document Name	

Comment

EEI recommends the references to the OATT and "other contractual arrangement" language be removed because such language adds little to the requirement from results-based Reliability Standard standpoint. Additionally, while EEI supports the Applicability Section, it is overly complicated and offer the following non-substantive changes for consideration:

Applicability:

4.1 Functional Entities:

4.1.1. Generator Owner

4.1.2. Generator Operator

4.2. Facilities: The term "generating unit" subject to these requirements means:

4.2.1. A Bulk Electric System (BES) generating unit **t**hat commits or is obligated to serve a Balancing Authority load exclud**ing** a BES generating unit **that is not committed or obligated to operate** at or below thirty-two (32) degrees Fahrenheit (zero degrees Celsius) for any continuous run of more than four hours. The exclusion **continues to apply should** such BES generating unit be called **upon** to **operate for more than four hours in order to** assist in the mitigation of BES Emergencies, Capacity Emergencies, or Energy Emergencies during periods at or below 32 degrees Fahrenheit.

4.2.2. That is identified as a Blackstart Resource.

Likes 0	
Dislikes 0	

Response	
Thank you for the comment. The drafting team has added clarifying language for the final ballot.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Diana Torres - Imperial Irrigation District - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
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	
Thank you for your support.	
Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Michael Watt - Oklahoma Municipal Power Authority - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Glenn Pressler - CPS Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Lenise Kimes - City and County of San Francisco - 1,5 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Donna Johnson - Oglethorpe Power Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Scott McGough - Georgia System Operations Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	Yes
Document Name	
Comment	

Thank you for your support.	
Likes 0	
Dislikes 0	
Response	
Eric Ruskamp - Lincoln Electric System - 6, Group Name LES	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Young - Tenaska, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Foung Mua, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Wei Shao, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; - Tim Kelley, Group Name SMUD / BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
John Liang - Snohomish County PUD No. 1 - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE understands the intent of the SDT to include generation units that operate in different types of market structures, including the ERCOT region. Texas RE recommends, however, clarifying Section 4.2.1.1, as it could benefit additional detail and clarity. The use of the term "to serve BA load" could lead to confusion for how the standard applies to generation-only BAs in the Eastern or Western interconnection as well as to ancillary services.

Texas RE recommends the type of market structure be removed from the Facilities section and the applicability focus on the reliability need.

Texas RE suggests the following proposed language, which focuses on the reliability needs that the generation units provide:

4.2.1 A Bulk Electric System generating unit:

4.2.1.1 That commits, or is committed by the BA, to provide energy to serve BA load, or;

4.2.1.2 That commits, or is committed by the BA or Reserve Sharing Group, to provide ancillary services to the BA or RSG for frequency control, frequency response, voltage control, or Operating Reserves, or;

4.2.1.3 That commits, or is committed by the BA or Reserve Sharing Group, to maintain BES elements within System Operating Limits, or;

4.2.1.4 Is identified as a Blackstart Resource.

4.2.2 The term excludes ….. (may want to include an example, such as a unit that is in a seasonal mothball status and only runs during summer months)

If the SDT feels that it is critical to maintain the market structure within the applicability section, Texas RE proposes the following language:

4.2.1 A Bulk Electric System generating unit:

4.2.1.1 That commits, or is committed by the BA, to provide energy under market processes, or; 4.2.1.2 That commits, or is committed by the BA or Reserve Sharing Group, to provide ancillary services to the BA or RSG for frequency control, voltage control, or Operating Reserves, or; 4.2.1.3 Is obligated to serve a Balancing Authority load pursuant to an Open Access Transmission Tariff (OATT) or other contractual arrangement, or; 4.2.1.4 Is identified as a Blackstart Resource. 4.2.2 The term excludes …..	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, the team has made some clarifying changes to the applicability section for final ballot that may address some of your concerns. The SDT declines to make substantive changes to the language, but may consider your additional recommendations in phase two.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
"Please see comments submitted by the Edison Electric Institute"	
Likes 0	
Dislikes 0	

Response
Thank you for your comment, please see response to EEI.

4. Do you support the SDT proposed 12-hour timeframe to require new Generation units to be capable of performing at or below the Extreme Cold Weather Temperature? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.	
Rhonda Jones - Invenergy LLC - 5	
Answer	No
Document Name	
Comment	
Invenergy recommends striking “continuous” from the requirement to reflect the fact that certain generation technologies, including wind and solar generators, have variable, not continuous output. Even with the recommended edit above, the capability requirement does not account for all relevant circumstances. Two examples illustrate the issue: (1) Solar generators are not capable of operating in a 12-hour period that extends beyond daylight hours. (2) The capability of storage generators is constrained by their duration. Further, the performance expectations of all generators should be the same, and the separate performance criteria proposed for new and existing generating units in R1 and R2 respectively set precedents for the unequitable treatment of Generator Owners based on a fluid effective date of the Standard. If the SDT decides to regulate new and existing generators differently, then the SDT should establish a definition for new and existing units not based on the effective date of the Requirement, but rather the age of the generating unit.	
Likes 0	
Dislikes 0	
Response	

The team has reviewed your comment and believes that making the suggested modification will substantially change the Standard that was approved by the industry. During the drafting process of the Standard, the team discussed this at length and intended to have a higher expectation for new generation.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
AEPC has signed on to ACES comments, please see their responses.	
Likes 0	
Dislikes 0	
Response	
See response to ACES comments.	
Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)	
Answer	No
Document Name	
Comment	
The proposed Standard requires generating units to perform at or below the ECWT for twelve hours. The SRC does not think this language, as written, suffices because it limits a unit's obligation to winterize to run for only a twelve-hour period. For example, in PJM, units with capacity obligations are required to perform whenever called upon by PJM during a declared system emergency and are subject to very high penalties if they do not perform during the hours when they can be called upon. Yet, as written, the standard would potentially erode if not create an ambiguity with that requirement by requiring a lesser only 12 hour run requirement.	

The SRC recognizes this issue needs further discussion and is willing to coordinate with the SDT to address the issue.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments received and will evaluate during Phase Two of the project.	
Deanna Carlson - Cowlitz County PUD - 5	
Answer	No
Document Name	
Comment	
Agree with comments provided by Russell Noble.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to Russell Noble.	
Russell Noble - Cowlitz County PUD - 3	
Answer	No
Document Name	
Comment	
Cowlitz is concerned how this will be demonstrated by compliance documentation short of actual performance, although the intent is reasonable. The requirement should recognize good faith effort in design, but clearly define the action the responsible entity should take if the design proves inadequate in during operations.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The RSAW will address the method of compliance and determine how compliance will be measured.	
Whitney Wallace - Calpine Corporation - 5 - WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
R1 requires the GO to operate for no less than 12 continuous hours at the ECW Temperature with wind speeds up to 20 mph. First, wind speed should be specified as "sustained wind speed". Second, ***this question infers GOs will be required to operate reliably below the ECW Temperature***. That is not the R1 requirement. R1 does not require operating at below the ECW. Furthermore, consistent with the comment in Response 3, NERC should clearly specify the types of units that it intends to exempt from this Standard and explain why exempting these units is not unduly discriminatory.	
Likes 0	
Dislikes 0	
Response	
The team has reviewed your comment and believes that making the suggested modification is unnecessary as "sustained" is implicit in the 20 mph requirement. The SDT question should not have included the statement "or below" with reference to the Extreme Cold Weather Temperature criteria. The intent of the standard is as written: new units should have freeze protection measures implemented to provide "capability to operate…at the Extreme Cold Weather Temperature[.]"	
Colin Chilcoat - Invenergy LLC - 6	
Answer	No
Document Name	

Comment	
Invenergy recommends striking "continuous" from the requirement to reflect the fact that certain generation technologies, including wind and solar generators, have variable, not continuous output. Even with the recommended edit above, the capability requirement does not account for all relevant circumstances. Two examples illustrate the issue: (1) Solar generators are not capable of operating in a 12-hour period that extends beyond daylight hours. (2) The capability of storage generators is constrained by their duration. Further, the performance expectations of all generators should be the same, and the separate performance criteria proposed for new and existing generating units in R1 and R2 respectively set precedents for the unequitable treatment of Generator Owners based on a fluid effective date of the Requirement. If the SDT decides to regulate new and existing generators differently, then the SDT should establish a definition for new and existing units not based on the effective date of the Requirement(s), but rather the age of the generating unit.	
Likes 0	
Dislikes 0	
Response	
The freeze protection measures must provide the level of protection that would allow operation for 12 continuous hours if the sun were to shine that long or the wind blow that long. The SDT believes that to set a point in time for the industry to use to differentiate between existing and new units is appropriate and the team has chosen the effective date of the standard as that differentiating date.	
Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations	
Answer	No
Document Name	
Comment	
It is our recommendation that wind should not be included in the design criteria for new Generation units unless added to ECWT definition. The reasoning behind this recommendation is due to the inconsistencies between R1 and R3. The language in R1 states that the GO *shall*	

include a concurrent 20 MPH wind speed in the design criteria for new generating units. Whereas the language in R3 states that the cold weather preparedness plan *may* include measures used to reduce the cooling effects of wind. Is the GO required to include wind in their calculations for all stations and all scenarios? If not, then what is the benefit for including this in the design criteria for new generating units? Furthermore, the 20 MPH value seems to be somewhat arbitrary. Please provide additional clarification as to how this value was derived and the rationale behind this derivation.	
Likes 0	
Dislikes 0	
Response	
The key recommendation identifies wind and freezing precipitation as examples of weather conditions to consider during the design of new generating units and modifications to existing plants. Realizing the many differences in weather conditions that generator sites face across the Regions, the 2021-07 SDT developed language to provide additional context and detail around these weather conditions, while allowing flexibility for site-specific circumstances. The requirement language considers wind at a specific rate when designing new facilities. As far as including/specifying a wind criterion for existing units, the SDT determined that it is difficult to apply a wind specification on already-constructed facilities, where most of the facility components have a fixed physical location and orientation, versus ability of taking wind into account for design and construction of new units. To address the cooling effects of wind on existing generating units, the SDT proposes utilization of actual experience at existing generating unit facilities (e.g., best locations for installing wind breaks that mitigated past freezing issues). The proposed R3 requires documenting freeze protection measures, which may include those measures used to reduce the cooling effects of wind necessary to protect against heat loss. The Technical Rational has been modified to clarify why 20 MPH was selected.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
MISO supports the comments submitted by the ISO/RTO Council Standards Review Committee (IRC SRC).	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment, please see response to IRC SRC.	
Steven Sconce - EDF Renewable Energy - 5	
Answer	No
Document Name	
Comment	
EDF believes that it is extremely difficult to apply a “one-size-fits-all” strategy to the timeframe. As an example, the R1 definition refers to twelve (12) continuous hours which is unrealistic during winter period (in cold climates) for inverter based resources (Photovoltaic – PV and Battery Energy Storage System – BESS), i.e., 12 hours of sunlight are not available for PV generation, and many BESS units are only rated for 4 hours. PV and BESS would be producing less than 12 hours during these months on a normal basis. Wind resource, unlike PV and BESS, is unpredictable and we cannot guarantee 12 hours, since the production time will depend of wind availability. We recommend defining a timeframe based on conventional and another for renewables (wind may need to be separate from solar and battery storage)	
Likes 0	
Dislikes 0	
Response	
The freeze protection measures must provide the level of protection that would allow operation for 12 continuous hours if the sun were to shine or the wind were to blow for that period.	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	No
Document Name	
Comment	

For some Canadian entites, units already operate in cold weather annually from November to March. These requirements represent and added administrative burden.	
Likes 0	
Dislikes 0	
Response	
SDT appreciates your comment. Please note that the SDT performed spot reviews of existing fleets of generating assets that currently operate in extreme cold weather, and to the extent that these units are employing current industry best practices, the SDT feels that the additional compliance documentation in meeting the proposed new standard will not be significant in either cost or effort.	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	No
Document Name	
Comment	
ISO-NE believes that new generation units be capable of performing “Continuously” at the ECWT. The requirement should also include the 20 mph wind speed on exposed critical equipment.	
Likes 0	
Dislikes 0	
Response	
SDT had discussions on the length of time and believes 12 hours is an appropriate timeframe for new units. As far as including/specifying a wind criterion for existing units, the SDT determined that it is difficult to apply a wind specification on already-constructed facilities, where most of the facility components have a fixed physical location and orientation, versus ability of taking wind into account for design and construction of new units. To address the cooling effects of wind on existing generating units, the SDT proposes utilization of actual experience at existing generating unit facilities (e.g., best locations for installing wind breaks that mitigated past freezing issues). The	

proposed R3 requires documenting freeze protection measures, which may include those measures used to reduce the cooling effects of wind necessary to protect against heat loss.	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	No
Document Name	
Comment	
Cold weather performance needs to be sustained for the duration of a weather event. Historically, extreme weather events have lasted more than 12 hours. Hence, equipment should be expected to operate continuously at a stated level, albeit at a level below nameplate. Operating for 12 hours only delays onset of problems without ensuring mitigation of reliability impacts.	
Likes 0	
Dislikes 0	
Response	
SDT had discussions on the length of time and believes 12 hours is an appropriate timeframe.	
Stewart Rake - Luminant Mining Company LLC - 7	
Answer	No
Document Name	
Comment	
As a general principle, Vistra believes that the requirements for existing and new resources should be substantively similar, such that neither has a material cost burden or advantage over the other. With that said, the 12-hour standard is not inherently unreasonable, in itself, ***if*** the term "Extreme Cold Weather Temperature" is defined in a less conservative manner, such as the 99th percentile minimum average ambient temperature over some timeframe (e.g., 12 to 72 hours) since a specified date (e.g., Jan. 1, 2000) at the nearest weather station. However, based on the current, very conservative proposed definition of Extreme Cold Weather Temperature, which effectively equates to a 99.8th percentile lowest hourly temperature recorded at the nearest weather station since Jan. 1, 2000, it may not be economically feasible for a new Generation unit to achieve 12-hours of sustained operations at that temperature, based on current design specifications for the	

particular type of resource. The costs of achieving 12-hours of sustained operations at a 1-hour 99.8th percentile standard could be cost-prohibitive and cause investors to cancel planned investments, which, in turn, would be detrimental to resource adequacy, as described in response to Question 2. If a 12-hour operations standard will be required, then the definition of Extreme Cold Weather Temperature should also be tied to historical temperatures over at least a continuous 12-hour timeframe. The Extreme Cold Weather Temperature definition, as currently framed, looks only at a single hourly temperature in the lowest 0.2 percentile since Jan. 1, 2000 and then requires a new resource to prove that it can operate at that temperature for at least 12 hours *and* at 20 mph winds. As noted under Question 2, in the draft Technical Requirements document, the example 0.2 percentile temperature had only ever occurred in 11 separate hours since 2000. Thus, there is no basis under the historical data underlying that definition of Extreme Cold Weather Temperature to require a new resource to prove it can operate for 12 consecutive hours at a temperature that apparently has not occurred in the past 22 years for 12 consecutive hours. Thus, as described under Question 2, Vistra would recommend using an average temperature over a period of hours that at least matches (if not exceeds) the required hours for which the resource must sustain operations at that temperature (and would recommend setting the percentile at something less conservative than the lowest 0.2 percentile/99.8th percentile). If the Extreme Cold Weather Temperature definition is not changed as proposed, then new resources should not be required to prove sustained operations at that temperature for more than one hour. In addition, Requirement R1 allows a new resource to submit a declaration if it cannot satisfy the 12-hour operation requirement, but it is not clear what happens in that instance. The standard should clarify what standard will be imposed if a new resource declares that it cannot meet the standard in the requirement (e.g., 12 hours). Will the resource be held to a lower standard consistent with its design specifications? Will that lower standard relate to the applicable cold weather temperature at which the resource must sustain operations or the number of hours for which the resource must sustain operations or both? Will the Technical Feasibility Exception process be used?	
Likes 0	
Dislikes 0	
Response	
During the drafting process of the Standard, the team discussed this at length. Therefore, the team believes that making the suggested modification will substantially change the Standard that was approved by the industry.	
Dan Roethemeyer - Vistra Energy - 5	
Answer	No

Document Name	
Comment	

As a general principle, Vistra believes that the requirements for existing and new resources should be substantively similar, such that neither has a material cost burden or advantage over the other. With that said, the 12-hour standard is not inherently unreasonable, in itself, ***if*** the term “Extreme Cold Weather Temperature” is defined in a less conservative manner, such as the 99th percentile minimum average ambient temperature over some timeframe (e.g., 12 to 72 hours) since a specified date (e.g., Jan. 1, 2000) at the nearest weather station. However, based on the current, very conservative proposed definition of Extreme Cold Weather Temperature, which effectively equates to a 99.8th percentile lowest hourly temperature recorded at the nearest weather station since Jan. 1, 2000, it may not be economically feasible for a new Generation unit to achieve 12-hours of sustained operations at that temperature, based on current design specifications for the particular type of resource. The costs of achieving 12-hours of sustained operations at a 1-hour 99.8th percentile standard could be cost-prohibitive and cause investors to cancel planned investments, which, in turn, would be detrimental to resource adequacy, as described in response to Question 2. If a 12-hour operations standard will be required, then the definition of Extreme Cold Weather Temperature should also be tied to historical temperatures over at least a continuous 12-hour timeframe. The Extreme Cold Weather Temperature definition, as currently framed, looks only at a single hourly temperature in the lowest 0.2 percentile since Jan. 1, 2000 and then requires a new resource to prove that it can operate at that temperature for at least 12 hours *and* at 20 mph winds. As noted under Question 2, in the draft Technical Requirements document, the example 0.2 percentile temperature had only ever occurred in 11 separate hours since 2000. Thus, there is no basis under the historical data underlying that definition of Extreme Cold Weather Temperature to require a new resource to prove it can operate for 12 consecutive hours at a temperature that apparently has not occurred in the past 22 years for 12 consecutive hours. Thus, as described under Question 2, Vistra would recommend using an average temperature over a period of hours that at least matches (if not exceeds) the required hours for which the resource must sustain operations at that temperature (and would recommend setting the percentile at something less conservative than the lowest 0.2 percentile/99.8th percentile). If the Extreme Cold Weather Temperature definition is not changed as proposed, then new resources should not be required to prove sustained operations at that temperature for more than one hour.

In addition, Requirement R1 allows a new resource to submit a declaration if it cannot satisfy the 12-hour operation requirement, but it is not clear what happens in that instance. The standard should clarify what standard will be imposed if a new resource declares that it cannot meet the standard in the requirement (e.g., 12 hours). Will the resource be held to a lower standard consistent with its design specifications? Will

that lower standard relate to the applicable cold weather temperature at which the resource must sustain operations or the number of hours for which the resource must sustain operations or both? Will the Technical Feasibility Exception process be used?	
Likes 0	
Dislikes 0	
Response	
During the drafting process of the Standard, the team discussed this at length. Therefore, the team believes that making the suggested modification will substantially change the Standard that was approved by the industry.	
Tony Skourtas - Los Angeles Department of Water and Power - 3	
Answer	No
Document Name	
Comment	
LDWP recommends this requirement to be region specific applicable only to areas that are susceptible to Extreme Cold Weather. In addition, require Generator Owners that plan to operate generating units in areas susceptible to Extreme Cold Weather to specify the need for continuous operation at or below the Extreme Cold Weather Temperature.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments received and will evaluate during Phase Two of the project.	
Sheila Suurmeier - Black Hills Corporation - 1,3,5,6	
Answer	No
Document Name	
Comment	

BHC does not feel 12 hours is an adequate amount of time once a new unit has gone commercial, dependent upon when that commercial date was achieved. Hypotehtically, if the unit achieved commercial operation during spring/summer, therefore, the unit may not have had a chance for capability testing during winter/extreme temperatures.	
Likes 0	
Dislikes 0	
Response	
SDT had discussions on the length of time and believes 12 hours is an appropriate timeframe.	
Micah Runner - Black Hills Corporation - 1	
Answer	No
Document Name	
Comment	
BHC does not feel 12 hours is an adequate amount of time once a new unit has gone commercial, dependent upon when that commercial date was achieved. Hypothetically, if the unit achieved commercial operation during spring/summer, therefore, the unit may not have had a chance for capability testing during winter/extreme temperatures.	
Likes 0	
Dislikes 0	
Response	
SDT had discussions on the length of time and believes 12 hours is an appropriate timeframe.	
Josh Combs - Black Hills Corporation - 3	
Answer	No
Document Name	
Comment	

BHC does not feel 12 hours is an adequate amount of time once a new unit has gone commercial, dependent upon when that commercial date was achieved. Hypothetically, if the unit achieved commercial operation during spring/summer, therefore, the unit may not have had a chance for capability testing during winter/extreme temperatures.
Likes 0
Dislikes 0
Response
SDT had discussions on the length of time and believes 12 hours is an appropriate timeframe.
Claudine Bates - Black Hills Corporation - 6
Answer No
Document Name
Comment
BHC does not feel 12 hours is an adequate amount of time once a new unit has gone commercial, dependent upon when that commercial date was achieved. Hypothetically, if the unit achieved commercial operation during spring/summer, therefore, the unit may not have had a chance for capability testing during winter/extreme temperatures.
Likes 0
Dislikes 0
Response
SDT had discussions on the length of time and believes 12 hours is an appropriate timeframe.
Patricia Lynch - NRG - NRG Energy, Inc. - 5
Answer No
Document Name
Comment

The 12-hour timeframe imposes a larger performance burden on new fossil generation since many renewable technologies are unlikely to meet this benchmark in the winter period as the nature of their operation is less than 12 continuous hours. In addition, renewable technology such as wind turbines cannot operate in certain winter conditions (freezing precipitation, high winds) allowing for technical exemptions. Since these IRRs could potentially be exempted under a technical exception, this creates a disadvantage for new thermal generators further slants the market playing field by giving one type of technology a competitive advantage over another type of technology. *NRG* also *has concerns with the language around the exclusion for technical, operational, and commercial reasons. Clarity is needed as to what are acceptable criteria for these exclusions as this will be subject to interpretation.*	
Likes 0	
Dislikes 0	
Response	
SDT had discussions on the length of time and believes 12 hours is an appropriate timeframe. The freeze protection measures must provide the level of protection that would allow operation for 12 continuous hours if the sun were to shine or the wind were to blow for that period.	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	No
Document Name	
Comment	
The 12-hour timeframe imposes a larger performance burden on new fossil generation since many renewable technologies are unlikely to meet this benchmark in the winter period as the nature of their operation is less than 12 continuous hours. In addition, renewable technology such as wind turbines cannot operate in certain winter conditions (freezing precipitation, high winds) allowing for technical exemptions. Since these IRRs could potentially be exempted under a technical exception, this creates a disadvantage for new thermal generators further slanting the market playing field by giving one type of technology a competitive advantage over another type of technology.	

NRG also has concerns with the language around the exclusion for technical, operational, and commercial reasons. Clarity is needed as to what are acceptable criteria for these exclusions as this will be subject to interpretation.	
Likes 0	
Dislikes 0	
Response	
SDT had discussions on the length of time and believes 12 hours is an appropriate timeframe. The freeze protection measures must provide the level of protection that would allow operation for 12 continuous hours if the sun were to shine or the wind were to blow for that period.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation does not agree with the fine-toothed level of specificity that is proposed. A standard that is too specific only sets up entities for compliance failure and does not improve reliability. Creating overly-specific requirements and allowing exemptions creates loopholes in the solution, which ultimately sabotages reliability. Reclamation recommends the applicability be targeted to specific geographic region(s) or specific types of generating units that are the root causes of the cold weather problems FERC is attempting to solve. Mandatory compliance for these units should not be diminished in any way.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments received and will evaluate during Phase Two of the project.	
Mark Spencer - LS Power Development, LLC - 5	
Answer	No
Document Name	

Comment	
We note that the proposed standard requires performance at the ECWT, yet the question asks whether we support an open-ended requirement below the ECWT. We do not.	
Likes 1	Vistra Energy, 5, Roethemeyer Dan
Dislikes 0	
Response	
Thank you for your response. The SDT question should not have included the statement "or below" with reference to the Extreme Cold Weather Temperature criteria. The intent of the standard is as written: new units should have freeze protection measures implemented to provide "capability to operate…at the Extreme Cold Weather Temperature[.]"	
Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 1	
Answer	No
Document Name	
Comment	
We do not have a concern where viable technical solutions exist but do have a concern where installing such measures would void manufacturer warranties and increase the risk of equipment failure. Additionally, renewable generation (Solar or Wind) is only capable of performing if the resource is available.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. Please note the ability to take a declaration for technical exceptions as required.	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	No

Document Name	
Comment	
Talen Energy Marketing supports Talen Generation's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to Talen Generation.	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
The equations in IEEE-515, IEEE Standard for the Testing, Design, Installation, and Maintenance of Electrical Resistance Trace Heating for Industrial Applications, have a steady-state basis. Granting an exception for inadequately protected equipment so long as it takes a long time to freeze would put the BES at risk and is not in accordance with industry practice. There is also no apparent basis for a figure of 12 hours as representing the maximum duration of a weather emergency. The historical worst-case winter storm in our area produced freeze protection-challenging cold weather (-15 F WCT or lower) for approx. 30 consecutive hours. Additionally, freeze protection margins cannot be reliably sliced so thin – there is great uncertainty in protecting a plant, due to frequent design and installation errors by heat tracing and insulation contractors. There is also no big-picture incentive to do so. The cost difference between a steady-state design and one with a survival limit of 12 hours is negligible in comparison to the cost to society of inadequate protection and the cost to GOs if finding that their forecasts are off and R6 retrofits are needed.	
Likes 0	
Dislikes 0	

Response	
SDT had discussions on the length of time and believes 12 hours is an appropriate timeframe. We recognize that heat tracing design specifications will generally require indefinite operation at the specified conditions.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	No
Document Name	
Comment	
Entergy agrees with the statement "at the Extreme Cold Weather Temperature" but does not agree with "or below".	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT question should not have included the statement "or below" with reference to the Extreme Cold Weather Temperature criteria. The intent of the standard is as written: new units should have freeze protection measures implemented to provide "capability to operate…at the Extreme Cold Weather Temperature[.]"	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	No
Document Name	
Comment	
This is an arbitrary timeframe with an arbitrary assumption. I don't see a good technical basis established regarding this requirement.	
Likes 0	
Dislikes 0	
Response	

SDT has proposed the justification for the timeframes proposed and are captured in the Technical Rationale.	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the language proposed in Requirement R1, which if approved, would require new generation to have the capability to operate for a period of not less than 12 hours at the Extreme Cold Weather Temperature for the unit, but we do not agree that the unit needs to be capable of operating below the Extreme Cold Weather Temperature for 12 hours, as indicated in this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT question should not have included the statement “or below” with reference to the Extreme Cold Weather Temperature criteria. The intent of the standard is as written: new units should have freeze protection measures implemented to provide “capability to operate…at the Extreme Cold Weather Temperature[.]”	

Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Avista supports the language proposed in Requirement R1, which if approved, would require new generation to have the capability to operate for a period of not less than 12 hours at the Extreme Cold Weather Temperature for the unit, but we do not agree that the unit needs to be capable of operating below the Extreme Cold Weather Temperature for 12 hours, as indicated in this question. There should be an allowance for act of god situations which a plant can not reasonably account for.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT question should not have included the statement “or below” with reference to the Extreme Cold Weather Temperature criteria. The intent of the standard is as written: new units should have freeze protection measures implemented to provide “capability to operate…at the Extreme Cold Weather Temperature[.]”	
George Brown - Acciona Energy North America - 5	
Answer	Yes
Document Name	
Comment	
Acciona Energy has no comments.	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	Yes
Document Name	
Comment	
Capital Power supports the North American Generators Forum (NAGF) response to this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to NAGF.	
Imane Mrini - Austin Energy - 6	
Answer	Yes
Document Name	
Comment	
The last sentence of M1 is incomplete and therefore confusing. Is it supposed to be part of the sentence prior?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, the SDT has made a clarifying change.	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	

Answer	Yes
Document Name	
Comment	
MidAmerican Energy supports the MRO NSRF comments for this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see MRO NSRF comment.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
While the NAGF agrees with the proposal as being reasonable, there are still concerns related to this proposal. Those concerns include the expectation that this proposal will not protect against another event like Uri, and that the Extreme Cold Weather Temperature is not addressing wind and moisture. With this said, the proposal is considered by most to be clear and enforceable and provides clear guidance and expectations to design future generators to meet a design criterion. The NAGF does have concern with the language around the exclusion for technical operational and commercial reasons. This language essentially makes this requirement optional to anyone that does not want to meet the design requirement. While we recognize the reasoning for the exemption language, we feel it makes the standard unenforceable by NERC. Instead of creating the optional requirement, a more immediate impact would be seen by ensuring that Balancing Authorities and others are using information detailing generator capabilities when performing their planning processes to reduce the expectation of unplanned outages	

due to the lack of appropriate planning. This would allow the appropriate entities, including regulatory officials, to identify where issues might arise and how to best address the issue rather than creating optional requirements.	
Likes 0	
Dislikes 0	
Response	
R1 requires that a 20 mph wind concurrent with the ECWT be considered for new units. As far as including/specifying a wind criterion for existing units, the SDT determined that it is difficult to apply a wind specification on already-constructed facilities, where most of the facility components have a fixed physical location and orientation, versus ability of taking wind into account for design and construction of new units. To address the cooling effects of wind on existing generating units, the SDT proposes utilization of actual experience at existing generating unit facilities (e.g., best locations for installing wind breaks that mitigated past freezing issues). The proposed R3 requires documenting freeze protection measures, which may include those measures used to reduce the cooling effects of wind necessary to protect against heat loss. The SDT appreciates the comments received and will evaluate during Phase Two of the project.	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
SIGE supports EEI's comment for Question 4 and agrees with the language of R1 for new generations units to implement freeze protection measures that provide capability to operate for a period of not less than twelve (12) continuous hours at the Extreme Cold Weather Temperature if the constraint exemption (bullet 2) remains in the requirement.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to EEI.	
Daniel Gacek - Exelon - 1	

Answer	Yes
Document Name	
Comment	
Exelon concurs with EEI's comment to Question 4. Submitted on behalf of Exelon, Segments 1 & 3	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to EEI.	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	Yes
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for question #4.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to EEI.	

Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	
PNM supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to EEI.	
Alison Mackellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco, on behalf of Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco, on behalf of Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Devin Shines - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company	
Answer	Yes
Document Name	
Comment	
LouisvilleG&E/KU support EEI's comments.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment, please see response to EEI.

Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	

AEP supports the proposed 12-hour timeframe in the current draft, however we disagree with Q4’s inference that the unit needs to be capable of performing *below* the Extreme Cold Weather Temperature for 12 hours.

AEP interprets the text proposed in the final bullet of R1 as allowing a declaration to be used as an exception based on operational restrictions outside of the Generator Owner’s control such as environmental permit limits for a new installation.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT question should not have included the statement “or below” with reference to the Extreme Cold Weather Temperature criteria. The intent of the standard is as written: new units should have freeze protection measures implemented to provide “capability to operate…at the Extreme Cold Weather Temperature[.]”

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	Yes
Document Name	
Comment	

PG&E supports the requirement for a new generator to operate for a period not less than 12 hours as noted in the Requirement.

PG&E also supports the comments supplied by EEI that is not a 12-hour timeframe as indicated in this question and the concerns indicated in the NAGF comments regarding the Standard being unenforceable by the ERO and NAGF's input on addressing the optional requirement language.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to EEI.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Please see Texas RE's answer to #5.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to question 5.	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3, Group Name OGE Energy	
Answer	Yes
Document Name	
Comment	

OG&E supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to EEI.	
Joe Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Xcel Energy supports comments from EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to EEI.	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Ameren agrees with the EEI and the NAGF comments.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment, please see response to EEI and NAGF.	
Scott Kinney - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Avista supports the language proposed in Requirement R1, which if approved, would require new generation to have the capability to operate for a period of not less than 12 hours at the Extreme Cold Weather Temperature for the unit, but we do not agree that the unit needs to be capable of operating below the Extreme Cold Weather Temperature for 12 hours, as indicated in this question. There should be an allowance for act of god situations which a plant can not reasonably account for.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT question should not have included the statement “or below” with reference to the Extreme Cold Weather Temperature criteria. The intent of the standard is as written: new units should have freeze protection measures implemented to provide “capability to operate…at the Extreme Cold Weather Temperature[.]”	
Brooke Jockin - Portland General Electric Co. - 1, Group Name Portland General Electric Co.	
Answer	Yes
Document Name	
Comment	

Portland General Electric Company supports the survey response provided by EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to EEI.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Avista supports the language proposed in Requirement R1, which if approved, would require new generation to have the capability to operate for a period of not less than 12 hours at the Extreme Cold Weather Temperature for the unit, but we do not agree that the unit needs to be capable of operating below the Extreme Cold Weather Temperature for 12 hours, as indicated in this question. There should be an allowance for act of god situations which a plant can not reasonably account for.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT question should not have included the statement “or below” with reference to the Extreme Cold Weather Temperature criteria. The intent of the standard is as written: new units should have freeze protection measures implemented to provide “capability to operate…at the Extreme Cold Weather Temperature[.]”	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	

Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company agrees with the 12-hour continuous hours as proposed in R1.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	

DTE Electric supports NAGF comments provided for this project	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments, please see response to NAGF.	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	Yes
Document Name	
Comment	

It is our recommendation that wind should not be included in the design criteria for new Generation units unless added to Extreme Cold Weather Temperature definition. The rationale is due to the inconsistencies between R1 and R3. The language in R1 states that the GO shall include a concurrent 20 MPH wind speed in the design criteria for new generating units. Whereas the language in R3 states that the cold weather preparedness plan may include measures used to reduce the cooling effects of wind. Is the GO required to include wind in their calculations for all stations and all scenarios? If not, then what is the benefit for including this in the design criteria for new generating units?

Furthermore, the 20 MPH value seems to be somewhat arbitrary. Please provide additional clarification as to how this value was derived and the rationale behind this derivation.

Lastly, the standard drating team should consider how commercial constraints are referenced in R1. As written a declaration for a commercial constraint as defined by the Generator Owner could preclude the ability to implement appropriate freeze protection measures to provide capability of operating for twelve (12) hours at the documented Extreme Cold Weather Temperature. A commercial constraint could be defined by the Generator Owner to include the lack of budget allocated for winterization projects. This approach seems to not align with

the purpose of this standard, "To address the effects of operating in extreme cold weather by ensuring each Generator Owner has developed and implemented plan(s) to mitigate the reliability impacts of extreme cold weather on its generating units."	
Likes 0	
Dislikes 0	
Response	
The Technical Rational has been modified to clarify why 20 MPH was selected for new units. As far as including/specifying a wind criterion for existing units, the SDT determined that it is difficult to apply a wind specification on already-constructed facilities, where most of the facility components have a fixed physical location and orientation, versus ability of taking wind into account for design and construction of new units. To address the cooling effects of wind on existing generating units, the SDT proposes utilization of actual experience at existing generating unit facilities (e.g., best locations for installing wind breaks that mitigated past freezing issues). The proposed R3 requires documenting freeze protection measures, which may include those measures used to reduce the cooling effects of wind necessary to protect against heat loss. The SDT appreciates the additional comments received and will evaluate during Phase Two of the project.	
Natalie Johnson - Enel Green Power - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
LaKenya VanNorman - LaKenya VanNorman On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name Florida Municipal Power Agency (FMPA)	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
John Liang - Snohomish County PUD No. 1 - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Michelle Amarantos - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Foung Mua, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Wei Shao, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; - Tim Kelley, Group Name SMUD / BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Adam Lee - MGE Energy - Madison Gas and Electric Co. - 4	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ronald Bauer - MGE Energy - Madison Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Young - Tenaska, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Eric Ruskamp - Lincoln Electric System - 6, Group Name LES	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ruchi Shah - AES - AES Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Scott McGough - Georgia System Operations Corporation - 3	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Donna Johnson - Oglethorpe Power Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
James Baldwin - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Lenise Kimes - City and County of San Francisco - 1,5 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Glenn Pressler - CPS Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Michael Watt - Oklahoma Municipal Power Authority - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Brian Evans-Mongeon - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
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	
Thank you for your support.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Diana Torres - Imperial Irrigation District - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	

"Please see comments submitted by the Edison Electric Institute"	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to EEI.	

5. Do you support the SDT proposed 1-hour timeframe to allow existing Generation units to demonstrate their performance at or below the Extreme Cold Weather Temperature? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	No
Document Name	
Comment	
This continues to put an unnecessary burden on those generators that operate in freezing environments. This one hour timeline is arbitrary and doesn't seem to have any technical justification for the timeline.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT chose the one-hour standard to provide existing generators the opportunity to use historic operating data for initial demonstration of compliance. The SDT felt that finding historical operating data at both the ECWT and with a concurrent 20 MPH wind would create an inappropriately difficult condition that may not exist in historical records.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	No
Document Name	
Comment	
Entergy agrees with the statement “at the Extreme Cold Weather Temperature” but does not agree with “or below”.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. The SDT question should not have included the statement “or below” with reference to the Extreme Cold Weather Temperature criteria. The intent of the standard is as written: new units should have freeze protection measures implemented to provide “capability to operate…at the Extreme Cold Weather Temperature[.]”	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
DTE Electric supports NAGF comments provided for this project	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to NAGF.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Tri-State feels that a 1-hour is too short of a time frame for reliability, instead we recommend the time frame of 4-hours.	
Likes 0	
Dislikes 0	

Response	
The SDT chose the one-hour standard to provide existing generators the opportunity to use historic operating data for initial demonstration of compliance.	
Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 1	
Answer	No
Document Name	
Comment	
Need the ability to explain in a declaration, technical, commercial or operational constraints for existing units (as is proposed for new units under Requirement R1). We do not have a concern where viable technical solutions exist but do have a concern where installing such measures would void manufacturer warranties and increase the risk of equipment failure. Requiring a Corrective Action Plan (CAP) under Requirement R2 may not be feasible for certain generation, as the needed technological advancement may be delayed beyond the proposed implementation period or may never be achieved. Additionally, renewable generation (Solar or Wind) is only capable of performing if the resource is available.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please note that the Requirement R7 allows an existing generating unit to explain in a declaration the technical, commercial, or operational constraints for CAPS that are generated in R2 that would not allow them to complete the CAP.	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

How will it be proven that you've provided enough protection to sustain the minimum 1-hour capability during ECWT? It is still not clear why there is a different requirement for generating units existing prior to the effective date of the requirement. Shouldn't all generators have the same requirement of 12 hours while also allowing existing generatios to submit a corrective action plan?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT chose the one-hour standard to provide existing generators the opportunity to use historic operating data for initial demonstration of compliance. GOs may also utilize design temperatures or current cold weather performance temperatures determined by an engineering analysis for initial demonstration of compliance on existing units.	
Mark Spencer - LS Power Development, LLC - 5	
Answer	No
Document Name	
Comment	
We note that the proposed standard requires performance at the ECWT, yet the question asks whether we support an open-ended requirement below the ECWT. We do not. Additionally, we do not support disparate treatment of resource types that are otherwise similarly situated, and new versus existing creates disparate treatment. If the SDT selected 12 hours because they thought is was the duration necessary to enhance reliability, then it should apply to all generators. During the deliberation process, certain SDT team members were concerned a rigorous standard may cause "premature retirements." We understand that the sole reason that the existing generator standard differs from new is to mitigate the "premature retirements." Section 1341 of the Energy Policy Act of 2005, which was affirmed by the Commission in its Order 672, supports cost recovery for all costs prudently incurred to comply with the Reliability Standards, and it does not limit this consideration to specific types of units or circumstances, e.g., whether because of their "newness," or retirement considerations. Additionally, the SDT assumes that good historical performance assures good future performance. A permissive prescriptive standard may not result in this outcome. We agree with the SDT that many generators have performed well in the past and may have operated at or below	

their ECWT for extended durations. However, the proposed standard will only allow cost recovery for meeting the exact requirements of the standard and no more. If a generator owner elects to replace robust freeze protections that have demonstrated superlative performance with in-kind components at the end of their service life or after a major outage, the generator owner may not be able to recover the full cost of such replacement. In fact, ratemaking proceedings may expressly disallow costs incremental to meeting the one-hour standard. For these reasons, we do not support different standards between new and existing.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT question should not have included the statement “or below” with reference to the Extreme Cold Weather Temperature criteria. The intent of the standard is as written: new units should have freeze protection measures implemented to provide “capability to operate…at the Extreme Cold Weather Temperature[.]” R2 differs from R1 (existing vs. new) to allow existing units the one-hour standard to provide existing generators the opportunity to use historic operating data for initial demonstration of compliance. Design temperatures or current cold weather performance temperatures determined by an engineering analysis may also be used for initial demonstration of compliance on existing units. This is intended to avoid unnecessary expenditures on existing plants that are already adequately freeze protected. Should these units experience a Generator Cold Weather Reliability Event, then R6 will require a CAP to remedy the situation.	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	No
Document Name	
Comment	
PG&E agrees with the input provided by the NAGF that the 1-hour timeframe will not make an improvement in performance during an extreme event and supports the NAGF recommendation on how to decide on the adequacy of the proposed timeframe.	
Likes 0	

Dislikes 0	
Response	
The SDT chose the one-hour standard to provide existing generators the opportunity to use historic operating data for initial demonstration of compliance.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Dominion Energy strongly advocates for and supports appropriately addressing the reliability issues identified in the joint FERC/NERC report related to winter storm Uri in a non-arbitrary and cost-effective manner under the Federal Power Act. Accordingly, Dominion Energy recommends rather than a universal requirement to retrofit exiting generation to operate to an arbitrary temperature requirement that may be beyond its current design capabilities, a requirement to communicate the generating units' extreme cold weather operating capabilities to the RC and BA and a corresponding requirement to develop a corrective action plan to continue to operate to those capabilities if the unit fails to do so due to freezing. Dominion Energy is of the opinion that this modification will accomplish the reliability goal identified in the FERC/NERC report.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments received and will evaluate during Phase Two of the project.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	

Reclamation does not agree with the fine-toothed level of specificity that is proposed. The proposed calculations required to comply or determine whether compliance is required are unnecessary administrative and resource-intensive burdens that will not improve reliability and will detract from entities’ ability to comply with the standard.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments received and will evaluate during Phase Two of the project.	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
BHC agrees with comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to EEI.	
Josh Combs - Black Hills Corporation - 3	
Answer	No
Document Name	
Comment	

BHC agrees with comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to EEI.	
Micah Runner - Black Hills Corporation - 1	
Answer	No
Document Name	
Comment	
BHC agrees with comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to EEI.	
Sheila Suurmeier - Black Hills Corporation - 1,3,5,6	
Answer	No
Document Name	
Comment	
BHC agrees with comments submitted by EEI	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment, please see response to EEI.	
Tony Skourtas - Los Angeles Department of Water and Power - 3	
Answer	No
Document Name	
Comment	
The requirement should be for continuous operation. The capability of the unit operating for 1 hour under Extreme Cold Weather, does not mean the generating unit will be reliable in Extreme Cold Weather..	
Likes 0	
Dislikes 0	
Response	
The SDT chose the one-hour standard to provide existing generators the opportunity to use historic operating data for initial demonstration of compliance. This is intended to avoid unnecessary expenditures on existing plants that are already adequately freeze protected. Should these units experience a Generator Cold Weather Reliability Event, then R6 will require a CAP to remedy the situation.	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	No
Document Name	
Comment	
PNM has concern regarding how the acceptable evidence outline in M2 [Identification of generating units minimum temperature per Part 3.5.2 which is equal to or less than the unit’s Extreme Cold Weather Temperature, documentation of freeze protection measures, Facility cold	

weather preparedness plan, and CAP(s)] demonstrates the capability to operate a generating unit for a period of not less than one (1) hour at the unit(s) Extreme Cold Weather Temperature.	
Likes 0	
Dislikes 0	
Response	
The SDT chose the methodology outlined in M2 to provide the compliance necessary to meet the standard without unnecessary retrofits and engineering analysis to be performed. The SDT will adjust M2 to provide better guidance and clarity on how compliance will be measured.	
James Baldwin - Lower Colorado River Authority - 1	
Answer	No
Document Name	
Comment	
It is more appropriate to have a temperature profile for unit operation.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comment.	
Dan Roethemeyer - Vistra Energy - 5	
Answer	No
Document Name	
Comment	
The 1-hour timeframe, in itself, can be a reasonable standard. However, as discussed at length under Question 2, the term “Extreme Cold Weather Temperature” also must be defined in a similarly reasonable manner. As discussed under Question 2, Vistra proposes modifications	

to the definition of "Extreme Cold Weather Temperature" to make it more in line with the standards under consideration by the PUCT and to make it more economically feasible to meet.

In addition, Requirement R2 should expressly clarify that an existing resource will be deemed to have satisfied the requirements of R2 at its respective Extreme Cold Weather Temperature and that no new or modified freeze protection measures will be required if the Generator Owner: (i) has actual operating data demonstrating continuous operations for at least one hour at that plant's Extreme Cold Weather Temperature (as cacluated under NERC's Calculating Extreme Cold Weather Temperature guide), or (ii) in the absence of such data, can show that the plant is capable of sustained operations for one hour at that temperature based on design temperature or engineering analysis. Only if the plant cannot demonstrate (i) or (ii) above should the Generator Owner be required to implement a CAP to develop new or modified freeze protections to meet R2.

In addition, the language of R2 should make clear that the requirement is a weather preparedness standard, rather than a performance standard, and thus should avoid use of the word "ensure."

The language of R2 could be modified as follows:

R2. For each generating unit(s) in commercial operation prior to [Effective Date of this requirement], the Generator Owner shall prepare its generating unit(s) by adding new or modifying existing freeze protection measures as needed to provide the capability to operate for a period of not less than one (1) hour at the unit(s) Extreme Cold Weather Temperature. If a Generator Owner provides evidence that it has operated for at least one hour at or below its Extreme Cold Weather Temperature, or if the Generator Owner provides design specification information or other data (e.g., an engineering report) as detailed in M2 showing that it can operate for at least one hour at or below its Extreme Cold Weather Temperature, then the Generator Owner will be deemed to have met this Requirement R2, and need not implement new or additional freeze protection measures. Generating unit(s) that are not capable of operating for one (1) hour at its Extreme Cold Weather Temperature shall develop a Corrective Action Plan (CAP) for the identified issues, including identification of any needed modifications to the cold weather preparedness plan required under Requirement R3. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]

M2. Each Generator Owner will have dated evidence that demonstrates it has freeze protection measures for its unit(s) in accordance with R2, or it has developed a CAP for the identified issues. Acceptable evidence may include the following (electronic or hardcopy format): Identification of generating units minimum temperature per Part 3.5.2 which is equal to or less than the unit's Extreme Cold Weather Temperature, documentation of freeze protection measures, cold weather preparedness plan, engineering study, historical data demonstrating one hour of sustained operations by the unit(s) at the applicable Extreme Cold Weather Temperature, and CAP(s).

Further, the SDT should consider adding a definition of "freeze protection measures" (applicable to all of EOP-012 and not just to R2) to clarify what those measures could entail and, importantly, to make clear that those measures do not have to include capital expenditures for redesign or retrofitting. For example, it should be clarified that "freeze protection measures" include temporary equipment like wind barriers. A new definition could be added as follows:

Freeze protection measures include permanent or temporary equipment, procedures, or other measures reasonably targeted to contribute to sustained operation by an existing unit(s) for the timeframe in R1 or R2, as applicable, at the Extreme Cold Weather Temperature.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The team has reviewed your comment suggesting a revision to R2 and believes it is unnecessary. The suggested revisions to M2 present clarifications that support the intent of the SDT and those changes will be considered. Temporary equipment, measures, and actions intended to ensure operation during cold conditions constitute part of what is intended by "freeze protection measures".

Teresa Krabe - Lower Colorado River Authority - 5

Answer	No
Document Name	
Comment	
It is more appropriate to have a temperature profile for unit operation.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your comment.	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	No
Document Name	
Comment	
How does an existing unit "ensure" operation for one hour at a temperature that only occurs during an extreme cold weather event? This creates a liability for post event non-performance while doing little to maximize the possibility the unit will perform during such events. In addition, this imposes additional documentation and expense on entities with units that have demonstrated performance during actual events. Finally, there is no value "ensuring" capability to operate for 1 hour during an extreme event since performance needs to be maintained for the duration of the event, not just one hour.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. The SDT chose the one-hour standard to provide existing generators the opportunity to use historic operating data for initial demonstration of compliance.

Ruchi Shah - AES - AES Corporation - 5

Answer	No
Document Name	

Comment

AES Clean Energy supports comments submitted by NAGF. AES Clean Energy agrees with NAGF that the 1-hour timeframe will not make a significant difference in performance improvement during an extreme cold weather event and that a better approach that relies on data should be employed in setting the time requirement.

Likes 0	
Dislikes 0	

Response

The team has reviewed your comment and believes that making the suggested modification will substantially change the Standard that was approved by the industry.

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	No
Document Name	

Comment

While providing a clear expectation for Generator Owners to meet a performance level, the 1-hour timeframe to meet the Extreme Cold Weather Temperature has not been shown to make any level of improvement of performance during an extreme event such as Uri. The NAGF notes that the weather in Dallas was at or below the ECWT for over 50 hours straight and the Houston area met or exceeded the ECWT for 30 hours or more. The SDT has also not shown that the ECWT would address the issue the Joint Report mentioned multiple times related to

generators failing prior to reaching their minimum design temperature. The NAGF recommends that a comparison of these units' failure point and the ECWT be provided to industry before a determination is made as to the adequacy of the proposal.	
Likes 0	
Dislikes 0	
Response	
The team has reviewed your comment and believes that making the suggested modification will substantially change the Standard that was approved by the industry.	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	No
Document Name	
Comment	
ISO-NE believes that Generators will have difficulty creating the needed conditions to "demonstrate" performance for 1-hour at or below the ECWT absent historical data. How is this enforceable if a Unit can not demonstrate the performance. ISO-NE recommends that existing units be required to demonstrate through historical information or through design specifications (equipment ratings, etc.) the capability to operate continuously at the Extreme Cold Weather Temperature for the unit(s), assuming a concurrent twenty (20) mph wind speed on any exposed Generator Cold Weather Critical Components;	
Likes 0	
Dislikes 0	
Response	
The SDT chose the one-hour standard to provide existing generators the opportunity to use historic operating data for initial demonstration of compliance. GOs may also utilize design temperatures or current cold weather performance temperatures determined by an engineering analysis for initial demonstration of compliance on existing units. As far as including/specifying a wind criterion for existing units, the SDT determined that it is difficult to apply a wind specification on already-constructed facilities, where most of the facility components have a	

fixed physical location and orientation, versus ability of taking wind into account for design and construction of new units. To address the cooling effects of wind on existing generating units, the SDT proposes utilization of actual experience at existing generating unit facilities (e.g., best locations for installing wind breaks that mitigated past freezing issues). The proposed R3 requires documenting freeze protection measures, which may include those measures used to reduce the cooling effects of wind necessary to protect against heat loss.	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	No
Document Name	
Comment	
Requirement R4 appears to already fullfill the requirement of R2. The 2 requirements should be merged into one.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The R4 requirement is intended to drive a periodic review every five years to ensure continued compliance.	
Steven Sconce - EDF Renewable Energy - 5	
Answer	No
Document Name	
Comment	
Please refer to our comments in Question #3. In addition, the delta between R1 requesting 12 hours and R2 requesting 1 hour does not make sense short term / long term. Is it the intent of the SDT to converge to the same amount of time on the long term?	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. The SDT chose the one-hour standard to provide existing generators the opportunity to use historic operating data for initial demonstration of compliance. GOs may also utilize design temperatures or current cold weather performance temperatures determined by an engineering analysis for initial demonstration of compliance on existing units. This is intended to avoid unnecessary expenditures on existing plants that are already adequately freeze protected. Should these units experience a Generator Cold Weather Reliability Event, then R6 will require a CAP to remedy the situation.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
MISO supports the comments submitted by the ISO/RTO Council Standards Review Committee (IRC SRC).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to IRC SRC.	
Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	No
Document Name	
Comment	
Capital Power supports the North American Generators Forum (NAGF) response to this question.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment, please see response to NAGF.	
Colin Chilcoat - Invenergy LLC - 6	
Answer	No
Document Name	
Comment	
Invenergy believes the performance expectations of all generators should be the same, and the separate performance criteria proposed for new and existing generating units in R1 and R2 respectively set precedents for the unequitable treatment of Generator Owners based on a fluid effective date of the Requirement. If the SDT decides to regulate new and existing generators differently, then the SDT should establish a definition for new and existing units not based on the effective date of the Requirement(s), but rather the age of the generating unit.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The team has reviewed your comment and believes that making the suggested modification will substantially change the Standard that was approved by the industry. The SDT believes that to set a point in time for the industry to use to differentiate between existing and new units is appropriate and the team has chosen the effective date of the standard as that differentiating date.	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	No
Document Name	
Comment	
There should be more clarity for existing generation units to meet compliance for the 1 hr capability either in the requirement, Measure, or technical rational for the standard	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has made clarifying adjustments to the Requirement, Measure, and Technical Rationale to assist in understanding.	
Whitney Wallace - Calpine Corporation - 5 - WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
R2 requires the GO to operate for no less than 1 continuous hour at the ECW Temperature. First, wind speed should be specified here as in R1; the wind speed should be classified as “sustained wind speed,” and the “sustained wind speed” should be designated as 20 mph (greater sustained wind speeds exceed the ECW). Second, ***this question infers GOs will be required to operate reliably below the ECW Temperature***. That is not the R1 requirement or the R2 requirement.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The team has reviewed your comment and believes that making the suggested modification is unnecessary as “sustained” is implicit in the 20 mph requirement. The SDT question should not have included the statement “below” in the question and the intent of the Standard is as written.	
Russell Noble - Cowlitz County PUD - 3	
Answer	No
Document Name	
Comment	

While in agreement there should be an allowance for existing generation to demonstrate performance, 1-hour may be too lenient to cover the reliability gap.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT chose the one-hour standard to provide existing generators the opportunity to use historic operating data for initial demonstration of compliance.	
Deanna Carlson - Cowlitz County PUD - 5	
Answer	No
Document Name	
Comment	
Agree with comments provided by Russell Noble.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to Russell Noble.	
Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)	
Answer	No
Document Name	
Comment	

While the SRC generally supports the idea of making existing generators demonstrate they can operate at the ECWT (with the proposed revision in Question 2) for at least one hour, that language does not require adding a 20 mph wind, which differs from the requirement for new generation. The SRC believes the BES will be more resilient if *all* generators must demonstrate the ability to operate at the ECWT *plus* a 20 mph wind. The SRC believes Generators will have difficulty creating the needed conditions to demonstrate performance for one hour at or below the ECWT absent historical data. Thus, the SRC recommends the Standard require existing units to demonstrate - through historical information or design specifications (equipment ratings, *etc*.) - the capability to operate continuously at the ECWT for the unit(s), assuming a concurrent twenty (20) mph wind speed on any exposed Generator Cold Weather Critical Components.	
Likes 0	
Dislikes 0	
Response	
The team has reviewed your comment and believes that making the suggested modification will substantially change the Standard that was approved by the industry. The SDT chose the one-hour standard to provide existing generators the opportunity to use historic operating data for initial demonstration of compliance. The SDT felt that finding historical operating data at both the ECWT and with a concurrent 20 MPH wind would create an inappropriately difficult condition that may not exist in historical records. As far as including/specifying a wind criterion for existing units, the SDT determined that it is difficult to apply a wind specification on already-constructed facilities, where most of the facility components have a fixed physical location and orientation, versus ability of taking wind into account for design and construction of new units. To address the cooling effects of wind on existing generating units, the SDT proposes utilization of actual experience at existing generating unit facilities (e.g., best locations for installing wind breaks that mitigated past freezing issues). The proposed R3 requires documenting freeze protection measures, which may include those measures used to reduce the cooling effects of wind necessary to protect against heat loss.	
Rhonda Jones - Invenergy LLC - 5	
Answer	No
Document Name	
Comment	

Invenergy believes the performance expectations of all generators should be the same, and the separate performance criteria proposed for new and existing generating units in R1 and R2 respectively set precedents for the unequitable treatment of Generator Owners based on a fluid effective date of the Standard. If the SDT decides to regulate new and existing generators differently, then the SDT should establish a definition for new and existing units not based on the effective date of the Requirement, but rather the age of the generating unit.	
Likes 0	
Dislikes 0	
Response	
The team has reviewed your comment and believes that making the suggested modification will substantially change the Standard that was approved by the industry.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 6	
Answer	Yes
Document Name	
Comment	
Agree, but this could become problematic because there is no time period mentioned. How long is a historical run able to be used as meeting the requirement?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT chose the one-hour standard to provide existing generators the opportunity to use historic operating data for initial demonstration of compliance.	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	

Talen Energy supports the comments of the NAGF on this topac, and adds that a one-hour period is appropriate since the variability of weather conditions often makes a longer demonstration impossible. This is not the end of the matter, however; this achievement should be based for conventional plants on WCT (or DBT-plus-20 mph), not DBT alone.

The lack of credibility of DBT-based achievements can be seen in reviewing the events of January 2014 for our area. No problems were encountered on 1/4/2014 at -4 F DBT and a 4.6 mph wind (-14.6 F WCT). EOP-012-1 in its present form says that all plants online at that time had a proven DBT capability of at least -4 F. Many of these facilities were knocked offline three days later, however, when the Polar Vortex of 2014 bottomed-out at 0 F with a 21.9 mph wind (-22.8 WCT).

More importantly, R2 should allow declaring R3.5.2 WCT capability values as an alternative to retrofits, and EOP-012-1 should also permit R6 CAPS that consist of revising these inputs instead of modifying equipment. Existing facilities were built in accordance with all regulatory and market rules in place at the time, and it would be wrong to order them in ex post facto fashion to become something significantly different. The lack of winterization rules to-date is not a failing of GO/GOPs, so they should not be subjected to punitive measures.

RC/BA/TOP planning based on GO/GOP temperature capability inputs hasn't worked in the past, but only due to these entities insisting on an incorrect basis (DBT only) plus failing to differentiate between temperature-caused and precipitation-caused outages. Planning Assessments and real-time reserve margin forecasts should be highly accurate once EOP-012-1 puts an end to this confusion.

Likes 0	
Dislikes 0	

Response

The SDT appreciates your comments. The SDT chose the one-hour standard to provide existing generators the opportunity to use historic operating data for initial demonstration of compliance. GOs may also utilize design temperatures or current cold weather performance temperatures determined by an engineering analysis for initial demonstration of compliance on existing units. The SDT felt that finding historical operating data at both the ECWT and with a concurrent 20 MPH wind would create an inappropriately difficult condition that may not exist in historical records. Most existing facilities already utilize appropriate levels of wind breaks (permanent or temporary) based upon their site specific experience. Should these units experience a Generator Cold Weather Reliability Event, then R6 will require a CAP to remedy the situation. As far as including/specifying a wind criterion for existing units, the SDT determined that it is difficult to apply a wind specification on already-constructed facilities, where most of the facility components have a fixed physical location and orientation, versus

ability of taking wind into account for design and construction of new units. To address the cooling effects of wind on existing generating units, the SDT proposes utilization of actual experience at existing generating unit facilities (e.g., best locations for installing wind breaks that mitigated past freezing issues). The proposed R3 requires documenting freeze protection measures, which may include those measures used to reduce the cooling effects of wind necessary to protect against heat loss.	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Talen Energy Marketing LLC supports Talen Generation's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to Talen Generation.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company agrees with the 1-hour timeframe to allow existing Generation units to demonstrate their performance as proposed in R2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Avista supports the proposed R2 language that requires GOs of existing Generating units ensure new or modify existing freeze protection measures provide the capability to operate for a period of not less than one (1) hour at the unit(s) Extreme Cold Weather Temperature.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Scott Kinney - Avista - Avista Corporation - 3	
Answer	Yes

Document Name	
Comment	
Avista supports the proposed R2 language that requires GOs of existing Generating units ensure new or modify existing freeze protection measures provide the capability to operate for a period of not less than one (1) hour at the unit(s) Extreme Cold Weather Temperature.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Joe Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Xcel Energy can support the 1-hour time frame for existing units, predicated on the ability that R2 is tied to R6 and, subsequently, R7. The ability to declare qualifying units as unable to implement corrective actions is a required element for Xcel Energy to support R2 of the Standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	

Comment	
AEP supports the proposed 1-hour timeframe in the current draft, however we disagree with Q5's inference that the unit needs to be capable of operating *below* the Extreme Cold Weather Temperature for 1 hour.	
Likes 0	
Dislikes 0	
Response	
The SDT question should not have included the statement "or below" with reference to the Extreme Cold Weather Temperature criteria. The intent of the standard is as written: new units should have freeze protection measures implemented to provide "capability to operate…at the Extreme Cold Weather Temperature[.]"	
Devin Shines - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company	
Answer	Yes
Document Name	
Comment	
LG&E/KU supports the SDT proposed 1-hour timeframe.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	

Comment	
Constellation has no additional comments. Kimberly Turco, on behalf of Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Alison Mackellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco, on behalf of Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Martin Sidor - NRG - NRG Energy, Inc. - 6	

Answer	Yes
Document Name	
Comment	

Currently this draft requires Generator Owners to retrofit their units to meet the newly defined Extreme Weather temperature levels. NRG understands that to invoke any technical, operational, or commercial exclusions clauses (such as units designed above 32 F) that each facility would require development of a CAP which may not be able to be executed under R7. It would be more prudent to include a provision in R2 to allow generators to provide these exclusions and associated justifications upfront.

NRG believes that R2 should not require existing Generators to retrofit but rather report their extreme cold weather operating parameters to the appropriate parties and only require a CAP if they fail to meet their operating parameters as communicated to the appropriate entities. This will allow the appropriate entities to identify where issues might arise and how to best address the issue rather than placing an unreasonable reliability requirement on all Generator Owners. The weatherization requirements, as currently drafted without cost recovery mechanisms in place, may exacerbate current difficulties for independent generators to cover costs and earn a return overall. The potential cost implications may result in generators either retiring or opting out of the winter season through seasonal mothballing.

Likes 0	
Dislikes 0	

Response

The SDT believes that the vast majority of existing facilities with freeze protection measures will meet the R2 standard without requiring substantial retrofits. The SDT chose the one-hour standard to provide existing generators the opportunity to use historic operating data for initial demonstration of compliance. GOs may also utilize design temperatures or current cold weather performance temperatures determined by an engineering analysis for initial demonstration of compliance on existing units. This is intended to avoid unnecessary expenditures on existing plants that are already adequately freeze protected. Should these units experience a Generator Cold Weather Reliability Event, then R6 will require a CAP to remedy the situation.

Patricia Lynch - NRG - NRG Energy, Inc. - 5

Answer	Yes
Document Name	

Comment	
Currently this draft requires Generator Owners to retrofit their units to meet the newly defined Extreme Weather temperature levels. NRG understands that to invoke any technical, operational, or commercial exclusions clauses (such as units designed above 32 F) that each facility would require development of a CAP which may not be able to be executed under R7. It would be more prudent to include a provision in R2 to allow generators to provide these exclusions and associated justifications upfront. *NRG believes that R2 should not require existing Generators to retrofit but rather report their extreme cold weather operating parameters to the appropriate parties and only require a CAP if they fail to meet their operating parameters as communicated to the appropriate entities. This will allow the appropriate entities to identify where issues might arise and how to best address the issue rather than placing an unreasonable reliability requirement on all Generator Owners. The weatherization requirements, as currently drafted without cost recovery mechanisms in place, may exacerbate current difficulties for independent generators to cover costs and earn a return overall. The potential cost implications may result in generators either retiring or opting out of the winter season through seasonal mothballing.*	
Likes 0	
Dislikes 0	
Response	
The SDT believes that the vast majority of existing facilities with freeze protection measures will meet the R2 standard without requiring substantial retrofits. The SDT chose the one-hour standard to provide existing generators the opportunity to use historic operating data for initial demonstration of compliance. GOs may also utilize design temperatures or current cold weather performance temperatures determined by an engineering analysis for initial demonstration of compliance on existing units. This is intended to avoid unnecessary expenditures on existing plants that are already adequately freeze protected. Should these units experience a Generator Cold Weather Reliability Event, then R6 will require a CAP to remedy the situation.	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	Yes
Document Name	

Comment	
While Evergy supports EEI's comments in our responses, in an effort to answer the specific question from the SDT, Evergy holds no concerns with the 1-hour timeframe. Evergy agrees with the concerns about retrofits to existing resources with future transition plans but maintains that the SDT does not hold the authority to address the retrofit concern.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
SIGE supports the proposed 1-hour timeframe in R2; however, for clarity and consistency, SIGE recommends modifying R2 to mirror R1: *For each generating unit(s) in commercial operation prior to [Effective Date of this requirement], the Generator Owner shall:* • *Ensure its generating unit(s) add new or modify existing freeze protection measures as needed to provide the capability to operate for a period of not less than one (1) hour at the unit(s) Extreme Cold Weather Temperature. Generator Owner shall develop a Corrective Action Plan (CAP) for the identified issues, including identification of any needed modifications to the cold weather preparedness plan required under Requirement R3; or* • ***Explain in a declaration, any technical, commercial, or operational constraints as defined by the Generator Owner that preclude the ability to implement appropriate freeze protection measures to provide capability of operating for a period of not less than one (1) hour at the unit(s) Extreme Cold Weather Temperature.***	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. Should a CAP be required pursuant to R2, R4, or R6, R7 will allow a similar declaration to be made due to technical, commercial, or operational constraints.	
Stewart Rake - Luminant Mining Company LLC - 7	
Answer	Yes
Document Name	
Comment	

The 1-hour timeframe, in itself, can be a reasonable standard. However, as discussed at length under Question 2, the term “Extreme Cold Weather Temperature” also must be defined in a similarly reasonable manner. As discussed under Question 2, Vistra proposes modifications to the definition of “Extreme Cold Weather Temperature” to make it more in line with the standards under consideration by the PUCT and to make it more economically feasible to meet.

In addition, Requirement R2 should expressly clarify that an existing resource will be deemed to have satisfied the requirements of R2 at its respective Extreme Cold Weather Temperature and that no new or modified freeze protection measures will be required if the Generator Owner: (i) has actual operating data demonstrating continuous operations for at least one hour at that plant’s Extreme Cold Weather Temperature (as cacluated under NERC’s Calculating Extreme Cold Weather Temperature guide), or (ii) in the absence of such data, can show that the plant is capable of sustained operations for one hour at that temperature based on design temperature or engineering analysis. Only if the plant cannot demonstrate (i) or (ii) above should the Generator Owner be required to implement a CAP to develop new or modified freeze protections to meet R2.

In addition, the language of R2 should make clear that the requirement is a weather preparedness standard, rather than a performance standard, and thus should avoid use of the word “ensure.”

The language of R2 could be modified as follows:

R2. For each generating unit(s) in commercial operation prior to [Effective Date of this requirement], the Generator Owner shall prepare its generating unit(s) by adding new or modifying existing freeze protection measures as needed to provide the capability to operate for a period of not less than one (1) hour at the unit(s) Extreme Cold Weather Temperature. If a Generator Owner provides evidence that it has operated for at least one hour at or below its Extreme Cold Weather Temperature, or if the Generator Owner provides design specification information

or other data (e.g., an engineering report) as detailed in M2 showing that it can operate for at least one hour at or below its Extreme Cold Weather Temperature, then the Generator Owner will be deemed to have met this Requirement R2, and need not implement new or additional freeze protection measures. Generating unit(s) that are not capable of operating for one (1) hour at its Extreme Cold Weather Temperature shall develop a Corrective Action Plan (CAP) for the identified issues, including identification of any needed modifications to the cold weather preparedness plan required under Requirement R3. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning] M2. Each Generator Owner will have dated evidence that demonstrates it has freeze protection measures for its unit(s) in accordance with R2, or it has developed a CAP for the identified issues. Acceptable evidence may include the following (electronic or hardcopy format): Identification of generating units minimum temperature per Part 3.5.2 which is equal to or less than the unit's Extreme Cold Weather Temperature, documentation of freeze protection measures, cold weather preparedness plan, engineering study, historical data demonstrating one hour of sustained operations by the unit(s) at the applicable Extreme Cold Weather Temperature, and CAP(s). Further, the SDT should consider adding a definition of "freeze protection measures" (applicable to all of EOP-012 and not just to R2) to clarify what those measures could entail and, importantly, to make clear that those measures do not have to include capital expenditures for redesign or retrofitting. For example, it should be clarified that "freeze protection measures" include temporary equipment like wind barriers. A new definition could be added as follows: Freeze protection measures include permanent or temporary equipment, procedures, or other measures reasonably targeted to contribute to sustained operation by an existing unit(s) for the timeframe in R1 or R2, as applicable, at the Extreme Cold Weather Temperature.	
Likes 0	
Dislikes 0	
Response	
The team has reviewed your comment suggesting a revision to R2 and believes it is unnecessary. The suggested revisions to M2 present clarifications that support the intent of the SDT and those changes will be considered. Temporary equipment, measures and actions intended to ensure operation during cold conditions constitute part of what is intended by "freeze protection measures".	
George Brown - Acciona Energy North America - 5	
Answer	Yes

Document Name	
Comment	
Acciona Energy has no comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Avista supports the proposed R2 language that requires GOs of existing Generating units ensure new or modify existing freeze protection measures provide the capability to operate for a period of not less than one (1) hour at the unit(s) Extreme Cold Weather Temperature.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
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	
Thank you for your support.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Brian Evans-Mongeon - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Michael Watt - Oklahoma Municipal Power Authority - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brooke Jockin - Portland General Electric Co. - 1, Group Name Portland General Electric Co.	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Glenn Pressler - CPS Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Donna Johnson - Oglethorpe Power Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Scott McGough - Georgia System Operations Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Eric Ruskamp - Lincoln Electric System - 6, Group Name LES	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Young - Tenaska, Inc. - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Imane Mrini - Austin Energy - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ronald Bauer - MGE Energy - Madison Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Adam Lee - MGE Energy - Madison Gas and Electric Co. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Foung Mua, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Wei Shao, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; - Tim Kelley, Group Name SMUD / BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Michelle Amarantos - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
John Liang - Snohomish County PUD No. 1 - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
LaKenya VanNorman - LaKenya VanNorman On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name Florida Municipal Power Agency (FMPA)	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Natalie Johnson - Enel Green Power - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3, Group Name OGE Energy	
Answer	
Document Name	
Comment	
OG&E supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments, please see response to EEI.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not agree the proposed 1-hour timeframe in Requirement R2 is sufficient to allow existing Generation units to demonstrate their performance at or below the Extreme Cold Weather Temperature. Historical events in 2011, 2014, 2018, and 2021, have instances in which it has taken at least 6-12 hours for freezing issues to appear, depending on the unit status. During the South Central United States cold weather BES event in January 2018, for example, cold weather was sustained for two days. Between January 15 and January 17, 2018, generation resources experienced various outages, derates, or failures to start. Similarly, for over two days in February 2021, ERCOT	

averaged 34,000 MW of generation outages. The SDT should consider a longer duration to demonstrate performance at or below the Extreme Cold Weather Temperature based on historic events.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT chose the one-hour standard to provide existing generators the opportunity to use historic operating data for initial demonstration of compliance. For any facility that experience a Generator Cold Weather Reliability Event, they will have to develop a CAP per R6.	
Lenise Kimes - City and County of San Francisco - 1,5 - WECC	
Answer	
Document Name	
Comment	
Difficult to answer yes or no... the 1-hour timeframe for demonstrating (which we interpret to mean testing) a Generation unit's performance sounds reasonable, however, if operating at or below the Extreme Cold Weather Temperature, you would not be in a testing state, you would be in an *actual* Extreme Cold Weather Temperature state.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please note that Generating units can use actual unit performance data at temperatures below their ECWT to document their ability to operate at these temperatures. There is no expectation that they will need to perform a dedicated test to prove this ability to operate.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	

Document Name	
Comment	
"Please see comments submitted by the Edison Electric Institute"	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to EEI.	

6. Do you support the addition of a 20 megawatt minimum (corresponding to the definition of a BES impacting generating unit) for requiring CAPS for derates? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Natalie Johnson - Enel Green Power - 5	
Answer	No
Document Name	
Comment	
Please refer to comments in question 2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The Standard Drafting Team appreciates your response and believes this change may be substantive in nature. The 20MW threshold in the definition of Generator Cold Weather Event was set intentionally and is applicable regardless of the type of generating resource. The SDT may consider any further alignment with the definition of the Bulk Electric System in Phase II of this project.	

Rhonda Jones - Invenergy LLC - 5	
Answer	No
Document Name	
Comment	
Invenergy supports the addition of a megawatt minimum for requiring CAPs for derates. However, Invenergy believes the minimum could be better aligned with NERC's BES criteria by establishing a minimum of 20 MVA for individual generating units identified under Inclusion I2 of the BES definition, or a minimum of 75 MVA for generating units identified under Inclusion I4 of the BES definition.	

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The Standard Drafting Team appreciates your response and believes this change may be substantive in nature. The 20MW threshold in the definition of Generator Cold Weather Event was set intentionally and is applicable regardless of the type of generating resource. The SDT may consider any further alignment with the definition of the Bulk Electric System in Phase II of this project.

Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)

Answer	No
Document Name	

Comment

The SRC supports the addition of a 20 MW minimum to align with the BES definition of a generating unit. That said, we do not support the corresponding limitations on Corrective Action Plans (CAPs) in the Generator Cold Weather Reliability Event (GCWRE) definition. As written, when taking the proposed GCWRE definition in conjunction with Requirement 6, a GO must develop a CAP if a unit experiences, "a forced derate of *more than 10% of the total capacity* of the unit, ***and*** *exceeding 20 MWs*, for longer than four hours in duration…." The SRC believes this language could be interpreted to exclude all units rated at 200 MWs or less. Specifically, for 10% of unit capacity to exceed 20 MWs, the unit must have nameplate capacity of at least 201 MWs (*i.e.,* 10% of 201 MWs = 20.1 MWs).

The SRC cannot support such a broad carve out of applicability. The SRC recommends the SDT revise the GCWRE definition to make clear a *plant* or *facility* consisting of individual units less than 200 MW must aggregate the derate to apply to the entire plant/facility to reach the 10% and 20 MW threshold; *i.e.*, the GO of a plant consisting of five 190 MW units (950 MW) each experiencing a 10% derate (19 MWs) would aggregate the unit derates to determine whether the 20 MW threshold is met (19 MWs times 5 units = 95 MWs; because 95 MWs > 20 MWs, the Standard would apply).

Likes 0	
Dislikes 0	

Response	
Thank you for your comments. The Standard Drafting Team appreciates your response and believes this change may be substantive in nature. The 20MW threshold in the definition of Generator Cold Weather Event was set intentionally and is applicable regardless of the type of generating resource. The SDT may consider any further alignment with the definition of the Bulk Electric System in Phase II of this project.	
Whitney Wallace - Calpine Corporation - 5 - WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
The definition should be clarified. Is it 10% of the unit or 10% of the power block? In addition, as written, it is interpreted that it is only reportable if the impact is 10% of the unit capacity and exceeds 20 MW. The definition is not written as "or" as implied in the question. Further, there is no tie for the derate to be the result of a GCWRE. For example, a failed thermocouple on a duct burner runner in a heat recovery steam generator will require a CAP under this proposed language. However, thermocouples are consumable components that are replaced routinely due to the cyclic nature of duct burner operation in combined cycle power plants. Besides clarifying the definition of GCWRE to pertain only to GCWCC, NERC should consider implementing tiered limits (e.g., 50 MW for 500 MW or more, 25 MW for less than 500 MW, etc.). This type of tiering system would alleviate potentially excessive administrative burdens on plant staff associated with CAPs. For smaller units (less than 20 MWs), a CAP should not be required.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The Standard Drafting Team appreciates your response and believes this change may be substantive in nature. The 20MW threshold in the definition of Generator Cold Weather Event was set intentionally and is applicable regardless of the type of generating resource. The SDT may consider any further alignment with the definition of the Bulk Electric System in Phase II of this project. It is noted that a Generator Cold Weather Reliability Event by definition has freezing as the apparent cause.	
George Brown - Acciona Energy North America - 5	

Answer	No
Document Name	
Comment	
Acciona Energy supports Midwest Reliability Organization’s (MRO) NERC Standards Review Forum’s (NSRF) comments on this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to MRO NSRF.	
Colin Chilcoat - Invenergy LLC - 6	
Answer	No
Document Name	
Comment	
Invenergy supports the addition of a megawatt minimum for requiring CAPs for derates. However, Invenergy believes the minimum could be better aligned with NERC’s BES criteria by establishing a minimum of 20 MVA for individual generating units identified under Inclusion I2 of the BES definition, or a minimum of 75 MVA for generating units identified under Inclusion I4 of the BES definition.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The Standard Drafting Team appreciates your response and believes this change may be substantive in nature. The 20MW threshold in the definition of Generator Cold Weather Event was set intentionally and is applicable regardless of the type of generating resource. The SDT may consider any further alignment with the definition of the Bulk Electric System in Phase II of this project.	
Adam Lee - MGE Energy - Madison Gas and Electric Co. - 4	

Answer	No
Document Name	
Comment	
Madison Gas and Electric supports the comments of the MRO NSRF	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to MRO NSRF.	
Ronald Bauer - MGE Energy - Madison Gas and Electric Co. - 3	
Answer	No
Document Name	
Comment	
Madison Gas and Electric supports the comments from the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to MRO NSRF.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	

MISO supports the comments submitted by the ISO/RTO Council Standards Review Committee (IRC SRC).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to IRC SRC.	
Steven Sconce - EDF Renewable Energy - 5	
Answer	No
Document Name	
Comment	
The 20MW value is reasonable; however, for solar and wind generation, the term generating unit needs further definition for aggregate production (total-plant) vs. individual generator/inverter-based resource. EDF supports the comments submitted by Talen Generation.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The Standard Drafting Team appreciates your response and believes this change may be substantive in nature. The 20MW threshold in the definition of Generator Cold Weather Event was set intentionally and is applicable regardless of the type of generating resource. The SDT may consider any further alignment with the definition of the Bulk Electric System in Phase II of this project.	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	No
Document Name	
Comment	

MidAmerican Energy supports the MRO NSRF response to this question, referring to the answer to question 2 regarding the Generator Cold Weather Reliability Event definition.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to MRO NSRF.	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
Please refer to comments provided by the MRO NSRF for the Generator Cold Weather Reliability Event definition, in question 2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to MRO NSRF.	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	No
Document Name	
Comment	
Alliant Energy supports the comments submitted by the MRO NSRF.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to MRO NSRF.	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	No
Document Name	
Comment	
ISO-NE believes the term Generating unit is vague and is open to interpretation. Does this mean each generating unit or is it an entire facility. Depending on the interpretation of unit by a GO, they could declare each unit separate in the large plant with many separate units which could preclude them from the applicability section of this standard as well as exempt form the CAP requirements outlined in Requirement 6.	
Likes 0	
Dislikes 0	
Response	
The Standard Drafting Team appreciates your comment and refers to the definition of generating unit in the applicability section of the standard.	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	No
Document Name	
Comment	

This language exempts distributed generation, which is trending upward and is becoming a larger percentage of total generation, and creates a "perverse incentive" to implement multiple small units to avoid requirements. This subverts the purpose of mitigating reliability impacts during extreme cold weather.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The Standard Drafting Team appreciates your response and believes this change may be substantive in nature. The 20MW threshold in the definition of Generator Cold Weather Event was set intentionally and is applicable regardless of the type of generating resource. The SDT may consider any further alignment with the definition of the Bulk Electric System in Phase II of this project.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation does not agree with the fine-toothed level of specificity that is proposed. Too much effort is required to be spent determining whether or not the requirements apply or if they can be avoided. Reclamation recommends the standard be written in a plain and straightforward set of requirements. Please refer to the proposal submitted in Reclamation's comments to Draft 1 Question 4.	
Likes 0	
Dislikes 0	
Response	
The Standard Drafting Team appreciates your comment and believes this recommendation would be considered a substantive change to the proposed language. As such, no changes will be made to this effect for the final ballot.	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	No

Document Name	
Comment	
All generation, regardless of size, needs to be reliable for the range of conditions the industry agrees to.	
Likes 0	
Dislikes 0	
Response	
The Standard Drafting Team appreciates your comment and believes this recommendation would be considered a substantive change to the proposed language. As such, no changes will be made to this effect for the final ballot.	
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	
In the definition of Generator Cold Weather Reliability Event, Tacoma Power recommends changing “total capacity of the unit” to “facility rating of the unit.” Tacoma Power is concerned with the regulatory burden of trying to document the total capacity of a unit that is seasonally dependent/variable. By changing to “facility rating”, this would ensure a fixed and predictable number that constitutes the 10% value.	
Likes 1	LS Power Development, LLC, 5, Spencer Mark
Dislikes 0	
Response	
The Standard Drafting Team appreciates your response and believes this change may be substantive in nature. The 20MW threshold in the definition of Generator Cold Weather Event was set intentionally and is applicable regardless of the type of generating resource. The SDT may consider any further alignment with the definition of the Bulk Electric System in Phase II of this project.	

Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	No
Document Name	
Comment	
Talen Energy Marketing supports Talen Generation's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to Talen Generation.	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
The value of 20 MW is suitable, but it needs to be applied for EOP-012-1 in plant-total fashion, not per generation unit as in the presently proposed definition of a Generator Cold Weather Reliability Event. A criterion of 20 MW per wind turbine would be meaningless.	
Likes 1	LS Power Development, LLC, 5, Spencer Mark
Dislikes 0	
Response	
The Standard Drafting Team appreciates your response and believes this change may be substantive in nature. The 20MW threshold in the definition of Generator Cold Weather Event was set intentionally and is applicable regardless of the type of generating resource. The SDT may consider any further alignment with the definition of the Bulk Electric System in Phase II of this project.	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	

Answer	No
Document Name	
Comment	
We see no technical justification for the 20 MW threashold. How will this apply to Hydro resouces that are run-of-the-river where their capacity may diminish, but due to water flow (low fuel), they would never be able to generate to thier capacity?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The Generator Cold Weather Reliability Event is defined in the standard as certain events which are due to freezing of equipment within the Generator Owner's control. As such, low water level events would not apply.	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your review	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your review	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the addition of a 20 megawatt minimum, as proposed in the definition for a "Generator Gold Weather Event", however, Question 6 and language contained in the Technical Rationale (see page 8, Requirement R6), raises an important question about the intended alignment of the minimum value (as described in the definition of Generator Cold Weather Reliability Event) with the BES definition. If this threshold is intended to align with the BES definition, then the threshold should be adjusted to consider the differences between conventional and distributed/IBR resources. While the 20 MW value aligns with the BES definition for the minimum individual conventional generating resources, (see Inclusion I2); the threshold for Inverter Based Resources (i.e., dispersed power producing resources/Inclusion I4) is measure by the aggregated capacity of a plant resulting in a minimum value of 75 MW. For this reason, EEI asks for additional clarification whether the minimum threshold value is to be aligned with the BES definition, or not.	
Likes 0	
Dislikes 0	
Response	
The Standard Drafting Team appreciates your response and believes this change may be substantive in nature. The 20MW threshold in the definition of Generator Cold Weather Event was set intentionally and is applicable regardless of the type of generating resource. The SDT may consider any further alignment with the definition of the Bulk Electric System in Phase II of this project.	

Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Avista supports the addition of a 20 megawatt minimum with the proposed Generator Cold Weather Reliability Event and its impact on GO responsibilities as it relates to CAPS within Requirement R6.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Deanna Carlson - Cowlitz County PUD - 5	
Answer	Yes
Document Name	
Comment	
Deanna Carlson, Cowlitz PUD, 5, 9/1/22	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Michelle Amarantos - APS - Arizona Public Service Co. - 5	
Answer	Yes

Document Name	
Comment	
APS supports the addition of a 20 megawatt minimum as proposed in the definition of a "Generator Cold Weather Reliability Event." Additionally, APS echoes EEI's comments questioning the intended alignment of the minimum value described in the "Generator Cold Weather Reliability Event" definition with the BES definition. If the threshold is intended to align with the BES definition, then it should be adjusted to consider the differences between conventional and inverter-based resources. While the 20 MW value aligns with the BES definition for the minimum individual conventional generating resources, (see Inclusion I2); the threshold for Inverter Based Resources (i.e., dispersed power producing resources/Inclusion I4) is measure by the aggregated capacity of a plant resulting in a minimum value of 75 MW.	
Likes 0	
Dislikes 0	
Response	
The Standard Drafting Team appreciates your response and believes this change may be substantive in nature. The 20MW threshold in the definition of Generator Cold Weather Event was set intentionally and is applicable regardless of the type of generating resource. The SDT may consider any further alignment with the definition of the Bulk Electric System in Phase II of this project.	
Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	Yes
Document Name	
Comment	
Capital Power supports the North American Generators Forum (NAGF) response to this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see response to NAGF.	

Mark Young - Tenaska, Inc. - 5	
Answer	Yes
Document Name	
Comment	
As long as the 10% is an additional criteria, e.g. 10% AND 20 MW. We do not support just a 20 MW derate alone.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT agrees that both of these criteria must be met to trigger a Generator Cold Weather Event.	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	Yes
Document Name	
Comment	
Yes, the addition of a 20 megawatt minimum component to the 10% minimum adequately addresses the reliability need while uniformly applying the derate threshold to generating units regardless of total capacity or fuel source.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Stewart Rake - Luminant Mining Company LLC - 7	
Answer	Yes

Document Name	
Comment	
Vistra has no comments on this proposed change.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
SIGE does not oppose the 20 megawatts minimum; however, SIGE does have recommendations for how it is currently addressed in the Generator Cold Weather Reliability Event definition. See SIGE's response to Question 2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please refer to the responses to Question 2 that address changes made to the structure of the definition of a Generator Cold Weather Reliability Event.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	

Comment	
Exelon concurs with EEI's comment to Question 6. Submitted on behalf of Exelon, Segments 1 & 3	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see response to EEI.	
Dan Roethemeyer - Vistra Energy - 5	
Answer	Yes
Document Name	
Comment	
Vistra has no comments on this proposed change.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	Yes

Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for question #6.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see response to EEI.	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	
PNM supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see response to EEI.	
Alison Mackellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	

Constellation has no additional comments. Kimberly Turco, on behalf of Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco, on behalf of Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Devin Shines - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company	

Answer	Yes
Document Name	
Comment	
LouisvilleG&E/KU support EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see response to EEI.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
With reference to the definition of a "Generator Cold Weather Reliability Event" we believe the 20 MW minimum should apply not only to (1), but (2) and (3) as well. Having said that however, it is not clear how this 20 MW minimum would apply to dispersed generation, either collectively (say, in the case of a wind farm) or to their individual units. Various interpretations of its application are possible, and the requirement would benefit by including text which clearly shows exactly how the minimum would be applied to dispersed units.	
Likes 0	
Dislikes 0	
Response	
The 20 MW threshold is only applicable to a forced derate. Start-up failures and Forced Outages do not have a minimum MW threshold and are governed by the applicability section of EOP-012-1. The 20MW threshold in the definition of Generator Cold Weather Event was set	

intentionally and is applicable regardless of the type of generating resource. The SDT may consider any further alignment with the definition of the Bulk Electric System in Phase II of this project.	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	Yes
Document Name	
Comment	
PG&E supports the addition of the 20 MW minimum, and supports the input provided by EEI on additional clarification on aligning the minimum threshold value with the BES Definition.	
Likes 0	
Dislikes 0	
Response	
The Standard Drafting Team appreciates your response and believes this change may be substantive in nature. The 20MW threshold in the definition of Generator Cold Weather Event was set intentionally and is applicable regardless of the type of generating resource. The SDT may consider any further alignment with the definition of the Bulk Electric System in Phase II of this project.	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3, Group Name OGE Energy	
Answer	Yes
Document Name	
Comment	
OG&E supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	

Response	
Thank you for the comment, please see response to EEI.	
Joe Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Xcel Energy supports comments from EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see response to EEI.	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Ameren agrees with the EEI and the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see response to NAGF.	
Mark Spencer - LS Power Development, LLC - 5	

Answer	Yes
Document Name	
Comment	

We support the 20 megawatt threshold with the following caveats. We recommend that the SDT couple the MW threshold with a narrow dead band to the ECWT. If a generator is experiencing *any* derate due to a freezing issue, a minor derate may be signaling a potential weak link in its freeze protection measures. This derate would be particularly worrisome if the derate occurred at a temperature well exceeding the ECWT.

Additionally, the proposed draft allows for an exemption from developing a CAP only if the derate is less than four hours, yet the proposed standard for existing generators is one hour. Clearly, a four hour derate is longer than the one hour standard, so what would be the CAP for a derate of less than 20 MW and greater than four hours (particularly if the derate started in the 2nd hour)? What would be the CAP for a derate of greater than 20 MW but starting in hour two? Would the CAPs simply state that the generator met the reliability standard and no further action is required?

Likes 1	Vistra Energy, 5, Roethemeyer Dan
Dislikes 0	

Response

Thank you for the comments. The SDT declines to expand the conditions in which a forced derate would qualify as a Generator Cold Weather Reliability Event at this time. The standard sets a minimum requirement that entities must meet.

The one-hour provision in EOP-012-1 requirement R2 and the four-hour provision in the definition of Generator Cold Weather Reliability Event as it relates to EOP-012-1 requirement R6 are separate and should not be considered associated. The one-hour provision in EOP-012-2 requirement R2 is tied to the generator operating at its Extreme Cold Weather Temperature. The four-hour provision in the definition of a Generator Cold Weather Reliability Event is relates to when a CAP is required due to a derate when operating at or above its Extreme Cold Weather Temperature.

Scott Kinney - Avista - Avista Corporation - 3

Answer	Yes
Document Name	
Comment	
Avista supports the addition of a 20 megawatt minimum with the proposed Generator Cold Weather Reliability Event and its impact on GO responsibilities as it relates to CAPS within Requirement R6.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Brooke Jockin - Portland General Electric Co. - 1, Group Name Portland General Electric Co.	
Answer	Yes
Document Name	
Comment	
Portland General Electric Company supports the survey response provided by EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to EEI.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	

Comment	
Avista supports the addition of a 20 megawatt minimum with the proposed Generator Cold Weather Reliability Event and its impact on GO responsibilities as it relates to CAPS within Requirement R6.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	

Southern Company agrees that the 20 MW minimum is appropriate.	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
LaKenya VanNorman - LaKenya VanNorman On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name Florida Municipal Power Agency (FMPA)	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for the support.	
John Liang - Snohomish County PUD No. 1 - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Foung Mua, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Wei Shao, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; - Tim Kelley, Group Name SMUD / BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Imane Mrini - Austin Energy - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Eric Ruskamp - Lincoln Electric System - 6, Group Name LES	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Ruchi Shah - AES - AES Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for the support.	
Scott McGough - Georgia System Operations Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Donna Johnson - Oglethorpe Power Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
James Baldwin - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for the support.	
Tony Skourtas - Los Angeles Department of Water and Power - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Sheila Suurmeier - Black Hills Corporation - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Josh Combs - Black Hills Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for the support.	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	

Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Glenn Pressler - CPS Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Michael Watt - Oklahoma Municipal Power Authority - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Brian Evans-Mongeon - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Lindsey Mannion - ReliabilityFirst - 10	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for the support.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for the support.	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Diana Torres - Imperial Irrigation District - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	
Comment	
No Comment	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
"Please see comments submitted by the Edison Electric Institute"	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment, please see response to EEI.	
Lenise Kimes - City and County of San Francisco - 1,5 - WECC	
Answer	
Document Name	
Comment	
This does not apply to HHWP, so we choose to not weigh-in regarding this.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	
Yes, AECI supports the suggested approach.	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	

7. The SDT believes that with the proposed modifications to EOP-012-1, the initial proposed implementation plan is appropriate with one change. The 18-month implementation time frame is for all revised and new requirements in EOP-012-1, except Requirements R1 and R2 which have a 60-month implementation time frame, and R4 which has a 78-month implementation time frame. Do you agree with this implementation time frame? If you think an alternate timeframe is needed, please propose an alternate implementation plan and time period, and provide a detailed explanation of actions planned to meet the implementation deadline.

Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	No
Document Name	
Comment	
This implementation is so extended, that these requirements will not be in force when the next Texas winter weather event occures.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The referenced implementation timelines take into consideration the timelines associated with the effective date of EOP-011-2, and the timelines associated with R3, R5, R6 and R7. To the extent that phase two changes key portions of the phase one requirements, the SDT will review the implementation plans again.	

Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
The implementation plan must be reconsidered in light of the the changes recommended in these comments.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. To the extent that phase two changes key portions of the phase one requirements, the SDT will review the implementation plans again.	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	No
Document Name	
Comment	
Talen Energy Marketing supports Talen Generation's comments.	
Likes 0	
Dislikes 0	
Response	
Please see response to Talen Generation.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation supports the 18-month implementation time frame. Reclamation disagrees with the 60-month and 78-month implementation time frames. A 5-6 year implementation period is inconsistent with the expedited time frame that has been applied to the standards development process. Reclamation recommends the time would be better spent to conscientiously develop a workable standard than to expedite a defective standard and provide 5-6 years to try to make it work.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The referenced implementation timelines take into consideration the timelines associated with the effective date of EOP-011-2, and the timelines associated with R3, R5, R6 and R7. To the extent that phase two changes key portions of the phase one requirements, the SDT will review the implementation plans again.	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	No
Document Name	
Comment	
Excluding the concerns raised in previous questions, these proposed implementation times are reasonable except for R7. Since R1 and R2 are not enforceable until 60 months, then a CAP implementation for R7 identified under R2 should follow this, not precede this time interval.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The development of a CAP under R7 is also applicable to R6, so R7's implementation much match R6 as well. Since R2 has a longer implementation, the applicability of R7 relative to R2 matches that timeline. To the extent that phase two changes key portions of the phase one requirements, the SDT will review the implementation plans again.	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	

Excluding the concerns raised in previous questions, these proposed implementation times are reasonable except for R7. Since R1 and R2 are not enforceable until 60 months, then a CAP implementation for R7 identified under R2 should follow this, not precede this time interval.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The development of a CAP under R7 is also applicable to R6, so R7's implementation much match R6 as well. Since R2 has a longer implementation, the applicability of R7 relative to R2 matches that timeline. To the extent that phase two changes key portions of the phase one requirements, the SDT will review the implementation plans again.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
We recommend a twelve month implementation time frame for all revised and new requirements; and a three year implementation time frame for EOP-012-1 Requirements R1 and R2 as this seems to be a sufficient amount of time to become compliant given that the new requirements were included in The Joint Inquiry Report published on November 18, 2021, the additional year for standard development and regulatory review requirements. A twelve month implementation would only miss implementation for one winter (2023-2024).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. To the extent that phase two changes key portions of the phase one requirements, the SDT will review the implementation plans again.	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	No

Document Name	
Comment	
ISO-NE reiterates its comments regarding the implementation plan from the Round 1 Comments. ISO-NE believes the proposed 18 months for the implementation is excessive due to the fact that the first requirements that become effective with this 18 months are carried over from EOP-011-2 R7 & R8 into EOP-012-1 R3 and R5. These requirements are already due to be effective April 1, 2023. These "new" requirements in EOP-012-1 have been written to provide further details required for a previously written Generator Cold Weather Preparedness Plan, and changed Training to Annual Training. Also, based on the CAP requirements in R6 and R7, "*A CAP shall be written within 150 days or by July 1st, whichever is earlier*" already provides some additional time from the original effective date for Generators that actually experience a trip attrinuted to freezing under the Standard. Determined by the NERC Board approval date, an effective date of 12 months will potentially include the majority of the Winter Season of 2023-2024 under R3 and R5 instead of pushing the Standard off for another winter season, which was a concern for the EOP-011-2 implementation plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The implementation timelines take into consideration the timelines associated with the effective date of EOP-011-2. To the extent that phase two changes key portions of the phase one requirements, the SDT will review the implementation plans again.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
MISO supports the comments submitted by the ISO/RTO Council Standards Review Committee (IRC SRC).	
Likes 0	

Dislikes 0	
Response	
Please see response to IRC SRC.	
Whitney Wallace - Calpine Corporation - 5 - WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
No for R6 only. R6 should read, "a [GO] that experiences a Generator Cold Weather Reliability Event shall develop a CAP, ***no longer than July 1…***." This will ensure that sufficient time is allotted for corrective actions to be developed that may take many months to plan and implement effectively in accordance with all design and code requirements. The primary focus of the GO if a GCWRE should occur should be to first implement immediate corrective actions that will allow the forced outage to be ended and the generating unit to be returned to service as safely and quickly as possible during an extreme cold weather event, and then develop long term corrective actions. Allowing for additional time for development of a CAP will allow for improved engineering solutions since more planning and engineering resources can be allocated to developing and implementing the correction actions(s). Additionally, the implementation of a CAP should be for up to 24 months due to supply chain challenges that the industry continues to experience.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. R6 requires the development of the CAP but it is up to the Registered Entity to determine the date of completion based on prudent business practices. R6 does not preclude the modification of a CAP once developed should supply chain or other challenges arise.	
Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)	
Answer	No

Document Name	
Comment	
The proposed implementation plan provides up to sixty months to implement the standard for individual units (eighteen months to identify the ECWT and develop a winterization plan and forty-two months to meet the reporting requirements), which could deter earlier compliance. Specifically, many units compete in wholesale markets and a unit owner may refrain from spending capital dollars (driving up its costs and thus its market bids) earlier than its competitors who delay compliance to later dates. In this way, the timeline works as a disincentive to early compliance. The SRC understands the need to recognize the complexities of winterization for different technologies and individual unit characteristics, but to avoid creating disincentives to earlier compliance, the SRC recommends a shorter period of twelve months to identify the ECWT and develop a winterization plan and an additional twenty-four months for all units (new and old) to comply with the winterization requirements and adding an exception process to the extent a GO can document compliance will take longer due to an individual unit's characteristics. The GO should have to document unit-specific exceptions and make the documentation available for review and audit. The SRC believes an implementation plan with an early, but realistic, compliance date that allows for reasonable exceptions avoids the disincentive created by a lengthy process that would allow even units facing minimal winterization requirements to refrain from complying earlier.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The requirements in EOP-012-1 do not extend or negate EOP-011-2 R7 and R8. GO's must be compliant with EOP-011-2 R7 and have implemented a cold weather preparation plan that includes freeze protection measures prior to the implementation of EOP-012-1. To the extent that phase two changes key portions of the phase one requirements, the SDT will review the implementation plans again.	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your review.	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your review.	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
DTE Electric supports NAGF comments provided for this project	

Likes 0	
Dislikes 0	
Response	
Please see response to NAGF.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company agrees with EEI and supports the proposed implementation plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to EEI.	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Avista supports the proposed Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Scott Kinney - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Avista supports the proposed Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Spencer - LS Power Development, LLC - 5	
Answer	Yes

Document Name	
Comment	
We appreciate the SDT's consideration of industry comments and the modifications to the implementation timeline.	
Likes 1	Vistra Energy, 5, Roethemeyer Dan
Dislikes 0	
Response	
Thank you for your support.	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Ameren agrees with the EEI and the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Please see response to EEI and NAGF.	
Joe Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	

Xcel Energy supports comments from EEI.	
Likes 0	
Dislikes 0	
Response	
Please see response to EEI.	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3, Group Name OGE Energy	
Answer	Yes
Document Name	
Comment	
OG&E supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Please see response to EEI.	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	Yes
Document Name	
Comment	

PG&E believes the implementation timeframes are reasonable. PG&E agrees with the concerns raised by EEI and NAGF that are noted in the input to the earlier questions.	
Likes 0	
Dislikes 0	
Response	
Please see response to EEI. And NAGF.	
Devin Shines - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company	
Answer	Yes
Document Name	
Comment	
LouisvilleG&E/KU support EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Please see response to EEI.	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	

Constellation has no additional comments. Kimberly Turco, on behalf of Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Alison Mackellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco, on behalf of Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	Yes

Document Name	
Comment	
PNM supports the Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Dan Roethemeyer - Vistra Energy - 5	
Answer	Yes
Document Name	
Comment	
The implementation timeline seems reasonable if the adopted standards are modified as recommended in these comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	

Exelon supports the proposed implementation plan. Submitted on behalf of Exelon, Segments 1 & 3	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Stewart Rake - Luminant Mining Company LLC - 7	
Answer	Yes
Document Name	
Comment	
The implementation timeline seems reasonable if the adopted standards are modified as recommended in these comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	

Excluding the concerns raised in previous questions, the NAGF believes that the proposed implementation times are reasonable.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	Yes
Document Name	
Comment	
Capital Power supports the North American Generators Forum (NAGF) response to this question.	
Likes 0	
Dislikes 0	
Response	
Please see response to NAGF.	
Colin Chilcoat - Invenergy LLC - 6	
Answer	Yes
Document Name	
Comment	
Invenergy supports the proposed implementation time frame.	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
George Brown - Acciona Energy North America - 5	
Answer	Yes
Document Name	
Comment	
Acciona Energy has no comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Deanna Carlson - Cowlitz County PUD - 5	
Answer	Yes
Document Name	
Comment	
Deanna Carlson, Cowlitz PUD, 5, 9/1/22	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Avista supports the proposed Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Rhonda Jones - Invenergy LLC - 5	
Answer	Yes
Document Name	
Comment	
Invenergy supports the proposed implementation time frame.	
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 proposed Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Diana Torres - Imperial Irrigation District - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
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	
Thank you for your support.	
Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brian Evans-Mongeon - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Michael Watt - Oklahoma Municipal Power Authority - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brooke Jockin - Portland General Electric Co. - 1, Group Name Portland General Electric Co.	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Glenn Pressler - CPS Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Lenise Kimes - City and County of San Francisco - 1,5 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Josh Combs - Black Hills Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Sheila Suurmeier - Black Hills Corporation - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Tony Skourtas - Los Angeles Department of Water and Power - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
James Baldwin - Lower Colorado River Authority - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Donna Johnson - Oglethorpe Power Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Scott McGough - Georgia System Operations Corporation - 3	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ruchi Shah - AES - AES Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Eric Ruskamp - Lincoln Electric System - 6, Group Name LES	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Steven Sconce - EDF Renewable Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Mark Young - Tenaska, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Imane Mrini - Austin Energy - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ronald Bauer - MGE Energy - Madison Gas and Electric Co. - 3	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Adam Lee - MGE Energy - Madison Gas and Electric Co. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Foung Mua, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Wei Shao, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; - Tim Kelley, Group Name SMUD / BANC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Michelle Amarantos - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
John Liang - Snohomish County PUD No. 1 - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
LaKenya VanNorman - LaKenya VanNorman On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name Florida Municipal Power Agency (FMPA)	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Natalie Johnson - Enel Green Power - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	
Yes, AECI supports the suggested approach.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE appreciates the drafting team’s efforts to make the implementation plan more clear by adding a graphic with the various effective and compliance dates. Texas RE is concerned, however, with the 60-month timeframe to comply with Requirements R1 and R2. Texas RE believes this poses a reliability risk and that entities should implement freeze protection measures and provide the capability to operated for at least one hour at the unit(s) Extreme Cold Weather Temperature as soon as possible in order to ensure there is no reliability gap.	

In the ERCOT region, generation entities were not given five years to comply with weather emergency preparedness rules and required to complete winter weather emergency preparation measures by December 1, 2021. These measures included winterization, operation readiness, structural preparations, enclose sensors for cold weather critical components, address cold weather critical components failures that occurred between November 30, 2020, and March 1, 2020, provide training on winter weather preparations, and determine minimum design temperature or minimum experienced operating temperature, among other items.

Texas RE understands the intent of compliance various thresholds set forth in both Requirements R1 and R2 is to recognize that existing generation resources may find it more difficult to retrofit appropriate freeze protection measures. Texas RE understand the technical rationale for requiring existing units to ensure capability of operating for at least one hour at the Extreme Cold Weather Temperature (R2) whereas new generation should be able to demonstrate it can operate for 12 hours at the Extreme Cold Weather Temperature given the putative differences between newer and older generating units.

While Texas RE notes that the recently implemented Texas rules do not recognize this distinction between new and existing resources, Texas RE believes that the current proposed EOP-012-1 R1 and R2 define the scope of “existing” resources too broadly by appearing to connect the definition of “existing” resources to the effective date of the standard requirement. Instead, Texas RE recommends the language in Requirements R1 and R2 reference the effective date of the governmental authority’s order approving EOP-012-1. The effective date of the FERC order puts new and existing generating entities on notice that they will need to comply with the standard by the compliance date, obviating the need to extend the lower R2 compliance thresholds for “existing” resources to units constructed following the effective date of the FERC order. Otherwise, generating units built as much as 60 months from the FERC order date will be treated as “existing” units subject to the lower R2 requirements. As Texas RE stated above, entities should not have five years to comply with these requirements, but at a minimum, resources constructed within this five-year window should not be treated as “existing” resources, but rather be required to meet the 12-hour requirements for new generation resources.

Finally, Texas RE recommends clarifying the first section of the graphic to say that it is the Effective date of the Governmental Authorities’ approval of EOP-012-1 and the implementation plan. This is consistent with the language in the paragraph below regarding the effective date

of EOP-012-1. Texas RE furthermore recommends that the Standard EOP-012-1 section on page 4 specify that the effective date of the standard applies to all requirements unless specified for a different compliance date or initial performance date.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the graphic in the implementation plan to reflect Texas RE's suggested edit. The suggested edit to the Standard EOP-012-1 section on Page 4 has been referred to NERC Legal to consider changing in the Implementation Plan template. To the extent that phase two changes key portions of the phase one requirements, the SDT will review the implementation plan timelines again.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
"Please see comments submitted by the Edison Electric Institute"	
Likes 0	
Dislikes 0	
Response	
Please see response to EEI.	

8. The SDT proposes that the modifications in the proposed EOP-012-1 meet the key recommendations in The Report 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.

LaKenya VanNorman - LaKenya VanNorman On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name Florida Municipal Power Agency (FMPA)

Answer	No
Document Name	

Comment

R3.2 and R3.3 are unnecessary from a performance-based standard perspective. Requiring a CAP for any failure to run or any derate from a cold weather event is sufficient to provide performance under the standard. However, requiring the creation of lists of equipment and protective measures, while good engineering practice, are not good compliance activities. This results in administrative burden for administration’s sake.

In addition, the standard is full of subjective, ambiguous, and in-auditable language. Phrases like “typically available”, and provisions that allow for any “technical, commercial or operational constraints” as defined by the GO are subjective and open to interpretation, and will compliance certainty difficult for entities. This includes referencing non-NERC contracts such as OATTs or “other contracatual arrangement[s]” in the Applicability language. All of these factors will result in a high compliance burden and risk of fines and significant capital spends on upgrades due to standard uncertainty and ambiguity.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. R3.2 and R3.3 are recommendations from the Joint Inquiry Report and are within the scope of the SAR. The NERC document *Results-Based Reliability Standard Development Guidance* states that Reliability Standards should be viewed as a portfolio of

requirements designed to achieve an overall defense-in-depth strategy and "where each requirement in a [Standard] has a role in preventing system failures…" The SDT feels the requirements in question meets that threshold by identifying components subject to risk from freezing and the relevant freeze protection measures implemented to protect against freezing. Finally, the SDT has made some clarifying changes to the language of the applicability section that may address some of your concerns.	
Rhonda Jones - Invenergy LLC - 5	
Answer	No
Document Name	
Comment	
For EOP-012-1, Invenergy is unable to quantify the overall costs and benefits to arrive at a definitive conclusion about the cost effectiveness of the current draft. However, as noted in Invenergy's previous responses, the current proposal yields an arbitrarily stringent standard that could impose more onerous requirements than are necessary to ensure generator availability during the prolonged extreme cold events – occurring over multiple hours or days – that this Standard is intended to address. The alternative approach Invenergy suggests would reasonably be expected to yield a more cost-effective approach to meeting the key recommendations in the Joint Inquiry Report. Invenergy also remains concerned that certain generating units, including independent power producers, may be required to bear significant incremental costs to comply with the standard without a corresponding mechanism for recovering those costs.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The team believes that the proposed draft meets the intent of the recommendations in the report and yields a reasonable standard. Strikes a balance between the recommendations in the cold weather report for an industry wide standard by allowing entities to calculate the cold weather temperatures for its geographic location and determine the necessary freeze protection measure to meet the requirements of the standard. The team has previously discussed cost recovery in the response to comments on the initial ballot.	

Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)	
Answer	No
Document Name	
Comment	
The SRC believes the proposed revisions do not meet the key recommendations, regardless of whether they are "cost effective" (based on our comments, above). If the goal of this Standard is to ensure generators ride-through extreme weather events, the SDT should draft a Standard to accomplish that goal. NERC should leave the issue of compensation to FERC and other regulators to determine how to compensate GOs for the cost of winterization and freeze protection measures (*e.g.*, areas of the country using cost-based rates could include the cost of upgrades in the rate base to establish customer pricing; parts of the country with wholesale markets can develop market tools to provide compensation to generators who upgrade resources). *See*, Key Recommendation 2 in the Joint Report.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Deanna Carlson - Cowlitz County PUD - 5	
Answer	No
Document Name	
Comment	
Agree with comments provided by Russell Noble.	
Likes 0	
Dislikes 0	

Response	
Please see response provided to Russell Noble.	
Russell Noble - Cowlitz County PUD - 3	
Answer	No
Document Name	
Comment	
Cowlitz agrees with comments provided by the North American Generator Forum.	
Likes 0	
Dislikes 0	
Response	
Please see response to NAGF.	
Whitney Wallace - Calpine Corporation - 5 - WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
No for R5 only. The R5 requirement should focus on the content of the training to be given, the desired audience of that training, and the completion date. Requiring identification of the entity responsible for actually giving the training in the requirement will not increase the efficacy of the training material. It simply creates an administrative item to be tracked that adds nothing to generating unit reliability. Content, audience and completion of the required training accomplish that, not the denotation of who will be performing the training.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. EOP-012-1 R5 was moved from EOP-011-2 and only modified with the word "annual" to meet Key Recommendation 1e in the report.	
Colin Chilcoat - Invenergy LLC - 6	
Answer	No
Document Name	
Comment	
For EOP-012-1, Invenergy is unable to quantify the overall costs and benefits to arrive at a definitive conclusion about the cost effectiveness of the current draft. However, as noted in Invenergy's previous responses, the current proposal yields an arbitrarily stringent standard that could impose more onerous requirements than are necessary to ensure generator availability during the prolonged extreme cold events – occurring over multiple hours or days – that this Standard is intended to address. The alternative approach Invenergy suggests would reasonably be expected to yield a more cost-effective approach to meeting the key recommendations in the Joint Inquiry Report. Invenergy also remains concerned that certain generating units, including independent power producers, may be required to bear significant incremental costs to comply with the standard without a corresponding mechanism for recovering those costs.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The team may take your comments into consideration in phase two of this project. The team cannot comment on cost recovery mechanisms at this time. Please note that the SDT performed spot reviews of existing fleets of generating assets that currently operate in extreme cold weather and to the extent that these units are employing current industry best practices, the SDT feels that the additional compliance documentation in meeting the proposed new standard will not be significant in either cost or effort.	
Shannon Ferdinand - Decatur Energy Center LLC - 5	

Answer	No
Document Name	
Comment	
Capital Power supports the North American Generators Forum (NAGF) response to this question.	
Likes 0	
Dislikes 0	
Response	
Please see response to NAGF.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
MISO supports the comments submitted by the ISO/RTO Council Standards Review Committee (IRC SRC).	
Likes 0	
Dislikes 0	
Response	
Please see response to IRC SRC.	
Mark Young - Tenaska, Inc. - 5	
Answer	No
Document Name	
Comment	

This is essentially a return on investment question. It is difficult to answer this question until there is an understanding of total cost recovery required to implement this design standard for the entire BES. The Report's #2 recommendation was for markets or consumers to provide cost recovery. While NERC cannot mandate cost recovery, NERC can provide exemptions for compliance until markets and regulatory agencies determine the need and the method of compensating Generator Owners for their investment in winter weatherization.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The team has previously discussed cost recovery in the response to comments on the initial.	
Steven Sconce - EDF Renewable Energy - 5	
Answer	No
Document Name	
Comment	
EDFR supports the comments submitted by NAGF.	
Likes 0	
Dislikes 0	
Response	
Please see response to NAGF.	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	No
Document Name	
Comment	

For Canadian entites, the necessary cold weather practices are already in place. The administrative burden associated to the tasks being required in the standards outweigh the reliability benefits, as we already have a good handle on planning, operations and maintenance activites in cold (and even extreme cold) weather.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The team believes that for entities that have implemented adequate freeze protection measures, implementing this standard will require minimal effort. Please note that the SDT performed spot reviews of existing fleets of generating assets that currently operate in extreme cold weather and to the extent that these units are employing current industry best practices, the SDT feels that the additional compliance documentation in meeting the proposed new standard will not be significant in either cost or effort.	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	No
Document Name	
Comment	
ISO-NE supports the comments of the SRC that cost recovery mechanism be left to FERC and the Industry to determine how to compensate GOs for any upgrades if needed.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No

Document Name	
Comment	

The NAGF does not agree that the draft EOP-012 addresses the concerns from the Report in a cost-effective manner. The NAGF is concerned that the proposal, while a great improvement from the initial posting, fails to address the concerns from the Report in several areas. These areas include:

- The proposed standard does not require significant changes beyond calculating the Extreme Cold Weather Temperature and listing components susceptible to the cold weather.
- The design requirements only require the Generator Owner to identify why nothing was done, not make changes to the design to make the generator more reliable during winter. As the SDT is trying to address the issue of retrofit without being able to address the compensation issue, we understand why this compromise is being proposed.
- The Report states that many units failed before reaching their minimum design criteria. The proposed standard does not require a CAP if this occurs. The CAP is only required if a failure occurs above the ECWT, which has no significant meaning to a generator's design capability. This feature also appears to undermine the requirement to provide the BA, TOP and RC with a minimum operating temperature to be used during the planning process.
- The proposed standard does require generators to address the conditions seen, specifically temperature, wind and moisture combined. For example, a wind turbine is likely able to operate to a minimum temperature of 20 degrees Fahrenheit if it is dry but will have blade icing occur at 32 degrees Fahrenheit if there is moisture. If the ECWT for that site is 25, a CAP will be required for blade icing, but not if the nacelle ices at 22 degrees due to failure to close vents.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The team maintains that this standard is the first step in more reliability operation during cold weather and will continue to discuss communication between the BA, TOP, RC and GO, in addition to other topics, in the second phase of this project.

Ruchi Shah - AES - AES Corporation - 5

Answer	No
Document Name	

Comment	
AES Clean Energy supports comments submitted by NAGF.	
Likes 0	
Dislikes 0	
Response	
AES Clean Energy supports comments submitted by NAGF.	
Stewart Rake - Luminant Mining Company LLC - 7	
Answer	No
Document Name	
Comment	
The modifications in proposed EOP-012-1 continue to raise cost effectiveness concerns, because the standards are tied to a very conservative temperature standard of the 0.2 percentile lowest hourly temperature experienced at the closest weather station since Jan. 1, 2000. Generators in the TRE region have no mechanism for cost recovery for any capital expenditures or other expenses they incur to implement the new standards. Generators in other reliability regions similarly may not have the ability to recover costs to implement weather preparedness standards, especially if they are not rate regulated companies. If the standards are revised as recommended throughout Vistra's comments (and the comments being filed by Texas Competitive Power Advocates, of which Vistra is a member), then the standard would meet the key recommendations in The Report in a cost-effective manner. However, if the standard is adopted as currently proposed, there would be serious questions regarding the cost-effectiveness of the standard, and it could even lead to early retirements or cancellations or delays of new resources.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The team has previously discussed cost recovery in the response to comments on the initial ballot.	

LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	No
Document Name	
Comment	
Refer to above comments	
Likes 0	
Dislikes 0	
Response	
Please see responses above.	

Dan Roethemeyer - Vistra Energy - 5	
Answer	No
Document Name	
Comment	
The modifications in proposed EOP-012-1 continue to raise cost effectiveness concerns, because the standards are tied to a very conservative temperature standard of the 0.2 percentile lowest hourly temperature experienced at the closest weather station since Jan. 1, 2000. Generators in the TRE region have no mechanism for cost recovery for any capital expenditures or other expenses they incur to implement the new standards. Generators in other reliability regions similarly may not have the ability to recover costs to implement weather preparedness standards, especially if they are not rate regulated companies. If the standards are revised as recommended throughout Vistra's comments (and the comments being filed by Texas Competitive Power Advocates, of which Vistra is a member), then the standard would meet the key recommendations in The Report in a cost-effective manner. However, if the standard is adopted as currently proposed, there would be serious questions regarding the cost-effectiveness of the standard, and it could even lead to early retirements or cancellations or delays of new resources.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. The team has previously discussed cost recovery in the response to comments on the initial ballot. Please note that the SDT performed spot reviews of existing fleets of generating assets that currently operate in extreme cold weather and to the extent that these units are employing current industry best practices, the SDT feels that the additional compliance documentation in meeting the proposed new standard will not be significant in either cost or effort.	
Sheila Suurmeier - Black Hills Corporation - 1,3,5,6	
Answer	No
Document Name	
Comment	
BHC agrees with the first statement but cannot determine cost effectiveness and offers no comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Micah Runner - Black Hills Corporation - 1	
Answer	No
Document Name	
Comment	
BHC agrees with the first statement but cannot determine cost effectiveness and offers no comment on cost effectiveness.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment.	
Josh Combs - Black Hills Corporation - 3	
Answer	No
Document Name	
Comment	
BHC agrees with the first statement but cannot determine cost effectiveness and offers no comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
BHC agrees with the first statement but cannot determine cost effectiveness and offers no comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	

Answer	No
Document Name	
Comment	
The recommendations are inherently not cost-effective for Generator Owners, so changing the standard language will not make them so.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	No
Document Name	
Comment	
The recommendations are inherently not cost-effective for Generator Owners, so changing the standard language will not make them so.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	

Reclamation observes that the SDT has asserted that it has the support of industry except for minor details in the standard and is promising improvements in “Phase 2” of this project. Reclamation can identify no basis for this assertion based on the failure of the previous ballot and the refusal of this SDT and other SDTs to modify “legacy” language in subsequent standards modification projects once language has been approved. Reclamation asserts that a two-phase approach to developing standards that inherently requires re-versioning Phase 1 standards in Phase 2 is not cost effective. Reclamation recommends a good approach to promulgating quality standards is not to force a defective product through the system but rather to spend the necessary time to make the product right the first time. Reclamation observes that many entities have provided direct suggestions for improvement starting with Draft 1 of this project, but the SDT took neither the time nor the effort to properly consider them.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The project was designed to be completed in two phases based on the key recommendation deadlines in the report as well as the deadline from the NERC Board of Trustees. Since the two groups of recommendations work together, the team will be taking industry comments from this draft into consideration in phase two when more modifications are made to address the second group of recommendations.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Dominion Energy is of the opinion that the recommended alternative for Requirement 2 discussed previously in response to Question 5 is a more cost-effective manner to address the reliability concerns of generation not operating as planned during extreme cold weather.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. Please see response to Question 5.	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	No
Document Name	
Comment	
At this time PG&E cannot determine if the proposed modifications are cost effective.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Mark Spencer - LS Power Development, LLC - 5	
Answer	No
Document Name	
Comment	
Most BAs in the US are summer peaking systems (the seasonal spread increases to the south), and a significant fraction of generation is located in the RTOs with annual capacity markets that offer no distinction between summer peaking generators and all others generators. Consequently, the proposed standard will impose a requirement on a significant number of generators that are not needed to meet the winter load. Moreover, generators that historically have not been needed to serve winter load typically do not procure firm transportation rights or forward contract for fuel. This forces generators that may or may not be able to obtain fuel and have historically not been needed to serve winter load to incur the cost of compliance. Regardless whether these costs are born by the ratepayer or absorbed by	

the generator owner, this is not a cost effective outcome. A cost effective approach, while enhancing reliability, would be to procure the exact quantity, and no more, of reliable generation necessary to prevent wide-scale manual load shedding. We reiterate that the BAs are best positioned to quantify their needs under a range of weather scenarios aligned with their Emergency Operating Plans, to specify an absolute performance requirement (inclusive of weather, fuel, environmental restrictions, etc.), and levy penalties for non-performance in the most cost effective manner. As an example, if a BA procured sufficient weatherized winter supply backed by certain fuel, the SDT's concern of "premature retirements" would be moot. Additionally, the Regional Entities' would have bright line criteria to apply to determine whether generator owners are complying with any commitments made to their BAs.	
Likes 1	Vistra Energy, 5, Roethemeyer Dan
Dislikes 0	
Response	
Thank you for your comment. The team has previously discussed cost recovery in the response to comments on the initial ballot. The team will take your comments about BA's into consideration during the drafting in phase two.	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	No
Document Name	
Comment	
Without a definition of "commercial constraints" it is difficult to know how R1 and R7 should be evaluated for compliance. We recommend the Standard Drafting Team make it clear in the standard that "commercial constraint" is limited to the inability to obtain necessary equipment or services after reasonable efforts due to supply issues or unavailability of services. Without this limitation, "commercial constraints" could be interpreted to mean cost prohibitions or economic pressures on the commercial profitability of a unit. It is our understanding that cost prohibitions or economic pressures are not intended to be acceptable justifications for not implementing freeze protection measures.	
Likes 1	LS Power Development, LLC, 5, Spencer Mark
Dislikes 0	

Response	
Thank you for your comment. The team may take your comments about additional clarity around commercial constraints into consideration during phase two of the project.	
Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 1	
Answer	No
Document Name	
Comment	
NextEra Energy is not supplying a position or comment on the cost effectiveness of these proposed changes.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
We believe that establishing a new Extreme Cold Weather Temperature may result in the need for costly upgrades to coal handling facilities, which may only become apparent during the implementation period. Generator Owners will be reluctant to make these costly investments unless and until the need for them is proven.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The team has discussed the extreme cold weather temperature at length and declines to make any changes at this time.	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	No
Document Name	
Comment	
Talen Energy Marketing supports Talen Generation's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to Talen Generation.	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
The cost-effective sequence of events for bolstering generation plant cold weather protection is to firstly obtain valid capability data (based on WCT or DBT-plus-20 mph, not DBT alone), then have RCs, BAs and TOPs identify their true reserve margins for extreme cold weather events. These parties can then adopt the appropriate market solutions – incentivizing upgrades where shortages are predicted, and accepting the status quo where no action is needed. EOP-012-1 presently takes an extremely non-cost-effective approach, immediately leaping to a draconian and unnecessary requirement for retrofitting of existing units. This problem is exacerbated by using an incorrect basis for Extreme Cold Weather Temperature (DBT only, instead of WCT or DBT-plus-20 mph) and an incorrect protect-to target (0.2 percentile instead of historical worst-case weather). GOs can thereby be lured into installing inadequate protection, setting them up for immense market losses for 43 hours per decade (or more) if sold-	

ahead and, due to freeze-up, having to buy power on the spot market at prices that can reach $1000/MWh or higher (large units can lose $1MM per hour in this fashion). This situation also paves the way for having to tear-out marginal, EOP-012-1-based heat tracing/insulation systems that fail to protect as hoped and start over as an R6 CAP.

It also bears mentioning that the ultimate, "low hanging fruit," for enhancing BES wintertime reliability is to put additional generation units online out-of-merit when an extreme storm is impending, since it is far easier to keep a unit running during severe weather than it is to start-up under such circumstances. EOP-012-1 may not be the place to address this issue, but until NERC acts in this respect, or at least encourages ISOs to act, it is not apparent that a sincere effort is being made regarding cost effectiveness.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The team has discussed the extreme cold weather temperature at length and declines to make any changes at this time. The team believes that bringing units online out-of-merit is out of scope of this phase for this team.

Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric

Answer	No
Document Name	

Comment

DTE Electric supports NAGF comments provided for this project

Likes 0	
Dislikes 0	

Response

Please see response to NAGF.

Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6

Answer	No

Document Name	
Comment	
The modifications continue to burden small utilities who already operate in sub-freezing weather. These requirments put significant burden on staff unnecessarily, and expose the parent company to administrative penalties, not performance penalties.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please note that the SDT performed spot reviews of existing fleets of generating assets that currently operate in extreme cold weather and to the extent that these units are employing current industry best practices, the SDT feels that the additional compliance documentation in meeting the proposed new standard will not be significant in either cost or effort.	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your review.	
Brooke Jockin - Portland General Electric Co. - 1, Group Name Portland General Electric Co.	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your review.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Avista supports the proposed change to the standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
George Brown - Acciona Energy North America - 5	
Answer	Yes
Document Name	
Comment	
Acciona Energy supports Midwest Reliability Organization’s (MRO) NERC Standards Review Forum’s (NSRF) comments on this question.	
Likes 0	
Dislikes 0	

Response	
Please see response to MRO NSRF.	
Adam Lee - MGE Energy - Madison Gas and Electric Co. - 4	
Answer	Yes
Document Name	
Comment	
Madison Gas and Electric supports the comments of the MRO NSRF	
Likes 0	
Dislikes 0	
Response	
Please see response to MRO NSRF.	
Ronald Bauer - MGE Energy - Madison Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Madison Gas and Electric supports the comments from the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Please see response to MRO NSRF.	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	

Answer	Yes
Document Name	
Comment	
MidAmerican Energy supports the MRO NSRF comments for this question.	
Likes 0	
Dislikes 0	
Response	
Please see response to MRO NSRF.	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
The MRO NSRF agrees EOP-012-1 meets the key recommendations in The Report in a cost effective manner. The sum of all the components of the proposed Standard as written create a balanced approach between the need to improve grid reliability and resiliency during cold weather events and the need to participate in a competitive market.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	Yes

Document Name	
Comment	
Alliant Energy supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Please see response to MRO NSRF.	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	Yes
Document Name	
Comment	
NPPD agrees EOP-012-1 meets the key recommendations in The Report in a cost effective manner. The sum of all the components of the proposed Standard as written create a balanced approach between the need to improve grid reliability and resiliency during cold weather events and the need to participate in a competitive market.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Alison Mackellar - Constellation - 5	
Answer	Yes
Document Name	

Comment	
EOP-012 achieves a cost effective solution because of the exemptions built in R7 for technical, commercial, or operational constraints that may apply to a particular generator. Constellation notes, however, that the standard could provide greater clarification that lack of cost recovery is a commercial constraint to implementation of Requirement R1 and any Corrective Action Plan (CAP) under Requirement R2 or exception under Requirement R7. It is critical that any adopted weatherization requirements clearly ensure that lack of cost recovery is included under the qualified "commercial" constraints listed in Requirements R1, R2 and R7 and specifically outline how determinations for each category of constraint will be decided. In addition, under Requirement R2, Generator Owners should have the option to develop and implement a CAP or be allowed to explain in a declaration why corrective actions are not being implemented due to any technical, commercial, or operational constraints as defined by the Generator Owner. These options should not be across two separate Requirements (R2 and R7) within the draft standard. Streamlining R2 and R7 into one Requirement will create efficiencies in compliance for Generator Owners and in compliance monitoring reviews for the NERC Regional Entities. Kimberly Turco, on behalf of Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The team may take your comments about additional clarity on commercial constraint into consideration during phase two of the project. The team discussed the structure of the CAP requirement across multiple requirements and determined the current structure in the draft standard for the declaration to be in Requirement R7 which applies to all previous CAPs and declines to make any changes at this time.	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	

EOP-012 achieves a cost effective solution because of the exemptions built in R7 for technical, commercial, or operational constraints that may apply to a particular generator. Constellation notes, however, that the standard could provide greater clarification that lack of cost recovery is a commercial constraint to implementation of Requirement R1 and any Corrective Action Plan (CAP) under Requirement R2 or exception under Requirement R7. It is critical that any adopted weatherization requirements clearly ensure that lack of cost recovery is included under the qualified “commercial” constraints listed in Requirements R1, R2 and R7 and specifically outline how determinations for each category of constraint will be decided. In addition, under Requirement R2, Generator Owners should have the option to develop and implement a CAP or be allowed to explain in a declaration why corrective actions are not being implemented due to any technical, commercial, or operational constraints as defined by the Generator Owner. These options should not be across two separate Requirements (R2 and R7) within the draft standard. Streamlining R2 and R7 into one Requirement will create efficiencies in compliance for Generator Owners and in compliance monitoring reviews for the NERC Regional Entities.

Kimberly Turco, on behalf of Segments 5 and 6

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The team may take your comments about additional clarity on commercial constraint into consideration during phase two of the project. The team discussed the structure of the CAP requirement across multiple requirements and determined the current structure in the draft standard for the declaration to be in Requirement R7 which applies to all previous CAPs and declines to make any changes at this time.	
Joe Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	

Xcel Energy can support the cost-effectiveness of implementing this Standard, predicated on the ability that R2 is tied to R6 and, subsequently, R7. The ability to declare qualifying units as unable to implement corrective actions is a required element for Xcel Energy to support the implementation of this Standard in a cost-effective manner.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Scott Kinney - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Avista supports the proposed change to the standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	

Avista supports the proposed change to the standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southen Company agrees that the proposed requirements are cost effective assuming the exceptions provided in R1 and R7 remain the same.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment.	
Natalie Johnson - Enel Green Power - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
John Liang - Snohomish County PUD No. 1 - 6	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Michelle Amarantos - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Foung Mua, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Wei Shao, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; - Tim Kelley, Group Name SMUD / BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Eric Ruskamp - Lincoln Electric System - 6, Group Name LES	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Scott McGough - Georgia System Operations Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Donna Johnson - Oglethorpe Power Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
James Baldwin - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Tony Skourtas - Los Angeles Department of Water and Power - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Glenn Pressler - CPS Energy - 3	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Michael Watt - Oklahoma Municipal Power Authority - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brian Evans-Mongeon - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
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	
Thank you for your support.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Diana Torres - Imperial Irrigation District - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	
Document Name	
Comment	
CEPM believes that as an IPP (non-Utility) there needs to be better defined means for IPPs to recoup costs for modification of existing units to operate to the minimum operating temerpature prior to R2 becoming enforcable. We believe the SDT does have an obligation with support of these approaches along with the GO and ISO/RTO.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The team has previously discussed cost recovery in the response to comments on the initial ballot.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	
Comment	
No Comment	
Likes 0	
Dislikes 0	
Response	

Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	
Document Name	
Comment	
At this time, SIGE is unable to quantify if the modifications will be cost-effective.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
"Please see comments submitted by the Edison Electric Institute"	
Likes 0	
Dislikes 0	
Response	
Please see response to EEI.	
Lenise Kimes - City and County of San Francisco - 1,5 - WECC	
Answer	

Document Name	
Comment	
Difficult to weigh-in since actual potential costs are unknown at this time.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Devin Shines - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company	
Answer	
Document Name	
Comment	
LouisvilleG&E/KU support EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Please see response to EEI.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE recommends the SDT consider including parameters or examples for when the use of a technical, commercial, or operational constraint is justifiable for not implementing a CAP in Requirement R7. The use of the phrase “as defined by the Generator Owner” is broad and could lead to reliability gaps.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, the team may take this into consideration during phase two of the project.	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3, Group Name OGE Energy	
Answer	
Document Name	
Comment	
OG&E supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Please see response to EEI.	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	

Yes, AECI supports the suggested approach.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

9. Provide any additional comments for the standard drafting team to consider, including the provided technical rationale document, if desired.

Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	
Document Name	
Comment	
The focus needs to be on those entities who have failed to perform during cold weather, and should not impact those who operate facilities located and operated in cold climates where freezing temperatures are common. The standard and VSLs all point to admistrative activities and not performance activities. This creates a nighmare during audits and exposure to many companies who should not be considered risks.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The Standard Drafting Team is appreciative of the comments provided. We believe that facilities that have historically operated well during freezing temperatures are well positioned to meet the new requirements of EOP-012-1.	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	
AECI has 2 additional comments for this standard not covered in the previous comment sections. These comments are specific to R5 and R6 respectively.	

R5: In regards to the proposed verbiage requiring “generating unit-specific training”, it is our opinion that this could be overly burdensome for stations with multiple units; particular for those stations with multiple units of a similar design (a.k.a. “sister” units). Recommend modifying this
requirement to require station-specific training in lieu of generating unit-specific training. It is our opinion that this modification will allow the GO/GOP the flexibility to develop their training modules with an appropriate level of detail so as to sufficiently train station personnel without requiring them to create multiple modules with similar or identical content.

R6: Concerning the proposed timeline for the development of a CAP, it is our recommendation that the July 1st date be removed from this requirement. The rationale for this recommendations is thus: 150 days prior to July 1st is Feb 1st for non-leap years and Feb 2nd for leap years. Moreover, the July 1st timeline is further condensed if a Generator Cold Weather Reliability Event (GCWRE) occurs in March or April. Lastly, the stated intent of the timeframe options within the Technical Rationale is to allow GO’s to review multiple events holistically following a winter season. In certain areas of the country, a GCWRE could realistically occur as early as late-October. In this instance, the latest possible date for the development of a CAP would be March 30th.

Given that it is also realistic for a GCWRE to occur in March, 150 days seems a reasonable number of days to cover all but the most extreme scenarios. Therefore, we recommend removing the hard deadline of July 1st.

Thank you for the opportunity to comment. AECI thanks the standard drafting team for their diligence and commitment to improve system reliability with an expedited timeline.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The Standard Drafting Team is appreciative of the comments provided. With regards to unit vs site specific training, this is approved language and the team believes that training can be developed holistically with unit-specific differences highlighted where applicable. Additionally, we believe 150 days is a reasonable timeframe to act to develop a CAP.
Julie Hall - Entergy - 6, Group Name Entergy
Answer
Document Name
Comment
General area aspects have not been captured to help determine the extreme weather temperature aspect. Geographic guidance from the BA could be beneficial. From a technical view should we have some type of forwarding looking element.
Likes 0
Dislikes 0
Response
Thank you for your comments. The Standard Drafting Team is appreciative of the comments provided. We believe the Generator Owner to be in the best position to determine the Generator Cold Weather Temperature.
Diana Torres - Imperial Irrigation District - 6
Answer
Document Name
Comment
None
Likes 0
Dislikes 0
Response

Thank you for the comment.	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	
Document Name	
Comment	
DTE Electric supports NAGF comments provided for this project	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments, please see response to NAGF.	
Donald Lock - Talen Generation, LLC - 5	
Answer	
Document Name	
Comment	
Talen Energy supports the supplemental comments of the NAGF, and adds those presented below. {C}1. {C}R1 says that GO/GOPs must, "Explain in a declaration, any technical, commercial, or operational constraints," but there is no mechanism for these inputs to be conveyed to RCs, BAs and TOPs. Such limitations should be declared in R3.5 of EOP-012-1, and R3.5 should be amended to require that data be sent to RCs, BAs and TOPs. {C}2. {C}The exceptions of the second bullet point of R1 should be revised to disallow failure to winterize new units simply because the owners don't feel like spending the money. Reliability standards should set the rules for being allowed to sit at the table. Perhaps the	

expression, “preclude the ability,” was not meant to grant carte blanche in this respect, but if so it is an example of the need for use of clear language in reliability standards.

If there is an implied regulatory hurdle to be cleared in this respect, as opposed to relying solely on the judgment of GOs, guidance is required in EOP-012-1 for emerging technologies such as preventing ice accumulation on wind turbine blades. It may not be possible to set firm rules in such cases, but NERC should create incentives to advance the state of the art (the “best available technology”) rather than permanent loopholes.

{C}3. {C}The “demonstrates” of M1 should be limited to major freeze prevention measures, such as heat tracing/insulation systems and wind turbine nacelle heating. GOs should not have to obtain design calculations for every lube/seal oil reservoir heater, building heater, enclosure heater and other minor winterization measure for plants built many decades ago, especially since there are no calculations for wind barriers, CTG inlet air heaters and the like.

{C}4. {C}The entry, “features. Any,” in M1 should be, “features, any.”

{C}5. {C}The, “add new or modify,” language of R2 should be expunged, as well as the percentile based performance criterion of the Extreme Cold Weather Temperature definition, for the reasons given earlier in these comments. The CAPs of R2 should allow revising the capability declaration of R3.5.2 in lieu of modifying the facility, again as explained earlier.

{C}6. {C}The Extreme Cold Weather Temperature criterion should be replaced in R3.1, and everywhere else it is used in EOP-012-1, with the historical worst-case WCT (or DBT-with-20 mph wind value), as mentioned previously. The only calculations then required involve converting DBT+wind values to WCT, which is so simplistic that there’s no need to document the math as compliance evidence.

{C}7. {C}The Guidance section of EOP-012-1 should explain that the high level of uncertainty inherent in winterization makes it unnecessary to seek perfection in compiling weather data for R3 of EOP-012-1. Readings from the nearest airport are acceptable, and in fact are often more accurate than plant measurements. Non-official sources of weather data are acceptable so long as they have a reputable basis, e.g. extremeweatherwatch.com draws its information from the NOAA database.

{C}8. {C}Revise or eliminate R3.2, “Documentation identifying the Generator Cold Weather Critical Components,” as discussed earlier in these comments.

{C}9. {C}Revise R3.3 in accordance with our earlier comments, i.e.

{C}- include congealing when defining the term “freezing”

{C}- have precipitation stand separate from temperature/wind-related considerations

{C}- differentiate between principal and secondary winterization measures

{C}- cover temperature and wind in a combined fashion (WCT, or DBT-plus-20 mph)

Regarding the last of these points, DBT and wind speed are inputs to a single heat transfer calculation, ref. the formulae in IEEE-515, and must therefore be handled together. Calling for identification of DBT capability and, separately, “the cooling effects of wind,” is like identifying the load capability of a generator in terms of voltage, with separate consideration of the effect of current.

{C}10. {C}R3.5 is unchanged from EOP-011-2 and might therefore be thought to be noncontroversial, but this earlier standard is not yet enforceable, so no case law has been developed to bring its ambiguities and omissions into focus. These gaps should be closed in the Guidance section of EOP-012-1 as follows:

{C}a. “Capability” in the present context means real and reactive power output. That is, NERC is seeking information regarding factors that could limit output during winter storms below the values that grid operators are expecting. “Availability” refers to ability to start-up and remain online

{C}b. The word, “concerns,” in R3.5.1.2 pertains to fuel supply and inventory issues known to GO/GOPs or reasonably expected, not speculations about what might go wrong. Known inability of a NG pipeline company to support all plants on their system at maximum load during extended periods of peak demand would be reportable, for example, but GO/GOPs are not expected to evaluate fuel suppliers’ pipelines, compression/pumping equipment, contract terms or other matters over which generation entities have no control. Also, do not provide non-actionable inputs such as, “Fuel contracts contain a force majeure clause,” or, “Can’t get fuel oil deliveries if the roads are closed.”

{C}c. The term, “Environmental constraints,” in R3.5.1.4 pertains to maximum output. Narrowing of the max-to-min load environmentally compliant turndown range as the weather gets colder, as may be experienced by some combustion turbine generator units with dry low-NOx combustors, need not be reported.

{C}d. Cold-startup times for extreme winter weather conditions should be added to R3.5.1, given the use of this criterion in defining the term, “Generator Cold Weather Reliability Event”

{C}e. The need to provide evidence for the design temperature option of R3.5.2 should be limited to major freeze prevention elements, as was mentioned earlier in these comments. A unit with heat tracing and insulation designed for -25 F DBT and a 10 mph wind (-47 F WCT) may report a value of -19 F (-47 F WCT with a 20 mph wind), for example, without confirming that the lube oil heater has the same capability. This approach is especially important for peaking units that were built long ago and run primarily in the summer, not winter. They may not have the one-hour proof of R2, and design information for minor freeze prevention elements simply doesn’t exist. Demanding that such equipment be reverse-engineered would be unreasonable.

{C}f. A look-back period should be specified for the historical operating temperature option of R3.5.2. We suggest the shorter of five years and the time that the unit has been in service, with going back to the most recent extreme cold weather event being preferred for units old enough to do so.

{C}g. A requirement to report data to the RC, BA and TOP should be added to R3.5. They need to use these inputs, but there’s presently no requirement that they be reported to them.

{C}11. {C}R4 should be deleted. Plants must perform pre-winter preparations annually, and these activities should include updating for the past year the cold weather capability and other information communicated under R3.5 to the RC, BA and TOP. There is no benefit from endlessly repeating analyses, especially after implementing the changes recommended above.

{C}12. {C}The term, “unit-specific,” in R5 should be changed to, “plant-specific.” A facility with three fossil units, for example, should cover any individual-unit idiosynchrosies, but it does not need three different training courses.

{C}13. {C}The Guidance section of the standard should make it clear that annual training of maintenance and operations personnel for R5 should include on-condition activities in addition to the the NERC cold weather preparedness plan. That is, R3.4 establishes that the measures covered by EOP-012-1 are limited to those performed prior to winter in once-and-done fashion, and plants also have tasks to be performed as real-time weather conditions dictate, such as enhanced operator rounds, call-outs, and cycling mechanical-draft cooling tower fans to prevent excessive ice formation. The Guidance section of the standard should also advise that training may be split into a generic freeze prevention course and a supplemental, plant-specific module.

{C}14. {C}R6.3 does not identify the level of performance to be achieved by CAPs. It should be revised to explicitly say that it can consist of equipment modifications or adjustments to the cold weather capability declared for R3.5.2. If for example a plant with heat tracing and insulation designed for -20 F with a 20 mph wind incurs a freeze-related forced outage it can revise the R3.5.2 value or, as a market decision, add-to or modify equipment.

{C}15. {C}Regarding our earlier comments on historical worst-case temperature vs the present basis of the Extreme Cold Weather Temperature definition, R6 presently says that forced outages, derates and failures to start must be corrected if occurring during 0.2 percentile-and-up conditions, but for the coldest 43 hours per decade freeze-up instances and the blackouts, deaths and damage they cause, are acceptable – no corrective action is needed. How can this be called a "reliability" standard?

{C}16. {C}Having R6 require CAPs and R7 provide a no-limits offramp ("technical, commercial, or operational constraints") is strange and ineffective. PRC-004 has been cited as establishing a precedent in this respect, but this is not the case. R5 of PRC-004-6 says that entities must establish a CAP or state a valid technical (not commercial) justification for not doing so ("beyond the entity's control or would not improve BES reliability"), then R6 says that CAPs developed in R5 must be implemented.

R7.1 should be amended to simply require implementation of the CAP, given the R6.3 changes requested above (modification of R3.5.2 capability declarations is sufficient). Justifications are not then required. The present R6-R7 combination seems to says that GO/GOPs must identify solutions to freeze-up problems, then they have the option of doing nothing, but if they choose this alternative it remains an open compliance issue forever.

Likes 0	
Dislikes 0	

Response

The Standard Drafting Team is appreciative of the comments provided.
For comment 4, the grammatical edit for Measure 1 has been made.
For comments 2, 10d, 10g, and 13, the Standard Drafting Team may take these into consideration during phase two of this standards development timeframe. Specifically, in addressing Key Recommendation 1a and 1b in identifying cold-weather critical components and their freeze protection measures as well as in addressing Key Recommendation 1g in providing greater specificity about the relative roles of GOs, GOPs and BAs.
For all other comments, the Standard Drafting Team will not be making the recommended changes.

Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
The cold weather exclusion should be removed from the Applicability section and instead a requirement should be added to require the GO to prove operability in cold weather through analysis/studies. This is a common practice among standards that apply to a subset of BES Elements or Facilities. Tri-State suggests that the SDT look at similar standards/requirements such as TPL-007-4, R5, PRC-023-4 R6, and PRC-002-2 R1. The Applicability section is not auditable and leaving the exception within that section could allow for entities to incorrectly exclude their units with no repercussions. This in turn could cause a reduction in grid reliability as Generator Owners continue to be unprepared for cold weather events.	
Likes 0	
Dislikes 0	
Response	
The Standard Drafting Team is appreciative of the comments provided. Please see the comment responses to Question 3 around applicability.	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	
Document Name	
Comment	
Talen Energy Marketing supports Talen Generation's additional comments.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment, please see response to Talen Generation.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	

Southern Company would suggest the SDT include additional language in R1 to strengthen expectations that a generator that is committed or contractually obligated to serve a BA load per Appicablility section 4.2.1 will design and plan to operate under the conditions described in R1. The "Or" clause in R1, currently in this version, leaves too much latitude for generators not to perform prior to actually experiencing a Generator Cold Weather Reliability Event.

Southern Company suggests the following language to be added to R1:

- "If the generating unit(s) are contractually obligated to operate in the aforementioned conditions, and any technical, commercial, or operational constraint is identified by the Generator Owner, the Generator Owner shall notify their applicable Generator Operator, Transmission Operator, Balancing Authority and Reliability Coordinator in a timely manner. The Generator Owner shall specify the anticipated time required for mitigation and identify an approximate return to service date."

Likes 0	
Dislikes 0	
Response	
The Standard Drafting Team is appreciative of the comments provided. Please see the comment responses to Question 3 around applicability.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	

Answer	
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
FE requests clarification on the following two points : 1. Is bidding in a Unit as 'must run' for freeze protection of itself or neighboring Units (whether for radiant heat to a building, aux steam for heat or startup, or circulation of at-risk systems/fluids) an acceptable freeze protection measure? If entering a Unit 'must run' for freeze protection cannot be relied upon as an available measure, then the implementation/compliance most likely cannot be achieved in many cases in a 'cost effective manner' 2. If all Units at a specific location/plant were in reserve and none permitted to start ahead of extreme cold weather conditions, would a failure to start in extreme conditions be considered a qualifying event?	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The Standard Drafting Team is appreciative of the comments provided. The team may consider these comments during phase two of this standards development timeframe. Specifically, in addressing Key Recommendation 1a and 1b to identify cold-weather critical components and their freeze protection measures.	
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	
Document Name	
Comment	
For EOP-012-1 R6, Tacoma Power recommends deleting the "or by July 1, whichever is earlier" language. If a cold weather event occurred in late Spring or early Summer (i.e. April through June), an entity would have less than 150 days to holistically review the event and develop a CAP.	
Likes 0	
Dislikes 0	
Response	
The Standard Drafting Team is appreciative of the comments provided. We believe the proposed timeline is adequate and will not be making changes at this time.	
Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 1	
Answer	
Document Name	
Comment	

NextEra Energy supports a weatherization framework that provides flexibility for generators to adopt new effective, commercially viable and proven technologies, but cautions against requiring the adoption of unproven technology that could damage equipment or otherwise reduce the operating life and void warranties, thereby reducing overall reliability.	
Likes 0	
Dislikes 0	
Response	
The Standard Drafting Team is appreciative of the comments provided. The team may consider these comments during phase two of this standards development timeframe. Specifically, in addressing Key Recommendation 1a and 1b to identify cold-weather critical components and their freeze protection measures.	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thank you for the response.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	
Document Name	
Comment	

None at this time.	
Likes 0	
Dislikes 0	
Response	
Thank you for the response.	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	
Document Name	
Comment	
We request the SDT confirm in a Consideration of Comments that only one of the three bullets under 3.5.2 is required for a given generating unit. We recommend the SDT consider whether the proposed interaction between R2/R4/R6 and R7 will cause GOs needing to take the declaration in 7.1 an R2/R4/R6 noncompliance based on the Glossary of Terms definition of Corrective Action Plan. R7.1 allows an entity with an appropriate justification to declare that a CAP will not be implemented, but developing a CAP requires both developing a list of actions AND extablishing an associated timetable for implementation. As a timetable for implementation is not reasonable to require for corrective actions a GO is constrained from implementing, we recommend replacing “CAP” with “list of corrective actions” in R2/R4/R6 and changing R7 part 7.1 to “Create and Implement one or more Corrective Action Plans addressing each corrective action identified pursuant to Requirements R2, R4, or R6, or explain in a declaration why one or more identified corrective actions will not be implemented due to technical, commercial, or operational constraints as defined by the Generator Owner.”	
Likes 0	
Dislikes 0	
Response	

The Standard Drafting Team is appreciative of the comments provided. The team believes that the "or" in the bulleted list in 3.5.2 shows that only one of the three bullets is required for generating unit minimum. The team modeled the language after PRC-004 and will be keeping it as approved in second ballot.

Brian Evans-Mongeon - Utility Services, Inc. - 4	
Answer	
Document Name	
Comment	

We understand R1 and R2 as requiring GOs to implement freeze control measures that they reasonably believe, based on good engineering judgment and their experience with their particular units and weather patterns, will result in the unit being able to operate continuously for the applicable time at the Extreme Cold Weather Temperature. Our understanding of the proposed requirements is that if a new or existing unit experiences a Forced Outage as a result of a Generator Cold Weather Reliability Event, even if the Forced Outage occurs after less than twelve hours (for a new generator) or one hour (for an existing generator) of continuous operations, the Forced Outage will not constitute evidence of noncompliance with R1 or R2. Instead, the GO will develop and implement a CAP pursuant to R6 and R7, as it would in response to any Generator Cold Weather Reliability Event. The contrary interpretation—that R1 and R2 require freeze protection measures that are 100% guaranteed to work—would require a level of certainty that simply does not exist. Generators are complex machines; they sometimes fail in unforeseen ways. This problem is only compounded by the fact that, as noted by multiple panelists at the April 27-28, 2022 FERC, NERC, and Regional Entities Technical Conference on Improving Winter-Readiness of Generating Units, a cold weather event cannot be simulated ahead of time to allow functional testing of a unit's set of winterization measures. Finding a GO noncompliant with R1 or R2 based on the failure in a particular instance of winterization measures it reasonably believed, based on the information available to it prior to the cold weather event, would be adequate, would not enhance reliability.

We read R2 as providing that, where an existing unit is *not* capable of operating continuously for one hour at the Extreme Cold Weather Temperature, the method by which the GO "ensure[s] its generating unit(s) add new or modify existing freeze protection measures as needed" is the development of a CAP pursuant to R2. In other words, a GO demonstrates compliance with R2 by demonstrating either that it has implemented appropriate freeze protection measures, or that it has developed a CAP[A1] .

Suggested edit to Requirement R2 (making the 2 sentences in the Requirement 'or' statements): **R2.** For each generating unit(s) in commercial operation prior to [Effective Date of this requirement], the Generator Owner shall ensure its generating unit(s): · Add new or modify existing freeze protection measures as needed to provide the capability to operate for a period of not less than one (1) hour at the unit(s) Extreme Cold Weather Temperature; or · If generating unit(s) are not capable of operating for one (1) hour at its Extreme Cold Weather Temperature, shall develop a Corrective Action Plan (CAP) for the identified issues, including identification of any needed modifications to the cold weather preparedness plan required under Requirement R3. Suggested edit to Measure M2 (add the clause "ability to operate for 1 hour at"): **M2.** Each Generator Owner will have dated evidence that demonstrates it has freeze protection measures for its unit(s) in accordance with R2, or it has developed a CAP for the identified issues. Acceptable evidence may include the following (electronic or hardcopy format): Identification of generating units ability to operate for 1 hour at the minimum temperature per Part 3.5.2 which is equal to or less than the unit's Extreme Cold Weather Temperature, documentation of freeze protection measures, cold weather preparedness plan, and CAP(s).	
Likes 1	Illinois Municipal Electric Agency, 4, Todd Mary Ann
Dislikes 0	
Response	
The Standard Drafting Team is appreciative of the comments provided. We discussed the proposed change to R2 but found it did confuse the intent of the requirement so the team decided to maintain the language that was approved by industry. We did not make the change in the measure to stay consistent with the measure language in R1.	
Michael Watt - Oklahoma Municipal Power Authority - 4	
Answer	
Document Name	

Comment	
OMPA agrees with the TAPs comments below: We understand R1 and R2 as requiring GOs to implement freeze control measures that they reasonably believe, based on good engineering judgment and their experience with their particular units and weather patterns, will result in the unit being able to operate continuously for the applicable time at the Extreme Cold Weather Temperature. Our understanding of the proposed requirements is that if a new or existing unit experiences a Forced Outage as a result of a Generator Cold Weather Reliability Event, even if the Forced Outage occurs after less than twelve hours (for a new generator) or one hour (for an existing generator) of continuous operations, the Forced Outage will not constitute evidence of noncompliance with R1 or R2. Instead, the GO will develop and implement a CAP pursuant to R6 and R7, as it would in response to any Generator Cold Weather Reliability Event. The contrary interpretation—that R1 and R2 require freeze protection measures that are 100% guaranteed to work—would require a level of certainty that simply does not exist. Generators are complex machines; they sometimes fail in unforeseen ways. This problem is only compounded by the fact that, as noted by multiple panelists at the April 27-28, 2022 FERC, NERC, and Regional Entities Technical Conference on Improving Winter-Readiness of Generating Units, a cold weather event cannot be simulated ahead of time to allow functional testing of a unit's set of winterization measures. Finding a GO noncompliant with R1 or R2 based on the failure in a particular instance of winterization measures it reasonably believed, based on the information available to it prior to the cold weather event, would be adequate, would not enhance reliability. We read R2 as providing that, where an existing unit is *not* capable of operating continuously for one hour at the Extreme Cold Weather Temperature, the method by which the GO "ensure[s] its generating unit(s) add new or modify existing freeze protection measures as needed" is the development of a CAP pursuant to R2. In other words, a GO demonstrates compliance with R2 by demonstrating either that it has implemented appropriate freeze protection measures, or that it has developed a CAP. The SDT has indicated that it plans to revisit the language of EOP-012-1 as part of Phase 2 of this project. Although we believe that our readings of the requirements, as outlined above, are consistent with the SDT's intent, we strongly recommend that Phase 2 clarify the language of R1 and R2 on these issues. Expressing the SDT's intent more clearly would reduce the risk of confusion and conflicting interpretations.	
Likes 1	Illinois Municipal Electric Agency, 4, Todd Mary Ann

Dislikes 0	
Response	
The Standard Drafting Team is appreciative of the comments provided. We discussed these comments and changes will not be made at this time.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	
Document Name	
Comment	
Avista recommends some reconsideration as to the applicability of the EOP 12-2 as it relates to ALL BES generating facilities. Both the letter and intent of the draft standard appear to be related specifically to thermal or steam process plants that use a Rankin cycle to generate electricity, and their susceptibility for freezing during cold weather. Can the permit team under Part 2 reconsider the applicability of facilities to consider to just those facilities related to the Rankin cycle that use steam as a means of generating electricity. Many facilities such as hydroelectric facilities internal combustion generation, wind turbine generators, and are much less susceptible to extreme cold weather and should not be treated the same regarding compliance requirements of such a standard.	
Likes 0	
Dislikes 0	
Response	
The Standard Drafting Team is appreciative of the comments provided. Please see the comment responses to Question 3 around applicability.	
Brooke Jockin - Portland General Electric Co. - 1, Group Name Portland General Electric Co.	
Answer	
Document Name	
Comment	

Portland General Electric Company supports the survey response provided by EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to EEI.	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	
Document Name	
Comment	

We understand R1 and R2 as requiring GOs to implement freeze control measures that they reasonably believe, based on good engineering judgment and their experience with their particular units and weather patterns, will result in the unit being able to operate continuously for the applicable time at the Extreme Cold Weather Temperature. Our understanding of the proposed requirements is that if a new or existing unit experiences a Forced Outage as a result of a Generator Cold Weather Reliability Event, even if the Forced Outage occurs after less than twelve hours (for a new generator) or one hour (for an existing generator) of continuous operations, the Forced Outage will not constitute evidence of noncompliance with R1 or R2. Instead, the GO will develop and implement a CAP pursuant to R6 and R7, as it would in response to any Generator Cold Weather Reliability Event. The contrary interpretation—that R1 and R2 require freeze protection measures that are 100% guaranteed to work—would require a level of certainty that simply does not exist. Generators are complex machines; they sometimes fail in unforeseen ways. This problem is only compounded by the fact that, as noted by multiple panelists at the April 27-28, 2022 FERC, NERC, and Regional Entities Technical Conference on Improving Winter-Readiness of Generating Units, a cold weather event cannot be simulated ahead of time to allow functional testing of a unit's set of winterization measures. Finding a GO noncompliant with R1 or R2 based on the failure in a particular instance of winterization measures it reasonably believed, based on the information available to it prior to the cold weather event, would be adequate, would not enhance reliability.

We read R2 as providing that, where an existing unit is *not* capable of operating continuously for one hour at the Extreme Cold Weather Temperature, the method by which the GO "ensure[s] its generating unit(s) add new or modify existing freeze protection measures as needed" is the development of a CAP pursuant to R2. In other words, a GO demonstrates compliance with R2 by demonstrating either that it has implemented appropriate freeze protection measures, or that it has developed a CAP.

The SDT has indicated that it plans to revisit the language of EOP-012-1 as part of Phase 2 of this project. Although we believe that our readings of the requirements, as outlined above, are consistent with the SDT's intent, we strongly recommend that Phase 2 clarify the language of R1 and R2 on these issues. Expressing the SDT's intent more clearly would reduce the risk of confusion and conflicting interpretations.

Likes 0	
Dislikes 0	

Response

The Standard Drafting Team is appreciative of the comments provided. We discussed these comments and changes will not be made at this time.

Scott Kinney - Avista - Avista Corporation - 3

Answer	
Document Name	

Comment

Avista recommends some reconsideration as to the applicability of the EOP 12-2 as it relates to ALL BES generating facilities. Both the letter and intent of the draft standard appear to be related specifically to thermal or steam process plants that use a Rankin cycle to generate electricity, and their susceptibility for freezing during cold weather. Can the permit team under Part 2 reconsider the applicability of facilities to consider to just those facilities related to the Rankin cycle that use steam as a means of generating electricity. Many facilities such as hydroelectric facilities internal combustion generation, wind turbine generators, and are much less susceptible to extreme cold weather and should not be treated the same regarding compliance requirements of such a standard.

Likes 0	
Dislikes 0	

Response	
The Standard Drafting Team is appreciative of the comments provided. Please see the comment responses to Question 3 around applicability.	
Mark Spencer - LS Power Development, LLC - 5	
Answer	
Document Name	
Comment	
The SDT states that "cost recovery" is outside the scope of its work, yet wades into economic regulation by i) applying different standards to new and existing generators and ii) offering a "commercial constraint" exemption. In the former instance, the only justification the SDT offered is that a more stringent standard could create premature retirements. This is despite the plain language requirement of the statute that all prudent and necessary costs to comply with the reliability standards shall be recoverable. If generator owners are held harmless from the cost of compliance, then why would a rigorous standard drive retirements? In the latter case, the commercial constraint would violate NERC Market Principles. As an illustrative example, if two generators, A and B, were participating in the same market, owner of Generator A declared its intention to retire "soon" and declared a "commercial constraint" exemption from compliance. Generator A is not saddled with the compliance costs because of its "constraint," while Generator B has compliance costs; yet both generators compete in the same market in the same interval. We cannot think of a clearer example of a reliability standard creating an unfair competitive advantage. Additionally, the SDT's attempt at economic regulation is producing a diluted reliability standard that could actually reduce reliability. Our analysis demonstrates that all locations that experience freezing temperatures experienced multiple events that lasted more than one hour at or below their respective ECWT. As we describe above, we are concerned that fleet performance will regress towards the new 1-hour standard, even for existing generators that may have had historically good performance. This would reduce reliability. Additionally, setting a 12-hour duration for new resources would take decades to have any meaningful reliability impact as new generators replace existing. For these reasons, we urge the SDT to set a common standard for existing and new that will meaningfully enhance reliability.	

We also urge the SDT to eliminate the “commercial constraint” exemption. We are not aware of a similar provision in any other approved NERC reliability standard, and this provision may create unwanted debate regarding other reliability standards. First, it leaves it to the generator owner’s discretion to determine whether it is exempt from compliance, which favors states and merchant generators to rely on the most liberal interpretation of the exemption that achieves the lowest cost. This is extremely bad precedent. Second, the vaguely defined exemption will create inevitable disagreements between generator owners and auditors that may only be raised at the time of the audit. Third, it raises the question that if a retirement decision is a valid exemption then why should a generator that is “due to retire soon” be required to comply with *any* NERC reliability standard? This is bad precedent. Finally, a generator owner could make an argument that if its tariff does not allow cost recovery that too is a commercial constraint and merits an exemption. Unlike the regulated markets, this is particularly worrisome for the organized markets where cost recovery is not guaranteed before an investment is made.

We are also concerned NERC may not have the authority under the Federal Power Act to impose the proposed standard. NERC cites the definition of “reliability standard” as its authority to impose requirements on existing generators. The definition from the statute is replicated below:

“The term ‘reliability standard’ means a requirement, approved by the Commission under this section, to provide for reliable operation of the bulk-power system. The term includes requirements for the operation of existing bulk-power system facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation of the bulk-power system, but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity.”

However, the statute also defines the term “reliable operations”:

"The term 'reliable operation' means 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." The term 'reliable operations' is expressly limited to items that cause "sudden disturbances, including a cybersecurity incident" or an "unanticipated failure of system elements." "[U]nanticipated failure" is not a failure of a generator at a temperature below its cold weather rating. Thus, it appears that mandating expanded performance obligations directly on existing generators through a reliability standard is outside the scope of this definition. Additionally, we are not aware of any approved reliability standard mandating generators install components for an expanded range of services. For these reasons, we encourage NERC to reconsider its approach. We offer an alternative approach that would require the BAs to procure this expanded service and harmonize it with attributes in addition to freeze protection – e.g., fuel, environmental limitations, etc. Relying on BAs to procure their reliability needs is a more defensible and economically efficient approach to enhancing reliability. It is also an approach that eliminates the need for a "commercial constraint" exemption and permits for a more robust reliability standard. However, if NERC does not consider this alternate, we recommend that the Commission hold the compliance date in abeyance until cost recovery has been properly addressed. As background, in the ISO New England CIP IROL proceeding certain generators were designated IROL facilities, were promised that they would have an opportunity to recover their costs, and incurred substantial compliance costs. Unfortunately, the ISO's filing was after many generators incurred the costs and thus the Commission found that recovery of costs prior to the filing would violate the filed rate doctrine, and rejected recovery of those pre-filing costs.	
Likes 1	Vistra Energy, 5, Roethemeyer Dan
Dislikes 0	
Response	
The Standard Drafting Team is appreciative of the comments provided. Please see previous comment responses around cost recovery from the previous Ballot.	
David Jendras - Ameren - Ameren Services - 3	

Answer	
Document Name	
Comment	
Ameren agrees with the EEI and the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to EEI and NAGF.	
Joe Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	
Document Name	
Comment	
Xcel Energy supports comments from EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to EEI.	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3, Group Name OGE Energy	
Answer	
Document Name	
Comment	

OG&E supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to EEI.	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	
Document Name	
Comment	
PG&E thanks the SDT's for their effort to address the industry's concerns regarding the proposed Standard, the effort it has taken to complete the work up to this point, and the work necessary to complete the modifications in Phase Two of the project. PG&E also supports the additional input provided by EEI related to Requirement R2, and the NAGF concerns related to retrofitting and compensation on those retrofits. This includes the NAGF input that the Requirements in EOP-011 which is enforceable on 4/1/2023 should be allowed to take effect and determine if they are sufficient to address cold weather operations. PG&E also supports the NAGF proposed language if NERC wishes to add in the reliability requirements language.	
Likes 0	
Dislikes 0	
Response	
The Standard Drafting Team is appreciative of the comments provided. Please see response to EEI.	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	
Document Name	
Comment	
As stated above, Dominion Energy remains concerned with the requirement to retrofit or otherwise improve an existing generator's cold weather performance capability and proposes the drafting team consider the more cost-effective option of requiring generators to communicate their extreme cold weather operating capabilities to the BA and RC. Communicating operating capabilities and failing to meet them during an event would result in the CAP as outlined in R6. This option allows the BA and RC to appropriately plan for extreme cold weather events without placing a potentially unnecessary burden to retrofit existing generators and require them to perform beyond established designed operating parameters. Dominion Energy is of the opinion that ensuring operating parameters for extreme cold weather are communicated and understood by the appropriate entities is more beneficial to reliability during these events than a blanket retrofit requirement.	
Likes 0	
Dislikes 0	
Response	
The Standard Drafting Team is appreciative of the comments provided. The team may consider these comments during phase two of this standards development timeframe. Specifically, in addressing Key Recommendation 1g in providing greater specificity about the relative roles of GOs, GOPs and BAs.	
Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	

AEP recognizes the importance of this project, and the priority which it has been given. Having said that, AEP hopes that industry's outstanding concerns (those not currently met in the current draft) will be fully addressed in a Phase II of this project. In addition, we recommend that industry be allowed the customary time period to develop comments and cast ballots at that time.	
Likes 0	
Dislikes 0	
Response	
The Standard Drafting Team is appreciative of the comments provided. The Standard Drafting Team is committed to addressing Key Recommendations set to be addressed in Phase 2 of this standards development timeframe. The balloting timeframe will be in accordance with the customary standards drafting process timeline.	
Devin Shines - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company	
Answer	
Document Name	
Comment	
LouisvilleG&E/KU support EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to EEI.	
Lenise Kimes - City and County of San Francisco - 1,5 - WECC	
Answer	
Document Name	

Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Kimberly Turco - Constellation - 6	
Answer	
Document Name	
Comment	
One of the most important aspects of this Phase 1 EOP-12 and existing EOP-11-2 is the communication of limiting temperatures to the BA/TOP via IRO-010 and TOP-003. Although how the BA/TOP will use the temperature information is outside the scope of these efforts, BA/TOP knowledge of limiting operating temperature and Extreme Cold Weather Temperature (ECWT), and the expected dialogue between GO/GOPs and BA/TOPs, is expected to result in more robust, realistic cold weather resource planning. ..... Two editorial comments on the Technical Rationale doc: 1) The last two bullet points supporting R6 in the Technical Rationale document should be reworded, perhaps with examples. That is, the current bullet point language that the use of the ECWT instead of minimum operating temperature removes incentives and disincentives is confusing, and the two appear to be addressing the same issue, just coming from different perspectives. 2) Also in the same section is the capitalization of Generator Unit Minimum Temperature. Recommend a check be made to ensure this is an official definition. Kimberly Turco, on behalf of Segments 5 and 6	
Likes 0	

Dislikes 0	
Response	
The Standard Drafting Team is appreciative of the comments provided. We discussed these comments and changes will not be made at this time.	
Alison Mackellar - Constellation - 5	
Answer	
Document Name	
Comment	
One of the most important aspects of this Phase 1 EOP-12 and existing EOP-11-2 is the communication of limiting temperatures to the BA/TOP via IRO-010 and TOP-003. Although how the BA/TOP will use the temperature information is outside the scope of these efforts, BA/TOP knowledge of limiting operating temperature and Extreme Cold Weather Temperature (ECWT), and the expected dialogue between GO/GOPs and BA/TOPs, is expected to result in more robust, realistic cold weather resource planning. ..... Two editorial comments on the Technical Rationale doc: 1) The last two bullet points supporting R6 in the Technical Rationale document should be reworded, perhaps with examples. That is, the current bullet point language that the use of the ECWT instead of minimum operating temperature removes incentives and disincentives is confusing, and the two appear to be addressing the same issue, just coming from different perspectives. 2) Also in the same section is the capitalization of Generator Unit Minimum Temperature. Recommend a check be made to ensure this is an official definition Kimberly Turco, on behalf of Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
The Standard Drafting Team is appreciative of the comments provided. We discussed these comments and changes will not be made at this time.	

Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	
Document Name	
Comment	

Reclamation is providing the language it proposed for EOP-012 in Draft 1 here for convenience:

Reclamation recommends rewriting the requirements of EOP-012-1 as follows:

R1. *use existing language from Draft 1 EOP-012-1 R1.1* with the following corrections:

Each Generator Owner shall design new and maintain existing generating units to be capable of continuous operations at the documented minimum hourly temperature experienced at each unit's location since 1/1/1975 or a lesser period if reliable data is not available to 1975.

R2. *use existing language from Draft 1 EOP-012-1 R1* with the following corrections:

Each Generator Owner shall implement new or modify existing protection based on the documented minimum hourly temperature for its generating units including the following minimum criteria:

R2.1. the cooling effect of wind; and

R2.2. impacts on equipment operation due to precipitation (e.g., sleet, snow, ice, and freezing rain).

R3. *use existing language from Draft 1 EOP-012-1 R1.4* with the following corrections:

For each existing generating unit that requires new or modified protection based on the documented minimum hourly temperature, the Generator Owner shall develop and implement a Corrective Action Plan (CAP) or, where deemed appropriate by the Generator Owner based on the review of parts R3.1.1 through R3.1.3., declare that no corrective actions will be taken.

R3.1. A CAP shall contain the following minimum information:

R3.1.1. Corrective action(s) for the affected unit(s).

R3.1.2. Any temporary operating limitations that would apply until the corrective actions are implemented.

R3.1.3. A schedule for implementing the corrective action(s).

R3.2. A declaration shall document any technical, commercial, or operational constraints of each affected unit, as defined by the Generator Owner, in support of the declaration.

R4. *use existing language from Draft 1 EOP-012-1 R2* with the following corrections:

Each Generator Owner that does not implement new or modify existing protection based on the documented minimum hourly temperature in accordance with R2 due to technical, commercial, or operational constraints, as defined by the Generator Owner, shall:

R4.1. Document its determination and the constraints; and

R4.2. Review its determination every five calendar years to determine whether the constraints remain applicable.

R5. *use existing language from Draft 1 EOP-012-1 R3*

R6. *use existing language from Draft 1 EOP-012-1 R4, update Part numbers as necessary*

R7. *use existing language from Draft 1 EOP-012-1 R5* with the following corrections:

Each Generator Owner, in conjunction with its Generator Operator, shall ensure generating unit-specific cold weather preparedness plan training is provided to its personnel responsible for implementing cold weather preparedness plans.

R7.1. The Generator Owner and Generator Operator shall identify the entity responsible for providing the training.

R7.2. The Generator Owner and Generator Operator shall ensure the training is provided to personnel responsible for implementing cold weather preparedness plans upon entrance on duty and annually thereafter.

R8. *use existing language from Draft 1 EOP-012-1 R6* with the following corrections:

Each Generator Owner that owns a generating unit that experiences an event resulting in a derate of more than 10% of the total capacity of the unit for longer than four hours in duration, a start-up failure where the unit fails to synchronize within a specified start-up time, or a Forced Outage for which (i) the apparent cause(s) of the event is due to extreme cold weather effects within the Generator Owner’s control to protect against, and (ii) the ambient conditions at the site at the time of the event are at or above the temperature documented in Part 3.4.2 shall:

R8.1. No later than 150 days subsequent to the event or by July 1 that follows the event, whichever is ***later***, develop a CAP; or

R8.2. Declare, where deemed appropriate by the Generator Owner based on review of Parts 8.3.1. through 8.3.5, that no revisions to the cold weather preparedness plan are required and that no further corrective actions will be taken.

R8.3. At a minimum, a CAP shall contain:

R8.3.1. A summary of the identified cause(s) ***of*** the equipment ***derate, failure to start, or Forced Outage***, and any relevant associated data.

8.3.2 use existing 6.2.1. language

8.3.3. use existing 6.2.2. language

8.3.4. (modified 6.2.3.) Specific corrective action(s) for the affected unit(s) and identified similar units, including:

8.3.4.1. (modified 6.2.3.) any necessary modifications to the Generator Owner's cold weather preparedness plan(s); and

8.3.4.2. (modified 6.2.4.) consideration of any technical, commercial, or operational constraints, as defined by the Generator Owner.

8.3.5. A ***schedule*** for implementing the corrective actions.

R8.4. At a minimum, a declaration shall document technical, commercial, or operational constraints, as defined by the Generator Owner, as support for the declaration.

Reclamation recommends the timeframe for developing a CAP be 150 days subsequent to the event or by July 1 that follows the event, whichever is ***later***. Using whichever is earlier could subject an entity to an unreasonably short deadline depending on when the event occurs.

Reclamation recommends moving the language pertaining to the cold weather preparedness plans from the original R1 to the original R3 (new R5 based on Reclamation's proposed renumbering in the above comments). Modifications to the cold weather preparedness plan should relate back to the CAP, if necessary, not the CAP requirements relating forward to the cold weather preparedness plan.

Reclamation recommends not limiting the training on cold weather preparedness plans to “maintenance or operations” personnel, as other personnel may also be responsible for implementing cold weather preparedness plans and should not be excluded from the training. Reclamation recommends the annual cold weather preparedness plan training be contained in PER-006 instead of EOP-012. Reclamation supports the retention and reuse of pertinent information from the Draft 1 Measures.	
Likes 0	
Dislikes 0	
Response	
The Standard Drafting Team is appreciative of the comments provided. We discussed these comments and changes will not be made at this time.	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	
Document Name	
Comment	
NRG agrees with the NAGF that communicating operating parameters for extreme cold weather that are understood by the appropriate entities is more appropriate and beneficial to reliability during these events rather than a blanket retrofit requirement to operate to a defined condition. *We realize NERC cannot address the compensation issue for required improvements, but unless there is agreement from and with parties that can provide compensation for upgrades, this standard becomes an unfunded mandate on Generator Owners.*	
Likes 0	
Dislikes 0	
Response	

The Standard Drafting Team is appreciative of the comments provided. Please see previous comments responses on cost recovery in the previous Ballot.	
Romel Aquino - Edison International - Southern California Edison Company - 3	
Answer	
Document Name	
Comment	
Please see comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to EEI.	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	
Document Name	
Comment	
NRG agrees with the NAGF that communicating operating parameters for extreme cold weather that are understood by the appropriate entities is more appropriate and beneficial to reliability during these events than a blanket retrofit requirement to operate to a defined condition. *We realize NERC cannot address the compensation issue for required improvements, but unless there is agreement from and with parties that can provide compensation for upgrades, this standard becomes an unfunded mandate on Generator Owners.*	

Likes 0	
Dislikes 0	
Response	
The Standard Drafting Team is appreciative of the comments provided. Please see previous comments responses on cost recovery in the previous Ballot.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
"Please see comments submitted by the Edison Electric Institute"	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to EEI.	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	
Document Name	
Comment	
PNM supports EEI's comments regarding modification of Requirement R2 to link with Requirement R7.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment, please see response to EEI.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	
Document Name	
Comment	

The IESO reiterates its comment for Draft 1, where it requested that removal of the 'commercial' reference in Requirements 1 and 7.1 as this language is vague, creates an ambiguity as to the obligation otherwise provided for in the standard, and a review of commercial issues is not within NERC's domain and expertise.

In the Reliability Standard CIP-014 – Physical Security, NERC recognized that it does not have the physical security expertise to appropriately evaluate the risk assessment performed by the Transmission Owner. As such, CIP-014 requires an unaffiliated third party with the appropriate expertise to verify it.

Given that NERC's purview is reliability of the bulk power system, and not commercial matters, the SRC proposes that NERC adopt a similar approach for the proposed standard. Should a Generator Owner opt out of a Corrective Action Plan for commercial constraints, an unaffiliated third party should verify the finanacial assessment performed by the Generator Owner. The third party should have financial analysis experience, such as an auditing/accounting firm.

We also suggest that NERC develop clear boundaries regarding the use of commercial constraints to opt out of a CAP, such as:

- the investment in freezing protection measures is cost prohibitive due to new technology not yet advanced (i.e., economies of scale to yet reached) or
- the investment is below the registered entity's rate of return.

We recognize that cost recovery for generators is also not within the purview of NERC. Cost recovery for generators usually falls within state/provincial purview, and through market mechanisms. The SRC proposes that NERC consider adding a stakeholder process in the proposed requirement, similar to that in Reliability Standard TPL-001 – Transmission Planning on use of planned consequential load loss. An

open stakeholder process that ensures state/provincial agencies are aware of the need for freeze protection measures to meet the reliability requirements in the proposed standard will allow affected parties to assess the cost recovery issues.	
Likes 0	
Dislikes 0	
Response	
The Standard Drafting Team is appreciative of the comments provided. Commercial constraints have been discussed by the Standard Drafting team and changes will not be made at this time.	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for question #9.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see response to EEI.	
Dan Roethemeyer - Vistra Energy - 5	
Answer	
Document Name	
Comment	

Vistra has additional recommendations/requested clarifications on the proposed requirements described below:

The NERC Calculating Extreme Cold Weather Temperature guide should be modified to address circumstances where National Oceanic and Atmospheric Administration (NOAA) data dating back to January 1, 2000 does not exist for the particular location. For example, NOAA has weather data for Andrews, Texas dating back only to 2014, and there are no other representative NOAA locations in the dataset. There may be other instances of rural airports or other NOAA weather data locations that do not have data going back to 2000. The Guide should specify an alternate source(s) of acceptable weather data for calculation of the Extreme Cold Weather Temperature in instances where NOAA data does not exist back to 2000, as well as how to select the location for the substitute temperature data, how to input that substitute data into the NOAA dataset, and how to treat missing temperature data (blanks) when the NOAA report is run.

Proposed R3.1 requires that a Generator Owner include in its cold weather preparedness plan the “Extreme Cold Weather Temperature for their unit(s) including the calculation date and source of temperature data.” If the Technical Requirements document titled “Calculating Extreme Cold Weather Temperature” is intended to provide the source of temperature data for all Generator Owners, then this language should be modified to state “Extreme Cold Weather Temperature for their unit(s) including the calculation date using NERC’s guide for Calculating Extreme Cold Weather Temperature.” Otherwise, the standard should be modified to clarify what sources of data are permissible, including data provided by the balancing authority (as noted in response to Question 2).

Proposed R3.5.1.2 requires Generator Owners to include within their cold weather preparedness plans “Generating unit(s) cold weather data, to include: … Fuel supply and inventory concerns.” This language should be revised to clarify that the Generator Owner is only responsible for fuel supply and inventory within its control and knowledge, as Generator Owners do not always own the source or transportation for their fuel supply and thus cannot always identify or anticipate fuel supply and inventory concerns. For example, the requirement could be modified to read: “Generating unit(s) cold weather data, to include: … Fuel supply and inventory concerns, to the extent known to the Generator Owner.”

Proposed R4 should clarify that a redesign of the unit(s) will not be required every five years. The standard requires that a Generator Owner calculate a new Extreme Cold Weather Temperature and update its cold weather preparedness plan and freeze protection measures as needed, or else, develop a Corrective Action Plan (CAP). As drafted, the standard could be interpreted as potentially requiring a redesign or retrofitting of a unit every 5 years. Vistra recommends that, in conjunction with adding a definition of "freeze protection measures" that includes procedures and temporary equipment among those measures (as recommended under Question 5), R4.3 could be modified to add the following sentence at the end: "If a CAP is required under this Requirement R4, the CAP cannot require a Generator Owner to redesign or retrofit its unit to meet the requirements in R1 or R2, as applicable, at the updated Extreme Cold Weather Temperature for the unit(s)."

Proposed R5 should clarify that the required training will be site-specific, rather than unit-specific: "Each Generator Owner in conjunction with its Generator Operator shall identify the entity responsible for providing the generating unit-site specific training, and that identified entity shall provide annual training at each site to its maintenance or operations personnel responsible for implementing the cold weather preparedness plan(s) at that site developed pursuant to Requirement R3."

Proposed R6 should require a CAP to be developed within 150 days, rather than the earlier of 150 days or July 1. If a Generator Cold Weather Reliability Event occurs at the end of the winter season (or during a freak winter-like storm in March or April), a Generator Owner could have significantly fewer than 150 days to develop a CAP if the standard is based on the earlier of July 1 or 150 days. At the same time, even if an event occurred as late as early April, the 150 day standard would still require that the CAP be developed in advance of the next winter season (e.g., 150 days, or roughly 5 months, after April would still be in September). Thus, R6 should strike the alternative reference to July 1.

Likes 0	
Dislikes 0	

Response

The Standard Drafting Team is appreciative of the comments provided. With regards to NERC Calculating Extreme Cold Weather Temperature guide, this topic is covered in the technical rationale document. With regards to unit vs site specific training, this is approved language and the team believes that training can be developed holistically with unit-specific differences highlighted where applicable.

Daniel Gacek - Exelon - 1

Answer	
Document Name	
Comment	
Exelon concurs with EEI's comment to Question 9 Submitted on behalf of Exelon, Segments 1 & 3	
Likes 0	
Dislikes 0	
Response	
Thank you for the response, please see response to EEI.	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	
Document Name	
Comment	
Nothing additional to add at this time.	
Likes 0	
Dislikes 0	
Response	
Thank you for the response.	
Donna Johnson - Oglethorpe Power Corporation - 5	

Answer	
Document Name	
Comment	
For R5: In regards to the proposed verbiage requiring "generating unit-specific training", it is OPC's opinion that this could be overly repetitious for stations that have multiple units, which are considered sister units and hence would have the same generator protection measures in place. We recomenend modifying this requirement to require station-specitic training in lieu of generating unit-specific training. In cased where there are different freeze protection measures for unit(s), those measures would be defined within the training anyway since it covers freeze protection for all units at a station.	
Likes 0	
Dislikes 0	
Response	
The Standard Drafting Team is appreciative of the comments provided. With regards to unit vs site specific training, this is approved language and the team believes that training can be developed holistically with unit-specific differences highlighted where applicable and as such, changes will not be made at this time.	
Scott McGough - Georgia System Operations Corporation - 3	
Answer	
Document Name	
Comment	
For **R5:** In regards to the proposed verbiage requiring “generating unit-specific training”, it is OPC’s opinion that this could be overly repetitious for stations that have multiple units, which are considered sister units and hence would have the same generator protection measures in place. We recommend modifying this requirement to require station-specific training in lieu of generating unit-specifc training. In cases where there are different freeze protection measures for unit(s), those measures would be defined within the training anyway since it covers freeze protection for all units at a station.	

Likes 0	
Dislikes 0	
Response	
The Standard Drafting Team is appreciative of the comments provided. With regards to unit vs site specific training, this is approved language and the team believes that training can be developed holistically with unit-specific differences highlighted where applicable and as such, changes will not be made at this time.	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	
Document Name	
Comment	
The industry already voted other requirements into standards, and now the SDT is expanding the requirements to a new standard which is unnecessary. These requirements are not an emergency operations standard as written. If such standards are needed, they constitute a facilities standard (as in Facilities Design, Connections, and Maintenance).	
Likes 0	
Dislikes 0	
Response	
The Standard Drafting Team is appreciative of the comments provided. We believe these requirements properly belong in the EOP family as it is preparing facilities for extreme weather emergencies.	
Stewart Rake - Luminant Mining Company LLC - 7	
Answer	
Document Name	
Comment	

Vistra has additional recommendations/requested clarifications on the proposed requirements described below:

The NERC Calculating Extreme Cold Weather Temperature guide should be modified to address circumstances where National Oceanic and Atmospheric Administration (NOAA) data dating back to January 1, 2000 does not exist for the particular location. For example, NOAA has weather data for Andrews, Texas dating back only to 2014, and there are no other representative NOAA locations in the dataset. There may be other instances of rural airports or other NOAA weather data locations that do not have data going back to 2000. The Guide should specify an alternate source(s) of acceptable weather data for calculation of the Extreme Cold Weather Temperature in instances where NOAA data does not exist back to 2000, as well as how to select the location for the substitute temperature data, how to input that substitute data into the NOAA dataset, and how to treat missing temperature data (blanks) when the NOAA report is run.

Proposed R3.1 requires that a Generator Owner include in its cold weather preparedness plan the “Extreme Cold Weather Temperature for their unit(s) including the calculation date and source of temperature data.” If the Technical Requirements document titled “Calculating Extreme Cold Weather Temperature” is intended to provide the source of temperature data for all Generator Owners, then this language should be modified to state “Extreme Cold Weather Temperature for their unit(s) including the calculation date and source of temperature data, using NERC’s guide for Calculating Extreme Cold Weather Temperature.” Otherwise, the standard should be modified to clarify what sources of data are permissible, including data provided by the balancing authority (as noted in response to Question 2).

Proposed R3.5.1.2 requires Generator Owners to include within their cold weather preparedness plans “Generating unit(s) cold weather data, to include: … Fuel supply and inventory concerns.” This language should be revised to clarify that the Generator Owner is only responsible for fuel supply and inventory within its control and knowledge, as Generator Owners do not always own the source or transportation for their fuel supply and thus cannot always identify or anticipate fuel supply and inventory concerns. For example, the requirement could be modified to read: “Generating unit(s) cold weather data, to include: … Fuel supply and inventory concerns, to the extent known to the Generator Owner.”

Proposed R4 should clarify that a redesign of the unit(s) will not be required every five years. The standard requires that a Generator Owner calculate a new Extreme Cold Weather Temperature and update its cold weather preparedness plan and freeze protection measures as needed, or else, develop a Corrective Action Plan (CAP). As drafted, the standard could be interpreted as potentially requiring a redesign or retrofitting of a unit every 5 years. Vistra recommends that, in conjunction with adding a definition of “freeze protection measures” that includes procedures and temporary equipment among those measures (as recommended under Question 5), R4.3 could be modified to add the following sentence at the end: “If a CAP is required under this Requirement R4, the CAP cannot require a Generator Owner to redesign or retrofit its unit to meet the requirements in R1 or R2, as applicable, at the updated Extreme Cold Weather Temperature for the unit(s).”

Proposed R5 should clarify that the required training will be site-specific, rather than unit-specific: “Each Generator Owner in conjunction with its Generator Operator shall identify the entity responsible for providing the generating unit-site specific training, and that identified entity shall provide annual training at each site to its maintenance or operations personnel responsible for implementing the cold weather preparedness plan(s) at that site developed pursuant to Requirement R3.”

Proposed R6 should require a CAP to be developed within 150 days, rather than the earlier of 150 days or July 1. If a Generator Cold Weather Reliability Event occurs at the end of the winter season (or during a freak winter-like storm in March or April), a Generator Owner could have significantly fewer than 150 days to develop a CAP if the standard is based on the earlier of July 1 or 150 days. At the same time, even if an event occurred as late as early April, the 150 day standard would still require that the CAP be developed in advance of the next winter season (e.g., 150 days, or roughly 5 months, after April would still be in September). Thus, R6 should strike the alternative reference to July 1.

Proposed R3.1 requires that a Generator Owner include in its cold weather preparedness plan the “Extreme Cold Weather Temperature for their unit(s) including the calculation date and source of temperature data.” If the Technical Requirements document titled “Calculating Extreme Cold Weather Temperature” is intended to provide the source of temperature data for all Generator Owners, then this language should be modified to state “Extreme Cold Weather Temperature for their unit(s) including the calculation date and source of temperature data, using NERC’s guide for Calculating Extreme Cold Weather Temperature.” Otherwise, the standard should be modified to clarify what sources of data are permissible, including data provided by the balancing authority (as noted in response to Question 2).

Proposed R3.5.1.2 requires Generator Owners to include within their cold weather preparedness plans "Generating unit(s) cold weather data, to include: … Fuel supply and inventory concerns." This language should be revised to clarify that the Generator Owner is only responsible for fuel supply and inventory within its control and knowledge, as Generator Owners do not always own the source or transportation for their fuel supply and thus cannot always identify or anticipate fuel supply and inventory concerns. For example, the requirement could be modified to read: "Generating unit(s) cold weather data, to include: … Fuel supply and inventory concerns, to the extent known to the Generator Owner."

Proposed R4 should clarify that a redesign of the unit(s) will not be required every five years. The standard requires that a Generator Owner calculate a new Extreme Cold Weather Temperature and update its cold weather preparedness plan and freeze protection measures as needed, or else, develop a Corrective Action Plan (CAP). As drafted, the standard could be interpreted as potentially requiring a redesign or retrofitting of a unit every 5 years. Vistra recommends that, in conjunction with adding a definition of "freeze protection measures" that includes procedures and temporary equipment among those measures (as recommended under Question 5), R4.3 could be modified to add the following sentence at the end: "If a CAP is required under this Requirement R4, the CAP cannot require a Generator Owner to redesign or retrofit its unit to meet the requirements in R1 or R2, as applicable, at the updated Extreme Cold Weather Temperature for the unit(s)."

Proposed R5 should clarify that the required training will be site-specific, rather than unit-specific: "Each Generator Owner in conjunction with its Generator Operator shall identify the entity responsible for providing the generating unit-site specific training, and that identified entity shall provide annual training at each site to its maintenance or operations personnel responsible for implementing the cold weather preparedness plan(s) at that site developed pursuant to Requirement R3."

Proposed R6 should require a CAP to be developed within 150 days, rather than the earlier of 150 days or July 1. If a Generator Cold Weather Reliability Event occurs at the end of the winter season (or during a freak winter-like storm in March or April), a Generator Owner could have significantly fewer than 150 days to develop a CAP if the standard is based on the earlier of July 1 or 150 days. At the same time, even if an event occurred as late as early April, the 150 day standard would still require that the CAP be developed in advance of the next winter season (e.g., 150 days, or roughly 5 months, after April would still be in September). Thus, R6 should strike the alternative reference to July 1.

Proposed R3.1 requires that a Generator Owner include in its cold weather preparedness plan the “Extreme Cold Weather Temperature for their unit(s) including the calculation date and source of temperature data.” If the Technical Requirements document titled “Calculating Extreme Cold Weather Temperature” is intended to provide the source of temperature data for all Generator Owners, then this language should be modified to state “Extreme Cold Weather Temperature for their unit(s) including the calculation date and source of temperature data, using NERC’s guide for Calculating Extreme Cold Weather Temperature.” Otherwise, the standard should be modified to clarify what sources of data are permissible, including data provided by the balancing authority (as noted in response to Question 2).

Proposed R3.5.1.2 requires Generator Owners to include within their cold weather preparedness plans “Generating unit(s) cold weather data, to include: … Fuel supply and inventory concerns.” This language should be revised to clarify that the Generator Owner is only responsible for fuel supply and inventory within its control and knowledge, as Generator Owners do not always own the source or transportation for their fuel supply and thus cannot always identify or anticipate fuel supply and inventory concerns. For example, the requirement could be modified to read: “Generating unit(s) cold weather data, to include: … Fuel supply and inventory concerns, to the extent known to the Generator Owner.”

Proposed R4 should clarify that a redesign of the unit(s) will not be required every five years. The standard requires that a Generator Owner calculate a new Extreme Cold Weather Temperature and update its cold weather preparedness plan and freeze protection measures as needed, or else, develop a Corrective Action Plan (CAP). As drafted, the standard could be interpreted as potentially requiring a redesign or retrofitting of a unit every 5 years. Vistra recommends that, in conjunction with adding a definition of “freeze protection measures” that includes procedures and temporary equipment among those measures (as recommended under Question 5), R4.3 could be modified to add the following sentence at the end: “If a CAP is required under this Requirement R4, the CAP cannot require a Generator Owner to redesign or retrofit its unit to meet the requirements in R1 or R2, as applicable, at the updated Extreme Cold Weather Temperature for the unit(s).”

Proposed R5 should clarify that the required training will be site-specific, rather than unit-specific: “Each Generator Owner in conjunction with its Generator Operator shall identify the entity responsible for providing the generating unit-site specific training, and that identified entity shall provide annual training at each site to its maintenance or operations personnel responsible for implementing the cold weather preparedness plan(s) at that site developed pursuant to Requirement R3."

Proposed R6 should require a CAP to be developed within 150 days, rather than the earlier of 150 days or July 1. If a Generator Cold Weather Reliability Event occurs at the end of the winter season (or during a freak winter-like storm in March or April), a Generator Owner could have significantly fewer than 150 days to develop a CAP if the standard is based on the earlier of July 1 or 150 days. At the same time, even if an event occurred as late as early April, the 150 day standard would still require that the CAP be developed in advance of the next winter season (e.g., 150 days, or roughly 5 months, after April would still be in September). Thus, R6 should strike the alternative reference to July 1.

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Proposed R3.5.1.2 requires Generator Owners to include within their cold weather preparedness plans "Generating unit(s) cold weather data, to include: … Fuel supply and inventory concerns." This language should be revised to clarify that the Generator Owner is only responsible for fuel supply and inventory within its control and knowledge, as Generator Owners do not always own the source or transportation for their fuel supply and thus cannot always identify or anticipate fuel supply and inventory concerns. For example, the requirement could be modified to read: "Generating unit(s) cold weather data, to include: … Fuel supply and inventory concerns, to the extent known to the Generator Owner."

Proposed R4 should clarify that a redesign of the unit(s) will not be required every five years. The standard requires that a Generator Owner calculate a new Extreme Cold Weather Temperature and update its cold weather preparedness plan and freeze protection measures as needed, or else, develop a Corrective Action Plan (CAP). As drafted, the standard could be interpreted as potentially requiring a redesign or retrofitting of a unit every 5 years. Vistra recommends that, in conjunction with adding a definition of "freeze protection measures" that includes procedures and temporary equipment among those measures (as recommended under Question 5), R4.3 could be modified to add the following sentence at the end: "If a CAP is required under this Requirement R4, the CAP cannot require a Generator Owner to redesign or retrofit its unit to meet the requirements in R1 or R2, as applicable, at the updated Extreme Cold Weather Temperature for the unit(s)."

Proposed R5 should clarify that the required training will be site-specific, rather than unit-specific: "Each Generator Owner in conjunction with its Generator Operator shall identify the entity responsible for providing the generating unit-site specific training, and that identified entity shall provide annual training at each site to its maintenance or operations personnel responsible for implementing the cold weather preparedness plan(s) at that site developed pursuant to Requirement R3."

Proposed R6 should require a CAP to be developed within 150 days, rather than the earlier of 150 days or July 1. If a Generator Cold Weather Reliability Event occurs at the end of the winter season (or during a freak winter-like storm in March or April), a Generator Owner could have significantly fewer than 150 days to develop a CAP if the standard is based on the earlier of July 1 or 150 days. At the same time, even if an event occurred as late as early April, the 150 day standard would still require that the CAP be developed in advance of the next winter season (e.g., 150 days, or roughly 5 months, after April would still be in September). Thus, R6 should strike the alternative reference to July 1.

Proposed R3.1 requires that a Generator Owner include in its cold weather preparedness plan the "Extreme Cold Weather Temperature for their unit(s) including the calculation date and source of temperature data." If the Technical Requirements document titled "Calculating Extreme Cold Weather Temperature" is intended to provide the source of temperature data for all Generator Owners, then this language should be modified to state "Extreme Cold Weather Temperature for their unit(s) including the calculation date, using NERC's guide for Calculating Extreme Cold Weather Temperature." Otherwise, the standard should be modified to clarify what sources of data are permissible, including data provided by the balancing authority (as noted in response to Question 2).

Proposed R3.5.1.2 requires Generator Owners to include within their cold weather preparedness plans "Generating unit(s) cold weather data, to include: … Fuel supply and inventory concerns." This language should be revised to clarify that the Generator Owner is only responsible for fuel supply and inventory within its control and knowledge, as Generator Owners do not always own the source or transportation for their fuel supply and thus cannot always identify or anticipate fuel supply and inventory concerns. For example, the requirement could be modified to read: "Generating unit(s) cold weather data, to include: … Fuel supply and inventory concerns, to the extent known to the Generator Owner."

Proposed R4 should clarify that a redesign of the unit(s) will not be required every five years. The standard requires that a Generator Owner calculate a new Extreme Cold Weather Temperature and update its cold weather preparedness plan and freeze protection measures as needed, or else, develop a Corrective Action Plan (CAP). As drafted, the standard could be interpreted as potentially requiring a redesign or retrofitting of a unit every 5 years. Vistra recommends that, in conjunction with adding a definition of "freeze protection measures" that includes procedures and temporary equipment among those measures (as recommended under Question 5), R4.3 could be modified to add the following sentence at the end: "If a CAP is required under this Requirement R4, the CAP cannot require a Generator Owner to redesign or retrofit its unit to meet the requirements in R1 or R2, as applicable, at the updated Extreme Cold Weather Temperature for the unit(s)."

Proposed R5 should clarify that the required training will be site-specific, rather than unit-specific: "Each Generator Owner in conjunction with its Generator Operator shall identify the entity responsible for providing the generating unit-site specific training, and that identified entity shall provide annual training at each site to its maintenance or operations personnel responsible for implementing the cold weather preparedness plan(s) at that site developed pursuant to Requirement R3."

Proposed R6 should require a CAP to be developed within 150 days, rather than the earlier of 150 days or July 1. If a Generator Cold Weather Reliability Event occurs at the end of the winter season (or during a freak winter-like storm in March or April), a Generator Owner could have significantly fewer than 150 days to develop a CAP if the standard is based on the earlier of July 1 or 150 days. At the same time, even if an event occurred as late as early April, the 150 day standard would still require that the CAP be developed in advance of the next winter season (e.g., 150 days, or roughly 5 months, after April would still be in September). Thus, R6 should strike the alternative reference to July 1.

Likes 0	
Dislikes 0	
Response	
The Standard Drafting Team is appreciative of the comments provided. We discussed these comments and changes will not be made at this time.	
Ruchi Shah - AES - AES Corporation - 5	
Answer	
Document Name	
Comment	
AES Clean Energy agrees with the comments submitted by NAGF.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to NAGF.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
NAGF membership is concerned with the requirement to retrofit or otherwise improve an existing generator's cold weather performance capability without NERC having the ability to address the compensation issue identified in the Joint Inquiry Report under Key	

Recommendation 2. There is also concern that the proposed design requirements are not sufficient to protect against another event like Uri. Until industry addresses the compensation issue, it is unreasonable to adopt a design requirement for existing generating units. While the NAGF supports efforts for generators to take reasonable steps to provide reliable service through cold weather events, a mandatory requirement without reasonable compensation puts some generators at an unfair and potentially fatal disadvantage, which is detrimental for the electric industry. It has also been noted that some generators are unable to meet the design requirements due to technological issues or availability. With the efforts made by the drafting team to address these conflicting issues, the proposed requirements are optional at best and therefore unlikely to provide improved reliability. Given all of the challenges that we are seeing across the different regions regarding infrastructure issues , the creation of more uncertainty in the generation arena has the potential to further aggravate the situation rather than improve it. NAGF members support ensuring generator operating parameters are communicated to, understood, and used in the planning processes by the appropriate entities is more appropriate and beneficial to reliability during these events than a blanket retrofit requirement to operate to an arbitrary condition. The NAGF believes that the existing requirements in EOP-011 that are to be implemented no later than April 1, 2023, should be used first to determine if these proposed requirements are warranted. Until such time as these requirements become effective, NERC and FERC do not know where the need for further improvements exist. To the extent that NERC and FERC wish to add to the reliability requirements related to cold weather operation, the NAGF proposes the following language: “Generator Owners shall identify their minimum operating temperature based on operating history. This information shall include lowest temperature operated to, lowest wind chill temperature operated to, and the lowest temperature during which precipitation was occurring, if possible. These numbers shall be reviewed once each year to determine if new limits have been determined. “

Likes 0	
Dislikes 0	

Response
The Standard Drafting Team is appreciative of the comments provided. We discussed these comments and changes will not be made at this time.

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	
Document Name	
Comment	
For all above questions,we are agaisnt this standard as for some Canadian entites, units already operate in cold weather annually from November to March. These requirements represent an added administrative burden.	
Likes 0	
Dislikes 0	
Response	
The Standard Drafting Team is appreciative of the comments provided. We believe that facilities that have historically operated well during freezing temperatures are well positioned to meet the new requirements of EOP-012-1.	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	
Document Name	
Comment	
ISO-NE appreciates the efforts of the SDT however, as an ISO acting as the RC and BA for our area ISO has some concerns as described in the above comments as well as in the comments provided by the SRC. It appears that the Standard as written will ensure continued reliable operation of the BES under normal cold weather conditions, but would have limited effect on “Extreme” cold weather conditions such as those experienced during the 2014 Polar Vortex, the 2021 Storm Uri, or the 1994 North American cold wave (January 18-22). ISO-NE recommends that the Standard address at a minimum the extreme cold temperatures and duration experienced during the 2021 Storm Uri which has been the primary example as the need for this new Standard. ISO-NE Supports the Comments Provided by the SRC.	

Likes 0	
Dislikes 0	

Response

The Standard Drafting Team is appreciative of the comments provided. We discussed these comments and changes will not be made at this time.

Jamison Cawley - Nebraska Public Power District - 1

Answer	
Document Name	

Comment

NPPD suggests removing the ‘July 1’ requirement for the deadline in generating a corrective action plan and making the deadline a straight 150 days from the event. If an event occurs in early March an entity might only have approx. 110 days to generate the corrective action plan. With a straight 150 days, an entity can still create the CAP before the next winter season.

We believe the timeframe for development of Corrective Action Plans (CAP) in R2 and R4.3 is unclear. The glossary definition of CAP is A list of actions and an associated timetable for implementation to remedy a specific problem. While the language is clear that CAPs are to be developed within the Requirements, it is not clear how long an entity has to develop the CAP.

Proposed language:

R2: “…shall develop a Corrective Action Plan (CAP) within 150 days for the identified issues…”

R4.3: “…and if not develop a CAP within 150 days for the identified issues…”

R6: “…shall develop a CAP, within 150 days that contains at a minimum:”

NPPD would like to propose the following language modification for Requirement R3.4:

Existing language “Annual inspection and maintenance of generating unit(s)…”

Proposed language "Annual inspection and maintenance *as determined by the results of the inspection,* of generating unit(s)…"	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Under R2, the GO should complete its review of existing units and develop a CAP by the Implementation Date, which is proposed to be five calendar years from governmental approval. The timeframe for development of the CAP for R4.3 is tied to the ongoing and reoccurring five-year review requirement of R4. In other words, pursuant to requirement R4, once every five calendar years the GO must satisfy 4.1-4.3 for that five-year cycle.	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	
Document Name	
Comment	
Alliant Energy supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to MRO NSRF.	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	

Requirement R1

The MRO NSRF is concerned about Requirement R1, Bullet 1 as it relates to a “concurrent twenty (20) mph wind speed”. The MRO NSRF believes that 20 mph is an arbitrary velocity that will not capture the actual conditions based on the geographic location of the generating unit, unnecessarily raise the operational cost of the generating unit and not increase the reliability of the generating unit, as the fixed velocity may be too low/high for the geographical location. Rather than used a fixed velocity the MRO NSRF would like to suggest allowing the Generator Owner to calculate the appropriate wind speed using a statical methodology similar to how the Extreme Cold Weather Temperature is calculated. Entity B would like to suggest the following Requirement R1 language modification and §6. Definitions Used in this proposed standard:

R1, Bullet 1: “… assuming a Concurrent Wind Speed on any exposed Generator Cold Weather Critical Components; or”

Concurrent Wind Speed – The wind speed equal to the highest X percentile of the hourly wind speeds for the geographic location of the generating unit, measured in December, January and February for the previous 30 years through the date the temperature is calculated.

Proposed language modifications:

The MRO NSRF would like to propose the following language modification for Requirement R3.4:

Existing language “Annual inspection and maintenance of generating unit(s)…”
Proposed language “Annual inspection and maintenance, as determined by the results of the inspection, of generating unit(s)…”

The MRO NSRF would like to propose the following language modification for Requirement R4:

Existing language “Once every five calendar years, each Generator Owner shall for each generating unit:”

Proposed language “Once every five calendar years, with a calendar year starting on the first day of a new year (January 1) after an activity pursuant to the subparts below has been completed, each Generator owner shall for each generating unit:”

The MRO NSRF believes defining the calendar year, as it is in NERC Reliability Standard PRC-005-6, will provide added confines to when the five year cycle begins and does not leave interpretation for it to be a 60-month cycle.

The MRO NSRF would like to propose the following language modification for Requirement R6: Existing language: "…experiences a Generator Cold Weather Reliability Event shall develop a CAP, within 150 days or by July 1, whichever is earlier, that contains at a minimum…" Proposed language: "…experiences a Generator Cold Weather Reliability Event shall develop a CAP, within 150 calendar days, that contains at a minimum…" We believe that 150 calendar days after a Generator Cold Weather Reliability Event should be the standard to develop a CAP. If the generating unit experiences a Generator Cold Weather Reliability Event on February 28, a Generator Owner will only have 120 days to develop a CAP. Since CAPs may take additional resources to analyze and develop, 150 calendar days provides the same amount of time for Generator Owners to develop a CAP regardless of when during the winter season a Generator Cold Weather Reliably Event occurs. In addition, to align with the language in NERC Reliability Standard PRC-004-6, Entity B is recommending the inclusion of the word "calendar". Also please consdier adding timeframe requirements for the development of Corrective Action Plans (CAP) in R2 and R4.3. The glossary definition of CAP is "A list of actions and an associated timetable for implementation to remedy a specific problem". While the language is clear that CAPs are to be developed within the Requirements, it is not clear how long an entity has to develop the CAP. Proposed language: R2: "…shall develop a Corrective Action Plan (CAP) within 150 days for the identified issues…" R4.3: "…and if not develop a CAP within 150 days for the identified issues…"	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Under R2, the GO should complete its review of existing units and develop a CAP by the Implementation Date, which is proposed to be five calendar years from governmental approval. The timeframe for development of the CAP for R4.3 is tied to the ongoing and reoccurring five-year review requirement of R4. In other words, pursuant to requirement R4, once every five calendar years the GO must satisfy 4.1-4.3 for that five-year cycle.	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	

Document Name	
Comment	
MidAmerican Energy supports both the MRO NSRF and EEI comments for this section.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to MRO NSRF and EEI.	
Michele Richmond - Texas Competitive Power Advocates - NA - Not Applicable - Texas RE	
Answer	
Document Name	TCPA Comments on Revised NERC Weatherization Proposal - Filed 9-1-22.docx
Comment	
Please see attached comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The team has previously discussed cost recovery in the response to comments on the initial ballot. The SDT feels the language as written is clear and no further clarification is needed.	
Steven Sconce - EDF Renewable Energy - 5	
Answer	
Document Name	
Comment	

Note – From a design/development perspective, inverter-based generation resources are mostly operating to -25C for utility scale application. Any temperature below this would force the inverters to stop producing.	
Likes 0	
Dislikes 0	
Response	
The Standard Drafting Team is appreciative of the comments provided.	
Mark Young - Tenaska, Inc. - 5	
Answer	
Document Name	EOP-012-1 Second Draft - Tenaska Comments Rev 4 final.docx
Comment	
See attached comments document	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The team has previously discussed cost recovery in the response to comments on the initial ballot. Please see the graphic in the Implementation Plan for more clarity on effective dates. The SDT feels the language as written is clear and no further clarification is needed.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	
Document Name	
Comment	

MISO supports the comments submitted by the ISO/RTO Council Standards Review Committee (IRC SRC). In addition, we are submitting comments on behalf of MISO as an individual entity.

Guidance should be provided as to what is "economically feasible" so a consistent approach is used to assess "commercial constraints." (Part 7.1)

With respect to Part 7.1, which states:

"Each Generator Owner shall implement each CAP developed pursuant to Requirements R2, R4, or R6, or explain in a declaration why corrective actions are not being implemented due to any technical, *commercial*, or operational constraints as defined by the Generator Owner"

MISO observes that "commercial" aspects are typically outside of NERC's purview which raises the question: how will this provision be monitored and enforced without pre-defined criteria? Therefore, MISO asks the SDT to set guidance as to what is "economically feasible." Without meaningful guidance, providing a broad commercial "out" could encourage generators to elect this option as opposed to making improvements, particularly if a neighboring generator does likewise, thereby leaving the BES no more reliable than before the standard was drafted.

Finally, MISO acknowledges it is important to get this standard "right," particularly in light of the changing resource mix. As traditional resources retire and are replaced with intermittent resources, it will be important to have design criteria, such as the Extreme Cold Weather Temperature definition, set appropriately to ensure reliability benefits are achieved and maintained over time.

Likes 0	
Dislikes 0	

Response

The Standard Drafting Team is appreciative of the comments provided. The "commercial" term has been discussed at length by the SDT and changes will not be made at this time.

Imane Mrini - Austin Energy - 6

Answer	

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	
Document Name	
Comment	
Capital Power supports the North American Generators Forum (NAGF) response to this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to NAGF.	
Ronald Bauer - MGE Energy - Madison Gas and Electric Co. - 3	
Answer	
Document Name	
Comment	

Madison Gas and Electric supports the comments from the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to MRO NSRF.	
Adam Lee - MGE Energy - Madison Gas and Electric Co. - 4	
Answer	
Document Name	
Comment	
Madison Gas and Electric supports the comments of the MRO NSRF	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to MRO NSRF.	
Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations	
Answer	
Document Name	
Comment	
We have 2 additional comments for this standard not covered in the previous comment sections. These comments are specific to R5 and R6 respectively.	

R5: In regards to the proposed verbiage requiring "generating unit-specific training", it is our opinion that this could be overly burdensome for stations with multiple units; particular for those stations with multiple units of a similar design (a.k.a. "sister" units). Recommend modifying this requirement to require station-specific training in lieu of generating unit-specific training. It is our opinion that this modification will allow the GO/GOP the flexibility to develop their training modules with an appropriate level of detail so as to sufficiently train station personnel without requiring them to create multiple modules with similar or identical content. **R6:** Concerning the proposed timeline for the development of a CAP, it is our recommendation that the July 1st date be removed from this requirement. The rationale for this recommendations is thus: 150 days prior to July 1st is Feb 1st for non-leap years and Feb 2nd for leap years. Moreover, the July 1st timeline is further condensed if a Generator Cold Weather Reliability Event (GCWRE) occurs in March or April. Lastly, the stated intent of the timeframe options within the Technical Rationale is to allow GO's to review multiple events holistically following a winter season. In certain areas of the country, a GCWRE could realistically occur as early as late-October. In this instance, the latest possible date for the development of a CAP would be March 30th. Given that it is also realistic for a GCWRE to occur in March, 150 days seems a reasonable number of days to cover all but the most extreme scenarios. Therefore, we recommend removing the hard deadline of July 1st. Further, ACES has one member with the the following comments we would like to capture: • It should be noted that wind turbines are also highly susceptible to cold weather events. Ignoring wind units at a time when the grid is using them more and more may have long lasting consequences. • Finally, extreme weather should include calm cloudy days. The standard is targeted to units that are being retired more and more from the grid. Piling on additional compliance burdens will only hasten these units departures. The SDT should consider targeted reliability standards that require intermittent resources to run, ride through, and in general operate more reliably. Intermittent resources no longer operate on the periphery, they are a core component of the functional power grid. Thank you for the opportunity to comment.

Likes 0	
Dislikes 0	
Response	

The Standard Drafting Team is appreciative of the comments provided. With regards to unit vs site specific training, this is approved language and the team believes that training can be developed holistically with unit-specific differences highlighted where applicable and as such, changes will not be made at this time. With respect to CAPs, the SDT believes the current timeline is adequate and changes will not be made at this time.

Colin Chilcoat - Invenergy LLC - 6	
Answer	
Document Name	
Comment	

Invenergy appreciates the SDT's time and work on this important project, and would like to offer the below additional comments.

Invenergy recommends the following change to R2 to better align it with R1:

For each generating unit(s) in commercial operation prior to [Effective Date of this requirement], the Generator Owner shall:

- *Add new or modify existing freeze protection measures as needed to provide the capability to operate for a period of not less than one (1) hour at the unit(s) Extreme Cold Weather Temperature.*

Generating unit(s) that are not capable of operating for one (1) hour at its Extreme Cold Weather Temperature shall:

- *Develop a Corrective Action Plan (CAP) for the identified issue(s), including identification of any needed modifications to the cold weather preparedness plan required under Requirement R3;* ***or***
- *Explain in a declaration, any technical, commercial, or operational constraints as defined by the Generator Owner that preclude any ability to implement or modify appropriate freeze protection measures to provide capability of operating for one (1) hour at the documented Extreme Cold Weather Temperature.*

Corresponding changes to other sections of the standard that flow from this section should be made as well. In particular, the Violation Severity Level table for R2 should be edited to match those for R1.

Additionally, the SDT should consider adding language relieving Generator Owners of the need to develop CAPs for Generator Cold Weather Critical Components for which a technical, commercial, or operational constraint has already been declared. Lastly, the SDT should clarify how a Generator Owner is expected to incorporate the wind speed criterion in R1 ("...assuming a concurrent twenty (20) mph wind speed on any exposed Generator Cold Weather Critical Components;") into their design. Specifically, is it purely a design consideration, or is it meant to be factored into the calculation of the Extreme Cold Weather Temperature?	
Likes 0	
Dislikes 0	
Response	
The Standard Drafting Team is appreciative of the comments provided. The team discussed the suggested changes to R2 and decided the existing language more closely aligned with the intent of the drafting team. For other items, we discussed these comments and changes will not be made at this time as they be more substantive than clarifying.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	
Comment	
If "commercial" limitations can be defined by the GO, the auditor will have to respect and accept any commercial limitation which would allow the GO to exclude any unit.	
Likes 0	
Dislikes 0	
Response	
The Standard Drafting Team is appreciative of the comments provided.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee	
Answer	

Document Name	
Comment	
Evidence Retention should contain the words "since the last audit". The draft primarily has "…data or evidence to show compliance for three years". This standard is geared towards GO's. GO's at NPCC are normally on a six-year audit cycle.	
Likes 0	
Dislikes 0	
Response	
The Standard Drafting Team is appreciative of the comments provided. We discussed these comments and changes will not be made at this time.	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Thank you for your review.	
George Brown - Acciona Energy North America - 5	
Answer	
Document Name	

Comment	
Acciona Energy supports Midwest Reliability Organization's (MRO) NERC Standards Review Forum's (NSRF) comments on this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to MRO NSRF.	
Whitney Wallace - Calpine Corporation - 5 - WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
Calpine notes that most Independent System Operators (ISOs) are currently undertaking regulatory or stakeholder processes to examine improving reliability related to extreme weather events. These processes include a review of current and potential future planning standards, determining appropriate capacity accreditation for different resources, including fuel security considerations, as well as potentially differentiated levels of capacity compensation for resources providing different levels of reliability. As a result, any further cold weather standards should be developed by the ISOs as part of these regional processes. Additionally, because compliance with the proposed Standard could result in a significant cost burden for GOs, the proposed Standard should be revised to clearly state that GOs must have a mechanism to recover costs incurred to comply with this Standard. The Standard contemplates that a GO may not be able to comply with the Standard due to "technical, commercial or operational constraints" but does not specifically provide that lack of cost recovery is a commercial constraint that provides an exception to implementation of a CAP. The proposed Standard should be revised to make this clear.	
Likes 0	
Dislikes 0	
Response	

The Standard Drafting Team is appreciative of the comments provided. Please see previous response to comments on cost recovery in the previous Ballot.	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	
Document Name	
Comment	
Request the following language change for requirement R3.5.2 Generating Unit(s) minimum: Design temperature; ***OR***. Note the addition of the word "or".	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Bullets in standard requirements represent “or” and the team believes that the “or” in the bulleted list in 3.5.2 shows that only one of the three bullets is required for generating unit minimum. The team modeled the language after PRC-004 and will be keeping it as approved in second ballot.	
John Liang - Snohomish County PUD No. 1 - 6	
Answer	
Document Name	
Comment	
Request the following language change for requirement R3.5.2 Generating unit(s) minimum: Design temperature; ***OR***. Note the addition of the word "OR".	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. Bullets in standard requirements represent "or" and the team believes that the "or" in the bulleted list in 3.5.2 shows that only one of the three bullets is required for generating unit minimum. The team modeled the language after PRC-004 and will be keeping it as approved in second ballot.	
Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)	
Answer	
Document Name	
Comment	

The SRC appreciates the efforts of the SDT and realizes it has the unenviable task of balancing the competing interests of many stakeholder groups. Nonetheless, as ISO and RTOs, we, as Balancing Authorities and Reliability Coordinators, have a great stake in ensuring BES reliability. As independent operators and planners, we neither own, operate nor maintain generation assets; we must rely on the GOs' and GOPs' cooperation and response to meet interconnected reliability requirements with limited authority. Consequently, the SRC has an obligation to bring to the SDT's attention the comments mentioned above and the following additional comments.

A. **Align Requirement 1 and Part 7.1 with FERC-NERC joint report Key Recommendation 1f to require operation at the Extreme Cold Weather Temperature (ECWT).**

To recap, the second bullet in Requirement 1 states a GO must:

Explain in a declaration, any technical, commercial, or operational constraints as defined by the Generator Owner that preclude the ability to *implement appropriate freeze protection measures* to provide capability of operating for twelve (12) hours at the documented Extreme Cold Weather Temperature. (see Recommendation #2)

Additionally, Requirement 7, Part 7.1, requires a GO to implement each CAP, "or explain in a declaration why corrective actions are not being implemented due to any technical, commercial, or operational constraints as defined by the Generator Owner."

The SRC identified several issues with the proposed language regarding declarations:

(1) Key Recommendation 1f from the Joint Report states the NERC Reliability Standards should be revised to, "require GOs to retrofit existing generating units, and when building new generating units, to design them, *to operate to a specified ambient temperature and weather conditions* (*e.g*., wind, freezing precipitation)."

That language is quite prescriptive and does not provide for a technical, commercial or operational "out" (as currently contained in the draft Standard). The concern with providing a broad commercial "out" is it could encourage generators to elect this option as opposed to making improvements, particularly if a neighboring competitor chooses to do likewise, thereby leaving the BES no more resilient than before the Standard was drafted.

(2) The Standard does not identify to whom the GO provides the declaration. The SRC recommends the GO provide declarations to the RC and BA.

(3) Using the phrase "as defined by the Generator Owner" gives the GO absolute discretion to determine what constraints are valid. The SRC believes the standard should require documentation demonstrating the GO cannot comply with the Standard (such as an engineering analysis) to make it "auditable" by a Regional Entity.

B. **Align wind speed requirements for new (R1) and existing (R2) generating units.** Requirement 2 requires an existing unit to demonstrate it can, "...operate for a period of not less than one (1) hour at the unit(s) Extreme Cold Weather Temperature."

Requirement 1 indicates new units must operate at the ECWT, "assuming a concurrent twenty (20) mph wind speed." The SRC believes Requirement 2 should also include a twenty (20) mph wind speed on any exposed Generator Cold Weather Critical Components.

C. **Revise Part 7.1 to align with FERC-NERC joint report Key Recommendation 1d by requiring implementation of a CAP for identified equipment.** Collectively, Requirements 2, 6 and 7 require development and implementation of a CAP.

Key Recommendation 1d. in the Joint Report states the GO should implement a CAP for the identified equipment, ***and*** evaluate whether a CAP applies *to similar equipment for its other units* and: (i) either revise its cold weather preparedness plan or (ii) explain in a declaration why no revisions to the cold weather preparedness plan are appropriate.

The intent of this language is not to allow the GO to use a declaration to avoid implementing a CAP for *the equipment that **actually experienced** the forced outage, derate or failure to start.* Rather, the intent of the "declaration option" is to provide some leeway and flexibility to the GO when determining whether the CAP should also apply to *similar equipment for other generating units* the GO owns). Therefore, the SRC does not support the current language that would allow generating units that **actually experienced** an outage, derate or failure to start to avoid implementing a CAP by providing a declaration regarding the unit that experienced the GCWRE.

Additionally, Key Recommendation 1d. from the Joint Report states a new Standard should, "specify the specific timing for the CAP to be developed and implemented…but the CAP should be developed as quickly as possible, and *be completed by no later than the beginning of the next winter season*." As written, the Standard does not contain a requirement to develop a CAP "as quickly as possible" and ensure the CAP is completed "no later than the beginning of the next winter season." The SRC recommends adding language to address timing in the standard.

Finally, the Standard contains no criteria regarding the quality of a CAP (*e.g.*, review/approval by another entity). The SRC believes the Standard should require an unaffiliated, qualified third-party to review and approve a proposed CAP similar to the requirement in CIP-014.

D. **Require unaffiliated third-parties to review and approve proposed measures (akin to CIP-014).** Requirement 3.3 provides cold weather preparedness plans must include (among other things):

Documentation of freeze protection measures implemented on Generator Cold Weather Critical Components which may include measures used to reduce the cooling effects of wind determined necessary by the Generator Owner to protect against heat loss, and where applicable, the effects of freezing precipitation (e.g., sleet, snow, ice, and freezing rain)

Instead of saying "which *may* include measures," the requirement should read, "which *shall* include measures…."

Further, referring to the measures as "determined necessary by the GO" gives the GO absolute discretion to determine what measures to apply. The SRC proposes replacing "determined necessary" with "where applicable" as in the latter half of the requirement if the intent is to provide flexibility for generators with fully enclosed facilities (*e.g.*, those in the north that may not have to reduce the cooling effects of wind). In addition, the SRC believes some other entity should have the authority to review/approve appropriate measures. One possibility is to employ language like that used in CIP-014 in which an unaffiliated third-party verifies the work product.

E. **Additional Comments.** The SRC makes the following comments it considers less critical than those mentioned above yet still worthy of consideration.

(1) The definition of GCWRE (in sub-section (2)) includes, "a start-up failure where the unit fails to synchronize *within a specified start-up time*." The definition does not make clear how to determine the appropriate start-up time. The SRC proposes replacing "***a*** specified start-up

time" with "its specified longest start-up time: (i) pursuant to its design specifications, (ii) communicated to its BA or (iii) pursuant to its agreement to serve load." (2) The definition of GCWRE applies to events, "for which the apparent cause(s) is due to freezing of equipment within the Generator Owner's control and…." That wording indicates the event must be "apparently" due to freezing (with no way to determine whether freezing "apparently" caused the event). Thus, the SRC proposes replacing that phrase with "due to failure of equipment within the Generator Owner's control when..." (3) As written, the Generator Cold Weather Critical Component includes the phrase "which would likely lead to a Generator Cold Weather Reliability Event." That phrase includes subjective language ("would likely lead to") open to differing interpretations by different people. The SRC recommends revising the definition to read: "Any generating unit component or associated fixed fuel supply component, under the Generator Owner's control, susceptible to extreme cold weather that could cause a Generator Cold Weather Reliability Event." (4) The first bullet in Requirement 1 includes, "assuming a concurrent twenty (20) mph wind speed on any exposed Generator Cold Weather Critical Components." The SRC believes GOs should have to take into account the wind effect on the *entire facility* (not just Cold Weather Critical Components). Thus, the SRC believes that phrase should read simply, "assuming a concurrent twenty (20) mph wind." The SRC wishes to express our sincere gratitude to the Project's Standard Drafting Team Members and supporting roles. We understand the many work hours needed in developing multiple documents, as well as responding to comments. Please know we appreciate your hard work and dedication to this Project.	
Likes 0	
Dislikes 0	
Response	
The Standard Drafting Team is appreciative of the comments provided. For Additional Comments 3 and 4, these topics will be discussed further during Phase 2 of this standards drafting timeline. The SDT discussed the other comments provided and changes will not be made at this time.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	

Document Name	
Comment	
AEPC has signed on to ACES comments, please see their responses. Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see response to ACES.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	
Document Name	
Comment	
Avista recommends some reconsideration as to the applicability of the EOP 12-2 as it relates to ALL BES generating facilities. Both the letter and intent of the draft standard appear to be related specifically to thermal or steam process plants that use a Rankin cycle to generate electricity, and their susceptibility for freezing during cold weather. Can the permit team under Part 2 reconsider the applicability of facilities to consider to just those facilities related to the Rankin cycle that use steam as a means of generating electricity. Many facilities such as hydroelectric facilities internal combustion generation, wind turbine generators, and are much less susceptible to extreme cold weather and should not be treated the same regarding compliance requirements of such a standard.	
Likes 0	
Dislikes 0	

Response	
The Standard Drafting Team is appreciative of the comments provided. Please see the comment responses to Question 3 around applicability.	
Rhonda Jones - Invenergy LLC - 5	
Answer	
Document Name	
Comment	

Invenergy appreciates the SDTs time and work on this important project, and would like to offer the below additional comments.

Invenergy recommends the following change to R2 to better align it with R1:

For each generating unit(s) in commercial operation prior to [Effective Date of this requirement], the Generator Owner shall:

- Add new or modify existing freeze protection measures as needed to provide the capability to operate for a period of not less than one (1) hour at the unit(s) Extreme Cold Weather Temperature.

Generating unit(s) that are not capable of operating for one (1) hour at its Extreme Cold Weather Temperature shall:

- Develop a Corrective Action Plan (CAP) for the identified issue(s), including identification of any needed modifications to the cold weather preparedness plan required under Requirement R3; **or**
- Explain in a declaration, any technical, commercial, or operational constraints as defined by the Generator Owner that preclude any ability to implement or modify appropriate freeze protection measures to provide capability of operating for one (1) hour at the documented Extreme Cold Weather Temperature.

Corresponding changes to other sections of the standard that flow from this section should be made as well. In particular, the Violation Severity Level table for R2 should be edited to match those for R1.

Additionally, the SDT should consider adding language relieving Generator Owners of the need to develop CAPs for Generator Cold Weather Critical Components for which a technical, commercial, or operational constraint has already been declared.

Lastly, the SDT should clarify how a Generator Owner is expected to incorporate the wind speed criterion in R1 ("...assuming a concurrent twenty (20) mph wind speed on any exposed Generator Cold Weather Critical Components;") into their design. Specifically, is it purely a design consideration, or is it meant to be factored into the calculation of the Extreme Cold Weather Temperature?	
Likes 0	
Dislikes 0	
Response	
The Standard Drafting Team is appreciative of the comments provided. The team discussed the suggested changes to R2 and decided the existing language more closely aligned with the intent of the drafting team. For other items, we discussed these comments and changes will not be made at this time as they be more substantive than clarifying.	
LaKenya VanNorman - LaKenya VanNorman On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name Florida Municipal Power Agency (FMPA)	
Answer	
Document Name	
Comment	
FMPA also supports the comments of the Transmission Access Policy Study Group (TAPS), which are as follows: We understand R1 and R2 as requiring GOs to implement freeze control measures that they reasonably believe, based on good engineering judgment and their experience with their particular units and weather patterns, will result in the unit being able to operate continuously for the applicable time at the Extreme Cold Weather Temperature. Our understanding of the proposed requirements is that if a new or existing unit experiences a Forced Outage as a result of a Generator Cold Weather Reliability Event, even if the Forced Outage occurs after less than twelve hours (for a new generator) or one hour (for an existing generator) of continuous operations, the Forced Outage will not constitute evidence of noncompliance with R1 or R2. Instead, the GO will develop and implement a CAP pursuant to R6 and R7, as it would in response to any Generator Cold Weather Reliability Event. The contrary interpretation—that R1 and R2 require freeze protection measures that are 100% guaranteed to work—would require a level of certainty that simply does not exist. Generators are complex machines; they sometimes	

fail in unforeseen ways. This problem is only compounded by the fact that, as noted by multiple panelists at the April 27-28, 2022 FERC, NERC, and Regional Entities Technical Conference on Improving Winter-Readiness of Generating Units, a cold weather event cannot be simulated ahead of time to allow functional testing of a unit's set of winterization measures. Finding a GO noncompliant with R1 or R2 based on the failure in a particular instance of winterization measures it reasonably believed, based on the information available to it prior to the cold weather event, would be adequate, would not enhance reliability. We read R2 as providing that, where an existing unit is *not* capable of operating continuously for one hour at the Extreme Cold Weather Temperature, the method by which the GO "ensure[s] its generating unit(s) add new or modify existing freeze protection measures as needed" is the development of a CAP pursuant to R2. In other words, a GO demonstrates compliance with R2 by demonstrating either that it has implemented appropriate freeze protection measures, or that it has developed a CAP. The SDT has indicated that it plans to revisit the language of EOP-012-1 as part of Phase 2 of this project. Although we believe that our readings of the requirements, as outlined above, are consistent with the SDT's intent, we strongly recommend that Phase 2 clarify the language of R1 and R2 on these issues. Expressing the SDT's intent more clearly would reduce the risk of confusion and conflicting interpretations.

Likes 0	
Dislikes 0	

Response
The Standard Drafting Team is appreciative of the comments provided. The SDT discussed the comments provided and changes will not be made at this time.

Natalie Johnson - Enel Green Power - 5	
Answer	
Document Name	2021-07_Unofficial_Comment_Form_second ballot_082022 (Enel 9-1-2022).docx
Comment	

Enel would like clarifications included that criteria applies only to available capacity as indicated by the forecasted power curve. Intermittent resources may not be available due to low wind or irradiance. Another example would be a planned outage for maintenance. It should be clarified that criteria applies to available capacity and not nameplate for intermittent resources. Enel suggests this clarification could be added with an accompanying footnote in the appropriate places. Enel also suggests that R2 adds the following clarifying language: Generating unit(s) that are not capable of operating for one (1) hour at its Extreme Cold Weather Temperature shall develop a Corrective Action Plan (CAP), ***according to R7,*** for the identified issues, including identification of any needed modifications to the cold weather preparedness plan required under Requirement R3. Additionally, Enel suggests that the language for CAPS only refer to 150 days for a deadline without the July 1 reference for clarity and fairness so everyone gets the same deadline. Enel agrees with MRO NSRF's concern regarding the concurrent twenty (20) mph wind speed.

Likes 0	
Dislikes 0	

Response
The Standard Drafting Team is appreciative of the comments provided. Please see the comment responses to Question 3 around applicability. The SDT discussed the other comments provided and changes will not be made at this time.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

This is the final draft of the proposed standard for a formal 8-day ballot period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR)	11/17/2021
SAR posted for comment	11/22/21 – 12/21/21
30-day formal comment period with ballot	5/19/22 – 6/21/22

Anticipated Actions	Date
8-day final ballot	9/23/22 – 9/30/22
NERC Board of Trustees (Board) adoption	October 2022

A. Introduction

1. **Title:** **Emergency Operations**
2. **Number:** **EOP-011-3**
3. **Purpose:** To address the effects of operating Emergencies by ensuring each Transmission Operator and Balancing Authority has developed plan(s) to mitigate operating Emergencies and that those plans are implemented and coordinated within the Reliability Coordinator Area as specified within the requirements.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Reliability Coordinator

   4.1.3 Transmission Operator
5. **Effective Date:** See Implementation Plan for Project 2021-07.

B. Requirements and Measures

R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

1.1. Roles and responsibilities for activating the Operating Plan(s);

1.2. Processes to prepare for and mitigate Emergencies including:

1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency;

1.2.2. Cancellation or recall of Transmission and generation outages;

1.2.3. Transmission system reconfiguration;

1.2.4. Redispatch of generation request;

1.2.5. Operator-controlled manual Load shedding during an Emergency that accounts for each of the following:

1.2.5.1. Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;

1.2.5.2. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that serve designated critical loads;

1.2.5.3. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for underfrequency load shed (UFLS) or undervoltage load

shed (UVLS); and

1.2.5.4. Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions.

1.2.6. Provisions to determine reliability impacts of:

1.2.6.1. cold weather conditions; and

1.2.6.2. extreme weather conditions.

M1. Each Transmission Operator will have a dated Operating Plan(s) developed in accordance with Requirement R1 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R1.

R2. Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

2.1. Roles and responsibilities for activating the Operating Plan(s);

2.2. Processes to prepare for and mitigate Emergencies including:

2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;

2.2.2. Requesting an Energy Emergency Alert, per Attachment 1;

2.2.3. Managing generating resources in its Balancing Authority Area to address:

2.2.3.1. capability and availability;

2.2.3.2. fuel supply and inventory concerns;

2.2.3.3. fuel switching capabilities; and

2.2.3.4. environmental constraints.

2.2.4. Public appeals for voluntary Load reductions;

2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions;

2.2.6. Reduction of internal utility energy use;

2.2.7. Use of Interruptible Load, curtailable Load and demand response;

2.2.8. Provisions for Transmission Operators to implement operator-controlled

manual Load shed in accordance with Requirement R1 Part 1.2.5; and

2.2.9. Provisions to determine reliability impacts of:

2.2.9.1. cold weather conditions; and

2.2.9.2. extreme weather conditions.

M2. Each Balancing Authority will have a dated Operating Plan(s) developed in accordance with Requirement R2 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R2.

R3. The Reliability Coordinator shall review the Operating Plan(s) to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority regarding any reliability risks that are identified between Operating Plans. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

3.1. Within 30 calendar days of receipt, the Reliability Coordinator shall:

3.1.1. Review each submitted Operating Plan(s) on the basis of compatibility and inter-dependency with other Balancing Authorities' and Transmission Operators' Operating Plans;

3.1.2. Review each submitted Operating Plan(s) for coordination to avoid risk to Wide Area reliability; and

3.1.3. Notify each Balancing Authority and Transmission Operator of the results of its review, specifying any time frame for resubmittal of its Operating Plan(s) if revisions are identified.

M3. The Reliability Coordinator will have documentation, such as dated emails or other correspondences that it reviewed, Transmission Operator and Balancing Authority Operating Plans, within 30 calendar days of submittal in accordance with Requirement R3.

R4. Each Transmission Operator and Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R3 and resubmit its Operating Plan(s) to its Reliability Coordinator within a time period specified by its Reliability Coordinator. *[Violation Risk Factor: High] [Time Horizon: Operation Planning]*

M4. The Transmission Operator and Balancing Authority will have documentation, such as dated emails or other correspondence, with an Operating Plan(s) version history showing that it responded and updated the Operating Plan(s) within the timeframe identified by its Reliability Coordinator in accordance with Requirement R4.

R5. Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and

neighboring Reliability Coordinators. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M5. Each Reliability Coordinator that receives an Emergency notification from a Balancing Authority or Transmission Operator within its Reliability Coordinator Area will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that will be used to determine if the Reliability Coordinator communicated, in accordance with Requirement R5, with other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators.

R6. Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M6. Each Reliability Coordinator, with a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area, will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that it declared an Energy Emergency Alert, as detailed in Attachment 1, in accordance with Requirement R6.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

"Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with the 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 CEA may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

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

- The Transmission Operator shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R1 and R4 and Measures M1 and M4.

- The Balancing Authority shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R2 and R4, and Measures M2 and M4.
- The Reliability Coordinator shall maintain evidence of compliance since the last audit for Requirements R3, R5, and R6 and Measures M3, M5, and M6.

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.

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real-time Operations, Operations Planning, Long-term Planning	High	N/A	The Transmission Operator developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to maintain it.	The Transmission Operator developed an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to have it reviewed by its Reliability Coordinator.	The Transmission Operator failed to develop an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. OR The Transmission Operator developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to implement it.
R2	Real-time Operations, Operations	High	N/A	The Balancing Authority developed a Reliability Coordinator-	The Balancing Authority developed an Operating Plan(s) to mitigate operating	The Balancing Authority failed to develop an

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	Planning, Long-term Planning			reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to maintain it.	Emergencies within its Balancing Authority Area, but failed to have it reviewed by its Reliability Coordinator.	Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area. OR The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to implement it.
R3	Operations Planning	High	N/A	N/A	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission Operator.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					Operator within 30 calendar days.	
R4	Operations Planning	High	N/A	N/A	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator within the timeframe specified by its Reliability Coordinator.	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator.
R5	Real-time Operations	High	N/A	N/A	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority did notify neighboring Reliability Coordinators, Balancing Authorities	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority failed to notify neighboring Reliability Coordinators, Balancing Authorities

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					and Transmission Operators, but failed to notify within 30 minutes from the time of receiving notification.	and Transmission Operators.
R6	Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to declare an Energy Emergency Alert.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	November 13, 2014	Adopted by Board of Trustees	Merged EOP-001-2.1b, EOP-002-3.1 and EOP-003-2.
1	November 19, 2015	FERC approved EOP-011-1. Docket Nos. RM15-7-000, RM15-12-000, and RM15-13-000. Order No. 818	
2	June 11,2021	Adopted by Board of Trustees	Revised under Project 2019-06
2	August 24,2021	FERC approved EOP-011-2. Docket Number RD21-5-000	
2	August 24,2021	Effective Date	4/1/ 2023
3	TBD		Revised under Project 2021-07

Attachment 1-EOP-011-3
Energy Emergency Alerts

Introduction

This Attachment provides the process and descriptions of the levels used by the Reliability Coordinator in which it communicates the condition of a Balancing Authority which is experiencing an Energy Emergency.

A. General Responsibilities

1. **Initiation by Reliability Coordinator.** An Energy Emergency Alert (EEA) may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of an energy deficient Balancing Authority.

2. **Notification**. A Reliability Coordinator who declares an EEA shall notify all Balancing Authorities and Transmission Operators in its Reliability Coordinator Area. The Reliability Coordinator shall also notify all neighboring Reliability Coordinators.

B. EEA Levels

Introduction

To ensure that all Reliability Coordinators clearly understand potential and actual Energy Emergencies in the Interconnection, NERC has established three levels of EEAs. The Reliability Coordinators will use these terms when communicating Energy Emergencies to each other. An EEA is an Emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC Reliability Standards.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. **EEA 1 — All available generation resources in use. Circumstances:**
   - The Balancing Authority is experiencing conditions where all available generation resources are committed to meet firm Load, firm transactions, and reserve commitments, and is concerned about sustaining its required Contingency Reserves.
   - Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. **EEA 2 — Load management procedures in effect. Circumstances:**
   - The Balancing Authority is no longer able to provide its expected energy requirements and is an energy deficient Balancing Authority.
   - An energy deficient Balancing Authority has implemented its Operating Plan(s) to mitigate Emergencies.

- An energy deficient Balancing Authority is still able to maintain minimum Contingency Reserve requirements.

During EEA 2, Reliability Coordinators and energy deficient Balancing Authorities have the following responsibilities:

2.1 Notifying other Balancing Authorities and market participants. The energy deficient Balancing Authority shall communicate its needs to other Balancing Authorities and market participants. Upon request from the energy deficient Balancing Authority, the respective Reliability Coordinator shall post the declaration of the alert level, along with the name of the energy deficient Balancing Authority on the RCIS website.

2.2 Declaration period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators.

2.3 Sharing information on resource availability. Other Reliability Coordinators of Balancing Authorities with available resources shall coordinate, as appropriate, with the Reliability Coordinator that has an energy deficient Balancing Authority.

2.4 Evaluating and mitigating Transmission limitations. The Reliability Coordinator shall review Transmission outages and work with the Transmission Operator(s) to see if it's possible to return to service any Transmission Elements that may relieve the loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).

2.5 Requesting Balancing Authority actions. Before requesting an EEA 3, the energy deficient Balancing Authority must make use of all available resources; this includes, but is not limited to:

2.5.1 All available generation units are on line. All generation capable of being on line in the time frame of the Emergency is on line.

2.5.2 Demand-Side Management. Activate Demand-Side Management within provisions of any applicable agreements.

3. EEA 3 —Firm Load interruption is imminent or in progress. Circumstances:

- The energy deficient Balancing Authority is unable to meet minimum Contingency Reserve requirements.

During EEA 3, Reliability Coordinators and Balancing Authorities have the following responsibilities:

3.1 Continue actions from EEA 2. The Reliability Coordinators and the energy deficient Balancing Authority shall continue to take all actions initiated during EEA 2.

3.2 Declaration Period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities, and Transmission Operators.

3.3 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator shall evaluate the risks of revising SOLs and IROLs for the possibility of delivery of energy to the energy deficient Balancing Authority. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Transmission Operator whose Transmission Owner (TO) equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists, or as allowed by the Transmission Owner whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.3.1 Energy deficient Balancing Authority obligations. The energy deficient Balancing Authority, upon notification from its Reliability Coordinator of the situation, will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding.

3.4 Returning to pre-Emergency conditions. Whenever energy is made available to an energy deficient Balancing Authority such that the Systems can be returned to its pre- Emergency SOLs or IROLs condition, the energy deficient Balancing Authority shall request the Reliability Coordinator to downgrade the alert level.

3.4.1 Notification of other parties. Upon notification from the energy deficient Balancing Authority that an alert has been downgraded, the Reliability Coordinator shall notify the neighboring Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Operators that its Systems can be returned to its normal limits.

Alert 0 - Termination. When the energy deficient Balancing Authority is able to meet its Load and Operating Reserve requirements, it shall request its Reliability Coordinator to terminate the EEA.

3.4.2 Notification. The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the neighboring Balancing Authorities and Transmission Operators.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

This is the final draft of the proposed standard for a formal 8-day ballot period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR)	11/17/2021
SAR posted for comment	11/22/21 – 12/21/21
30-day formal comment period with ballot	5/19/22 – 6/21/22

Anticipated Actions	Date
8-day final ballot	9/23/22 – 9/30/22
NERC Board of Trustees (Board) adoption	October 2022

A. Introduction

1. **Title:** **Emergency Operations**

2. **Number:** **EOP-011-3**

3. **Purpose:** To address the effects of operating Emergencies by ensuring each Transmission Operator and Balancing Authority has developed plan(s) to mitigate operating Emergencies and that those plans are implemented and coordinated within the Reliability Coordinator Area as specified within the requirements.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Reliability Coordinator

   4.1.3 Transmission Operator

5. **Effective Date:** See Implementation Plan for Project 2021-07.

B. Requirements and Measures

R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

1.1. Roles and responsibilities for activating the Operating Plan(s);

1.2. Processes to prepare for and mitigate Emergencies including:

1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency;

1.2.2. Cancellation or recall of Transmission and generation outages;

1.2.3. Transmission system reconfiguration;

1.2.4. Redispatch of generation request;

1.2.5. Operator-controlled manual ~~l~~Load shedding during an Emergency that accounts for each of the following:

1.2.5.1. Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;

1.2.5.2. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that serve designated critical loads;

1.2.5.3. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for underfrequency load shed (UFLS) or undervoltage load

shed (UVLS); and

1.2.5.4. Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions.

1.2.6. Provisions to determine reliability impacts of:

1.2.6.1. cold weather conditions; and

1.2.6.2. extreme weather conditions.

M1. Each Transmission Operator will have a dated Operating Plan(s) developed in accordance with Requirement R1 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R1.

R2. Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

2.1. Roles and responsibilities for activating the Operating Plan(s);

2.2. Processes to prepare for and mitigate Emergencies including:

2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;

2.2.2. Requesting an Energy Emergency Alert, per Attachment 1;

2.2.3. Managing generating resources in its Balancing Authority Area to address:

2.2.3.1. capability and availability;

2.2.3.2. fuel supply and inventory concerns;

2.2.3.3. fuel switching capabilities; and

2.2.3.4. environmental constraints.

2.2.4. Public appeals for voluntary Load reductions;

2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions;

2.2.6. Reduction of internal utility energy use;

2.2.7. Use of Interruptible Load, curtailable Load and demand response;

2.2.8. Provisions for Transmission Operators to implement operator-controlled

manual Load shed in accordance with Requirement R1 Part 1.2.5; and

2.2.9. Provisions to determine reliability impacts of:

2.2.9.1. cold weather conditions; and

2.2.9.2. extreme weather conditions.

M2. Each Balancing Authority will have a dated Operating Plan(s) developed in accordance with Requirement R2 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R2.

R3. The Reliability Coordinator shall review the Operating Plan(s) to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority regarding any reliability risks that are identified between Operating Plans. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

3.1. Within 30 calendar days of receipt, the Reliability Coordinator shall:

3.1.1. Review each submitted Operating Plan(s) on the basis of compatibility and inter-dependency with other Balancing Authorities' and Transmission Operators' Operating Plans;

3.1.2. Review each submitted Operating Plan(s) for coordination to avoid risk to Wide Area reliability; and

3.1.3. Notify each Balancing Authority and Transmission Operator of the results of its review, specifying any time frame for resubmittal of its Operating Plan(s) if revisions are identified.

M3. The Reliability Coordinator will have documentation, such as dated emails or other correspondences that it reviewed, Transmission Operator and Balancing Authority Operating Plans, within 30 calendar days of submittal in accordance with Requirement R3.

R4. Each Transmission Operator and Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R3 and resubmit its Operating Plan(s) to its Reliability Coordinator within a time period specified by its Reliability Coordinator. *[Violation Risk Factor: High] [Time Horizon: Operation Planning]*

M4. The Transmission Operator and Balancing Authority will have documentation, such as dated emails or other correspondence, with an Operating Plan(s) version history showing that it responded and updated the Operating Plan(s) within the timeframe identified by its Reliability Coordinator in accordance with Requirement R4.

R5. Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and

neighboring Reliability Coordinators. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M5. Each Reliability Coordinator that receives an Emergency notification from a Balancing Authority or Transmission Operator within its Reliability Coordinator Area will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that will be used to determine if the Reliability Coordinator communicated, in accordance with Requirement R5, with other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators.

R6. Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M6. Each Reliability Coordinator, with a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area, will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that it declared an Energy Emergency Alert, as detailed in Attachment 1, in accordance with Requirement R6.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

"Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with the 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 CEA may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

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

- The Transmission Operator shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R1 and R4 and Measures M1 and M4.

- The Balancing Authority shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R2 and R4, and Measures M2 and M4.
- The Reliability Coordinator shall maintain evidence of compliance since the last audit for Requirements R3, R5, and R6 and Measures M3, M5, and M6.

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.

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real-time Operations, Operations Planning, Long-term Planning	High	N/A	The Transmission Operator developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to maintain it.	The Transmission Operator developed an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to have it reviewed by its Reliability Coordinator.	The Transmission Operator failed to develop an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. OR The Transmission Operator developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to implement it.
R2	Real-time Operations, Operations	High	N/A	The Balancing Authority developed a Reliability Coordinator-	The Balancing Authority developed an Operating Plan(s) to mitigate operating	The Balancing Authority failed to develop an

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	Planning, Long-term Planning			reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to maintain it.	Emergencies within its Balancing Authority Area, but failed to have it reviewed by its Reliability Coordinator.	Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area. OR The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to implement it.
R3	Operations Planning	High	N/A	N/A	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission Operator.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					Operator within 30 calendar days.	
R4	Operations Planning	High	N/A	N/A	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator within the timeframe specified by its Reliability Coordinator.	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator.
R5	Real-time Operations	High	N/A	N/A	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority did notify neighboring Reliability Coordinators, Balancing Authorities	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority failed to notify neighboring Reliability Coordinators, Balancing Authorities

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					and Transmission Operators, but failed to notify within 30 minutes from the time of receiving notification.	and Transmission Operators.
R6	Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to declare an Energy Emergency Alert.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	November 13, 2014	Adopted by Board of Trustees	Merged EOP-001-2.1b, EOP-002-3.1 and EOP-003-2.
1	November 19, 2015	FERC approved EOP-011-1. Docket Nos. RM15-7-000, RM15-12-000, and RM15-13-000. Order No. 818	
2	June 11,2021	Adopted by Board of Trustees	Revised under Project 2019-06
2	August 24,2021	FERC approved EOP-011-2. Docket Number RD21-5-000	
2	August 24,2021	Effective Date	4/1/ 2023
3	TBD		Revised under Project 2021-07

Attachment 1-EOP-011-3
Energy Emergency Alerts

Introduction

This Attachment provides the process and descriptions of the levels used by the Reliability Coordinator in which it communicates the condition of a Balancing Authority which is experiencing an Energy Emergency.

A. General Responsibilities

1. **Initiation by Reliability Coordinator.** An Energy Emergency Alert (EEA) may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of an energy deficient Balancing Authority.

2. **Notification**. A Reliability Coordinator who declares an EEA shall notify all Balancing Authorities and Transmission Operators in its Reliability Coordinator Area. The Reliability Coordinator shall also notify all neighboring Reliability Coordinators.

B. EEA Levels

Introduction

To ensure that all Reliability Coordinators clearly understand potential and actual Energy Emergencies in the Interconnection, NERC has established three levels of EEAs. The Reliability Coordinators will use these terms when communicating Energy Emergencies to each other. An EEA is an Emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC Reliability Standards.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. **EEA 1 — All available generation resources in use. Circumstances:**

   - The Balancing Authority is experiencing conditions where all available generation resources are committed to meet firm Load, firm transactions, and reserve commitments, and is concerned about sustaining its required Contingency Reserves.
   - Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. **EEA 2 — Load management procedures in effect. Circumstances:**

   - The Balancing Authority is no longer able to provide its expected energy requirements and is an energy deficient Balancing Authority.
   - An energy deficient Balancing Authority has implemented its Operating Plan(s) to mitigate Emergencies.

- An energy deficient Balancing Authority is still able to maintain minimum Contingency Reserve requirements.

During EEA 2, Reliability Coordinators and energy deficient Balancing Authorities have the following responsibilities:

2.1 Notifying other Balancing Authorities and market participants. The energy deficient Balancing Authority shall communicate its needs to other Balancing Authorities and market participants. Upon request from the energy deficient Balancing Authority, the respective Reliability Coordinator shall post the declaration of the alert level, along with the name of the energy deficient Balancing Authority on the RCIS website.

2.2 Declaration period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators**.**

2.3 Sharing information on resource availability. Other Reliability Coordinators of Balancing Authorities with available resources shall coordinate, as appropriate, with the Reliability Coordinator that has an energy deficient Balancing Authority.

2.4 Evaluating and mitigating Transmission limitations. The Reliability Coordinator shall review Transmission outages and work with the Transmission Operator(s) to see if it's possible to return to service any Transmission Elements that may relieve the loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).

2.5 Requesting Balancing Authority actions. Before requesting an EEA 3, the energy deficient Balancing Authority must make use of all available resources; this includes, but is not limited to:

2.5.1 All available generation units are on line. All generation capable of being on line in the time frame of the Emergency is on line.

2.5.2 Demand-Side Management. Activate Demand-Side Management within provisions of any applicable agreements.

3. EEA 3 —Firm Load interruption is imminent or in progress. Circumstances:

- The energy deficient Balancing Authority is unable to meet minimum Contingency Reserve requirements.

During EEA 3, Reliability Coordinators and Balancing Authorities have the following responsibilities:

3.1 Continue actions from EEA 2. The Reliability Coordinators and the energy deficient Balancing Authority shall continue to take all actions initiated during EEA 2.

3.2 Declaration Period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities, and Transmission Operators.

3.3 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator shall evaluate the risks of revising SOLs and IROLs for the possibility of delivery of energy to the energy deficient Balancing Authority. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Transmission Operator whose Transmission Owner (TO) equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists, or as allowed by the Transmission Owner whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.3.1 Energy deficient Balancing Authority obligations. The energy deficient Balancing Authority, upon notification from its Reliability Coordinator of the situation, will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding.

3.4 Returning to pre-Emergency conditions. Whenever energy is made available to an energy deficient Balancing Authority such that the Systems can be returned to its pre- Emergency SOLs or IROLs condition, the energy deficient Balancing Authority shall request the Reliability Coordinator to downgrade the alert level.

3.4.1 Notification of other parties. Upon notification from the energy deficient Balancing Authority that an alert has been downgraded, the Reliability Coordinator shall notify the neighboring Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Operators that its Systems can be returned to its normal limits.

Alert 0 - Termination. When the energy deficient Balancing Authority is able to meet its Load and Operating Reserve requirements, it shall request its Reliability Coordinator to terminate the EEA.

3.4.2 Notification. The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the neighboring Balancing Authorities and Transmission Operators.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

This is the final draft of the proposed standard for a formal 8-day ballot period.

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Anticipated Actions	Date
8-day final ballot	9/23/22 – 9/30/22
NERC Board of Trustees (Board) adoption	October 2022

A. Introduction

1. **Title:** **Emergency ~~Preparedness and~~ Operations**

2. **Number:** **EOP-~~011-2~~011-3**

3. **Purpose:** To address the effects of operating ~~emergencies~~Emergencies by ensuring each Transmission Operator~~,~~ and Balancing Authority~~, and Generator Owner~~ has developed plan(s) to mitigate operating Emergencies and that those plans are implemented and coordinated within the Reliability Coordinator Area as specified within the requirements.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Reliability Coordinator

   4.1.3 Transmission Operator

   ~~**3.0.4** Generator Owner~~

   ~~**3.1.5** Generator Operator~~

   ~~**4.2. Facilities**~~

   ~~**4.2.1** For the purpose of this standard, the term "generating unit" means all Bulk Electric System generators.~~

5. **Effective Date:** See Implementation Plan for Project ~~2019-06~~2021-07.

B. Requirements and Measures

R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

1.1. Roles and responsibilities for activating the Operating Plan(s);

1.2. Processes to prepare for and mitigate Emergencies including:

1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency;

1.2.2. Cancellation or recall of Transmission and generation outages;

1.2.3. Transmission system reconfiguration;

1.2.4. Redispatch of generation request;

1.2.5. Operator-controlled manual Load shedding during an Emergency that accounts for each of the following:

1.2.5.1. ~~**1.2.5.**~~ Provisions for ~~operator-controlled~~ manual Load shedding ~~that minimizes the overlap with automatic Load shedding and are~~ capable of being implemented in a timeframe adequate for mitigating the Emergency;~~ and~~

1.2.5.2. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that serve designated critical loads;

1.2.5.3. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for underfrequency load shed (UFLS) or undervoltage load shed (UVLS); and

1.2.5.4. Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions.

1.2.6. Provisions to determine reliability impacts of:

1.2.6.1. cold weather conditions; and

1.2.6.2. extreme weather conditions.

M1. Each Transmission Operator will have a dated Operating Plan(s) developed in accordance with Requirement R1 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R1.

R2. Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

2.1. Roles and responsibilities for activating the Operating Plan(s);

2.2. Processes to prepare for and mitigate Emergencies including:

2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;

2.2.2. Requesting an Energy Emergency Alert, per Attachment 1;

2.2.3. Managing generating resources in its Balancing Authority Area to address:

2.2.3.1. capability and availability;

2.2.3.2. fuel supply and inventory concerns;

2.2.3.3. fuel switching capabilities; and

2.2.3.4. environmental constraints.

2.2.4. Public appeals for voluntary Load reductions;

2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions;

2.2.6. Reduction of internal utility energy use;

2.2.7. Use of Interruptible Load, curtailable Load and demand response;

2.2.8. Provisions for Transmission Operators to implement operator-controlled manual Load ~~shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency~~shed in accordance with Requirement R1 Part 1.2.5; and

2.2.9. Provisions to determine reliability impacts of:

2.2.9.1. cold weather conditions; and

2.2.9.2. extreme weather conditions.

M2. Each Balancing Authority will have a dated Operating Plan(s) developed in accordance with Requirement R2 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R2.

R3. The Reliability Coordinator shall review the Operating Plan(s) to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority regarding any reliability risks that are identified between Operating Plans. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

3.1. Within 30 calendar days of receipt, the Reliability Coordinator shall:

3.1.1. Review each submitted Operating Plan(s) on the basis of compatibility and inter-dependency with other Balancing Authorities' and Transmission Operators' Operating Plans;

3.1.2. Review each submitted Operating Plan(s) for coordination to avoid risk to Wide Area reliability; and

3.1.3. Notify each Balancing Authority and Transmission Operator of the results of its review, specifying any time frame for resubmittal of its Operating Plan(s) if revisions are identified.

M3. The Reliability Coordinator will have documentation, such as dated ~~e-mails~~emails or other correspondences that it reviewed, Transmission Operator and Balancing Authority Operating Plans, within 30 calendar days of submittal in accordance with

Requirement R3.

R4. Each Transmission Operator and Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R3 and resubmit its Operating Plan(s) to its Reliability Coordinator within a time period specified by its Reliability Coordinator. *[Violation Risk Factor: High] [Time Horizon: Operation Planning]*

M4. The Transmission Operator and Balancing Authority will have documentation, such as dated emails or other correspondence, with an Operating Plan(s) version history showing that it responded and updated the Operating Plan(s) within the timeframe identified by its Reliability Coordinator in accordance with Requirement R4.

R5. Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and

neighboring Reliability Coordinators. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M5. Each Reliability Coordinator that receives an Emergency notification from a Balancing Authority or Transmission Operator within its Reliability Coordinator Area will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that will be used to determine if the Reliability Coordinator communicated, in accordance with Requirement R5, with other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators.

R6. Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M6. Each Reliability Coordinator, with a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area, will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that it declared an Energy Emergency Alert, as detailed in Attachment 1, in accordance with Requirement R6.

~~**R7.** Each Generator Owner shall implement and maintain one or more cold weather preparedness plan(s) for its generating units. The cold weather preparedness plan(s) shall include the following, at a minimum: [*Violation Risk Factor: High*] [*Time Horizon: Operations Planning and Real-Time Operations*]~~

~~**7.1.** Generating unit(s) freeze protection measures based on geographical location and plant configuration;~~

~~**7.2.** Annual inspection and maintenance of generating unit(s) freeze protection measures;~~

~~**7.3.** Generating unit(s) cold weather data, to include:~~

~~**7.3.1.** Generating unit(s) operating limitations in cold weather to include:~~

~~**7.3.1.1.** capability and availability;~~

~~**7.3.1.2.** fuel supply and inventory concerns;~~

~~**7.3.1.3.** fuel switching capabilities; and~~

~~**7.3.1.4.** environmental constraints.~~

~~**7.3.2.** Generating unit(s) minimum:~~

~~**7.3.2.1.** design temperature; or~~

~~**7.3.2.2.** historical operating temperature; or~~

~~**7.3.1.3.** current cold weather performance temperature determined by an engineering analysis.~~

~~**M7.** Each Generator Owner will have evidence documenting that its cold weather preparedness plan(s) was implemented and maintained in accordance with Requirement R7.~~

~~**R8.** Each Generator Owner in conjunction with its Generator Operator shall identify the entity responsible for providing the generating unit-specific training, and that identified entity shall provide the training to its maintenance or operations personnel responsible for implementing cold weather preparedness plan(s) developed pursuant to Requirement R7. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]*~~

~~**M8.** Each Generator Operator or Generator Owner will have documented evidence that the applicable personnel completed training of the Generator Owner's cold weather preparedness plan(s). This evidence may include, but is not limited to, documents such as personnel training records, training materials, date of training, agendas or learning objectives, attendance at pre-work briefings, review of work order tasks, tailboards, attendance logs for classroom training, and completion records for computer-based training in fulfillment of Requirement R8.~~

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

"Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with the 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~~CEA may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

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

- The Transmission Operator shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R1 and R4 and Measures M1 and M4.

- The Balancing Authority shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R2 and R4, and Measures M2 and M4.
- The Reliability Coordinator shall maintain evidence of compliance since the last audit for Requirements R3, R5, and R6 and Measures M3, M5, and M6.

1.3. Compliance Monitoring and Enforcement Program:

- ~~The Generator Owner shall retain the cold weather preparedness plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirement R7 and Measure M7.~~

~~**1.3.** The Generator Owner or Generator Operator shall keep data or evidence to show compliance for three years or since its last compliance audit, whichever timeframe is greater, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation, for Requirement R8 and Measure M8.~~ ~~**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.

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real-time Operations, Operations Planning, Long-term Planning	High	N/A	The Transmission Operator developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to maintain it.	The Transmission Operator developed an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to have it reviewed by its Reliability Coordinator.	The Transmission Operator failed to develop an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. OR The Transmission Operator developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission ~~s~~ Operator Area, but failed to implement it.
R2	Real-time Operations, Operations	High	N/A	The Balancing Authority developed a Reliability Coordinator-	The Balancing Authority developed an Operating Plan(s) to mitigate operating	The Balancing Authority failed to develop an

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	Planning, Long-term Planning			reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to maintain it.	Emergencies within its Balancing Authority Area, but failed to have it reviewed by its Reliability Coordinator.	Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area. OR The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to implement it.
R3	Operations Planning	High	N/A	N/A	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission Operator.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					Operator within 30 calendar days.	
R4	Operations Planning	High	N/A	N/A	The Transmission Operator or Balancing Authority failed to update and resubmit ~~tis~~its Operating Plan(s) to its Reliability Coordinator within the timeframe specified by its Reliability Coordinator.	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator.
R5	Real-time Operations	High	N/A	N/A	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority did notify neighboring Reliability Coordinators, Balancing Authorities	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority failed to notify neighboring Reliability Coordinators, Balancing Authorities

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					and Transmission Operators, but failed to notify within 30 minutes from the time of receiving notification.	and Transmission Operators.
R6	Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to declare an Energy Emergency Alert.
~~**R7**~~	~~Operations Planning and Real-time Operations~~	~~High~~	~~The Generator Owner implemented a cold weather preparedness plan(s) but failed to maintain it.~~	~~The Generator Owner's cold weather preparedness plan failed to include one of the applicable requirement Parts within Requirement R7.~~	~~The Generator Owner had and maintained a cold weather preparedness plan(s) but failed to fully implement it.~~ ~~OR~~	~~The Generator Owner does not have a cold weather preparedness plan.~~ ~~OR~~ ~~The Generator Owner has a cold~~

~~R #~~	~~Time Horizon~~	~~VRF~~	~~Violation Severity Levels~~			
			~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
					~~The Generator Owner's cold weather preparedness plan failed to include two of the applicable requirement Parts within Requirement R7.~~	~~weather preparedness plan, but failed to include any of the applicable requirement Parts within Requirement R7.~~
~~R8~~	~~Operations Planning and Real-time Operations~~	~~Medium~~	~~The Generator Owner or Generator Operator failed to provide generating unit-specific training as described in Requirement R8 to the greater of:~~ • ~~one applicable personnel at a single generating unit; or~~ • ~~5% or less of its total applicable personnel.~~	~~The Generator Owner or Generator Operator failed to provide generating unit-specific training as described in Requirement R8 to the greater of:~~ • ~~two applicable personnel at a single generating unit; or~~ • ~~more than 5% or less than or equal to 10% of its total applicable personnel.~~	~~The Generator Owner or Generator Operator failed to provide generating unit-specific training as described in Requirement R8 to the greater of:~~ • ~~three applicable personnel at a single generating unit; or~~ • ~~more than 10% or less than or equal to 15% of its total applicable personnel.~~	~~The Generator Owner or Generator Operator failed to provide generating unit-specific training as described in Requirement R8 to the greater of:~~ • ~~four applicable personnel at a single generating unit; or~~ • ~~more than 15% of its total applicable personnel.~~

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	November 13, 2014	Adopted by Board of Trustees	Merged EOP-001-2.1b, EOP-002-3.1 and EOP-003-2.
1	November 19, 2015	FERC approved EOP-011-1. Docket Nos. RM15-7-000, RM15-12-000, and RM15-13-000. Order No. 818	
2	June 11,2021	Adopted by ~~the~~ Board of Trustees	Revised under Project 2019-06
2	August 24,2021	FERC approved EOP-011-2. Docket Number RD21-5-000	
2	August 24,2021	Effective Date	4/1/ 2023
3	TBD		Revised under Project 2021-07

Attachment 1-EOP-~~011-2~~011-3 Energy Emergency Alerts

Introduction

This Attachment provides the process and descriptions of the levels used by the Reliability Coordinator in which it communicates the condition of a Balancing Authority which is experiencing an Energy Emergency.

A. General Responsibilities

1. **Initiation by Reliability Coordinator.** An Energy Emergency Alert (EEA) may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of an energy deficient Balancing Authority.

2. **Notification**. A Reliability Coordinator who declares an EEA shall notify all Balancing Authorities and Transmission Operators in its Reliability Coordinator Area. The Reliability Coordinator shall also notify all neighboring Reliability Coordinators.

B. EEA Levels

Introduction

To ensure that all Reliability Coordinators clearly understand potential and actual Energy Emergencies in the Interconnection, NERC has established three levels of EEAs. The Reliability Coordinators will use these terms when communicating Energy Emergencies to each other. An EEA is an Emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC Reliability Standards.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. **EEA 1 — All available generation resources in use. Circumstances:**

   - The Balancing Authority is experiencing conditions where all available generation resources are committed to meet firm Load, firm transactions, and reserve commitments, and is concerned about sustaining its required Contingency Reserves.
   - Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. **EEA 2 — Load management procedures in effect. Circumstances:**

   - The Balancing Authority is no longer able to provide its expected energy requirements and is an energy deficient Balancing Authority.
   - An energy deficient Balancing Authority has implemented its Operating Plan(s) to mitigate Emergencies.

- An energy deficient Balancing Authority is still able to maintain minimum Contingency Reserve requirements.

During EEA 2, Reliability Coordinators and energy deficient Balancing Authorities have the following responsibilities:

2.1 Notifying other Balancing Authorities and market participants. The energy deficient Balancing Authority shall communicate its needs to other Balancing Authorities and market participants. Upon request from the energy deficient Balancing Authority, the respective Reliability Coordinator shall post the declaration of the alert level, along with the name of the energy deficient Balancing Authority on the RCIS website.

2.2 Declaration period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators**.**

2.3 Sharing information on resource availability. Other Reliability Coordinators of Balancing Authorities with available resources shall coordinate, as appropriate, with the Reliability Coordinator that has an energy deficient Balancing Authority.

2.4 Evaluating and mitigating Transmission limitations. The Reliability Coordinator shall review Transmission outages and work with the Transmission Operator(s) to see if it's possible to return to service any Transmission Elements that may relieve the loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).

2.5 Requesting Balancing Authority actions. Before requesting an EEA 3, the energy deficient Balancing Authority must make use of all available resources; this includes, but is not limited to:

2.5.1 All available generation units are on line. All generation capable of being on line in the time frame of the Emergency is on line.

2.5.2 Demand-Side Management. Activate Demand-Side Management within provisions of any applicable agreements.

3. EEA 3 —Firm Load interruption is imminent or in progress. Circumstances:

- The energy deficient Balancing Authority is unable to meet minimum Contingency Reserve requirements.

During EEA 3, Reliability Coordinators and Balancing Authorities have the following responsibilities:

3.1 Continue actions from EEA 2. The Reliability Coordinators and the energy deficient Balancing Authority shall continue to take all actions initiated during EEA 2.

3.2 Declaration Period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities, and Transmission Operators.

3.3 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator shall evaluate the risks of revising SOLs and IROLs for the possibility of delivery of energy to the energy deficient Balancing Authority. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Transmission Operator whose Transmission Owner (TO) equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists, or as allowed by the Transmission Owner whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.3.1 Energy deficient Balancing Authority obligations. The energy deficient Balancing Authority, upon notification from its Reliability Coordinator of the situation, ~~it~~ will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding.

3.4 Returning to pre-Emergency conditions. Whenever energy is made available to an energy deficient Balancing Authority such that the Systems can be returned to its pre- Emergency SOLs or IROLs condition, the energy deficient Balancing Authority shall request the Reliability Coordinator to downgrade the alert level.

3.4.1 Notification of other parties. Upon notification from the energy deficient Balancing Authority that an alert has been downgraded, the Reliability Coordinator shall notify the neighboring Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Operators that its Systems can be returned to its normal limits.

Alert 0 - Termination. When the energy deficient Balancing Authority is able to meet its Load and Operating Reserve requirements, it shall request its Reliability Coordinator to terminate the EEA.

3.4.2 Notification. The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the neighboring Balancing Authorities and Transmission Operators.

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 for a formal 8-day ballot period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	11/17/2021
SAR posted for comment	11/22/21 – 12/21/21
30-day formal or informal comment period with ballot	5/19/22 – 6/21/22
30-day formal or informal comment period with additional ballot	8/3/22- 9/1/22

Anticipated Actions	Date
8-day final ballot	9/23/22 – 9/30/22
Board adoption	October 2022

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):

Generator Cold Weather Critical Component - Any generating unit component or associated fixed fuel supply component, that is under the Generator Owner's control, and is susceptible to freezing issues, the occurrence of which would likely lead to a Generator Cold Weather Reliability Event.

Extreme Cold Weather Temperature – The temperature equal to the lowest 0.2 percentile of the hourly temperatures measured in December, January, and February from 1/1/2000 through the date the temperature is calculated.

Generator Cold Weather Reliability Event - One of the following events for which the apparent cause(s) is due to freezing of equipment within the Generator Owner's control and the dry bulb temperature at the time of the event was at or above the Extreme Cold Weather Temperature:

(1) a forced derate of more than 10% of the total capacity of the unit and exceeding 20 MWs for longer than four hours in duration;

(2) a start-up failure where the unit fails to synchronize within a specified start-up time; or

(3) a Forced Outage.

A. Introduction

1. **Title:** **Extreme Cold Weather Preparedness and Operations**

2. **Number:** EOP-012-1

3. **Purpose:** To address the effects of operating in extreme cold weather by ensuring each Generator Owner has developed and implemented plan(s) to mitigate the reliability impacts of extreme cold weather on its generating units.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Generator Owner

   4.1.2. Generator Operator

   4.2. Facilities:

   4.2.1 For purposes of this standard, the term "generating unit" subject to these requirements refers to the following Bulk Electric System (BES) resources:

   4.2.1.1 A Bulk Electric System generating unit that commits or is obligated to serve a Balancing Authority load pursuant to a tariff obligation, state requirement as defined by the relevant electric regulatory authority, or other contractual arrangement, rule, or regulation, for a continuous run of four hours or more at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius); or

   4.2.1.2 A Blackstart Resource

   4.2.2 Exemptions:

   4.2.2.1 Any Bulk Electric System generating unit included under Section 4.2.1 above that has a calculated Extreme Cold Weather Temperature exceeding 32 degrees Fahrenheit (zero degrees Celsius) under Requirement R3 Part 3.1 and as part of the required five year review in Requirement R4 Part 4.1 is exempt from further requirements in this standard.

   4.2.2.2 A Bulk Electric System generating unit that is not committed or obligated to operate at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius) for any continuous run of more than four hours, but is called upon to operate for more than four hours in order to assist in the mitigation of BES Emergencies, Capacity Emergencies, or Energy Emergencies during periods at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius).

5. **Effective Date:** See Implementation Plan for Project 2021-07.

B. Requirements and Measures

R1. For each generating unit(s) with a commercial operation date subsequent to [Effective Date of this requirement], the Generator Owner shall: [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning, Operations Planning*]

- Implement freeze protection measures that provide capability to operate for a period of not less than twelve (12) continuous hours at the Extreme Cold Weather Temperature for the unit(s), assuming a concurrent twenty (20) mph wind speed on any exposed Generator Cold Weather Critical Components; or
- Explain in a declaration any technical, commercial, or operational constraints, as defined by the Generator Owner, that preclude the ability to implement appropriate freeze protection measures to provide capability of operating for twelve (12) hours at the documented Extreme Cold Weather Temperature.

M1. Each Generator Owner will have dated evidence that demonstrates it has the capability to operate in accordance with Requirement R1. Acceptable evidence may include, but is not limited to, the following (electronic or hardcopy format): Documentation of cold weather preparedness plan, documentation of design features, any declaration that contains dated documentation to support constraints identified by the Generator Owner.

R2. For each generating unit(s) in commercial operation prior to [Effective Date of this requirement], the Generator Owner shall ensure its generating unit(s) add new or modify existing freeze protection measures as needed to provide the capability to operate for a period of not less than one (1) hour at the unit(s) Extreme Cold Weather Temperature. Generating unit(s) that are not capable of operating for one (1) hour at its Extreme Cold Weather Temperature shall develop a Corrective Action Plan (CAP) for the identified issues, including identification of any needed modifications to the cold weather preparedness plan required under Requirement R3. [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning, Operations Planning*]

M2. Each Generator Owner will have dated evidence that demonstrates it has freeze protection measures for its unit(s) in accordance with R2, or it has developed a CAP for the identified issues. Acceptable evidence may include the following (electronic or hardcopy format): Identification of generating units minimum temperature per Part 3.5.2 which is equal to or less than the unit's Extreme Cold Weather Temperature, documentation of freeze protection measures, cold weather preparedness plan, and CAP(s).

R3. Each Generator Owner shall implement and maintain one or more cold weather preparedness plan(s) for its generating units. The cold weather preparedness plan(s) shall include the following, at a minimum: *[Violation Risk Factor: High] [Time Horizon: Operations Planning and Real-time Operations]*

3.1 The Extreme Cold Weather Temperature for their unit(s) including the calculation date and source of temperature data;

3.2 Documentation identifying the Generator Cold Weather Critical Components;

3.3 Documentation of freeze protection measures implemented on Generator Cold Weather Critical Components which may include measures used to reduce the cooling effects of wind determined necessary by the Generator Owner to protect against heat loss, and where applicable, the effects of freezing precipitation (e.g., sleet, snow, ice, and freezing rain);

3.4 Annual inspection and maintenance of generating unit(s) freeze protection measures; and

3.5 Generating unit(s) cold weather data, to include:

3.5.1 Generating unit(s) operating limitations in cold weather to include:

3.5.1.1 Capability and availability;

3.5.1.2 Fuel supply and inventory concerns;

3.5.1.3 Fuel switching capabilities; and

3.5.1.4 Environmental constraints.

3.5.2 Generating unit(s) minimum:

- Design temperature;
- Historical operating temperature; or
- Current cold weather performance temperature determined by an engineering analysis.

M3. Each Generator Owner will have evidence documenting that its cold weather preparedness plan(s) was implemented and maintained in accordance with Requirement R3.

R4. Once every five calendar years, each Generator Owner shall for each generating unit: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning, Real-Time Operations]*

4.1 Calculate the Extreme Cold Weather Temperature, and update the cold weather preparedness plan if this temperature is now lower than the previous lowest calculation;

4.2 Review its documented generating unit(s) minimum temperature contained within its cold weather preparedness plan(s), pursuant to Part 3.5.2; and

4.3 Review whether its generating units have the freeze protection measures required to operate at the Extreme Cold Weather Temperature pursuant to R1 or R2 as applicable, and if not develop a CAP for the identified issues, including identification of any needed modifications to the cold weather preparedness plan required under Requirement R3.

M4. Each Generator Owner will have dated, documented evidence that it reviewed temperature data and updated its cold weather preparedness plan(s) in accordance with Requirement R4.

R5. Each Generator Owner in conjunction with its Generator Operator shall identify the entity responsible for providing the generating unit-specific training, and that identified entity shall provide annual training to its maintenance or operations personnel responsible for implementing the cold weather preparedness plan(s) developed pursuant to Requirement R3. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]*

M5. Each Generator Operator or Generator Owner will have documented evidence that the applicable personnel completed annual training of the Generator Owner's cold weather preparedness plan(s). This evidence may include, but is not limited to, documents such as personnel training records, training materials, date of training, agendas or learning objectives, attendance at pre-work briefings, review of work order tasks, tailboards, attendance logs for classroom training, and completion records for computer-based training in fulfillment of Requirement R5.

R6. Each Generator Owner that owns a generating unit that experiences a Generator Cold Weather Reliability Event shall develop a CAP, within 150 days or by July 1, whichever is earlier, that contains at a minimum: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

6.1 A summary of the identified cause(s) for the Generator Cold Weather Reliability Event, where applicable, and any relevant associated data;

6.2 A review of applicability to similar equipment at other generating units owned by the Generator Owner;

6.3 An identification of any temporary operating limitations or impacts to the cold weather preparedness plan, that would apply until execution of the corrective action(s) identified in the CAP.

M6. Each Generator Owner will have documented evidence that it developed a CAP in accordance with Requirement R6. Acceptable evidence may include, but is not limited to, the following dated documentation (electronic or hardcopy format): CAP(s) and updated cold weather preparedness plan(s) where indicated as needed by the CAP.

R7. Each Generator Owner shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

7.1 Implement each CAP developed pursuant to Requirements R2, R4, or R6, or explain in a declaration why corrective actions are not being implemented due to any technical, commercial, or operational constraints as defined by the Generator Owner.

7.2 Update each CAP if actions or timetables change, until completed.

M7. Each Generator Owner shall have dated evidence that demonstrates it implemented each CAP, including updating actions or timetables, or has explained in a declaration why corrective actions are not being implemented in accordance with Requirement R7. Acceptable evidence may include, but is not limited to the following dated documentation (electronic or hardcopy format): records that document the implementation of each CAP and the completion of actions for each CAP including revision history of each CAP. Evidence may also include work management program records, work orders, and maintenance records. Any declaration shall contain dated documentation to support constraints identified by the Generator Owner.

C. Compliance

1. Compliance Monitoring Process

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

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

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

- The Generator Owner shall keep data or evidence to show compliance for three years for Requirement R1, R3, and R5 and Measure M1, M3, and M5.
- The Generator Owner shall keep data or evidence to show compliance for three years, or until any Corrective Action Plan under Requirement R2 is complete, whichever timeframe is greater, for Requirement R2 and Measure M2.
- The Generator Owner shall retain the current cold weather preparedness plan(s), as evidence of review or revision history, plus each version issued since the last audit and evidence of compliance since the last audit for Requirement R4 and Measure M4. The Generator Owner shall retain any Corrective Action Plans under Requirement R4 Part 4.3 for three years or until the Corrective Action Plan is complete, whichever timeframe is greater.

- The Generator Owner shall keep data or evidence to show compliance for three years, or until any Corrective Action Plan under Requirement R6 is complete, whichever timeframe is greater, for Requirement R6 and Measure M6.
- The Generator Owner shall keep data or evidence to show compliance for three years, or until any Corrective Action Plan is complete, whichever time frame is greater, for Requirement R7 and Measure M7.

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.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 for 5% or less of its units. OR The Generator Owner did not explain in a declaration any technical, commercial, or operational constraints that preclude the ability to implement appropriate freeze protection measures for 5% or less of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 for more than 5%, but less than or equal to 10% of its units. OR The Generator Owner did not explain in a declaration any technical, commercial, or operational constraints that preclude the ability to implement appropriate freeze protection measures for more than 5%, but less than or equal to 10% of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 for more than 10%, but less than or equal to 20% of its units. OR The Generator Owner did not explain in a declaration any technical, commercial, or operational constraints that preclude the ability to implement appropriate freeze protection measures for more than 10%, but less than or equal to 20% of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 for more than 20% of its units. OR The Generator Owner did not explain in a declaration any technical, commercial, or operational constraints that preclude the ability to implement appropriate freeze protection measures for more than 20% of its units.
R2.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R2 for 5% or less of its units. OR The Generator Owner did not develop a CAP as required by	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R2 for more than 5%, but less than or equal to 10% of its units. OR The Generator Owner did not develop a CAP as required by Requirement R2 for more than	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R2 for more than 10%, but less than or equal to 20% of its units. OR The Generator Owner did not develop a CAP as required by Requirement R2 for more than	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R2 for more than 20% of its units. OR The Generator Owner did not develop a CAP as required by

	Requirement R2 for 5% or less of its units.	5%, but less than or equal to 10% of its units.	10%, but less than or equal to 20% of its units.	Requirement R2 for more than 20% of its units.
R3.	The Generator Owner implemented a cold weather preparedness plan(s), but failed to maintain it.	The Generator Owner's cold weather preparedness plan failed to include one of the applicable Parts within Requirement R3.	The Generator Owner had and maintained a cold weather preparedness plan(s), but failed to implement it. OR The Generator Owner's cold weather preparedness plan failed to include two of the applicable requirement parts within Requirement R3.	The Generator Owner does not have cold weather preparedness plan(s). OR The Generator Owner's cold weather preparedness plan failed to include three or more of the applicable requirement parts within Requirement R3.
R4.	The Generator Owner completed the actions required in Requirement R4, but was late by 30 calendar days or less.	The Generator Owner completed the actions required in Requirement R4, but was late by greater than 30 calendar days, but less than or equal to 60 calendar days.	The Generator Owner failed to complete one of the applicable requirement parts in Requirement R4 Parts 4.1 through 4.3; OR The Generator Owner completed the actions required in Requirement R4, but was late by greater than 60 calendar days.	The Generator Owner failed to complete two or more of the applicable requirement parts in Requirement R4 Parts 4.1 through 4.3.
R5.	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5 to the greater of:	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5 to the greater of:	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5 to the greater of:	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5 to the greater of:

	• one applicable personnel at a single generating unit; or • 5% or less of its total applicable personnel.	• two applicable personnel at a single generating unit; or • more than 5%, but less than or equal to 10% of its total applicable personnel.	• three applicable personnel at a single generating unit; or • more than 10%, but less than or equal to 15% of its total applicable personnel.	• four applicable personnel at a single generating unit; or • more than 15% of its total applicable personnel.
R6.	The Generator Owner developed a CAP, but not within 150 days or by July 1 as required in Requirement R6.	The Generator Owner's CAP failed to comply with one of the elements in Requirement R6, Parts 6.1 through 6.3.	The Generator Owner's CAP failed to comply with two of the elements in Requirement R6, Parts 6.1 through 6.3.	The Generator Owner's CAP failed to comply with three of the elements in Requirement R6, Parts 6.1 through 6.3. OR The Generator Owner did not develop a CAP as required by Requirement R6.
R7.	The Generator Owner implemented a CAP or explained in a declaration why corrective actions are not being implemented, but failed to update the CAP when actions or timetables changed, in accordance with Requirement R7.			The Generator Owner failed to implement a CAP or explain in a declaration why corrective actions are not being implemented in accordance with Requirement R7.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	TBD	Drafted by Project 2021-07	New

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~~ final draft of the proposed standard for a formal ~~30~~8-day ~~comment~~ ballot period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	11/17/2021
SAR posted for comment	11/22/21 – 12/21/21
30-day formal or informal comment period with ballot	5/19/22 – 6/21/22

~~Anticipated Actions~~	~~Date~~
30-day formal or informal comment period with additional ballot	8/3/22- 9/1/22

Anticipated Actions	Date
~~10~~8-day final ballot	~~September 2022~~9/23/22 – 9/30/22
Board adoption	October 2022

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):

Generator Cold Weather Critical Component - Any generating unit component or associated fixed fuel supply component, that is under the Generator Owner's control, and is susceptible to freezing issues, the occurrence of which would likely lead to a Generator Cold Weather Reliability Event.

Extreme Cold Weather Temperature – The temperature equal to the lowest 0.2 percentile of the hourly temperatures measured in December, January, and February from 1/1/2000 through the date the temperature is calculated.

Generator Cold Weather Reliability Event - One of the following events for which the apparent cause(s) is due to freezing of equipment within the Generator Owner's control and the dry bulb temperature at the time of the event was at or above the Extreme Cold Weather Temperature:

(1) a forced derate of more than 10% of the total capacity of the unit and exceeding 20 MWs for longer than four hours in duration;

(2) a start-up failure where the unit fails to synchronize within a specified start-up time; or

(3) a Forced Outage~~,~~.

~~for which the apparent cause(s) is due to freezing of equipment within the Generator Owner's control and the dry bulb temperature at the time of the event was at or above the Extreme Cold Weather Temperature.~~

A. Introduction

1. **Title:** **Extreme Cold Weather Preparedness and Operations**
2. **Number:** EOP-012-1
3. **Purpose:** To address the effects of operating in extreme cold weather by ensuring each Generator Owner has developed and implemented plan(s) to mitigate the reliability impacts of extreme cold weather on its generating units.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Generator Owner

   4.1.2. Generator Operator

   4.2. Facilities:

   4.2.1 ~~**4.2. Facilities:**~~ For purposes of this standard, the term "generating unit" subject to these requirements ~~means~~refers to the following Bulk Electric System (BES) resources:

   4.2.1.1 ~~**4.2.1**~~ A Bulk Electric System generating unit~~:~~

~~**4.2.1.1**~~ that ~~That~~ commits or is obligated to serve a Balancing Authority load pursuant to ~~an Open Access Transmission Tariff (OATT)~~a tariff obligation, state requirement as defined by the relevant electric regulatory authority, or other contractual arrangement~~;~~, rule, or regulation, for a continuous run of four hours or more at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius); or

   4.2.1.2 A Blackstart Resource

   4.2.2 Exemptions:

   4.2.2.1 Any Bulk Electric System generating unit included under Section 4.2.1 above that has a calculated Extreme Cold Weather Temperature exceeding 32 degrees Fahrenheit (zero degrees Celsius) under Requirement R3 Part 3.1 and as part of the required five year review in Requirement R4 Part 4.1 is exempt from further requirements in this standard.

   4.2.2.2 ~~**4.2.1.1.1** The term excludes a~~A Bulk Electric System generating unit that is ~~typically not available~~not committed or obligated to operate at or below ~~thirty-two (~~a temperature of 32~~)~~ degrees Fahrenheit (zero degrees Celsius) for any continuous run of more than four hours~~. The exclusion applies even when such BES generator has been called~~, but is called upon to operate for more than four hours in order to assist in the mitigation of BES Emergencies, Capacity Emergencies, or Energy Emergencies during periods at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius).

~~4.2.1.2 That is identified as a Blackstart Resource.~~

5. **Effective Date:** See Implementation Plan for Project 2021-07.

B. Requirements and Measures

R1. For each generating unit(s) with a commercial operation date subsequent to [Effective Date of this requirement], the Generator Owner shall: [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning, Operations Planning*]

- Implement freeze protection measures that provide capability to operate for a period of not less than twelve (12) continuous hours at the Extreme Cold Weather Temperature for the unit(s), assuming a concurrent twenty (20) mph wind speed on any exposed Generator Cold Weather Critical Components; or
- Explain in a declaration~~,~~ any technical, commercial, or operational constraints, as defined by the Generator Owner, that preclude the ability to implement appropriate freeze protection measures to provide capability of operating for twelve (12) hours at the documented Extreme Cold Weather Temperature.~~.~~

M1. Each Generator Owner will have dated evidence that demonstrates it has the capability to operate in accordance with Requirement R1. Acceptable evidence may include, but is not limited to, the following (electronic or hardcopy format): Documentation of cold weather preparedness plan, documentation of design features~~. Any~~, any declaration that contains dated documentation to support constraints identified by the Generator Owner.

R2. For each generating unit(s) in commercial operation prior to [Effective Date of this requirement], the Generator Owner shall ensure its generating unit(s) add new or modify existing freeze protection measures as needed to provide the capability to operate for a period of not less than one (1) hour at the unit(s) Extreme Cold Weather Temperature. Generating unit(s) that are not capable of operating for one (1) hour at its Extreme Cold Weather Temperature shall develop a Corrective Action Plan (CAP) for the identified issues, including identification of any needed modifications to the cold weather preparedness plan required under Requirement R3. [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning, Operations Planning*]

M2. Each Generator Owner will have dated evidence that demonstrates it has freeze protection measures for its unit(s) in accordance with R2, or it has developed a CAP for the identified issues. Acceptable evidence may include the following (electronic or hardcopy format): Identification of generating units minimum temperature per Part 3.5.2 which is equal to or less than the unit's Extreme Cold Weather Temperature, documentation of freeze protection measures, cold weather preparedness plan, and CAP(s).

R3. Each Generator Owner shall implement and maintain one or more cold weather preparedness plan(s) for its generating units. The cold weather preparedness plan(s) shall include the following, at a minimum: *[Violation Risk Factor: High] [Time Horizon: Operations Planning and Real-time Operations]*

3.1 The Extreme Cold Weather Temperature for their unit(s) including the calculation date and source of temperature data;

3.2 Documentation identifying the Generator Cold Weather Critical Components;

3.3 Documentation of freeze protection measures implemented on Generator Cold Weather Critical Components which may include measures used to reduce the cooling effects of wind determined necessary by the Generator Owner to protect against heat loss, and where applicable, the effects of freezing precipitation (e.g., sleet, snow, ice, and freezing rain);

3.4 Annual inspection and maintenance of generating unit(s) freeze protection measures; and

3.5 Generating unit(s) cold weather data, to include:

3.5.1 Generating unit(s) operating limitations in cold weather to include:

3.5.1.1 Capability and availability;

3.5.1.2 Fuel supply and inventory concerns;

3.5.1.3 Fuel switching capabilities; and

3.5.1.4 Environmental constraints.

3.5.2 Generating unit(s) minimum:

- Design temperature;
- Historical operating temperature; or
- Current cold weather performance temperature determined by an engineering analysis.

M3. Each Generator Owner will have evidence documenting that its cold weather preparedness plan(s) was implemented and maintained in accordance with Requirement R3.

R4. Once every five calendar years, each Generator Owner shall for each generating unit: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning, Real-Time Operations]*

4.1 Calculate the Extreme Cold Weather Temperature, and update the cold weather preparedness plan if this temperature is now lower than the previous lowest calculation;

4.2 Review its documented generating unit(s) minimum temperature contained within its cold weather preparedness plan(s), pursuant to Part 3.5.2; and

4.3 Review whether its generating units have the freeze protection measures required to operate at the Extreme Cold Weather Temperature pursuant to R1 or R2 as applicable, and if not develop a CAP for the identified issues, including identification of any needed modifications to the cold weather preparedness plan required under Requirement R3.

M4. Each Generator Owner will have dated, documented evidence ~~documenting~~ that it reviewed ~~documented~~ temperature data and updated its cold weather preparedness plan(s) in accordance with Requirement R4.

R5. Each Generator Owner in conjunction with its Generator Operator shall identify the entity responsible for providing the generating unit-specific training, and that identified entity shall provide annual training to its maintenance or operations personnel responsible for implementing the cold weather preparedness plan(s) developed pursuant to Requirement R3. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]*

M5. Each Generator Operator or Generator Owner will have documented evidence that the applicable personnel completed annual training of the Generator Owner's cold weather preparedness plan(s). This evidence may include, but is not limited to, documents such as personnel training records, training materials, date of training, agendas or learning objectives, attendance at pre-work briefings, review of work order tasks, tailboards, attendance logs for classroom training, and completion records for computer-based training in fulfillment of Requirement R5.

R6. Each Generator Owner that owns a generating unit that experiences a Generator Cold Weather Reliability Event shall develop a CAP, within 150 days or by July 1, whichever is earlier, that contains at a minimum: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

6.1 A summary of the identified cause(s) for the Generator Cold Weather Reliability Event, where applicable, and any relevant associated data;

6.2 A review of applicability to similar equipment at other generating units owned by the Generator Owner;

6.3 An identification of any temporary operating limitations or impacts to the cold weather preparedness plan, that would apply until execution of the corrective action(s) identified in the CAP.

M6. Each Generator Owner will have documented evidence that it developed a CAP in accordance with Requirement R6. Acceptable evidence ~~for these requirements~~ may include, but is not limited to, the following dated documentation (electronic or hardcopy format): CAP(s) and updated cold weather preparedness plan(s) where indicated as needed by the CAP. ~~Any declaration shall contain dated documentation to support constraints identified by the Generator Owner.~~

R7. Each Generator Owner shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

7.1 Implement each CAP developed pursuant to Requirements R2, R4, or R6, or explain in a declaration why corrective actions are not being implemented due to any technical, commercial, or operational constraints as defined by the Generator Owner.

7.2 Update each CAP if actions or timetables change, until completed.

M7. Each Generator Owner shall have dated evidence that demonstrates it implemented each CAP, including updating actions or timetables, or has explained in a declaration why corrective actions are not being implemented in accordance with Requirement R7. Acceptable evidence ~~for Requirement R7~~ may include, but is not limited to the following dated documentation (electronic or hardcopy format): records that document the implementation of each CAP and the completion of actions for each CAP including revision history of each CAP. Evidence may also include work management program records, work orders, and maintenance records. Any declaration shall contain dated documentation to support constraints identified by the Generator Owner.

C. Compliance

1. Compliance Monitoring Process

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

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

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

- The Generator Owner shall keep data or evidence to show compliance for three years for Requirement R1, R3, and R5 and Measure M1, M3, and M5.
- The Generator Owner shall keep data or evidence to show compliance for three years, or until any Corrective Action Plan under Requirement R2 is complete, whichever timeframe is greater, for Requirement R2 and Measure M2.
- The Generator Owner shall retain the current cold weather preparedness plan(s), as evidence of review or revision history, plus each version issued since the last audit and evidence of compliance since the last audit for

Requirement R4 and Measure M4. The Generator Owner shall retain any Corrective Action Plans under Requirement R4 Part 4.3 for three years or until the Corrective Action Plan is complete, whichever timeframe is greater.

- The Generator Owner shall keep data or evidence to show compliance for three years, or until any Corrective Action Plan under Requirement R6 is complete, whichever timeframe is greater, for Requirement R6 and Measure M6.
- The Generator Owner shall keep data or evidence to show compliance for three years, or until any Corrective Action Plan is complete, whichever time frame is greater, for Requirement R7 and Measure M7.

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.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 for 5% or less of its units. OR The Generator Owner did not explain in a declaration any technical, commercial, or operational constraints that preclude the ability to implement appropriate freeze protection measures for 5% or less of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 for more than 5%, but less than or equal to 10% of its units. OR The Generator Owner did not explain in a declaration any technical, commercial, or operational constraints that preclude the ability to implement appropriate freeze protection measures for more than 5%, but less than or equal to 10% of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 for more than 10%, but less than or equal to 20% of its units. OR The Generator Owner did not explain in a declaration any technical, commercial, or operational constraints that preclude the ability to implement appropriate freeze protection measures for more than 10%, but less than or equal to 20% of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 for more than 20% of its units. OR The Generator Owner did not explain in a declaration any technical, commercial, or operational constraints that preclude the ability to implement appropriate freeze protection measures for more than 20% of its units.
R2.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R2 for 5% or less of its units. OR The Generator Owner did not develop a CAP as required by	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R2 for more than 5%, but less than or equal to 10% of its units. OR The Generator Owner did not develop a CAP as required by Requirement R2 for more than	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R2 for more than 10%, but less than or equal to 20% of its units. OR The Generator Owner did not develop a CAP as required by Requirement R2 for more than	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R2 for more than 20% of its units. OR The Generator Owner did not develop a CAP as required by

	Requirement R2 for 5% or less of its units.	5%, but less than or equal to 10% of its units.	10%, but less than or equal to 20% of its units.	Requirement R2 for more than 20% of its units.
R3.	The Generator Owner implemented a cold weather preparedness plan(s), but failed to maintain it.	The Generator Owner's cold weather preparedness plan failed to include one of the applicable Parts within Requirement R3.	The Generator Owner had and maintained a cold weather preparedness plan(s), but failed to implement it. OR The Generator Owner's cold weather preparedness plan failed to include two of the applicable requirement parts within Requirement R3.	The Generator Owner does not have cold weather preparedness plan(s). OR The Generator Owner's cold weather preparedness plan failed to include three or more of the applicable requirement parts within Requirement R3.
R4.	The Generator Owner completed the actions required in Requirement R4, but was late by 30 calendar days or less.	The Generator Owner completed the actions required in Requirement R4, but was late by greater than 30 calendar days, but less than or equal to 60 calendar days.	The Generator Owner failed to complete one of the applicable requirement parts in Requirement R4 Parts 4.1 through 4.3; OR The Generator Owner completed the actions required in Requirement R4, but was late by greater than 60 calendar days.	The Generator Owner failed to complete two or more of the applicable requirement parts in Requirement R4 Parts 4.1 through 4.3.
R5.	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5 to the greater of:	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5 to the greater of:	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5 to the greater of:	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5 to the greater of:

	• one applicable personnel at a single generating unit; or • 5% or less of its total applicable personnel.	• two applicable personnel at a single generating unit; or • more than 5%, but less than or equal to 10% of its total applicable personnel.	• three applicable personnel at a single generating unit; or • more than 10%, but less than or equal to 15% of its total applicable personnel.	• four applicable personnel at a single generating unit; or • more than 15% of its total applicable personnel.
R6.	The Generator Owner developed a CAP, but not within 150 days or by July 1 as required in Requirement R6.	The Generator Owner's CAP failed to comply with one of the elements in Requirement R6, Parts 6.1 through 6.3.	The Generator Owner's CAP failed to comply with two of the elements in Requirement R6, Parts 6.1 through 6.3.	The Generator Owner's CAP failed to comply with three of the elements in Requirement R6, Parts 6.1 through 6.3. OR The Generator Owner did not develop a CAP as required by Requirement ~~R7~~R6.
R7.	The Generator Owner implemented a CAP or explained in a declaration why corrective actions are not being implemented, but failed to update the CAP when actions or timetables changed, in accordance with Requirement R7.			The Generator Owner failed to implement a CAP or explain in a declaration why corrective actions are not being implemented in accordance with Requirement R7.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	TBD	Drafted by Project 2021-07	New

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NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan

Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination
Reliability Standards EOP-011-3 and EOP-012-1

Applicable Standard(s)

- EOP-011-3 Emergency Operations
- EOP-012-1 Extreme Cold Weather Preparedness and Operations

Requested Retirement(s)

- EOP-011-2

Prerequisite Standard(s)

- None

Proposed Definition(s)

- Generator Cold Weather Critical Component
- Extreme Cold Weather Temperature
- Generator Cold Weather Reliability Event

Applicable Entities

- See subject Reliability Standards.

Background

The purpose of Project 2021-07 is to develop Reliability Standards to enhance the reliability of the Bulk Electric System (BES) through improved operations, preparedness, and coordination during extreme cold weather, as recommended by the Federal Energy Regulatory Commission (FERC), NERC, and Regional Entity Joint Staff Inquiry into the February 2021 extreme cold weather event (the "Report").[1]

The February 2021 Event

From February 8 through 20, 2021, extreme cold weather and precipitation caused large numbers of generating units to experience outages, derates, or failures to start, resulting in energy and transmission emergencies (referred to as "the Event"). The total Event firm load shed was the

[1] *See* FERC, NERC and Regional Entity Staff Report, *The February 2021 Cold Weather Outages in Texas and the South Central United States* (Nov. 2021) (referred to as "the Report").

largest controlled firm load shed event in U.S. history and was the third largest in quantity of outaged megawatts (MW) of load after the August 2003 northeast blackout and the August 1996 west coast blackout. The Event was most severe from February 15 through February 18, 2021, and it contributed to power outages affecting millions of electricity customers throughout the regions of ERCOT, SPP, and MISO South.

Extreme cold weather has repeatedly challenged the reliable operation of the bulk-power system (BPS). The Event was the fourth in the past 10 years which jeopardized BPS reliability. In February 2011, an arctic cold front impacted the southwest U.S. and resulted in numerous generation outages, natural gas facility outages, and emergency power grid conditions with firm customer load shed. In January 2014, a polar vortex affected Texas, central and eastern U.S, which triggered many generation outages, natural gas availability issues, and resulted in emergency conditions including load shed. In January 2018, an arctic high-pressure system and below average temperatures in the south-central U.S. resulted in many generation outages and voluntary load management measures.

Project 2021-07

Project 2021-07 is a two-phase project to address the 10 sub-recommendations in Key Recommendation 1 of the Report for new or enhanced NERC Reliability Standards. This implementation plan addresses Reliability Standards EOP-011-3 and EOP-012-1, which were developed to address the first phase of Reliability Standards recommendations.

Proposed Reliability Standard EOP-012-1 is a new extreme cold weather preparedness and operations Reliability Standard that addresses Recommendations 1d, 1e, and 1f of the Report. This standard includes requirements for implementing freeze protection measures for new and existing BES generating units to operate at location-specific temperature (Requirements R1 and R2), and for addressing the causes of outages, de-rates, and failures to synchronize caused by freezing (Requirement R6). For accountability, the proposed Reliability Standard includes a requirement to implement any required Corrective Action Plans under the standard and update such plans if actions or timetables change (Requirement R7). The proposed Reliability Standard also includes requirements for cold weather preparedness plans and training (Requirements R3 and R5), originally included in Reliability Standard EOP-011-2. Proposed Reliability Standard EOP-012-1 builds upon the existing cold weather preparedness plans and training requirements by requiring entities to periodically review their local cold weather conditions to ensure the continued effectiveness of cold weather operating plans and freeze protection measures (Requirement R4) and make any updates that are needed based on changes in the local weather, and by specifying that cold weather training under Requirement R5 must be completed on an annual basis.

Proposed Reliability Standard EOP-011-3 is a revised Reliability Standard that addresses Recommendation 1j of the Report, minimizing the overlap of manual Load shed and automatic Load shed programs such as underfrequency Load shed (UFLS) and undervoltage Load shed (UVLS). This revision also removes Requirements R7 and R8, as this language was moved to the new EOP-012-1, noted above.

General Considerations

This implementation plan reflects consideration that entities will need time to develop, implement, and maintain cold weather plans and freeze protection measures. This implementation plan covers the key recommendations from the Report identified for phase one only, Recommendations 1d, 1e, 1f, and 1j.

Effective Date and Phased-In Compliance Dates

The effective dates for the proposed Reliability Standards are provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of a proposed Reliability Standard (i.e., an entire Requirement or a portion thereof), the additional time for compliance with that section is specified below. The phased-in compliance date for those particular sections represents the date 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.

Please see Figure 1 EOP-012 Implementation Timeline below for an illustration of the implementation timeline in those jurisdictions where governmental approval is required.

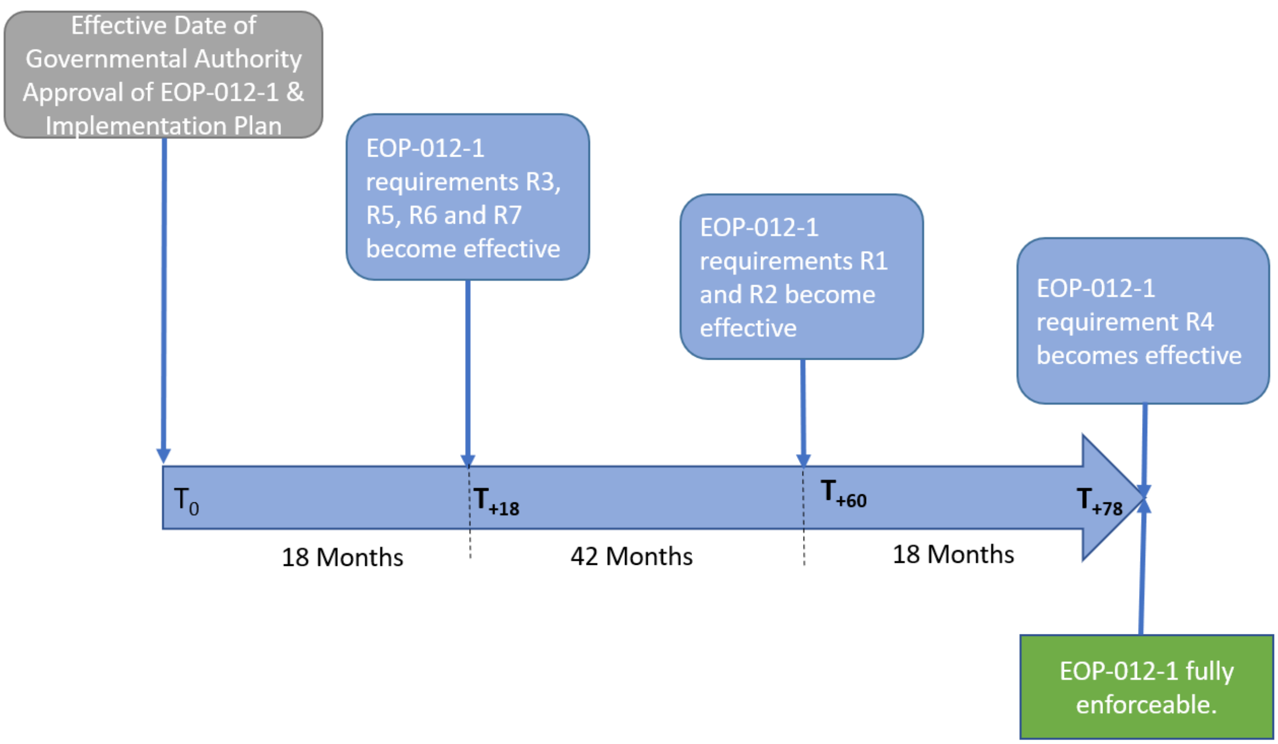

Figure 1 EOP-012 Implementation Timeline

Standard EOP-011-3

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 18 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 18 months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Standard EOP-012-1

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 18 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 18 months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Compliance Date for EOP-012-1 - Requirement R1 and R2

Entities shall not be required to comply with Requirement R1 and R2 until 42 months after the effective date of Reliability Standard EOP-012-1.

Compliance Date for EOP-012-1 - Requirement R4

Entities shall not be required to comply with Requirement R4 until 60 months after the effective date of Reliability Standard EOP-012-1.

Retirement Date

Standard EOP-011-2

Reliability Standard EOP-011-2 shall be retired immediately prior to the effective date of Reliability Standards EOP-011-3 and EOP-012-1 in the particular jurisdiction in which the revised standards are becoming effective.

Initial Performance of Periodic Requirements

Entities shall perform their first periodic review under Reliability Standard EOP-012-1 Requirement R4 by the Compliance Date (i.e. no more than 60 months after the effective date of EOP-012-1). Subsequent periodic reviews under Requirement R4 shall be performed once every five calendar years.

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Implementation Plan

Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination
Reliability Standards EOP-011-3 and EOP-012-1

Applicable Standard(s)

- EOP-011-3 Emergency ~~Preparedness and~~ Operations
- EOP-012-1 Extreme Cold Weather Preparedness and Operations

Requested Retirement(s)

- EOP-011-2

Prerequisite Standard(s)

- None

Proposed Definition(s)

- Generator Cold Weather Critical Component
- Extreme Cold Weather Temperature
- Generator Cold Weather ~~Reliablity~~Reliability Event

Applicable Entities

- See subject Reliability Standards.

Background

The purpose of Project 2021-07 is to develop Reliability Standards to enhance the reliability of the Bulk Electric System (BES) through improved operations, preparedness, and coordination during extreme cold weather, as recommended by the Federal Energy Regulatory Commission (FERC), NERC, and Regional Entity Joint Staff Inquiry into the February 2021 extreme cold weather event (the "Report").[1]

The February 2021 Event

From February 8 through 20, 2021, extreme cold weather and precipitation caused large numbers of generating units to experience outages, derates, or failures to start, resulting in energy and transmission emergencies (referred to as "the Event"). The total Event firm load shed was the

[1] *See* FERC, NERC and Regional Entity Staff Report, *The February 2021 Cold Weather Outages in Texas and the South Central United States* (Nov. 2021) (referred to as "the Report").

largest controlled firm load shed event in U.S. history and was the third largest in quantity of outaged megawatts (MW) of load after the August 2003 northeast blackout and the August 1996 west coast blackout. The Event was most severe from February 15 through February 18, 2021, and it contributed to power outages affecting millions of electricity customers throughout the regions of ERCOT, SPP, and MISO South.

Extreme cold weather has repeatedly challenged the reliable operation of the bulk-power system (BPS). The Event was the fourth in the past 10 years which jeopardized BPS reliability. In February 2011, an arctic cold front impacted the southwest U.S. and resulted in numerous generation outages, natural gas facility outages, and emergency power grid conditions with firm customer load shed. In January 2014, a polar vortex affected Texas, central and eastern U.S, which triggered many generation outages, natural gas availability issues, and resulted in emergency conditions including load shed. In January 2018, an arctic high-pressure system and below average temperatures in the south-central U.S. resulted in many generation outages and voluntary load management measures.

Project 2021-07

Project 2021-07 is a two-phase project to address the 10 sub-recommendations in Key Recommendation 1 of the Report for new or enhanced NERC Reliability Standards. This implementation plan addresses Reliability Standards EOP-011-3 and EOP-012-1, which were developed to address the first phase of Reliability Standards recommendations.

Proposed Reliability Standard EOP-012-1 is a new extreme cold weather preparedness and operations Reliability Standard that addresses Recommendations 1d, 1e, and 1f of the Report. This standard includes requirements for implementing freeze protection measures for new and existing BES generating units to operate at location-specific temperature (Requirements R1 and R2), and for addressing the causes of outages, de-rates, and failures to synchronize caused by freezing (Requirement R6). For accountability, the proposed Reliability Standard includes a requirement to implement any required Corrective Action Plans under the standard and update such plans if actions or timetables change (Requirement R7). The proposed Reliability Standard also includes requirements for cold weather preparedness plans and training (Requirements R3 and R5), originally included in Reliability Standard EOP-011-2. Proposed Reliability Standard EOP-012-1 builds upon the existing cold weather preparedness plans and training requirements by requiring entities to periodically review their local cold weather conditions to ensure the continued effectiveness of cold weather operating plans and freeze protection measures (Requirement R4) ~~by making~~and make any updates that are needed based on changes in the local weather, and by specifying that cold weather training under Requirement R5 must be completed on an annual basis.

Proposed Reliability Standard EOP-011-3 is a revised Reliability Standard that addresses Recommendation 1j of the Report, minimizing the overlap of manual Load shed and automatic Load shed programs such as underfrequency Load shed (UFLS) and undervoltage Load shed (UVLS). This revision also removes Requirements R7 and R8, as this language was moved to the new EOP-012-1, noted above.

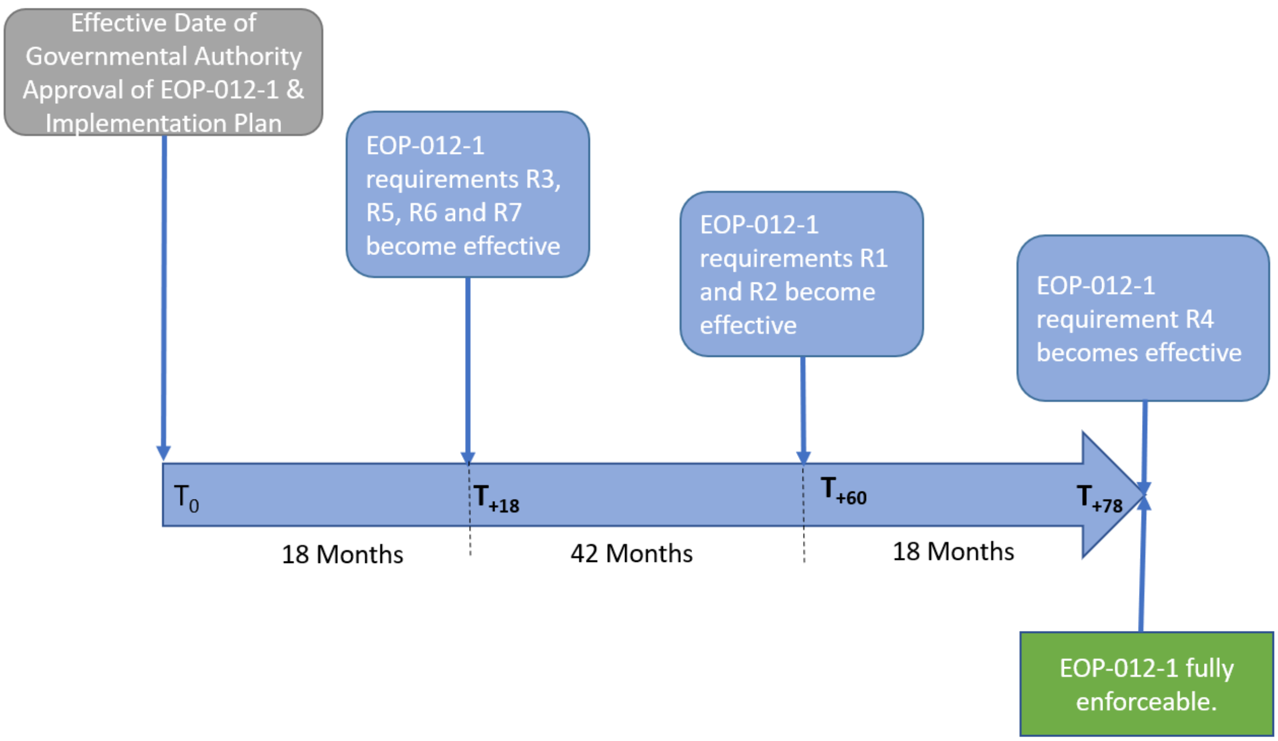
General Considerations

This implementation plan reflects consideration that entities will need time to develop, implement, and maintain cold weather plans and freeze protection measures. This implementation plan covers the key recommendations from the Report identified for phase one only, Recommendations 1d, 1e, 1f, and 1j.

Effective Date and Phased-In Compliance Dates

The effective dates for the proposed Reliability Standards are provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of a proposed Reliability Standard (i.e., an entire Requirement or a portion thereof), the additional time for compliance with that section is specified below. The phased-in compliance date for those particular sections represents the date 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.

Please see Figure 1 EOP-012 Implementation Timeline below for an illustration of the implementation timeline in those jurisdictions where governmental approval is required.



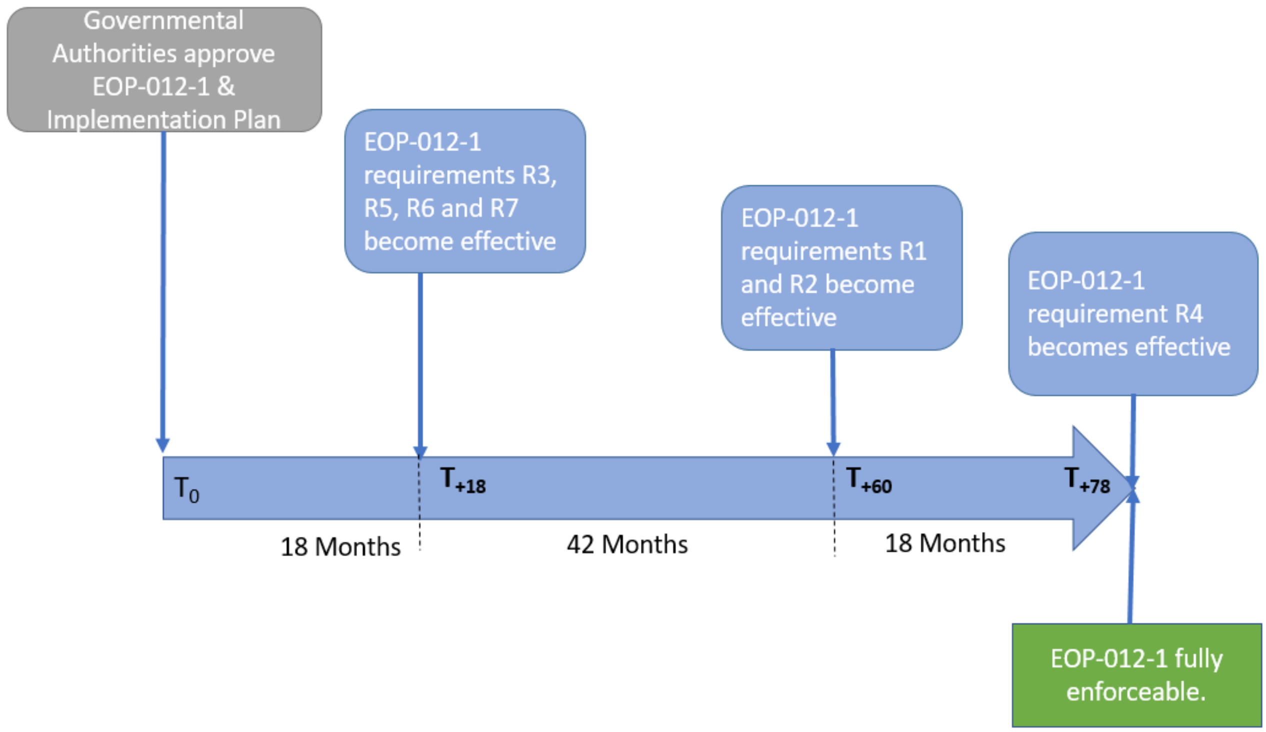


Figure 1 EOP-012 Implementation Timeline

Standard EOP-011-3

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 18 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 18 months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Standard EOP-012-1

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 18 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 18 months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Compliance Date for EOP-012-1 - Requirement R1 and R2

Entities shall not be required to comply with Requirement R1 and R2 until 42 months after the effective date of Reliability Standard EOP-012-1.

Compliance Date for EOP-012-1 - Requirement R4

Entities shall not be required to comply with Requirement R4 until 60 months after the effective date of Reliability Standard EOP-012-1.

Retirement Date

Standard EOP-011-2

Reliability Standard EOP-011-2 shall be retired immediately prior to the effective date of Reliability Standards EOP-011-3 and EOP-012-1 in the particular jurisdiction in which the revised standards are becoming effective.

Initial Performance of Periodic Requirements

Entities shall perform their first periodic review under Reliability Standard EOP-012-1 Requirement R4 by the Compliance Date (i.e. no more than 60 months after the effective date of EOP-012-1). Subsequent periodic reviews under Requirement R4 shall be performed once every five calendar years.

Mapping Document

Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination

Summary

This mapping document maps the recommendations from The February 2021 Cold Weather Outages in Texas and the South Central United States report (The Report) to the creation of new standard EOP-012 as well as the revised EOP-011-3.

Recommendation 1d

Generator Owners that experience outages, failures to start, or derates due to freezing are to review the generating unit's outage, failure to start, or derate and develop and implement a corrective action plan (CAP) for the identified equipment, and evaluate whether the CAP applies to similar equipment for its other generating units. Based on the evaluation, the Generator Owner will either revise its cold weather preparedness plan to apply the CAP to the similar equipment, or explain in a declaration (a) why no revisions to the cold weather preparedness plan are appropriate, and (b) that no further corrective actions will be taken. The Standard Drafting Team (SDT) should specify the specific timing for the CAP to be developed and implemented after the outage, derate or failure to start, but the CAP should be developed as quickly as possible, and be completed by no later than the beginning of the next winter season.

Standard: EOP-012-1		
Requirement in Approved Standard	**Transition to New Standard or Other Action**	**Description and Change Justification**
This requirement does not exist in an already approved standard. It is new to EOP-012-1.	**EOP-012-1 Requirement R6** **R6.** Each Generator Owner that owns a generating unit that experiences a Generator Cold Weather Reliability Event shall develop a CAP, within 150 days or by July 1, whichever is earlier, that contains at a minimum: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*	This requirement addresses recommendation 1d for Generator Owners to develop and implement a CAP following an outage, failure to start, or derate. CAPs will be required any time a generating unit experiences a Generator Cold Weather Reliability Event. The CAP requirement thus applies to any forced outage due to freezing, regardless of duration. Derates which are short-lived or of small capacity impact are excluded from the Generator Cold Weather Reliability Event definition, and therefore from the CAP requirement. R6 requires the GO to act within 150 days or July 1 to develop

	6.1 A summary of the identified cause(s) for the Generator Cold Weather Reliability Event, where applicable, and any relevant associated data; **6.2** A review of applicability to similar equipment at other generating units owned by the Generator Owner; **6.3** An identification of any temporary operating limitations or impacts to the cold weather preparedness plan, that would apply until execution of the corrective action(s) identified in the CAP. **New Glossary Definition, Generator Cold Weather Reliability Event** Generator Cold Weather Reliability Event - One of the following events for which the apparent cause(s) is due to freezing of equipment within the Generator Owner's control and the dry bulb temperature at the time of the event was at or above the Extreme Cold Weather Temperature.: (1) a forced derate of more than 10% of the total capacity of the unit and exceeding 20 MWs for longer than four hours in duration;	the CAP. This timeframe was chosen to allow Generator Owners to review multiple events holistically following a winter season, and create one CAP for equipment with common failure causes while meeting the recommendation charge to be "developed as quickly as possible".

	(2) a start-up failure where the unit fails to synchronize within a specified start-up time; or (3) a Forced Outage.	
This requirement does not exist in an already approved standard. It is new to EOP-012-1.	**R7.** Each Generator Owner shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]* **7.1** Implement each CAP developed pursuant to Requirements R2, R4, or R6, or explain in a declaration why corrective actions are not being implemented due to any technical, commercial, or operational constraints as defined by the Generator Owner. **7.2** Update each CAP if actions or timetables change, until completed.	The recommendation in 1d continues to be addressed through Requirement R7. Generator Owners shall implement any CAPs for equipment freezing events developed under Requirement R6 or explain in a declaration why corrective actions are not being implemented. The declaration in Requirement R7 applies to any CAP developed in R2 (existing generators freeze protection measures), R4 (5-year review) or R6 (CAP for Cold Weather Reliability Event).

Recommendation 1e

To revise EOP-011-2, R8, to require Generator Owners and Generator Operators are to conduct annual unit-specific cold weather preparedness plan training

Standard: EOP-012-1		
Requirement in Approved Standard	**Transition to New Standard or Other Action**	**Description and Change Justification**
EOP-011-2 Requirement R8 **R8.** Each Generator Owner in conjunction with its Generator Operator shall identify the entity responsible for providing the generating unit-specific training, and that identified entity shall provide the training to its maintenance or operations personnel responsible for implementing cold weather preparedness plan(s) developed pursuant to Requirement R7.	**EOP-012-1 Requirement R5** **R5.** Each Generator Owner in conjunction with its Generator Operator shall identify the entity responsible for providing the generating unit-specific training, and that identified entity shall provide annual training to its maintenance or operations personnel responsible for implementing the cold weather preparedness plan(s) developed pursuant to Requirement R3.	EOP-011-2 Requirement R8 was moved to new standard EOP-012-1 Requirement R5. The language remains the same with the addition of the word annual to meet the charge in recommendation 1e of The Report.

Recommendation 1f

To require Generator Owners to retrofit existing generating units, and when building new generating units, to design them to operate to a specified ambient temperature and weather conditions (e.g., wind, freezing precipitation). The specified ambient temperature and weather conditions should be based on available extreme temperature and weather data for the generating unit's location.

Standard: EOP-012-1		
Requirement in Approved Standard	**Transition to New Standard**	**Description and Change Justification**
This requirement does not exist in an already approved standard. It is new to EOP-012-1.	**EOP-012-1 Requirement R1** **R1.** For each generating unit(s) with a commercial operation date subsequent to [Effective Date of this requirement], the Generator Owner shall: [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning, Operations Planning*] • Implement freeze protection measures that provide capability to operate for a period of not less than twelve (12) continuous hours at the Extreme Cold Weather Temperature for the unit(s), assuming a concurrent twenty (20) mph wind speed on any exposed Generator Cold Weather Critical Components; or • Explain in a declaration, any technical, commercial, or operational constraints as defined by the Generator Owner that preclude the ability to implement appropriate freeze protection measures to provide capability of operating for twelve (12) hours at the documented Extreme Cold Weather Temperature.	This requirement addresses new build generation to have freeze protection measures to meet the criteria listed. This criteria includes operating for 12 hours at the Extreme Cold Weather Temperature which is based on the available temperature and weather data for the unit's location, and accounting for the cooling effects of wind, as suggested by the recommendation. If the unit cannot implement appropriate freeze protection measures it must be explained in a declaration. Following regulatory approval, the bracketed language, [Effective Date of this requirement], will be replaced with the date by which entities shall be compliant with this requirement. It is the intent of the Project 2021-07 drafting team that this date will remain static in any future versions of the EOP-012 standard, to distinguish between requirements applicable to generation that exists at the time the first version of the standard becomes effective, and requirements applicable to generation that comes online after the first standard becomes effective, unless a future drafting team determines an alternative approach is appropriate.

This requirement does not exist in an already approved standard. It is new to EOP-012-1.	**R2.** For each generating unit(s) in commercial operation prior to [Effective Date of this requirement], the Generator Owner shall ensure its generating unit(s) add new or modify existing freeze protection measures as needed to provide the capability to operate for a period of not less than one (1) hour at the unit(s) Extreme Cold Weather Temperature. Generating unit(s) that are not capable of operating for one (1) hour at its Extreme Cold Weather Temperature shall develop a Corrective Action Plan (CAP) for the identified issues, including identification of any needed modifications to the cold weather preparedness plan required under Requirement R3. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]*	This requirement addresses existing generation to have freeze protection measures to provide for the capability to operate for one hour at the calculated Extreme Cold Weather temperature. If the unit cannot meet these criteria, then a CAP is required to address the identified issues. FERC staff from the Joint Inquiry Report team clarified to the SDT that the reliability goal of the recommendation for existing generating units is to have the necessary freeze protection measures to be able to operate at extreme cold temperatures and weather for the generating unit's location. For example, those measures may consist of existing or new, permanent and/or temporary measures to maintain operation during extreme cold temperatures. Following regulatory approval, the bracketed language, [Effective Date of this requirement], will be replaced with the date by which entities shall be compliant with this requirement. It is the intent of the Project 2021-07 drafting team that this date will remain static in any future versions of the EOP-012 standard, to distinguish between requirements applicable to generation that exists at the time the first version of the standard becomes effective, and requirements applicable to generation that comes online after the first standard becomes effective, unless a future drafting team determines an alternative approach is appropriate.

Recommendation 1j

In minimizing the overlap of manual and automatic load shed, the load shed procedures of Transmission Operators, Transmission Owners (TOs) and Distribution Providers (DPs) should separate the circuits that will be used for manual load shed from circuits used for underfrequency load shed (UFLS)/undervoltage load shed (UVLS) or serving critical load. UFLS/UVLS circuits should only be use d for manual load shed as a last resort and should start with the final stage (lowest frequency).

Standard: EOP-011-3		
Requirement in Approved Standard	**Transition to New Standard or Other Action**	**Description and Change Justification**
EOP-011-2 Requirement R1 Part 1.2.5 **1.2.5** Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and	**EOP-011-3 Requirement R1 Part 1.2.5** **1.2.5.** Operator-controlled manual Load shedding during an Emergency that accounts for each of the following: **1.2.5.1.** Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency; **1.2.5.2.** Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that serve designated critical loads; **1.2.5.3.** Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for underfrequency load shed (UFLS) or undervoltage load shed (UVLS); and **1.2.5.4.** Provisions for limiting the	The second posting does not include any changes to EOP-011-3 since the initial posting. EOP-011-3 adds additional provisions and clarifies what the TOP must include in their Operating Plan to mitigate operating Emergencies. Specific clarifications are to minimize the overlap of manual Load shed and circuits that serve designated critical loads; minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for underfrequency load shed (UFLS) or undervoltage load shed (UVLS); and provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed. The SDT elected to keep the phase “minimize the overlap” instead of moving to language that specifically requires the separation of circuits in recognition of the fact that it is not always practical or warranted to completely separate circuits used for each of these purposes.

	utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions.	
EOP-011-2 Requirement R2 Part 2.2.8 **2.2.8.** Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and	**EOP-011-3 Requirement R2 Part 2.2.8** **2.2.8.** Provisions for Transmission Operators to implement operator-controlled manual Load shed in accordance with Requirement R1 Part 1.2.5; and	The second posting does not include any changes to EOP-011-3 since the initial posting. This part of R2 has been modified to refer back to Requirement R1, Part 1.2.5 in an effort to clarify that the Transmission Operator is responsible for addressing operator-controlled manual load shed requirements in their Operating Plan. Balancing Authorities are expected to specify manual load shed requirements for Transmission Operators within their areas in accordance with Part 1.2.5, but do not have the control or visibility to design and implement manual load shed programs and UFLS/UVLS programs that meet the requirements of Part 1.2.5.

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Mapping Document

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Recommendation 1d

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Standard: EOP-012-1		
Requirement in Approved Standard	**Transition to New Standard or Other Action**	**Description and Change Justification**
This requirement does not exist in an already approved standard. It is new to EOP-012-1.	**EOP-012-1 Requirement R6** **R6.** Each Generator Owner that owns a generating unit that experiences a Generator Cold Weather Reliability Event shall develop a CAP, within 150 days or by July 1, whichever is earlier, that contains at a minimum: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*	This requirement addresses recommendation 1d for Generator Owners to develop and implement a CAP following an outage, failure to start, or derate. CAPs will be required any time a generating unit experiences a Generator Cold Weather Reliability Event. The CAP requirement thus applies to any forced outage due to freezing, regardless of duration. Derates which are short-lived or of small capacity impact are excluded from the Generator Cold Weather Reliability Event definition, and therefore from the CAP requirement. R6 requires the GO to act within 150 days or July 1 to develop

	6.1 A summary of the identified cause(s) for the Generator Cold Weather Reliability Event, where applicable, and any relevant associated data; **6.2** A review of applicability to similar equipment at other generating units owned by the Generator Owner; **6.3** An identification of any temporary operating limitations or impacts to the cold weather preparedness plan, that would apply until execution of the corrective action(s) identified in the CAP. **New Glossary Definition, Generator Cold Weather Reliability Event** Generator Cold Weather Reliability Event - One of the following events for which the apparent cause(s) is due to freezing of equipment within the Generator Owner's control and the dry bulb temperature at the time of the event was at or above the Extreme Cold Weather Temperature.: (1) a forced derate of more than 10% of the total capacity of the unit and exceeding 20 MWs for longer than four hours in duration;	the CAP. This timeframe was chosen to allow Generator Owners to review multiple events holistically following a winter season, and create one CAP for equipment with common failure causes while meeting the recommendation charge to be "developed as quickly as possible".

	(2) a start-up failure where the unit fails to synchronize within a specified start-up time; or (3) a Forced Outage.~~, for which the apparent cause(s) is due to freezing of equipment within the Generator Owner's control and the dry bulb temperature at the time of the event was at or above the Extreme Cold Weather Temperature.~~	
This requirement does not exist in an already approved standard. It is new to EOP-012-1.	**R7.** Each Generator Owner shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]* **7.1** Implement each CAP developed pursuant to Requirements R2, R4, or R6, or explain in a declaration why corrective actions are not being implemented due to any technical, commercial, or operational constraints as defined by the Generator Owner. **7.2** Update each CAP if actions or timetables change, until completed.	The recommendation in 1d continues to be addressed through Requirement R7. Generator Owners shall implement any CAPs for equipment freezing events developed under Requirement R6 or explain in a declaration why corrective actions are not being implemented. The declaration in Requirement R7 applies to any CAP developed in R2 (existing generators freeze protection measures), R4 (5-year review) or R6 (CAP for Cold Weather Reliability Event).

Recommendation 1e

To revise EOP-011-2, R8, to require Generator Owners and Generator Operators are to conduct annual unit-specific cold weather preparedness plan training

Standard: EOP-012-1		
Requirement in Approved Standard	**Transition to New Standard or Other Action**	**Description and Change Justification**
EOP-011-2 Requirement R8 **R8.** Each Generator Owner in conjunction with its Generator Operator shall identify the entity responsible for providing the generating unit-specific training, and that identified entity shall provide the training to its maintenance or operations personnel responsible for implementing cold weather preparedness plan(s) developed pursuant to Requirement R7.	**EOP-012-1 Requirement R5** **R5.** Each Generator Owner in conjunction with its Generator Operator shall identify the entity responsible for providing the generating unit-specific training, and that identified entity shall provide annual training to its maintenance or operations personnel responsible for implementing the cold weather preparedness plan(s) developed pursuant to Requirement R3.	EOP-011-2 Requirement R8 was moved to new standard EOP-012-1 Requirement R5. The language remains the same with the addition of the word annual to meet the charge in recommendation 1e of The Report.

Recommendation 1f

To require Generator Owners to retrofit existing generating units, and when building new generating units, to design them to operate to a specified ambient temperature and weather conditions (e.g., wind, freezing precipitation). The specified ambient temperature and weather conditions should be based on available extreme temperature and weather data for the generating unit's location.

Standard: EOP-012-1		
Requirement in Approved Standard	**Transition to New Standard**	**Description and Change Justification**
This requirement does not exist in an already approved standard. It is new to EOP-012-1.	**EOP-012-1 Requirement R1** **R1.** For each generating unit(s) with a commercial operation date subsequent to [Effective Date of this requirement], the Generator Owner shall: [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning, Operations Planning*] • Implement freeze protection measures that provide capability to operate for a period of not less than twelve (12) continuous hours at the Extreme Cold Weather Temperature for the unit(s), assuming a concurrent twenty (20) mph wind speed on any exposed Generator Cold Weather Critical Components; or • Explain in a declaration, any technical, commercial, or operational constraints as defined by the Generator Owner that preclude the ability to implement appropriate freeze protection measures to provide capability of operating for twelve (12) hours at the documented Extreme Cold Weather Temperature.	This requirement addresses new build generation to have freeze protection measures to meet the criteria listed. This criteria includes operating for 12 hours at the Extreme Cold Weather Temperature which is based on the available temperature and weather data for the unit's location, and accounting for the cooling effects of wind, as suggested by the recommendation. If the unit cannot implement appropriate freeze protection measures it must be explained in a declaration. Following regulatory approval, the bracketed language, [Effective Date of this requirement], will be replaced with the date by which entities shall be compliant with this requirement. It is the intent of the Project 2021-07 drafting team that this date will remain static in any future versions of the EOP-012 standard, to distinguish between requirements applicable to generation that exists at the time the first version of the standard becomes effective, and requirements applicable to generation that comes online after the first standard becomes effective, unless a future drafting team determines an alternative approach is appropriate.

This requirement does not exist in an already approved standard. It is new to EOP-012-1.	**R2.** For each generating unit(s) in commercial operation prior to [Effective Date of this requirement], the Generator Owner shall ensure its generating unit(s) add new or modify existing freeze protection measures as needed to provide the capability to operate for a period of not less than one (1) hour at the unit(s) Extreme Cold Weather Temperature. Generating unit(s) that are not capable of operating for one (1) hour at its Extreme Cold Weather Temperature shall develop a Corrective Action Plan (CAP) for the identified issues, including identification of any needed modifications to the cold weather preparedness plan required under Requirement R3. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]*	This requirement addresses existing generation to have freeze protection measures to provide for the capability to operate for one hour at the calculated Extreme Cold Weather temperature. If the unit cannot meet these criteria, then a CAP is required to address the identified issues. FERC staff from the Joint Inquiry Report team clarified to the SDT that the reliability goal of the recommendation for existing generating units is to have the necessary freeze protection measures to be able to operate at extreme cold temperatures and weather for the generating unit's location. For example, those measures may consist of existing or new, permanent and/or temporary measures to maintain operation during extreme cold temperatures. Following regulatory approval, the bracketed language, [Effective Date of this requirement], will be replaced with the date by which entities shall be compliant with this requirement. It is the intent of the Project 2021-07 drafting team that this date will remain static in any future versions of the EOP-012 standard, to distinguish between requirements applicable to generation that exists at the time the first version of the standard becomes effective, and requirements applicable to generation that comes online after the first standard becomes effective, unless a future drafting team determines an alternative approach is appropriate.

Recommendation 1j

In minimizing the overlap of manual and automatic load shed, the load shed procedures of Transmission Operators, Transmission Owners (TOs) and Distribution Providers (DPs) should separate the circuits that will be used for manual load shed from circuits used for underfrequency load shed (UFLS)/undervoltage load shed (UVLS) or serving critical load. UFLS/UVLS circuits should only be use d for manual load shed as a last resort and should start with the final stage (lowest frequency).

Standard: EOP-011-3		
Requirement in Approved Standard	**Transition to New Standard or Other Action**	**Description and Change Justification**
EOP-011-2 Requirement R1 Part 1.2.5 **1.2.5** Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and	**EOP-011-3 Requirement R1 Part 1.2.5** **1.2.5.** Operator-controlled manual Load shedding during an Emergency that accounts for each of the following: **1.2.5.1.** Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency; **1.2.5.2.** Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that serve designated critical loads; **1.2.5.3.** Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for underfrequency load shed (UFLS) or undervoltage load shed (UVLS); and **1.2.5.4.** Provisions for limiting the	The second posting does not include any changes to EOP-011-3 since the initial posting. EOP-011-3 adds additional provisions and clarifies what the TOP must include in their Operating Plan to mitigate operating Emergencies. Specific clarifications are to minimize the overlap of manual Load shed and circuits that serve designated critical loads; minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for underfrequency load shed (UFLS) or undervoltage load shed (UVLS); and provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed. The SDT elected to keep the phase “minimize the overlap” instead of moving to language that specifically requires the separation of circuits in recognition of the fact that it is not always practical or warranted to completely separate circuits used for each of these purposes.

	utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions.	
EOP-011-2 Requirement R2 Part 2.2.8 **2.2.8.** Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and	**EOP-011-3 Requirement R2 Part 2.2.8** **2.2.8.** Provisions for Transmission Operators to implement operator-controlled manual Load shed in accordance with Requirement R1 Part 1.2.5; and	The second posting does not include any changes to EOP-011-3 since the initial posting. This part of R2 has been modified to refer back to Requirement R1, Part 1.2.5 in an effort to clarify that the Transmission Operator is responsible for addressing operator-controlled manual load shed requirements in their Operating Plan. Balancing Authorities are expected to specify manual load shed requirements for Transmission Operators within their areas in accordance with Part 1.2.5, but do not have the control or visibility to design and implement manual load shed programs and UFLS/UVLS programs that meet the requirements of Part 1.2.5.

Violation Risk Factor and Violation Severity Level Justifications

Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination

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 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination. 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.

EOP-011-3

VRF Justification for EOP-011-3, Requirement R1

The VRF did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VSL Justification for EOP-011-3, Requirement R1

The VSL did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VRF Justification for EOP-011-3, Requirement R2

The VRF did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VSL Justification for EOP-011-3, Requirement R2

The VSL did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VRF Justification for EOP-011-3, Requirement R3

The VRF did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VSL Justification for EOP-011-3, Requirement R3

The VSL did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VRF Justification for EOP-011-3, Requirement R4

The VRF did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VSL Justification for EOP-011-3, Requirement R4

The VSL did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VRF Justification for EOP-011-3, Requirement R5

The VRF did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VSL Justification for EOP-011-3, Requirement R5

The VSL did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VRF Justification for EOP-011-3, Requirement R6
The VRF did not change from the previously FERC approved EOP-011-2 Reliability Standard.

VSL Justification for EOP-011-3, Requirement R6
The VSL did not change from the previously FERC approved EOP-011-2 Reliability Standard.

EOP-012-1

VRF Justifications for EOP-012-1, Requirement R1	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that not designing or implementing freeze protection measures for a unit to operate during the local cold weather that can be expected could directly affect the electrical state or the capability of the bulk electric system. In addition, a violation of this 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. Therefore, it is in line with the definition of a Medium VRF.
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	This VRF is in line with the definition of a medium VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
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 EOP-012-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 for 5% or less of its units. OR The Generator Owner did not explain in a declaration any technical, commercial, or operational constraints that preclude the ability to implement appropriate freeze protection measures for 5% or less of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 for more than 5%, but less than or equal to 10% of its units. OR The Generator Owner did not explain in a declaration any technical, commercial, or operational constraints that preclude the ability to implement appropriate freeze protection measures for more than 5%, but less than or equal to 10% of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 for more than 10%, but less than or equal to 20% of its units. OR The Generator Owner did not explain in a declaration any technical, commercial, or operational constraints that preclude the ability to implement appropriate freeze protection measures for more than 10%, but less than or equal to 20% of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 for more than 20% of its units. OR The Generator Owner did not explain in a declaration any technical, commercial, or operational constraints that preclude the ability to implement appropriate freeze protection measures for more than 20% of its units.

VSL Justifications for EOP-012-1, 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 VSLs 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 VSLs 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 EOP-012-1, Requirement R2	
Proposed VRF	**Low**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that not implementing freeze protection measures for a unit to operate during the local cold weather that can be expected could directly affect the electrical state or the capability of the bulk electric system. In addition, a violation of this 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. Therefore, it is in line with the definition of a Medium VRF.
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	This VRF is in line with the definition of a medium VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
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 EOP-012-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R2 for 5% or less of its units. OR The Generator Owner did not develop a CAP as required by Requirement R2 for 5% or less of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R2 for more than 5%, but less than or equal to 10% of its units. OR The Generator Owner did not develop a CAP as required by Requirement R2 for more than 5%, but less than or equal to 10% of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R2 for more than 10%, but less than or equal to 20% of its units. OR The Generator Owner did not develop a CAP as required by Requirement R2 for more than 10%, but less than or equal to 20% of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R2 for more than 20% of its units. OR The Generator Owner did not develop a CAP as required by Requirement R2 for more than 20% of its units.

VSL Justifications for EOP-012-1, 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 VSLs 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	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.

VSL Justifications for EOP-012-1, Requirement R2	
Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs 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 Justification for EOP-012-1, Requirement R3

The VRF did not change from the previously FERC approved EOP-011-2 Requirement R7 Reliability Standard.

VSL Justification for EOP-012-1, Requirement R3

The VSL did not change from the previously FERC approved EOP-011-2 Requirement R7 Reliability Standard.

VRF Justifications for EOP-012-1, Requirement R4	
Proposed VRF	**Low**
NERC VRF Discussion	A VRF of Low is appropriate due to the fact that this 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
FERC VRF G1 Discussion	This VRF is in line with the identified areas from the FERC list of critical areas in the Final Blackout Report.

VRF Justifications for EOP-012-1, Requirement R4	
Proposed VRF	**Low**
Guideline 1- Consistency with 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	This VRF is in line with the definition of a low VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
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 EOP-012-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner completed the actions required in Requirement R4, but was late by 30 calendar days or less.	The Generator Owner completed the actions required in Requirement R4, but was late by greater than 30 calendar days, but less than or equal to 60 calendar days.	The Generator Owner failed to complete one of the applicable requirement parts in Requirement R4 Parts 4.1 through 4.3; OR	The Generator Owner failed to complete two or more of the applicable requirement parts in Requirement R4 Parts 4.1 through 4.3.

		The Generator Owner completed the actions required in Requirement R4, but was late by greater than 60 calendar days.	

VSL Justifications for EOP-012-1, 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 VSLs 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 VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment	Each VSL is based on a single violation and not cumulative violations.

VSL Justifications for EOP-012-1, Requirement R4	
Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	

VRF Justification for EOP-012-1, Requirement R5
The VRF did not change from the previously FERC approved EOP-011-2 Requirement R8 Reliability Standard.

VSL Justification for EOP-012-1, Requirement R5
The VSL did not substantively change from the previously FERC approved EOP-011-2 Requirement R8 Reliability Standard. The language was only updated to reflect the annual nature of the revised requirement language.

VRF Justifications for EOP-012-1, Requirement R6	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate. If violated, this requirement to take corrective actions if a generating unit experiences a derate, failure to start or forced outage due to freezing event 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.
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.

VRF Justifications for EOP-012-1, Requirement R6	
Proposed VRF	**High**
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is in line with the definition of a high VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
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 EOP-012-1, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner developed a CAP, but not within 150 days or by July 1 as required in Requirement R6.	The Generator Owner's CAP failed to comply with one of the elements in Requirement R6, Parts 6.1 through 6.3.	The Generator Owner's CAP failed to comply with two of the elements in Requirement R6, Parts 6.1 through 6.3.	The Generator Owner's CAP failed to comply with three of the elements in Requirement R6, Parts 6.1 through 6.3. OR The Generator Owner did not develop a CAP as required by Requirement R6.

VSL Justifications for EOP-012-1, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.

VSL Justifications for EOP-012-1, Requirement R6	
Current 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 VSLs 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 EOP-012-1, Requirement R7	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of medium is appropriate due to the fact that this requirement to implement a CAP develop pursuant to Requirement R2, R4 and R6, if violated, could, directly affect the electrical state or the capability of the bulk electric

VRF Justifications for EOP-012-1, Requirement R7	
Proposed VRF	**Medium**
	system. In addition, a violation of this 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. Therefore, it is in line with the definition of a Medium VRF.
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	This VRF is in line with the definition of a medium VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
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 EOP-012-1, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
The Generator Owner implemented a CAP or explained in a declaration why corrective actions are not being implemented, but failed to update the CAP when actions or timetables changed, in accordance with Requirement R7.	N/A	N/A	The Generator Owner failed to implement a CAP or explain in a declaration why corrective actions are not being implemented in accordance with Requirement R7.

VSL Justifications for EOP-012-1, 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 VSLs 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 do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for EOP-012-1, Requirement R7	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs 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

Extreme Cold Weather Preparedness

Technical Rationale and Justification for EOP-011-3

September 2022

RELIABILITY | RESILIENCE | SECURITY




3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

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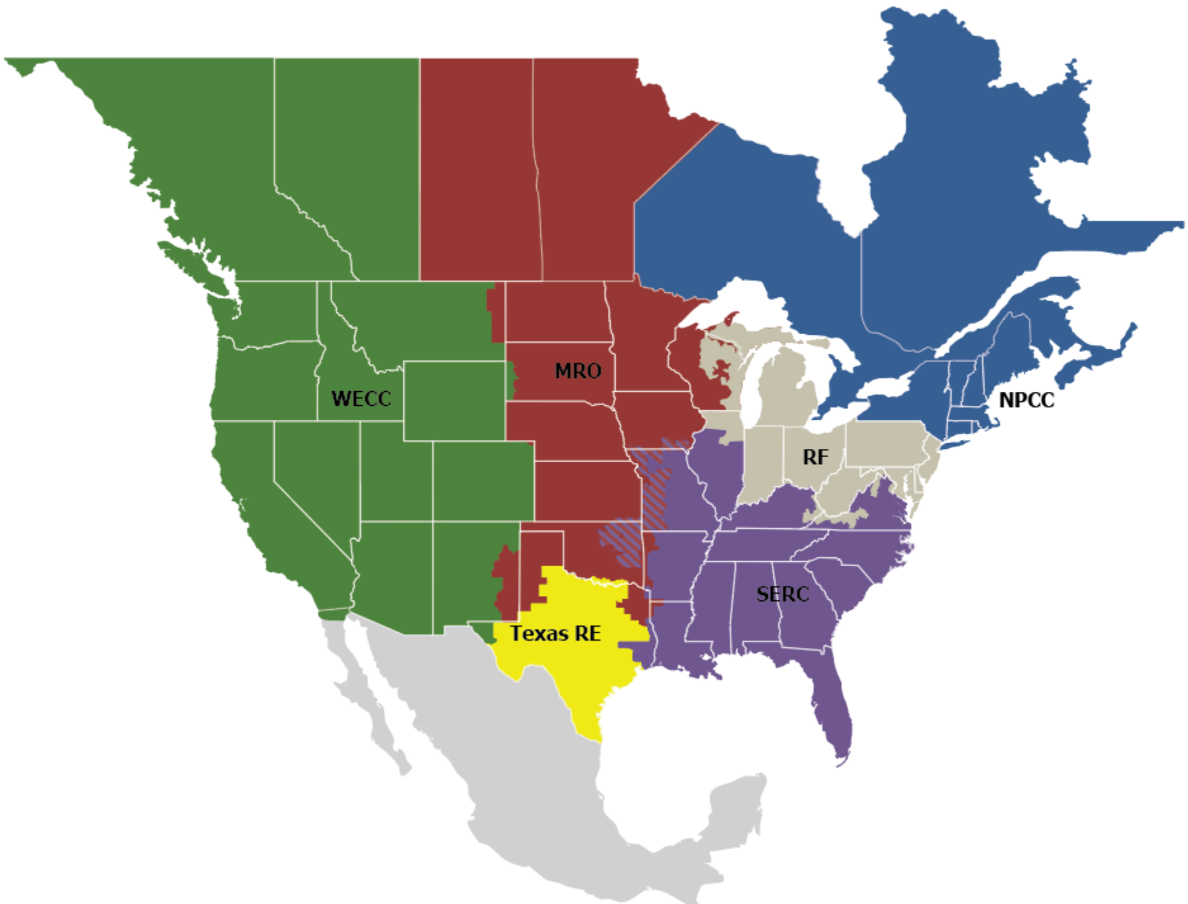
Preface

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 the North American Electric Reliability Corporation (NERC) and the six Regional Entities, is a highly reliable 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 Entity boundaries as shown in the map and 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 Standards EOP-011-3 and EOP-012-1. It provides stakeholders and the ERO Enterprise with an understanding of the technology and technical requirements in the Reliability Standard. This Technical Rationale and Justifications for EOP-011-3 and EOP-NEW is not a Reliability Standard and should not be considered mandatory and enforceable.

Background

From February 8 through February 20, 2021, extreme cold weather and precipitation caused large numbers of generating units to experience outages, derates or failures to start, resulting in energy and transmission emergencies (referred to as "the Event"). The total Event firm Load shed was the largest controlled firm Load shed event in U.S. history and was the third largest in quantity of outaged megawatts (MW) of Load after the August 2003 northeast blackout and the August 1996 west coast blackout. The Event was most severe from February 15 through February 18, 2021, and it contributed to power outages affecting millions of electricity customers throughout the regions of ERCOT, SPP and MISO South. Additionally, the February 2021 event is the fourth cold weather event in the past 10 years, which jeopardized bulk-power system reliability. A joint inquiry was conducted to discover reliability-related findings and recommendations from FERC, NERC, and Regional Entity staff. The FERC, NERC, and Regional Entity Staff Joint Staff Inquiry into the February 2021 Cold Weather Grid Operations ("Joint Inquiry Report") was published on November 16, 2021.

The scope of the proposed project is to address the ten recommendations for new or enhanced NERC Reliability Standards proposed by the Joint Inquiry Report. In November 2021, the NERC Board of Trustees (Board) approved a Board Resolution directing that new or revised Reliability Standards addressing these recommendations be completed in accordance with the timelines recommended by the joint inquiry team, as follows:

- New and revised Reliability Standards to be submitted for regulatory approval before Winter 2022/2023: development completed by September 30, 2022, for the Board's consideration in October 2022 to address Key Recommendations 1d, 1e, 1f, and 1j;
- New and revised Reliability Standards to be submitted for regulatory approval before Winter 2023/2024: development completed by September 30, 2023, for the Board's consideration in October 2023 to address Key Recommendations 1a, 1b, 1c, 1g, 1h, and 1i.

Requirement R1 and R2

R1. *Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

1.1. *Roles and responsibilities for activating the Operating Plan(s);*

1.2. *Processes to prepare for and mitigate Emergencies including:*

1.2.1. *Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency;*

1.2.2. *Cancellation or recall of Transmission and generation outages;*

1.2.3. *Transmission system reconfiguration;*

1.2.4. *Redispatch of generation request;*

1.2.5. *Operator-controlled manual Load shedding during an Emergency that accounts for each of the following:*

1.2.5.1. *Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;*

1.2.5.2. *Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that serve designated critical loads;*

1.2.5.3. *Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for underfrequency load shed (UFLS) or undervoltage load shed (UVLS); and*

1.2.5.4. *Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions.*

1.2.6. *Provisions to determine reliability impacts of:*

1.2.6.1. *cold weather conditions; and*

1.2.6.2. *extreme weather conditions.*

R2. *Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

2.1. *Roles and responsibilities for activating the Operating Plan(s);*

2.2. *Processes to prepare for and mitigate Emergencies including:*

2.2.1. *Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;*

2.2.2. *Requesting an Energy Emergency Alert, per Attachment 1;*

2.2.3. *Managing generating resources in its Balancing Authority Area to address:*

2.2.3.1. *capability and availability;*

2.2.3.2. *fuel supply and inventory concerns;*

2.2.3.3. *fuel switching capabilities; and*

2.2.3.4. *environmental constraints.*

2.2.4. *Public appeals for voluntary Load reductions;*

2.2.5. *Requests to government agencies to implement their programs to achieve necessary energy reductions;*

2.2.6. *Reduction of internal utility energy use;*

2.2.7. *Use of Interruptible Load, curtailable Load and demand response;*

2.2.8. *Provisions for Transmission Operators to implement operator-controlled manual Load shed in accordance with Requirement R1 Part 1.2.5; and*

2.2.9. *Provisions to determine reliability impacts of:*

2.2.9.1. *cold weather conditions; and*

2.2.9.2. *extreme weather conditions.*

<u>Key Recommendation 1j:</u> In minimizing the overlap of manual and automatic load shed, the load shed procedures of Transmission Operators, Transmission Owners and Distribution Providers should separate circuits that will be used for manual load shed from circuits used for underfrequency load shedding/undervoltage load shedding or serving critical load. Underfrequency load shedding/undervoltage load shedding circuits should only be used for manual load shed as a last resort and should start with the final stage (lowest frequency).

Requirement R1, Part 1.2.5

Minimizing the Overlap of Circuits

EOP-011 version 2, Requirement R1.2.5 states the TOP's Operating Plan shall include provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding. EOP-011-3 adds additional provisions and clarifies what the TOP must include in their Operating Plan to mitigate operating Emergencies. Specific clarifications are to minimize the overlap of manual Load shed and circuits that serve designated critical loads; minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for underfrequency load shed (UFLS) or undervoltage load shed (UVLS); and provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed.

Minimizing the overlap of manual Load shed circuits and circuits that serve critical loads is necessary to prioritize certain critical loads, which may be essential to the integrity of the electric system. The standard drafting team elected to keep the phase "minimize the overlap" instead of moving to language that specifically requires the separation of circuits in recognition of the fact that it is not always practical or warranted to completely separate circuits used for each of these purposes. This requirement can be accomplished in many different ways, such as creating separate and distinct lists for each circuit type, or by using prioritization and control-inhibit functions in an energy management system. This list is not exhaustive and there are certainly other acceptable methods of meeting this requirement.

Additionally, it is important to recognize that criticality designations must be considered in the context of the situation. Critical loads should not all receive the same level of priority, and the characteristics of a Load shed event (depth/duration/season) will impact the treatment of certain critical loads. Transmission Operators should consider establishing priorities for different types of critical loads. The critical Load designation, priority, and conditions during the event will influence which critical loads may be included in manual Load shed. For example, if system conditions continue to deteriorate and other Load shed options are exhausted, then some critical loads may need to be shed in the interest of preserving the system. It is important to have the awareness and flexibility to include or exclude certain loads based on the Load shed scenario.

The standard purposely does not state the method through which overlap is to be minimized. Transmission Operators may use a number of different approaches to satisfy this requirement. Each system is unique and will have various constraints that must be balanced in addressing these requirements.

Provisions

The term provisions, which has been carried forward from EOP-011-2, is intended to mean that it is the responsibility of the Transmission Operator to work with other entities, as necessary, to ensure that their Operating Plan is responsive to these requirements.

Limit the utilization of UFLS or UVLS for manual Load shed

In certain situations, it may be necessary and appropriate to utilize UFLS or UVLS circuits for manual Load shed. These situations may be driven by Load shed magnitudes, local constraints, or other factors. It is important for Transmission Operators to understand the circumstances where UFLS or UVLS circuits may be needed for manual Load shed. Their Operating Plans should identify system conditions that would allow for the utilization of UFLS or UVLS for manual Load shed and how it will be implemented. The Operating Plans should ensure that potential reliability impacts are appropriately considered and balanced. Three examples of such situations are discussed below.

Manual Load Shed Capabilities are Exhausted

During a major Load shed event, Transmission Operators may run out of circuits that are designated for manual Load shed. Due to the large amounts of Load shedding ordered, the duration of the Load shedding, and the exclusion of circuits serving critical Load, Transmission Operators may be forced to manually shed circuits that are utilized for UFLS or UVLS in order to maintain their obligation of total pro rata Load shed.

In such a situation, protecting system reliability requires the lesser evil of using some UFLS circuits to implement the required Load shedding. Transmission Operators should include provisions in their Operating Plans that balances the risk of the immediate emergency need to balance generation and Load to maintain reliability, with the potential for frequency disturbances in the future. In this case, Transmission Operators may elect to utilize UFLS circuits. In this scenario, the recommended practice is to start with the lowest frequency block to meet the Load shed obligations

Proactive Utilization of UFLS Circuits to Improve Outage Rotations and Balance UFLS Levels

Refer to NERC Lesson Learned on this topic:
https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20220301_Managing_UFLS_Obligations_Service_Critical_Loads_during_Energy_Emergency.pdf

Local Emergency Condition

Local emergency conditions are different from a system-wide short-supply situation. During local emergencies, it may be appropriate, and possibly necessary, to manually shed circuits that serve critical loads or that are utilized for UFLS or UVLS.

Requirement R2, Part 2.2.8

This part of R2 has been modified to refer back to Requirement R1, Part 1.2.5 in an effort to clarify that the Transmission Operator is responsible for addressing operator-controlled manual Load shed requirements in their Operating Plan. Balancing Authorities are expected to specify manual Load shed requirements for Transmission Operators within their areas in accordance with Part 1.2.5, but do not have the control or visibility to design and implement manual Load shed programs and UFLS/UVLS programs that meet the requirements of Part 1.2.5.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Extreme Cold Weather Preparedness

Technical Rationale and Justification for EOP-011-3

~~May~~ September 2022

RELIABILITY | RESILIENCE | SECURITY




3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

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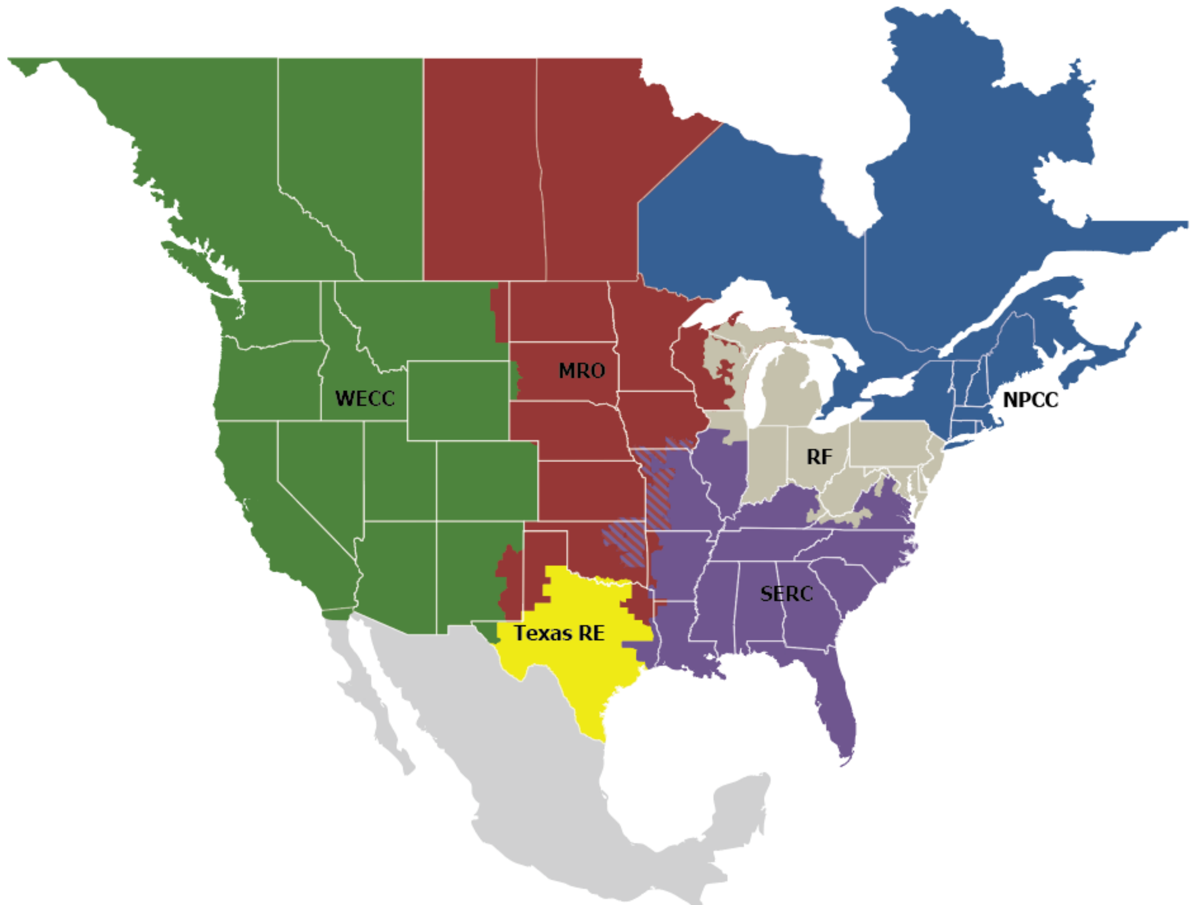
Preface

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 the North American Electric Reliability Corporation (NERC) and the six Regional Entities, is a highly reliable 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 Entity boundaries as shown in the map and 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 Standards EOP-011-3 and EOP-012-1. It provides stakeholders and the ERO Enterprise with an understanding of the technology and technical requirements in the Reliability Standard. This Technical Rationale and Justifications for EOP-011-3 and EOP-NEW is not a Reliability Standard and should not be considered mandatory and enforceable.

Background

From February 8 through February 20, 2021, extreme cold weather and precipitation caused large numbers of generating units to experience outages, derates or failures to start, resulting in energy and transmission emergencies (referred to as "the Event"). The total Event firm Load shed was the largest controlled firm Load shed event in U.S. history and was the third largest in quantity of outaged megawatts (MW) of Load after the August 2003 northeast blackout and the August 1996 west coast blackout. The Event was most severe from February 15 through February 18, 2021, and it contributed to power outages affecting millions of electricity customers throughout the regions of ERCOT, SPP and MISO South. Additionally, the February 2021 event is the fourth cold weather event in the past 10 years, which jeopardized bulk-power system reliability. A joint inquiry was conducted to discover reliability-related findings and recommendations from FERC, NERC, and Regional Entity staff. The FERC, NERC, and Regional Entity Staff Joint Staff Inquiry into the February 2021 Cold Weather Grid Operations ("Joint Inquiry Report") was published on November 16, 2021.

The scope of the proposed project is to address the ten recommendations for new or enhanced NERC Reliability Standards proposed by the Joint Inquiry Report. In November 2021, the NERC Board of Trustees (Board) approved a Board Resolution directing that new or revised Reliability Standards addressing these recommendations be completed in accordance with the timelines recommended by the joint inquiry team, as follows:

- New and revised Reliability Standards to be submitted for regulatory approval before Winter 2022/2023: development completed by September 30, 2022, for the Board's consideration in October 2022 to address Key Recommendations 1d, 1e, 1f, and 1j;
- New and revised Reliability Standards to be submitted for regulatory approval before Winter 2023/2024: development completed by September 30, 2023, for the Board's consideration in October 2023 to address Key Recommendations 1a, 1b, 1c, 1g, 1h, and 1i.

Requirement R1 and R2

R1. *Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

1.1. *Roles and responsibilities for activating the Operating Plan(s);*

1.2. *Processes to prepare for and mitigate Emergencies including:*

1.2.1. *Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency;*

1.2.2. *Cancellation or recall of Transmission and generation outages;*

1.2.3. *Transmission system reconfiguration;*

1.2.4. *Redispatch of generation request;*

1.2.5. *Operator-controlled manual L~~l~~oad shedding during an Emergency that accounts for each of the following:*

1.2.5.1. *Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;*

1.2.5.2. *Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that serve designated critical loads;*

1.2.5.3. *Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for underfrequency load shed (UFLS) or undervoltage load shed (UVLS); and*

1.2.5.4. *Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions.*

1.2.6. *Provisions to determine reliability impacts of:*

1.2.6.1. *cold weather conditions; and*

1.2.6.2. *extreme weather conditions.*

R2. *Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

2.1. *Roles and responsibilities for activating the Operating Plan(s);*

2.2. *Processes to prepare for and mitigate Emergencies including:*

2.2.1. *Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;*

2.2.2. *Requesting an Energy Emergency Alert, per Attachment 1;*

2.2.3. *Managing generating resources in its Balancing Authority Area to address:*

2.2.3.1. *capability and availability;*

2.2.3.2. *fuel supply and inventory concerns;*

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2.2.7. *Use of Interruptible Load, curtailable Load and demand response;*

2.2.8. *Provisions for Transmission Operators to implement operator-controlled manual Load shed in accordance with Requirement R1 Part 1.2.5; and*

2.2.9. *Provisions to determine reliability impacts of:*

2.2.9.1. *cold weather conditions; and*

2.2.9.2. *extreme weather conditions.*

Key Recommendation 1j: In minimizing the overlap of manual and automatic load shed, the load shed procedures of Transmission Operators, Transmission Owners and Distribution Providers should separate circuits that will be used for manual load shed from circuits used for underfrequency load shedding/undervoltage load shedding or serving critical load. Underfrequency load shedding/undervoltage load shedding circuits should only be used for manual load shed as a last resort and should start with the final stage (lowest frequency).

Requirement R1, Part 1.2.5

Minimizing the Overlap of Circuits

EOP-011 version 2, Requirement R1.2.5 states the TOP's Operating Plan shall include provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding. EOP-011-3 adds additional provisions and clarifies what the TOP must include in their Operating Plan to mitigate operating Emergencies. Specific clarifications are to minimize the overlap of manual Load shed and circuits that serve designated critical loads; minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for underfrequency load shed (UFLS) or undervoltage load shed (UVLS); and provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed.

Minimizing the overlap of manual Load shed circuits and circuits that serve critical loads is necessary to prioritize certain critical ~~loads which~~loads, which may be essential to the integrity of the electric system~~, public health, or the welfare of the community~~. The standard drafting team elected to keep the phase "minimize the overlap" instead of moving to language that specifically requires the separation of circuits in recognition of the fact that it is not always practical or warranted to completely separate circuits used for each of these purposes. This requirement can be accomplished in many different ways, such as creating separate and distinct lists for each circuit type, or by using prioritization and control-inhibit functions in an energy management system. This list is not exhaustive and there are certainly other acceptable methods of meeting this requirement.

Additionally, it is important to recognize that criticality designations must be considered in the context of the situation. Critical loads should not all receive the same level of priority, and the characteristics of a Load shed event (depth/duration/season) will impact the treatment of certain critical loads. Transmission Operators should consider establishing priorities for different types of critical loads. The critical Load designation, priority, and conditions during the event will influence which critical loads may be included in manual Load shed. For example, if system conditions continue to deteriorate and other Load shed options are exhausted, then some critical loads may need to be shed in the interest of preserving the system. It is important to have the awareness and flexibility to include or exclude certain loads based on the Load shed scenario.

The standard purposely does not state the method through which overlap is to be minimized. Transmission Operators may use a number of different approaches to satisfy this requirement. Each system is unique and will have various constraints that must be balanced in addressing these requirements.

Provisions

The term provisions, which has been carried forward from EOP-011-2, is intended to mean that it is the responsibility of the Transmission Operator to work with other entities, as necessary, to ensure that their Operating Plan is responsive to these requirements.

Limit the utilization of UFLS or UVLS for manual Load shed

In certain situations, it may be necessary and appropriate to utilize UFLS or UVLS circuits for manual Load shed. These situations may be driven by Load shed magnitudes, local constraints, or other factors. It is important for Transmission Operators to understand the circumstances where UFLS or UVLS circuits may be needed for manual Load shed. Their Operating Plans should identify system conditions that would allow for the utilization of UFLS or UVLS for manual Load shed and how it will be implemented. The Operating Plans should ensure that potential reliability impacts are appropriately considered and balanced. Three examples of such situations are discussed below.

Manual Load Shed Capabilities are Exhausted

During a major Load shed event, Transmission Operators may run out of circuits that are designated for manual Load shed. Due to the large amounts of Load shedding ordered, the duration of the Load shedding, and the exclusion of circuits serving critical Load, Transmission Operators may be forced to manually shed circuits that are utilized for UFLS or UVLS in order to maintain their obligation of total pro rata Load shed.

In such a situation, protecting system reliability requires the lesser evil of using some UFLS circuits to implement the required Load shedding. Transmission Operators should include provisions in their Operating Plans that balances the risk of the immediate emergency need to balance generation and Load to maintain reliability, with the potential for frequency disturbances in the future. In this case, Transmission Operators may elect to utilize UFLS circuits. In this scenario, the recommended practice is to start with the lowest frequency block to meet the Load shed obligations

Proactive Utilization of UFLS Circuits to Improve Outage Rotations and Balance UFLS Levels

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Local Emergency Condition

Local emergency conditions are different from a system-wide short-supply situation. During local emergencies, it may be appropriate, and possibly necessary, to manually shed circuits that serve critical loads or that are utilized for UFLS or UVLS.

Requirement R2, Part 2.2.8

This part of R2 has been modified to refer back to Requirement R1, Part 1.2.5 in an effort to clarify that the Transmission Operator is responsible for addressing operator-controlled manual Load shed requirements in their Operating Plan. Balancing Authorities are expected to specify manual Load shed requirements for Transmission Operators within their areas in accordance with Part 1.2.5, but do not have the control or visibility to design and implement manual Load shed programs and UFLS/UVLS programs that meet the requirements of Part 1.2.5.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Extreme Cold Weather Preparedness

Technical Rationale and Justification for EOP-012-1

September 2022

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Preface

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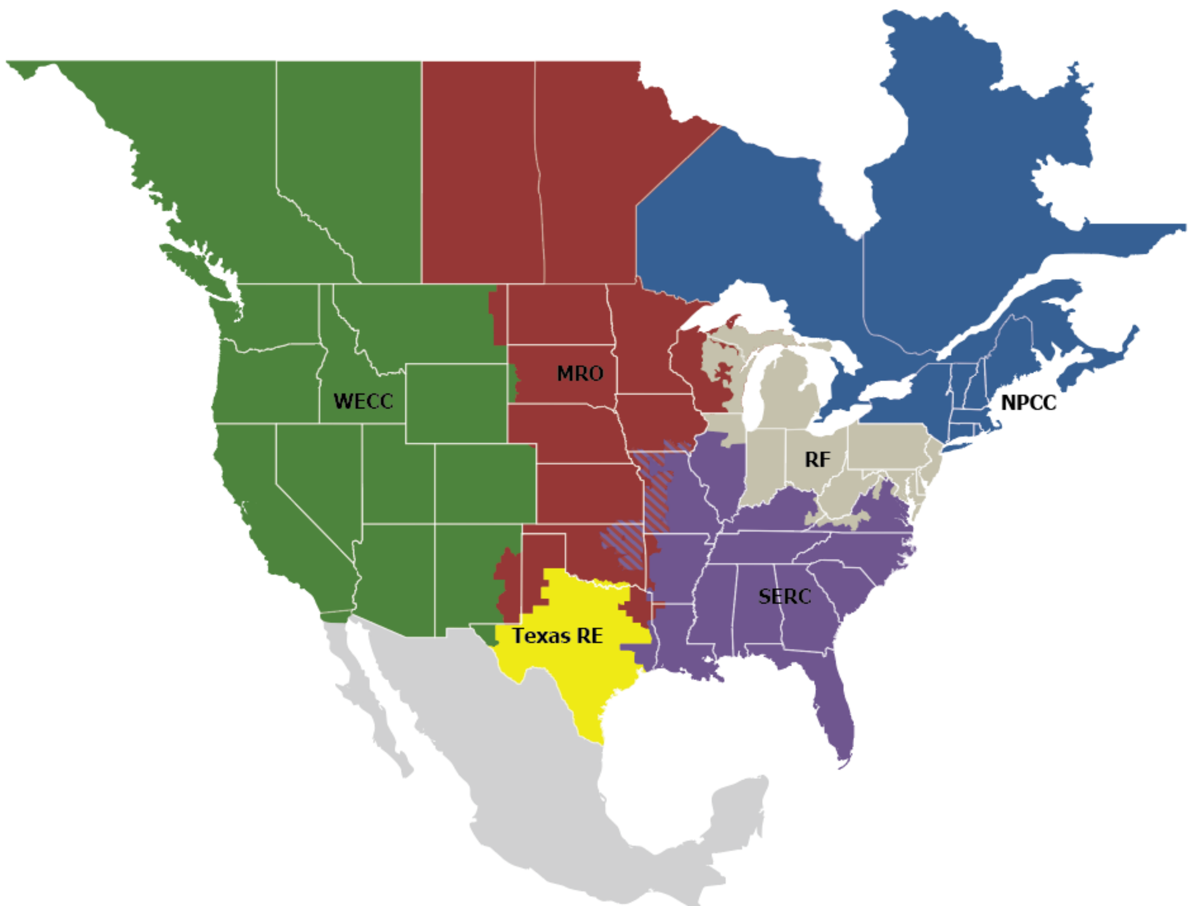

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Introduction

This document explains the technical rationale and justification for the proposed Reliability Standard EOP-012-1. 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 EOP-012-1 is not a Reliability Standard and should not be considered mandatory and enforceable.

Background

From February 8 through February 20, 2021, extreme cold weather and precipitation caused large numbers of generating units to experience outages, derates or failures to start, resulting in energy and transmission emergencies (referred to as “the Event”). The total Event firm load shed was the largest controlled firm load shed event in U.S. history and was the third largest in quantity of outaged megawatts (MW) of load after the August 2003 northeast blackout and the August 1996 west coast blackout. The Event was most severe from February 15 through February 18, 2021, and it contributed to power outages affecting millions of electricity customers throughout the regions of ERCOT, SPP, and MISO South. Additionally, the February 2021 event is the fourth cold weather event in the past 10 years, which jeopardized bulk-power system reliability. A joint inquiry was conducted to discover reliability-related findings and develop recommendations from FERC, NERC, and Regional Entity staff. The FERC, NERC, and Regional Entity Staff Report into the February 2021 Cold Weather Outages (“Joint Inquiry Report”) was published on November 16, 2021.

The scope of the proposed project is to address the ten recommendations for new or enhanced NERC Reliability Standards proposed by the Joint Inquiry Report. In November 2021, the NERC Board of Trustees (Board) approved a Board Resolution directing that new or revised Reliability Standards addressing these recommendations be completed in accordance with the timelines recommended by the joint inquiry team, as follows:

- New and revised Reliability Standards to be submitted for regulatory approval before Winter 2022/2023: development completed by September 30, 2022, for the Board’s consideration in October 2022 to address Key Recommendations 1d, 1e, 1f, and 1j;

- New and revised Reliability Standards to be submitted for regulatory approval before Winter 2023/2024: development completed by September 30, 2023, for the Board’s consideration in October 2023 to address Key Recommendations 1a, 1b, 1c, 1g, 1h, and 1i.

Facilities

4.2 Facilities:

4.2.1 For purposes of this standard, the term "generating unit" subject to these requirements refers to the following Bulk Electric System (BES) resources:

4.2.1.1 A Bulk Electric System generating unit that commits or is obligated to serve a Balancing Authority load pursuant to a tariff obligation, state requirement as defined by the relevant electric regulatory authority, or other contractual arrangement, rule, or regulation, for a continuous run of four hours or more at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius); or

4.2.1.2 A Blackstart Resource

4.2.2 Exemptions:

4.2.2.1 Any Bulk Electric System generating unit included under Section 4.2.1 above that has a calculated Extreme Cold Weather Temperature exceeding 32 degrees Fahrenheit (zero degrees Celsius) under Requirement R3 Part 3.1 and as part of the required five year review in Requirement R4 Part 4.1 is exempt from further requirements in this standard.

4.2.2.2 A Bulk Electric System generating unit that is not committed or obligated to operate at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius) for any continuous run of more than four hours, but is called upon to operate for more than four hours in order to assist in the mitigation of BES Emergencies, Capacity Emergencies, or Energy Emergencies during periods at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius).

In the Joint Inquiry Report, Key Recommendation 1f includes clarifying information, which states "consideration should be given to designing all new generation plants and designing modifications to existing plants (unless committed solely for summer peaking purposes)…[.][1] FERC staff from the Joint Inquiry Report team clarified further to the standard drafting team (SDT) that the reference to summer peaking units acknowledges that some units have not implemented freeze protection measures or may not be able to secure fuel in the winter and therefore, plan to commit solely to serve Balancing Authority load during non-winter conditions. The standard provides an Applicability section identifying which generating units are subject to the requirements, with two exemptions available if the generating unit meets two narrowly construed conditions.

The Applicability section first defines "generating unit" as a Bulk Electric System (BES) resource. The NERC Glossary of Terms provides the foundation for what BES resources are included in the definition (see Inclusions I2 through I4). The Applicability section further defines which BES resources are intended to be subject to the standards' requirements, and explains exemptions available consistent with Key Recommendation 1f. The intent of the proposed standard is not to mandate that all generating units provide capacity in extreme cold weather, but instead to ensure that those BES resources that are obligated to serve Balancing Authority load during periods at or below freezing due to commitments pursuant to tariff obligations, state requirements defined by regulatory authorities, or other contractual arrangements, rules, or regulations are subject to the winterization requirements. The SDT chose the four-hour timeframe in consideration of generators that typically do not commit during freezing conditions but are running when conditions drop below freezing for a short period of time (under four hours) and would therefore not

[1] See Report, page 189.

automatically be subject to the standard. Additionally, Blackstart Resources are also specifically declared subject to the winterization requirements. Such Blackstart Resource, consistent with the NERC Glossary of Terms, are those units designated in the Transmission Operator's restoration plans.

Applicability section 4.2.2.1 clarifies further that a BES resource that is included pursuant to Applicability section 4.2.1 but that has a calculated Extreme Cold Weather Temperature exceeding freezing is also exempt. However, such generators must comply with the ongoing five-year review requirements of R4 Part 4.1 to ensure its ongoing exemption is appropriate. If a five-year review determines that the Extreme Cold Weather Temperature for the BES resource has fallen to freezing or below, then such BES resource will become subject to the requirements. With regards to the exemption provision contained in the Applicability section 4.2.2.2, BES resources exempt under the Applicability section but are called upon during extreme cold weather emergency contingencies should be able to respond to the Balancing Authority's commitment requests without triggering the requirements. This language ensures that this intent is satisfied for all requirements that follow.

In summary, to meet the intent of Recommendation 1f as clarified by FERC staff, a BES resources as defined by the NERC Glossary of Terms is subject to EOP-12-1 if it operates pursuant to an obligation to run for more than four continuous hours at or below freezing. However, the BES resource may be exempt from the requirements if the BES resources not be committed or otherwise obligated to run at or below freezing conditions for more than a four-hour continuous operation.

Additionally, such exclusion applies even when such generator is called upon to assist in the mitigation of a declared energy contingency (defined in the NERC Glossary of Terms as a BES Emergency, Capacity Emergency, or Energy Emergency). The language works as a blanket inclusion of all BES resources that serve Balancing Authority load for a period of more than four hours in freezing conditions, with the exemption of summer units or BES Resources that are not committed to serve load during non-winter conditions (e.g. summer peaking units); and the exemption is maintained by such BES resources when committed for a short period during energy contingencies.

Defined Terms

The SDT developed three terms to be added to the NERC Glossary to make the requirements easier to read and understand. These three terms are:

Extreme Cold Weather Temperature

The temperature equal to the lowest 0.2 percentile of the hourly temperatures measured in December, January, and February from 1/1/2000 through the date the temperature is calculated.

The definition of Extreme Cold Weather Temperature was developed by the SDT to provide clarity to the Generator Owner on determining what temperature triggers the requirement obligations. Each Generator Owner should select a reliable source of data from a recording location near the plant to determine their Extreme Cold Weather Temperature. Sources would include, for example, the National Weather Service (NWS) or National Oceanographic and Atmospheric Administration (NOAA) weather stations, Federal Aviation Administration (FAA) weather stations, or Environment and Climate Change Canada location for Canadian entities[2], etc. NOAA's National Centers for Environmental Information provides Climate Data Online (CDO) as a free resource that includes quality-controlled weather data and 30-year Climate Normals[3]. In general, Generator Owners should use the location nearest the plant, but may select a further location if geographic or local climatic patterns make a further location more representative of the weather at the generating unit. Generator Owners may use on-site weather stations if data, which reasonably matches reliable nearby off-site sources since January 1, 2000, is available. The starting period chosen by the SDT to gather data to determine the lowest temperatures that occur near a facility is based on the completion of the

[2] Environment and Climate Change Canada - Canada.ca

[3] https://www.ncei.noaa.gov/products/land-based-station/us-climate-normals

modernization of the National Weather Service project known as MAR (Modernization and Associated Restructuring). This project was completed in the year 2000. In general, the National Weather Service modernization provides weather data to be available at most large airports at a 99%+ availability. This will make it fairly accessible for companies to gather data and perform the required analysis. The December through February timeframe was selected to correspond to the meteorological winter, as defined by NOAA.[4]

The SDT discussed methods for determining an Extreme Cold Weather Temperature with engineering design professionals, and it was determined that it is typical engineering practice to use a statistical approach to determine the design temperature when implementing generation facility freeze protection measures. The SDT determined that only winter temperature values (i.e. between December and February) shall be used for the statistical approach and based on analysis of multiple sites, it was determined that by using the lowest 0.2 percentile, there will be sufficient data points to ensure that a single hour at a temperature that may not be accurate, or may be a statistical anomaly, doesn't result in an overly conservative design or preclude the ability of the Generator Owner to use historical operating data to prove compliance to the standards. The SDT selected the 0.2 percentile of winter month temperatures since 1/1/2000 to identify a temperature which has been rarely surpassed, but which allows some margin for a Generator Owner to have previously demonstrated successful operation. The SDT considered using the lowest recorded hourly ambient temperature but, upon further review of the historical weather data and generally accepted design principles, determined that the statistical approach to setting the extreme cold weather temperature for a site was more reasonable.

Generator Cold Weather Critical Component

Any generating unit component or associated fixed fuel supply component, that is under the Generator Owner's control and that is susceptible to freezing issues, the occurrence of which would likely lead to a generating unit(s): (1) forced derate of more than 10% of the total capacity of the unit and exceeding 20 MWs for longer than four hours in duration, (2) a start-up failure where the unit fails to synchronize within a specified start-up time, or (3) a Forced Outage.

The SDT felt the best method to address where freeze protection measures should be implemented was to define a term which specifies a subset of components that may be susceptible to freezing, and are critical to the operation of generating units. A fixed fuel supply component is intended to cover non-mobile equipment that supports the reliable delivery of fuel to the generating unit that is controlled by the Generator Owner. It would include gaseous, liquid, or solid fuel handling components that are installed as fixed parts of the fuel delivery system that are under the Generator Owner's control. It would not include mobile equipment such as trains, bulldozers, or other equipment that are not fixed in one location.

The SDT's intent with regard to the language "that is under the Generator's Owner's control" was to clearly delineate that cold weather events external to Generation site such as loss of fuel supply or loss of auxiliary power to the site that resulted in a Cold Weather Reliability Event would not be subject to this standard. Furthermore, ice buildup on Transmission lines would not constitute a freezing condition in the context of this Standard and therefore these Transmission Lines would not be considered a Generator Cold Weather Critical Component.

Generator Cold Weather Reliability Event

One of the following events for which the apparent cause(s) is due to freezing of equipment within the Generator Owner's control and the dry bulb temperature at the time of the event was at or above the Extreme Cold Weather Temperature:

> *(1) a forced derate of more than 10% of the total capacity of the unit and exceeding 20 MWs for longer than four hours in duration;*

[4] https://www.ncei.noaa.gov/news/meteorological-versus-astronomical-seasons

(2) a start-up failure where the unit fails to synchronize within a specified start-up time; or

(3) a Forced Outage.

The SDT is using the definition of apparent as defined in the dictionary as "clear or manifest to the understanding". For more explanation on this definition please see Requirement R6 Technical Rationale Below.

Requirement R1 and R2

R1. *For a generating unit(s) with a commercial operation date subsequent to [Effective Date of this requirement], the Generator Owner shall: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]*

- *Implement freeze protection measures that provide capability to operate for a period of not less than twelve (12) continuous hours at the Extreme Cold Weather Temperature for the unit(s), assuming a concurrent twenty (20) mph wind speed on any exposed Generator Cold Weather Critical Components; or*
- *Explain in a declaration, any technical, commercial, or operational constraints as defined by the Generator Owner that preclude the ability to implement appropriate freeze protection measures to provide capability of operating for twelve (12) hours at the documented Extreme Cold Weather Temperature.*

R2. *For each generating unit(s) in commercial operation prior to [Effective Date of this requirement], the Generator Owner shall ensure its generating unit(s) add new or modify existing freeze protection measures as needed to provide the capability to operate for a period of not less than one (1) hour at the unit(s) Extreme Cold Weather Temperature. Generating unit(s) that are not capable of operating for one (1) hour at its Extreme Cold Weather Temperature shall develop a Corrective Action Plan (CAP) for the identified issues, including identification of any needed modifications to the cold weather preparedness plan required under Requirement R3. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]*

<u>Key Recommendation 1f:</u> To require Generator Owners to retrofit existing generating units, and when building new generating units, to design them to operate to a specified ambient temperature and weather conditions (e.g., wind, freezing precipitation). The specified ambient temperature and weather conditions should be based on available extreme temperature and weather data for the generating unit's location.

General Considerations

As referenced in Key Recommendation 1f above, the specified ambient temperature and weather conditions should be based on available extreme temperature and weather data for the generating unit's location. FERC staff from the Joint Inquiry Report team clarified to the SDT that the reliability goal of the recommendation for existing generating units is to have the necessary freeze protection measures to be able to operate at extreme cold temperatures and weather for the generating unit's location. For example, those measures may consist of existing[5] or new, permanent and/or temporary measures[6] to maintain operation during extreme cold temperatures. Therefore, FERC staff clarified that the joint team's intent of the word retrofit is "to implement new, and/or make modifications to existing freeze protection measures for existing generating units."

[5] While the dictionary definition of the word retrofit includes to install (new or modified parts or equipment) in something previously manufactured or constructed, its origin suggests the need for replacing existing equipment with new technologies, which was not the intent of the joint team in this case. See Merriam-Webster definition.

[6] Some freeze protection measures may need to be removed for summer temperature operation.

In discussions with the Joint Inquiry Report team and in reading the Joint Inquiry Report itself, it is clearly stated that "consideration should be given to designing all new generation plants and designing modifications to existing plants (unless committed solely for summer peaking purposes) to be able to perform at the lowest recorded ambient temperature for the nearest city for which historical weather data is available …)". The Report went on to provide evidence that "Not only did generating units fail to perform at the lowest recorded ambient temperature for the nearest city, but many failed to perform at their own ambient design temperatures". The Joint Inquiry Report also notes that "Over 40 percent of the GOs/GOPs in the south-central U.S. regions where "freezing issues" were identified as the predominant cause of unplanned generation outages, derates or failures to start stated that they did not incorporate specific generator-related recommendations from the 2011 Report[7] or specific recommendations from the Guideline[8]."

Based on the generating unit data contained in the Joint Inquiry Report, many generating units that operate in the winter season are not properly winterized to remain in reliable service during the most extreme cold weather conditions that they may reasonably be expected to experience at their locations. As the load on the grid is the most elevated at these extreme conditions, these are the periods when it is most critical that these generating units maintain their reliability. As such, Requirement 1 ensures that generating units are proactively taking steps to design and maintain their units to maintain their reliability during extreme cold weather.

Requirement R1

The Joint Inquiry Report key recommendation 1f references recommendation 12 of the 2011 report suggesting that consideration should be given to designing all new generation plants and designing modifications to existing plants (unless committed solely for summer peaking purposes) to be able to perform at the lowest recorded ambient temperature for the nearest city for which historical weather data is available. The Joint Inquiry Report states "The Standards Drafting Team can decide what additional specificity is desirable for this requirement, for example, specifying the number of years of weather data to be considered in establishing the required ambient temperature and weather conditions, and the source of the extreme temperature and weather data". The SDT considered several options of how many years back historical data should be analyzed (e.g., 10 years, 30 years, 50 years, 100 years). There is concern that some geographical areas may not have reliable data dating back 100 years. The SDT's meteorological research finds that significant improvements were made and modernization of weather stations implemented in the early years of the 21st century. Given this, the SDT settled on the look back date of January 1, 2000.

The key recommendation identifies wind and freezing precipitation as examples of weather conditions to consider during the design of new generating units and modifications to existing plants. Realizing the many differences in weather that generator sites face across the Regions, the 2021-07 SDT developed language to provide additional context and detail around these weather conditions, while allowing flexibility for site-specific circumstances. The requirement language considers wind at a specific rate when designing new facilities. New units with commercial operation dates after the effective date of EOP-012-1 shall implement freeze protection measures such that their facilities are capable of continuous operation for not less than 12 hours at the Extreme Cold Weather Temperature assuming a concurrent twenty (20) mph wind speed on any exposed Generator Cold Weather Critical Component.

Because R1 is applicable to newly designed facilities, there is no allowance for a CAP. However, it is recognized that technical, commercial, or operational constraints may exist that prevent a new generating unit(s) from being capable of twelve (12) continuous hours of operation at their identified Extreme Cold Weather Temperature. Thus, the SDT included in R1, the option for the Generator Owner to make a declaration supporting why technical, commercial, or operational constraints preclude the ability to implement appropriate freeze protection measures. The SDT chose 12 hours of continuous operation because it is a typical length of the nighttime in winter and the maximum amount of

[7] Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011

[8] Reliability Guideline Generating Unit Winter Weather Readiness - Current Industry Practices

time that generating units would experience the Extreme Cold Weather Temperature. The SDT chose a concurrent 20 mph speed after an evaluation using the wind chill formula developed by the US National Weather Service (NWS) in the United States. Though wind chill temperature is not an exact science, it is widely understood to reflect the non-linear increased rate of convective heat loss due to air moving at different velocities. Commonly available charts show wind chill temperatures as a function of actual air temperature at various wind speeds. As it turns out, about 2/3 of the wind chill temperature drop between 0 – 60 mph is already achieved at 20 mph. Using the NWS chart, this holds true for still air temperatures starting at 40 F and dropping in 20-degree increments to -40 F. Further, 20 mph is a wind speed commonly experienced across the NERC area and yet appropriately higher than the approximate average wind speeds in the United States and Canada, 6-12 mph and 8-11 mph respectively.

Requirement R2

The SDT created a requirement to develop a CAP for generating units in commercial operation prior to the effective date of EOP-012-1 that requires either new freeze protection measures, or modification of existing freeze protection measures, to be capable of one hour of continuous operation at their identified Extreme Cold Weather Temperature. The SDT chose one hour as opposed to 12 hours for existing generation to recognize the fact that it is extremely difficult to perform the same level of design analysis, and/or documented historical operation on existing generation as on new generation. However, it is recognized that modifications or corrective actions may not be feasible under all circumstances due to technical, commercial, or operational constraints.

Additionally, the SDT considered the potential for unintended consequences, such as limiting participation by generation units in cold temperatures or accelerating generator retirements, caused by requirements to develop and implement CAPs to be capable of operations under the conditions defined in R2.

The SDT discussed setting a timeframe needed for the CAP to be completed during the drafting phase. While it is important that the CAP be completed, it would be difficult to set a definite timeframe due to the number of variables that could impact the completion of the CAP once the cause is determined. The requirements five year implementation plan is focused solely on the development of the CAP, not completion of the CAP. The SDT believes that it is more important to develop a CAP that identifies the solution and resolves the situation correctly regardless of time. Therefore, the team did not define a time when the CAP needs to be completed.

Requirement R3

R3. *Each Generator Owner shall implement and maintain one or more cold weather preparedness plan(s) for its generating units. The cold weather preparedness plan(s) shall include the following, at a minimum: [Violation Risk Factor: High] [Time Horizon: Operations Planning and Real-time Operations]*

3.1 *The Extreme Cold Weather Temperature for their unit(s) including the calculation date and source of temperature data;*

3.2 *Documentation identifying the Generator Cold Weather Critical Components;*

3.3 *Documentation of freeze protection measures implemented on Generator Cold Weather Critical Components which may include measures used to reduce the cooling effects of wind determined necessary by the Generator Owner to protect against heat loss, and where applicable, the effects of freezing precipitation (e.g., sleet, snow, ice, and freezing rain);*

3.4 *Annual inspection and maintenance of generating unit(s) freeze protection measures; and*

3.5 *Generating unit(s) cold weather data, to include:*

3.5.1 *Generating unit(s) operating limitations in cold weather to include:*

3.5.1.1 *Capability and availability;*

3.5.1.2 *Fuel supply and inventory concerns;*

3.5.1.3 *Fuel switching capabilities; and*

3.5.1.4 *Environmental constraints.*

3.5.2 *Generating unit(s) minimum:*

- *Design temperature;*
- *Historical operating temperature; or*
- *Current cold weather performance temperature determined by an engineering analysis.*

General Considerations

Requirement R3 requires Generator Owners to develop and maintain cold weather preparedness plans for its unit(s) and describes the information and documentation required in such plans. It is an expansion of the cold weather preparedness plan required under Requirement R7 of EOP-011-2, and is intended to be used and reviewed regularly by the Generator Owner; R3.4 requires the GO to annually inspect the freeze protection measures. Working in concert with other parts of EOP-012, including R4 and R5, the plan will be regularly reviewed and updated and the GO is required to annually train personnel on its requirements.

Requirement R3 Part 3.1

In R3.1, the Generator Owner is required to determine the Extreme Cold Weather Temperature, as defined in the standard, for each unit using reliable source of data. The SDT believes that the GO is in the best position to select the most representative weather information relative to its generating unit.

Requirement R3 Part 3.2

In R3.2, the Generator Owner identifies the Generator Cold Weather Critical Components to help inform their decision on where to implement appropriate freeze protection measures. The document *Reliability Guideline, Generating Unit Winter Weather Readiness – Current Industry Practices*[9], NERC, 2012 presents a suggested list of components that Generator Owners may choose to utilize when developing their own Generator Cold Weather Critical Component inventory.

Requirement R3 Part 3.3

R3.3 requires GOs to document the freeze protection measures implemented on cold-weather-critical components. These freeze protection measures may include those to reduce the cooling effects of wind. Requirement R3 does not require Generator Owners to install new freeze protection measures to reduce the cooling effects of wind, but rather to document those measures. These measures would include temporary measures such as wind breaks. There is no expectation for entities to list all climate controlled areas as freeze protection measures. Similar to the cooling effects of wind, R3 requires Generator Owners to document freeze protection measures taken to reduce the effects of freezing precipitation on cold-weather-critical components, as the Generator Owners determine if necessary (e.g. water-resistant insulation, protective shielding, insulated boxes, etc.).

Requirement R3 Part 3.4

R3.4 is carried over from the previously approved EOP-011-2 standard, and requires annual inspection and maintenance of the freeze protection measures identified in the cold weather preparedness plan. This requirement ensures these freeze protection measures will be ready and serviceable when needed. Examples of documentation to demonstrate inspections and maintenance has been completed would be completed work order(s) from the Generator Owner's work management system and/or freeze protection checklists identifying the measures inspected and maintained.

[9] Reliability Guideline Generating Unit Winter Weather Readiness – Current Industry Practices

Requirement R3 Part 3.5

R3.5 is carried over from the previously approved EOP-011-2 standard, and requires the Generator Owner to document several cold weather performance parameters for the unit. This information is valuable, and in some cases, must be shared with other entities. Defining the operating limitations in R3.5.1 will make affected personnel more aware of unit capabilities and constraints as well as systems and practices that may be necessary to ensure reliability in cold weather, particularly when alternative fuels are involved. In addition, the unit minimum temperature identified in R3.5.2 is used to demonstrate compliance with R2 for existing units.

Requirement R4

R4. *Once every five calendar years, each Generator Owner shall for each generating unit: [Violation Risk Factor: Low] [Time Horizon: Operations Planning, Real-Time Operations]*

4.1 *Calculate the Extreme Cold Weather Temperature, and update the cold weather preparedness plan if this temperature is now lower than the previous lowest calculation;*

4.2 *Review its documented generating unit(s) minimum temperature contained within its cold weather preparedness plan(s), pursuant to Part 3.5.2; and*

4.3 *Review whether its generating units have the freeze protection measures required to operate at the Extreme Cold Weather Temperature pursuant to R1 or R2 as applicable, and if not develop a CAP for the identified issues, including identification of any needed modifications to the cold weather preparedness plan required under Requirement R3.*

The SDT has developed the new standard with language that supports the ongoing consideration of new technologies when protecting against extreme cold weather, and an ongoing review requirement to validate or update the Extreme Cold Weather Temperature associated with each unit. This five-year review supports the desire for Generator Owners to periodically vet these new technologies and consider whether any technical, commercial, or operational constraints are still applicable.

Requirement R5

R5. *Each Generator Owner in conjunction with its Generator Operator shall identify the entity responsible for providing the generating unit-specific training, and that identified entity shall provide annual training to its maintenance or operations personnel responsible for implementing cold weather preparedness plan(s) developed pursuant to Requirement R3. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]*

<u>Key Recommendation 1e:</u> To revise EOP-011-2, R8, to require Generator Owners and Generator Operators to conduct annual unit-specific cold weather preparedness plan training.

Project 2019-06 Cold Weather established the requirement that the Generator Owner, in conjunction with its Generator Operator, would provide generating unit-specific training for its personnel responsible for implementing cold weather preparedness plan(s) for its generating units. The Joint Inquiry Report recommended that EOP-011-2 R8 be revised to require the generating unit-specific training be provided on an "annual" basis. The report explains "Responses from the GOs/GOPs involved in the Event show that annual training is not yet universal in the Event Area." To address this recommendation, the SDT has utilized the existing language in EOP-011-2 and added the word "annual" to require the training on an annual basis. The requirement is deleted from EOP-011-3, and will be placed as a requirement in a new EOP-012-1 Reliability Standard dedicated solely to extreme cold weather preparedness.

Requirement R6

R6. *Each Generator Owner that owns a generating unit that experiences a Generator Cold Weather Reliability Event shall develop a CAP, within 150 days or by July 1, whichever is earlier, that contains at a minimum: [Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

6.1 *A summary of the identified cause(s) for the Generator Cold Weather Reliability Event where applicable and any relevant associated data;*

6.2 *A review of applicability to similar equipment at other generating units owned by the Generator Owner;*

6.3 *An identification of any temporary operating limitations or impacts to the cold weather preparedness plan, that would apply until execution of the corrective action(s) identified in the CAP.*

Key Recommendation 1d: To require Generator Owners that experience outages, failures to start, or derates due to freezing to review the generating unit's outage, failure to start, or derate and develop and implement a corrective action plan (CAP) for the identified equipment, and evaluate whether the CAP applies to similar equipment for its other generating units. Based on the evaluation, the Generator Owner will either revise its cold weather preparedness plan to apply the CAP to the similar equipment, or explain in a declaration (a) why no revisions to the cold weather preparedness plan are appropriate, and (b) that no further corrective actions will be taken. The standard drafting team should specify the specific timing for the CAP to be developed and implemented after the outage, derate, or failure to start, but the CAP should be developed as quickly as possible, and be completed by no later than the beginning of the next winter season.

The key recommendation from the report recommends a standard that requires Generator Owners to develop a CAP for generating units that experience outages, failures to starts, or derates due to freezing. The Report identifies that most of the outages and derates in the February 2021 event were due to freezing of instrumentation, transmitters, sensing lines, or wind turbine blades (p 166 in report). As such, the team followed the Report recommendation to require a CAP when the apparent cause of the event is freezing. The Project 2021-07 SDT has developed parameters around these events to clarify a reasonable baseline of what level of de-rate qualifies as an event, and provide additional language to identify what constitutes a start-up failure. With the additional clarifications, the SDT determined that the standard would benefit from a defined term, to clearly and efficiently state what constitutes an event. The result is to a new defined term, Generator Cold Weather Reliability Event, that defines the circumstances for which a CAP is required (i.e., when a freezing event effects the equipment within the control of the Generator Owner). The defined term will make the standard easier to understand and implement by providing clear and reasonable factors to determine whether the impact of an event requires mitigation

General Considerations for All CAPs

To simplify the proposed requirements related to creating a CAP, the SDT has modified the proposed requirements addressing the need for a CAP while better incorporating the NERC Definition of a CAP. The CAP definition reads "A list of actions and an associated timetable for implementation to remedy a specific problem." As written, the definition requires two parts for a document to qualify as a CAP, i.e., a list of items to be addressed and a timeline for completion. In the original posting, the SDT included both items in separate bullets to be included in the CAP. To simplify the requirements, the SDT has removed the bullets. As these two elements are both required for a document to qualify as a CAP, there is no need to list these items separately within the standard. A CAP without both a list of actions and the timeline to implement is not complete.

Requirement R6

The CAP requirement applies to any forced outage due to freezing, regardless of duration. Derates, which are short-lived (specified as 4 hours by the SDT) or of small capacity impact (specified as less than 20 MW by the SDT, which corresponds with the threshold for BES impacting Generation units), are excluded from the CAP requirement to limit the administrative burden to Generator Owners for events that are minimally impacting to the BES. It should be noted that nothing in this standard prevents a Generator Owner from taking its own corrective actions resulting from such events. Startup failures are defined using the GADS definition with the removal of "following an outage or reserve shutdown", since the definition of Reserve shutdown is different in GADS than it is in some of the RTO's.

R6 requires the Generator Owner to act within 150 days or by July 1 to develop the CAP. These timeframe options were chosen by the SDT to allow Generator Owner's to review multiple events holistically following a winter season if that scenario occurs, and create one CAP for components with common failure causes.

The SDT determined that CAPs will be required for any freezing event that occurs at temperatures above the site's Extreme Cold Weather Temperature. By using the site's Extreme Cold Weather Temperature, as opposed to the Generator Unit Minimum Temperature as defined by the Generator Owner as the threshold, this achieves the following:

- Provides a consistent basis for the temperature at which CAPS are required for all Generator Owners
- Provides a consistent basis for when CAPS are required for all Generation types
- Provides a consistent basis for when CAPS are required regardless of the level of effort that Generators may have applied to-date winterizing their generators such that they can operate to the Extreme Cold Weather Temperature that their sites will reasonably experience
- Removes any incentive (perceived or real) to not further winterize Generator Owner's sites to meet the Extreme Cold Weather temperature at the Generator Owner site by not providing a window where one site might not be subject to the CAP requirement while sites in the same vicinity experiencing the same temperatures are subject to this requirement
- Removes any disincentive for Generator Owner's to design the units to operate well below the Extreme Cold Weather Temperature for a site by not requiring them to perform CAPs while sites in the same vicinity experiencing the same temperatures are subject to this requirement

Requirement R7

R7. Each Generator Owner shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

7.1 Implement each CAP developed pursuant to Requirements R2, R4, or R6, or explain in a declaration why corrective actions are not being implemented due to any technical, commercial, or operational constraints as defined by the Generator Owner.

7.2 Update each CAP if actions or timetables change, until completed.

The SDT has also separated the requirement to implement a CAP from the requirement to create a CAP. This is similar in structure to PRC-004-6 R5 and R6. For CAPs developed pursuant to Requirements R2, R4, and R6 in the proposed standard, the Generator Owner creates a document with a date of approximately the time of the event/determination of the need to make changes. This shows that the Generator Owner identified issues caused by cold weather. Implementation of the CAP is demonstrated through updates to the original document or completion of the tasks listed in the CAP under a separate requirement. The separation of these distinct functions facilitates administration of the process and makes it less likely for a CAP to be written but not implemented. Requirement R7 also defines the requirement to make a declaration when technical, commercial, or operational constraints are asserted.

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Extreme Cold Weather Preparedness

Technical Rationale and Justification for EOP-012-1

~~August~~September 2022

RELIABILITY | RESILIENCE | SECURITY




3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

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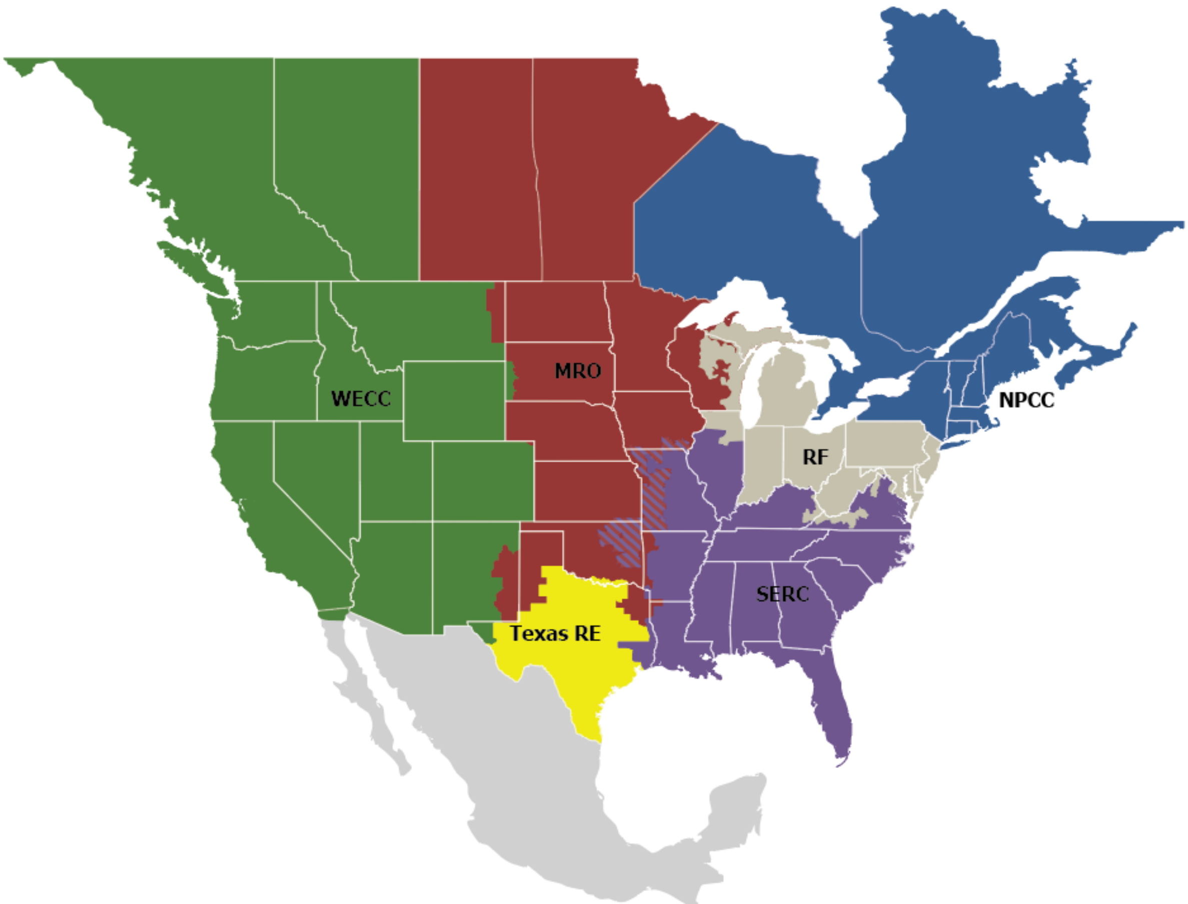
Preface

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 the North American Electric Reliability Corporation (NERC) and the six Regional Entities, is a highly reliable 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 Entity boundaries as shown in the map and 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 EOP-012-1. 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 EOP-012-1 is not a Reliability Standard and should not be considered mandatory and enforceable.

Background

From February 8 through February 20, 2021, extreme cold weather and precipitation caused large numbers of generating units to experience outages, derates or failures to start, resulting in energy and transmission emergencies (referred to as "the Event"). The total Event firm load shed was the largest controlled firm load shed event in U.S. history and was the third largest in quantity of outaged megawatts (MW) of load after the August 2003 northeast blackout and the August 1996 west coast blackout. The Event was most severe from February 15 through February 18, 2021, and it contributed to power outages affecting millions of electricity customers throughout the regions of ERCOT, SPP, and MISO South. Additionally, the February 2021 event is the fourth cold weather event in the past 10 years, which jeopardized bulk-power system reliability. A joint inquiry was conducted to discover reliability-related findings and develop recommendations from FERC, NERC, and Regional Entity staff. The FERC, NERC, and Regional Entity Staff Report into the February 2021 Cold Weather Outages ("Joint Inquiry Report") was published on November 16, 2021.

The scope of the proposed project is to address the ten recommendations for new or enhanced NERC Reliability Standards proposed by the Joint Inquiry Report. In November 2021, the NERC Board of Trustees (Board) approved a Board Resolution directing that new or revised Reliability Standards addressing these recommendations be completed in accordance with the timelines recommended by the joint inquiry team, as follows:

- New and revised Reliability Standards to be submitted for regulatory approval before Winter 2022/2023: development completed by September 30, 2022, for the Board's consideration in October 2022 to address Key Recommendations 1d, 1e, 1f, and 1j;

- New and revised Reliability Standards to be submitted for regulatory approval before Winter 2023/2024: development completed by September 30, 2023, for the Board's consideration in October 2023 to address Key Recommendations 1a, 1b, 1c, 1g, 1h, and 1i.

Facilities

4.2 Facilities:

4.2.1 For purposes of this standard, the term “generating unit” subject to these requirements ~~***means***~~refers to the following Bulk Electric System (BES) resources:

4.2.1.1 ~~***4.1.***~~ A Bulk Electric System generating unit~~:~~

~~***4.1.1.***~~ that ~~***That***~~ commits or is obligated to serve a Balancing Authority load pursuant to ~~***an Open Access Transmission Tariff (OATT)***~~a tariff obligation, state requirement as defined by the relevant electric regulatory authority, or other contractual arrangement~~;~~, rule, or regulation, for a continuous run of four hours or more at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius); or

4.2.1.2 A Blackstart Resource

4.2.2 Exemptions:

4.2.2.1 Any Bulk Electric System generating unit included under Section 4.2.1 above that has a calculated Extreme Cold Weather Temperature exceeding 32 degrees Fahrenheit (zero degrees Celsius) under Requirement R3 Part 3.1 and as part of the required five year review in Requirement R4 Part 4.1 is exempt from further requirements in this standard.

4.2.2.2 ~~***4.1.1.1. The term excludes a***~~ A Bulk Electric System generating unit that is ~~***typically not available***~~ not committed or obligated to operate at or below ~~***thirty-two (***~~a temperature of 32~~)~~ degrees Fahrenheit (zero degrees Celsius) for any continuous run of more than four hours~~***. The exclusion applies even when such BES generator has been called***~~, but is called upon to operate for more than four hours in order to assist in the mitigation of BES Emergencies, Capacity Emergencies, or Energy Emergencies during periods at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius).

~~***4.1.2.*** *Blackstart Resources*~~

In the Joint Inquiry Report, Key Recommendation 1f includes ~~support~~ clarifying information, which states “consideration should be given to designing all new generation plants and designing modifications to existing plants (unless committed solely for summer peaking purposes)...[.][1] FERC staff from the Joint Inquiry Report team clarified further to the standard drafting team (SDT) that the reference to summer peaking units acknowledges that some units have not implemented freeze protection measures or may not be able to secure fuel in the winter and therefore, plan to commit solely to serve Balancing Authority load during non-winter conditions. The standard provides an Applicability section identifying which generating units are subject to the requirements, with two exemptions available if the generating unit meets two narrowly construed conditions.

The Applicability section first defines “generating unit” as a Bulk Electric System (BES) resource. The NERC Glossary of Terms provides the foundation for what BES resources are included in the definition (see Inclusions I2 through I4). The Applicability section further defines which BES resources are intended to be subject to the standards’ requirements, and explains exemptions available consistent with Key Recommendation 1f. The intent of the proposed standard is not to mandate that all generating units provide capacity in extreme cold weather, but instead to ensure that those ~~units~~ BES resources that ~~commits or is~~ are obligated to serve Balancing Authority load during periods at or

[1] See Report, page 189.

below freezing due to commitments pursuant to tariff obligations, state requirements defined by regulatory authorities, or other contractual arrangements, rules, or regulations are subject to the winterization requirements. ~~Additionally, summer units~~ The SDT chose the four-hour timeframe in consideration of generators that typically do not commit during freezing conditions but are running when conditions drop below freezing for a short period of time (under four hours) and would therefore not automatically be subject to the standard. Additionally, Blackstart Resources are also specifically declared subject to the winterization requirements. Such Blackstart Resource, consistent with the NERC Glossary of Terms, are those units designated in the Transmission Operator's restoration plans.

Applicability section 4.2.2.1 clarifies further that a BES resource that is included pursuant to Applicability section 4.2.1 but that has a calculated Extreme Cold Weather Temperature exceeding freezing is also exempt. However, such generators must comply with the ongoing five-year review requirements of R4 Part 4.1 to ensure its ongoing exemption is appropriate. If a five-year review determines that the Extreme Cold Weather Temperature for the BES resource has fallen to freezing or below, then such BES resource will become subject to the requirements. With regards to the exemption provision contained in the Applicability section 4.2.2.2, BES resources exempt under the Applicability section but are called upon during extreme cold weather emergency contingencies should be able to respond to the Balancing Authority's commitment requests without triggering the requirements. This language ensures that this intent is satisfied for all requirements that follow.

~~To~~ In summary, to meet the intent of ~~the recommendation~~ Recommendation 1f as clarified by FERC staff, a ~~generator is excluded~~ BES resources as defined by the NERC Glossary of Terms is subject to EOP-12-1 if it operates pursuant to an obligation to run for more than four continuous hours at or below freezing. However, the BES resource may be exempt from the requirements if the ~~generator typically is not available~~ BES resources not be committed or otherwise obligated to run at or below freezing conditions for more than a four-hour continuous ~~run~~ operation.

~~The SDT chose the four-hour timeframe in consideration of generators that typically do not commit during freezing conditions but are running when conditions drop below freezing for a short period of time (under four hours) and would therefore not automatically be subject to the standard.~~ Additionally, such exclusion applies even when such generator is called upon to assist in the mitigation of a declared energy contingency (defined in the NERC Glossary of Terms as a BES Emergency, Capacity Emergency, or Energy Emergency). The language works as a blanket inclusion of all BES ~~generating units~~ resources that serve Balancing Authority load for a period of more than four hours in freezing conditions, with the ~~exception~~ exemption of summer units or BES Resources that are not ~~typically available~~ committed to serve load during non-winter conditions~~; and the exception includes even those~~ (e.g. summer peaking units ~~that are~~); and the exemption is maintained by such BES resources when committed for a short period during energy contingencies.

Defined Terms

The SDT developed three terms to be added to the NERC Glossary to make the requirements easier to read and understand. These three terms are:

Extreme Cold Weather Temperature

The temperature equal to the lowest 0.2 percentile of the hourly temperatures measured in December, January, and February from 1/1/2000 through the date the temperature is calculated.

The definition of Extreme Cold Weather Temperature was developed by the SDT to provide clarity to the Generator Owner on determining what temperature triggers the requirement obligations. Each Generator Owner should select a reliable source of data from a recording location near the plant to determine their Extreme Cold Weather Temperature. Sources would include, for example, the National Weather Service (NWS) or National Oceanographic and Atmospheric Administration (NOAA) weather stations, Federal Aviation Administration (FAA) weather stations, or Environment and Climate Change Canada location for Canadian entities[2], etc. NOAA's National Centers for Environmental Information provides Climate Data Online (CDO) as a free resource that includes quality-controlled weather data and 30-year Climate Normals[3]. In general, Generator Owners should use the location nearest the plant, but may select a further location if geographic or local climatic patterns make a further location more representative of the weather at the generating unit. Generator Owners may use on-site weather stations if data, which reasonably matches reliable nearby off-site sources since January 1, 2000, is available. The starting period chosen by the SDT to gather data to determine the lowest temperatures that occur near a facility is based on the completion of the modernization of the National Weather Service project known as MAR (Modernization and Associated Restructuring). This project was completed in the year 2000. In general, the National Weather Service modernization provides weather data to be available at most large airports at a 99%+ availability. This will make it fairly accessible for companies to gather data and perform the required analysis. The December through February timeframe was selected to correspond to the meteorological winter, as defined by NOAA.[4]

The SDT discussed methods for determining an Extreme Cold Weather Temperature with engineering design professionals, and it was determined that it is typical engineering practice to use a statistical approach to determine the design temperature when implementing generation facility freeze protection measures. The SDT determined that only winter temperature values (i.e. between December and February) shall be used for the statistical approach and based on analysis of multiple sites, it was determined that by using the lowest 0.2 percentile, there will be sufficient data points to ensure that a single hour at a temperature that may not be accurate, or may be a statistical anomaly, doesn't result in an overly conservative design or preclude the ability of the Generator Owner to use historical operating data to prove compliance to the standards. The SDT selected the 0.2 percentile of winter month temperatures since 1/1/2000 to identify a temperature which has been rarely surpassed, but which allows some margin for a Generator Owner to have previously demonstrated successful operation. The SDT considered using the lowest recorded hourly ambient temperature but, upon further review of the historical weather data and generally accepted design principles, determined that the statistical approach to setting the extreme cold weather temperature for a site was more reasonable.

Generator Cold Weather Critical Component

Any generating unit component or associated fixed fuel supply component, that is under the Generator Owner's control and that is susceptible to freezing issues, the occurrence of which would likely lead to a generating unit(s): (1) forced derate of more than 10% of the total capacity of the unit and exceeding 20 MWs for longer than four hours in duration, (2) a start-up failure where the unit fails to synchronize within a specified start-up time, or (3) a Forced Outage.

The SDT felt the best method to address where freeze protection measures should be implemented was to define a term which specifies a subset of components that may be susceptible to freezing, and are critical to the operation of generating units. A fixed fuel supply component is intended to cover non-mobile equipment that supports the reliable delivery of fuel to the generating unit that is controlled by the Generator Owner. It would include gaseous, liquid, or solid fuel handling components that are installed as fixed parts of the fuel delivery system that are under the Generator Owner's control. It would not include mobile equipment such as trains, bulldozers, or other equipment that are not fixed in one location.

The SDT's intent with regard to the language "that is under the Generator's Owner's control" was to clearly delineate that cold weather events external to Generation site such as loss of fuel supply or loss of auxiliary power to the site that resulted in a Cold Weather Reliability Event would not be subject to this standard. Furthermore, ice buildup on

[2] Environment and Climate Change Canada - Canada.ca

[3] ~~https://www.ncei.noaa.gov/products/land-based-station/us-climate-normals~~ https://www.ncei.noaa.gov/products/land-based-station/us-climate-normals

[4] https://www.ncei.noaa.gov/news/meteorological-versus-astronomical-seasons

Transmission lines would not constitute a freezing condition in the context of this Standard and therefore these Transmission Lines would not be considered a Generator Cold Weather Critical Component.

Generator Cold Weather Reliability Event

One of the following events for which the apparent cause(s) is due to freezing of equipment within the Generator Owner's control and the dry bulb temperature at the time of the event was at or above the Extreme Cold Weather Temperature:

(1) a forced derate of more than 10% of the total capacity of the unit and exceeding 20 MWs for longer than four hours in duration;

(2) a start-up failure where the unit fails to synchronize within a specified start-up time; or

(3) a Forced Outage~~,~~.

~~*for which the apparent cause(s) is due to freezing of equipment within the Generator Owner's control and the dry bulb temperature at the time of the event was at or above the Extreme Cold Weather Temperature.*~~

The SDT is using the definition of apparent as defined in the dictionary as "clear or manifest to the understanding". For more explanation on this definition please see Requirement R6 Technical Rationale Below.

Requirement R1 and R2

R1. *For a generating unit(s) with a commercial operation date subsequent to [Effective Date of this requirement], the Generator Owner shall: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]*

- *Implement freeze protection measures that provide capability to operate for a period of not less than twelve (12) continuous hours at the Extreme Cold Weather Temperature for the unit(s), assuming a concurrent twenty (20) mph wind speed on any exposed Generator Cold Weather Critical Components; or*

- *Explain in a declaration, any technical, commercial, or operational constraints as defined by the Generator Owner that preclude the ability to implement appropriate freeze protection measures to provide capability of operating for twelve (12) hours at the documented Extreme Cold Weather Temperature.*

R2. *For each generating unit(s) in commercial operation prior to [Effective Date of this requirement], the Generator Owner shall ensure its generating unit(s) add new or modify existing freeze protection measures as needed to provide the capability to operate for a period of not less than one (1) hour at the unit(s) Extreme Cold Weather Temperature. Generating unit(s) that are not capable of operating for one (1) hour at its Extreme Cold Weather Temperature shall develop a Corrective Action Plan (CAP) for the identified issues, including identification of any needed modifications to the cold weather preparedness plan required under Requirement R3. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]*

<u>Key Recommendation 1f:</u> To require Generator Owners to retrofit existing generating units, and when building new generating units, to design them to operate to a specified ambient temperature and weather conditions (e.g., wind, freezing precipitation). The specified ambient temperature and weather conditions should be based on available extreme temperature and weather data for the generating unit's location.

General Considerations

As referenced in Key Recommendation 1f above, the specified ambient temperature and weather conditions should be based on available extreme temperature and weather data for the generating unit's location. FERC staff from the

Joint Inquiry Report team clarified to the SDT that the reliability goal of the recommendation for existing generating units is to have the necessary freeze protection measures to be able to operate at extreme cold temperatures and weather for the generating unit's location. For example, those measures may consist of existing[5] or new, permanent and/or temporary measures[6] to maintain operation during extreme cold temperatures. Therefore, FERC staff clarified that the joint team's intent of the word retrofit is "to implement new, and/or make modifications to existing freeze protection measures for existing generating units."

In discussions with the Joint Inquiry Report team and in reading the Joint Inquiry Report itself, it is clearly stated that "consideration should be given to designing all new generation plants and designing modifications to existing plants (unless committed solely for summer peaking purposes) to be able to perform at the lowest recorded ambient temperature for the nearest city for which historical weather data is available …)". The Report went on to provide evidence that "Not only did generating units fail to perform at the lowest recorded ambient temperature for the nearest city, but many failed to perform at their own ambient design temperatures". The Joint Inquiry Report also notes that "Over 40 percent of the GOs/GOPs in the south-central U.S. regions where "freezing issues" were identified as the predominant cause of unplanned generation outages, derates or failures to start stated that they did not incorporate specific generator-related recommendations from the 2011 Report[7] or specific recommendations from the Guideline[8]."

Based on the generating unit data contained in the Joint Inquiry Report, many generating units that operate in the winter season are not properly winterized to remain in reliable service during the most extreme cold weather conditions that they may reasonably be expected to experience at their locations. As the load on the grid is the most elevated at these extreme conditions, these are the periods when it is most critical that these generating units maintain their reliability. As such, Requirement 1 ensures that generating units are proactively taking steps to design and maintain their units to maintain their reliability during extreme cold weather.

Requirement R1

The Joint Inquiry Report key recommendation 1f references recommendation 12 of the 2011 report suggesting that consideration should be given to designing all new generation plants and designing modifications to existing plants (unless committed solely for summer peaking purposes) to be able to perform at the lowest recorded ambient temperature for the nearest city for which historical weather data is available. The Joint Inquiry Report states "The Standards Drafting Team can decide what additional specificity is desirable for this requirement, for example, specifying the number of years of weather data to be considered in establishing the required ambient temperature and weather conditions, and the source of the extreme temperature and weather data". The SDT considered several options of how many years back historical data should be analyzed (e.g., 10 years, 30 years, 50 years, 100 years). There is concern that some geographical areas may not have reliable data dating back 100 years. The SDT's meteorological research finds that significant improvements were made and modernization of weather stations implemented in the early years of the 21st century. Given this, the SDT settled on the look back date of January 1, 2000.

The key recommendation identifies wind and freezing precipitation as examples of weather conditions to consider during the design of new generating units and modifications to existing plants. Realizing the many differences in weather that generator sites face across the Regions, the 2021-07 SDT developed language to provide additional context and detail around these weather conditions, while allowing flexibility for site-specific circumstances. The

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[5] While the dictionary definition of the word retrofit includes to install (new or modified parts or equipment) in something previously manufactured or constructed, its origin suggests the need for replacing existing equipment with new technologies, which was not the intent of the joint team in this case. See Merriam-Webster definition.

[6] Some freeze protection measures may need to be removed for summer temperature operation.

[7] Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011

[8] Reliability Guideline Generating Unit Winter Weather Readiness - Current Industry Practices

requirement language considers wind at a specific rate when designing new facilities. New units with commercial operation dates after the effective date of EOP-012-1 shall implement freeze protection measures such that their facilities are capable of continuous operation for not less than 12 hours at the Extreme Cold Weather Temperature assuming a concurrent twenty (20) mph wind speed on any exposed Generator Cold Weather Critical Component.

Because R1 is applicable to newly designed facilities, there is no allowance for a CAP. However, it is recognized that technical, commercial, or operational constraints may exist that prevent a new generating unit(s) from being capable of twelve (12) continuous hours of operation at their identified Extreme Cold Weather Temperature. Thus, the SDT included in R1, the option for the Generator Owner to make a declaration supporting why technical, commercial, or operational constraints preclude the ability to implement appropriate freeze protection measures. The SDT chose 12 hours of continuous operation because it is a typical length of the nighttime in winter and the maximum amount of time that generating units would experience the Extreme Cold Weather Temperature. The SDT chose a concurrent 20 mph speed after an evaluation using the wind chill formula developed by the US National Weather Service (NWS) in the United States. Though wind chill temperature is not an exact science, it is widely understood to reflect the non-linear increased rate of convective heat loss due to air moving at different velocities. Commonly available charts show wind chill temperatures as a function of actual air temperature at various wind speeds. As it turns out, about 2/3 of the wind chill temperature drop between 0 – 60 mph is already achieved at 20 mph. Using the NWS chart, this holds true for still air temperatures starting at 40 F and dropping in 20-degree increments to -40 F. Further, 20 mph is a wind speed commonly experienced across the NERC area and yet appropriately higher than the approximate average wind speeds in the United States and Canada, 6-12 mph and 8-11 mph respectively.

Requirement R2

The SDT created a requirement to develop a CAP for generating units in commercial operation prior to the effective date of EOP-012-1 that requires either new freeze protection measures, or modification of existing freeze protection measures, to be capable of one hour of continuous operation at their identified Extreme Cold Weather Temperature. The SDT chose one hour as opposed to 12 hours for existing generation to recognize the fact that it is extremely difficult to perform the same level of design analysis, and/or documented historical operation on existing generation as on new generation. However, it is recognized that modifications or corrective actions may not be feasible under all circumstances due to technical, commercial, or operational constraints.

Additionally, the SDT considered the potential for unintended consequences, such as limiting participation by generation units in cold temperatures or accelerating generator retirements, caused by requirements to develop and implement CAPs to be capable of operations under the conditions defined in R2.

The SDT discussed setting a timeframe needed for the CAP to be completed during the drafting phase. While it is important that the CAP be completed, it would be difficult to set a definite timeframe due to the number of variables that could impact the completion of the CAP once the cause is determined. The requirements five year implementation plan is focused solely on the development of the CAP, not completion of the CAP. The SDT believes that it is more important to develop a CAP that identifies the solution and resolves the situation correctly regardless of time. Therefore, the team did not define a time when the CAP needs to be completed.

Requirement R3

R3. *Each Generator Owner shall implement and maintain one or more cold weather preparedness plan(s) for its generating units. The cold weather preparedness plan(s) shall include the following, at a minimum: [Violation Risk Factor: High] [Time Horizon: Operations Planning and Real-time Operations]*

3.1 *The Extreme Cold Weather Temperature for their unit(s) including the calculation date and source of temperature data;*

3.2 *Documentation identifying the Generator Cold Weather Critical Components;*

3.3 *Documentation of freeze protection measures implemented on Generator Cold Weather Critical Components which may include measures used to reduce the cooling effects of wind determined necessary by the Generator Owner to protect against heat loss, and where applicable, the effects of freezing precipitation (e.g., sleet, snow, ice, and freezing rain);*

3.4 *Annual inspection and maintenance of generating unit(s) freeze protection measures; and*

3.5 *Generating unit(s) cold weather data, to include:*

3.5.1 *Generating unit(s) operating limitations in cold weather to include:*

3.5.1.1 *Capability and availability;*

3.5.1.2 *Fuel supply and inventory concerns;*

3.5.1.3 *Fuel switching capabilities; and*

3.5.1.4 *Environmental constraints.*

3.5.2 *Generating unit(s) minimum:*

- *Design temperature;*
- *Historical operating temperature; or*
- *Current cold weather performance temperature determined by an engineering analysis.*

General Considerations

Requirement R3 requires Generator Owners to develop and maintain cold weather preparedness plans for its unit(s) and describes the information and documentation required in such plans. It is an expansion of the cold weather preparedness plan required under Requirement R7 of EOP-011-2, and is intended to be used and reviewed regularly by the Generator Owner; R3.4 requires the GO to annually inspect the freeze protection measures. Working in concert with other parts of EOP-012, including R4 and R5, the plan will be regularly reviewed and updated and the GO is required to annually train personnel on its requirements.

Requirement R3 Part 3.1

In R3.1, the Generator Owner is required to determine the Extreme Cold Weather Temperature, as defined in the standard, for each unit using reliable source of data. The SDT believes that the GO is in the best position to select the most representative weather information relative to its generating unit.

Requirement R3 Part 3.2

In R3.2, the Generator Owner identifies the Generator Cold Weather Critical Components to help inform their decision on where to implement appropriate freeze protection measures. The document *Reliability Guideline, Generating Unit Winter Weather Readiness – Current Industry Practices*[9], NERC, 2012 presents a suggested list of components that Generator Owners may choose to utilize when developing their own Generator Cold Weather Critical Component inventory.

Requirement R3 Part 3.3

R3.3 requires GOs to document the freeze protection measures implemented on cold-weather-critical components. These freeze protection measures may include those to reduce the cooling effects of wind. Requirement R3 does not require Generator Owners to install new freeze protection measures to reduce the cooling effects of wind, but rather to document those measures. These measures would include temporary measures such as wind breaks. There is no expectation for entities to list all climate controlled areas as freeze protection measures. Similar to the cooling effects

[9] Reliability Guideline Generating Unit Winter Weather Readiness – Current Industry Practices

of wind, R3 requires Generator Owners to document freeze protection measures taken to reduce the effects of freezing precipitation on cold-weather-critical components, as the Generator Owners ~~determines is~~ determine if necessary (e.g. water-resistant insulation, protective shielding, insulated boxes, etc.).

Requirement R3 Part 3.4

R3.4 is carried over from the previously approved EOP-011-2 standard, and requires annual inspection and maintenance of the freeze protection measures identified in the cold weather preparedness plan. This requirement ensures these freeze protection measures will be ready and serviceable when needed. Examples of documentation to demonstrate inspections and maintenance has been completed would be completed work order(s) from the Generator Owner's work management system and/or freeze protection checklists identifying the measures inspected and maintained.

Requirement R3 Part 3.5

R3.5 is carried over from the previously approved EOP-011-2 standard, and requires the Generator Owner to document several cold weather performance parameters for the unit. This information is valuable, and in some cases, must be shared with other entities. Defining the operating limitations in R3.5.1 will make affected personnel more aware of unit capabilities and constraints as well as systems and practices that may be necessary to ensure reliability in cold weather, particularly when alternative fuels are involved. In addition, the unit minimum temperature identified in R3.5.2 is used to demonstrate compliance with R2 for existing units.

Requirement R4

R4. *Once every five calendar years, each Generator Owner shall for each generating unit: [Violation Risk Factor: Low] [Time Horizon: Operations Planning, Real-Time Operations]*

4.1 *Calculate the Extreme Cold Weather Temperature, and update the cold weather preparedness plan if this temperature is now lower than the previous lowest calculation;*

4.2 *Review its documented generating unit(s) minimum temperature contained within its cold weather preparedness plan(s), pursuant to Part 3.5.2; and*

4.3 *Review whether its generating units have the freeze protection measures required to operate at the Extreme Cold Weather Temperature pursuant to R1 or R2 as applicable, and if not develop a CAP for the identified issues, including identification of any needed modifications to the cold weather preparedness plan required under Requirement R3.*

The SDT has developed the new standard with language that supports the ongoing consideration of new technologies when protecting against extreme cold weather, and an ongoing review requirement to validate or update the Extreme Cold Weather Temperature associated with each unit. This five-year review supports the desire for Generator Owners to periodically vet these new technologies and consider whether any technical, commercial, or operational constraints are still applicable.

Requirement R5

R5. *Each Generator Owner in conjunction with its Generator Operator shall identify the entity responsible for providing the generating unit-specific training, and that identified entity shall provide annual training to its maintenance or operations personnel responsible for implementing cold weather preparedness plan(s) developed pursuant to Requirement R3. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]*

Key Recommendation 1e: To revise EOP-011-2, R8, to require Generator Owners and Generator Operators to conduct annual unit-specific cold weather preparedness plan training.

Project 2019-06 Cold Weather established the requirement that the Generator Owner, in conjunction with its Generator Operator, would provide generating unit-specific training for its personnel responsible for implementing cold weather preparedness plan(s) for its generating units. The Joint Inquiry Report recommended that EOP-011-2 R8 be revised to require the generating unit-specific training be provided on an "annual" basis. The report explains "Responses from the GOs/GOPs involved in the Event show that annual training is not yet universal in the Event Area." To address this recommendation, the SDT has utilized the existing language in EOP-011-2 and added the word "annual" to require the training on an annual basis. The requirement is deleted from EOP-011-3, and will be placed as a requirement in a new EOP-012-1 Reliability Standard dedicated solely to extreme cold weather preparedness.

Requirement R6

R6. *Each Generator Owner that owns a generating unit that experiences a Generator Cold Weather Reliability Event shall develop a CAP, within 150 days or by July 1, whichever is earlier, that contains at a minimum: [Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

6.1 *A summary of the identified cause(s) for the Generator Cold Weather Reliability Event where applicable and any relevant associated data;*

6.2 *A review of applicability to similar equipment at other generating units owned by the Generator Owner;*

6.3 *An identification of any temporary operating limitations or impacts to the cold weather preparedness plan, that would apply until execution of the corrective action(s) identified in the CAP.*

Key Recommendation 1d: To require Generator Owners that experience outages, failures to start, or derates due to freezing to review the generating unit's outage, failure to start, or derate and develop and implement a corrective action plan (CAP) for the identified equipment, and evaluate whether the CAP applies to similar equipment for its other generating units. Based on the evaluation, the Generator Owner will either revise its cold weather preparedness plan to apply the CAP to the similar equipment, or explain in a declaration (a) why no revisions to the cold weather preparedness plan are appropriate, and (b) that no further corrective actions will be taken. The standard drafting team should specify the specific timing for the CAP to be developed and implemented after the outage, derate, or failure to start, but the CAP should be developed as quickly as possible, and be completed by no later than the beginning of the next winter season.

The key recommendation from the report recommends a standard ~~the~~that requires Generator Owners to develop a CAP for generating units that experience outages, failures to starts, or derates due to freezing. The Report identifies that most of the outages and derates in the February 2021 event were due to freezing of instrumentation, transmitters, sensing lines, or wind turbine blades (p 166 in report). As such, the team followed the Report recommendation to require a CAP when the apparent cause of the event is freezing. The Project 2021-07 SDT has developed parameters around these events to clarify a reasonable baseline of what level of de-rate qualifies as an event, and provide additional language to identify what constitutes a start-up failure. With the additional clarifications, the SDT determined that the standard would benefit from a defined term, to clearly and efficiently state what constitutes an event. The result is to a new defined term, Generator Cold Weather Reliability Event, that defines the circumstances for which a CAP is required (i.e., when a freezing event effects the equipment within the control of the Generator Owner). The defined term will make the standard easier to understand and implement by providing clear and reasonable factors to determine whether the impact of an event requires mitigation

General Considerations for All CAPs

To simplify the proposed requirements related to creating a CAP, the SDT has modified the proposed requirements addressing the need for a CAP while better incorporating the NERC Definition of a CAP. The CAP definition reads "A list of actions and an associated timetable for implementation to remedy a specific problem." As written, the definition requires two parts for a document to qualify as a CAP, i.e., a list of items to be addressed and a timeline for completion. In the original posting, the SDT included both items in separate bullets to be included in the CAP. To simplify the requirements, the SDT has removed the bullets. As these two elements are both required for a document to qualify as a CAP, there is no need to list these items separately within the standard. A CAP without both a list of actions and the timeline to implement is not complete.

Requirement R6

The CAP requirement applies to any forced outage due to freezing, regardless of duration. Derates, which are short-lived (specified as 4 hours by the SDT) or of small capacity impact (specified as less than 20 MW by the SDT, which corresponds with the threshold for BES impacting Generation units), are excluded from the CAP requirement to limit the administrative burden to Generator Owners for events that are minimally impacting to the BES. It should be noted that nothing in this standard prevents a Generator Owner from taking its own corrective actions resulting from such events. Startup failures are defined using the GADS definition with the removal of "following an outage or reserve shutdown", since the definition of Reserve shutdown is different in GADS than it is in some of the RTO's.

R6 requires the Generator Owner to act within 150 days or by July 1 to develop the CAP. These timeframe options were chosen by the SDT to allow Generator Owner's to review multiple events holistically following a winter season if that scenario occurs, and create one CAP for components with common failure causes.

The SDT determined that CAPs will be required for any freezing event that occurs at temperatures above the site's Extreme Cold Weather Temperature. By using the site's Extreme Cold Weather Temperature, as opposed to the Generator Unit Minimum Temperature as defined by the Generator Owner as the threshold, this achieves the following:

- Provides a consistent basis for the temperature at which CAPS are required for all Generator Owners
- Provides a consistent basis for when CAPS are required for all Generation types
- Provides a consistent basis for when CAPS are required regardless of the level of effort that Generators may have applied to-date winterizing their generators such that they can operate to the Extreme Cold Weather Temperature that their sites will reasonably experience
- Removes any incentive (perceived or real) to not further winterize Generator Owner's sites to meet the Extreme Cold Weather temperature at the Generator Owner site by not providing a window where one site might not be subject to the CAP requirement while sites in the same vicinity experiencing the same temperatures are subject to this requirement
- Removes any disincentive for Generator Owner's to design the units to operate well below the Extreme Cold Weather Temperature for a site by not requiring them to perform CAPs while sites in the same vicinity experiencing the same temperatures are subject to this requirement

Requirement R7

R7. Each Generator Owner shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

7.1 Implement each CAP developed pursuant to Requirements R2, R4, or R6, or explain in a declaration why corrective actions are not being implemented due to any technical, commercial, or operational constraints as defined by the Generator Owner.

7.2 Update each CAP if actions or timetables change, until completed.

The SDT has also separated the requirement to implement a CAP from the requirement to create a CAP. This is similar in structure to PRC-004-6 R5 and R6. For CAPs developed pursuant to Requirements R2, R4, and R6 in the proposed standard, the Generator Owner creates a document with a date of approximately the time of the event/determination of the need to make changes. This shows that the Generator Owner identified issues caused by cold weather. Implementation of the CAP is demonstrated through updates to the original document or completion of the tasks listed in the CAP under a separate requirement. The separation of these distinct functions facilitates administration of the process and makes it less likely for a CAP to be written but not implemented. Requirement R7 also defines the requirement to make a declaration when technical, commercial, or operational constraints are asserted.

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3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
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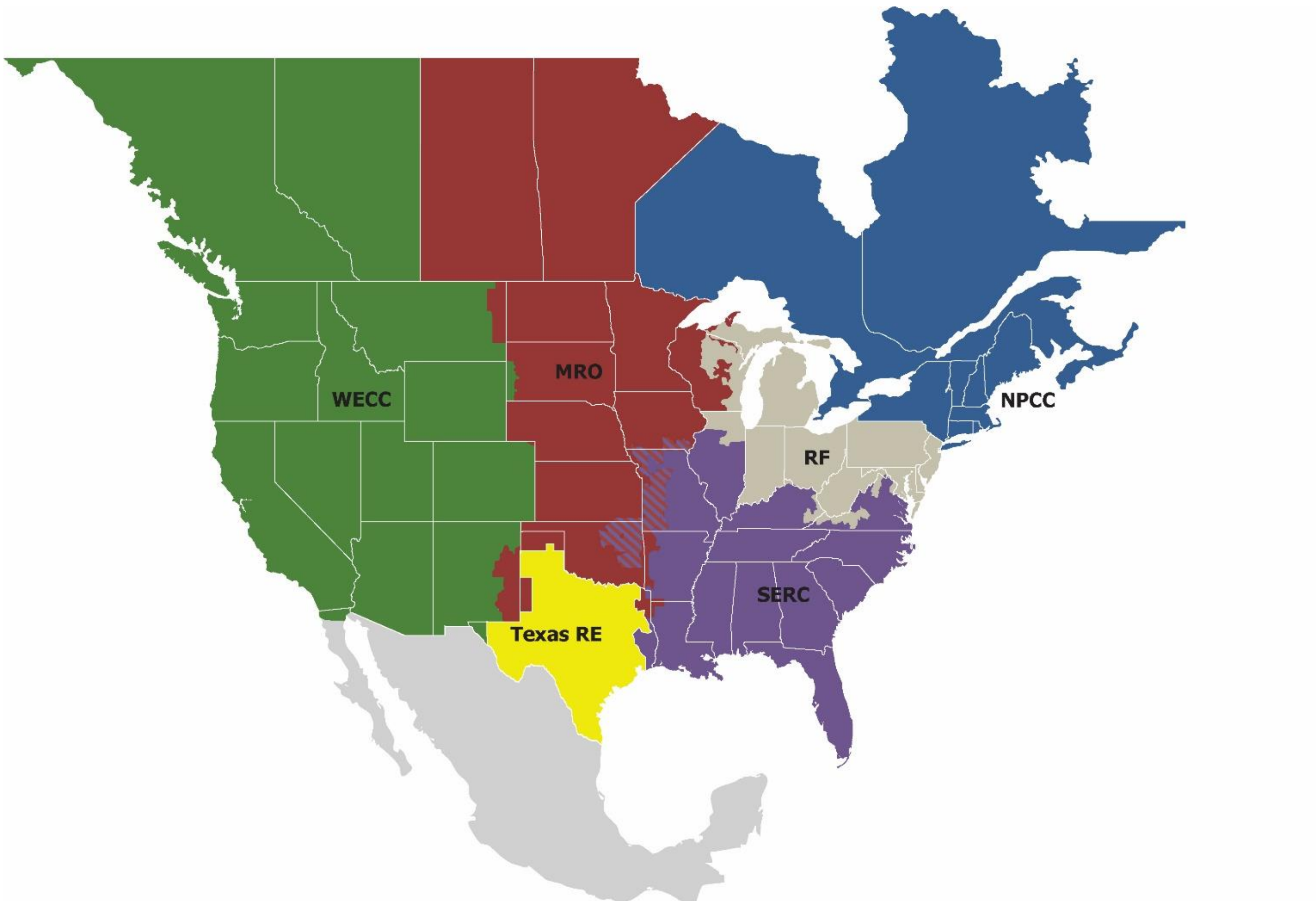
Preface

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 Entity boundaries as shown in the map and 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

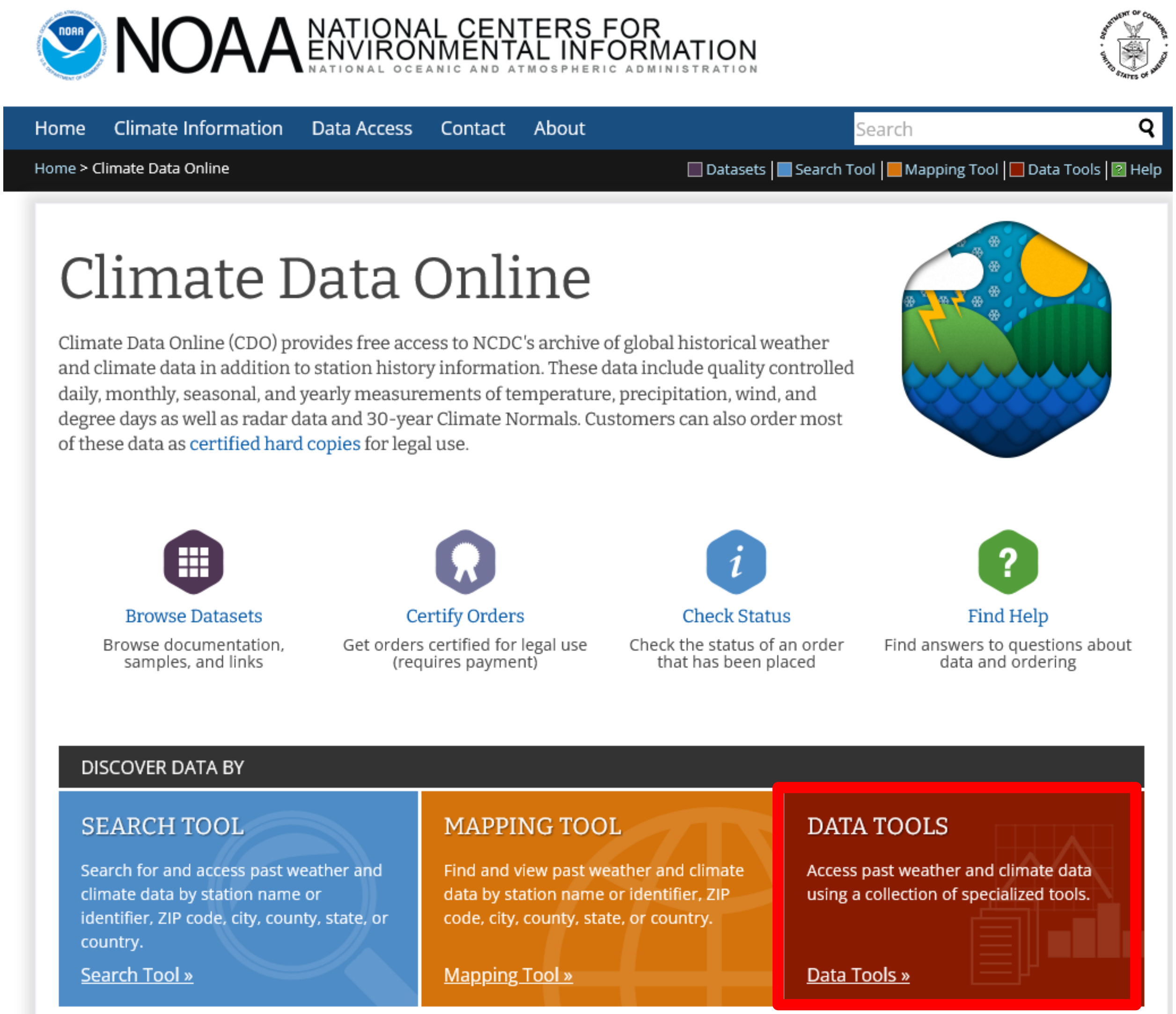
This document will demonstrate one method for acquiring the necessary data for a given location and a method of performing the statistical analysis of the data to determine the Extreme Cold Weather Temperature for a given location. This example is focused on United States and will use data obtained from NOAA's Climate Data Online database and perform the statistical analysis with Microsoft Excel. The method shown in this document only shows the collection of data from a single source and two methods of analyzing this data, both using Microsoft Excel.

Determination of Location's Extreme Cold Weather Temperature

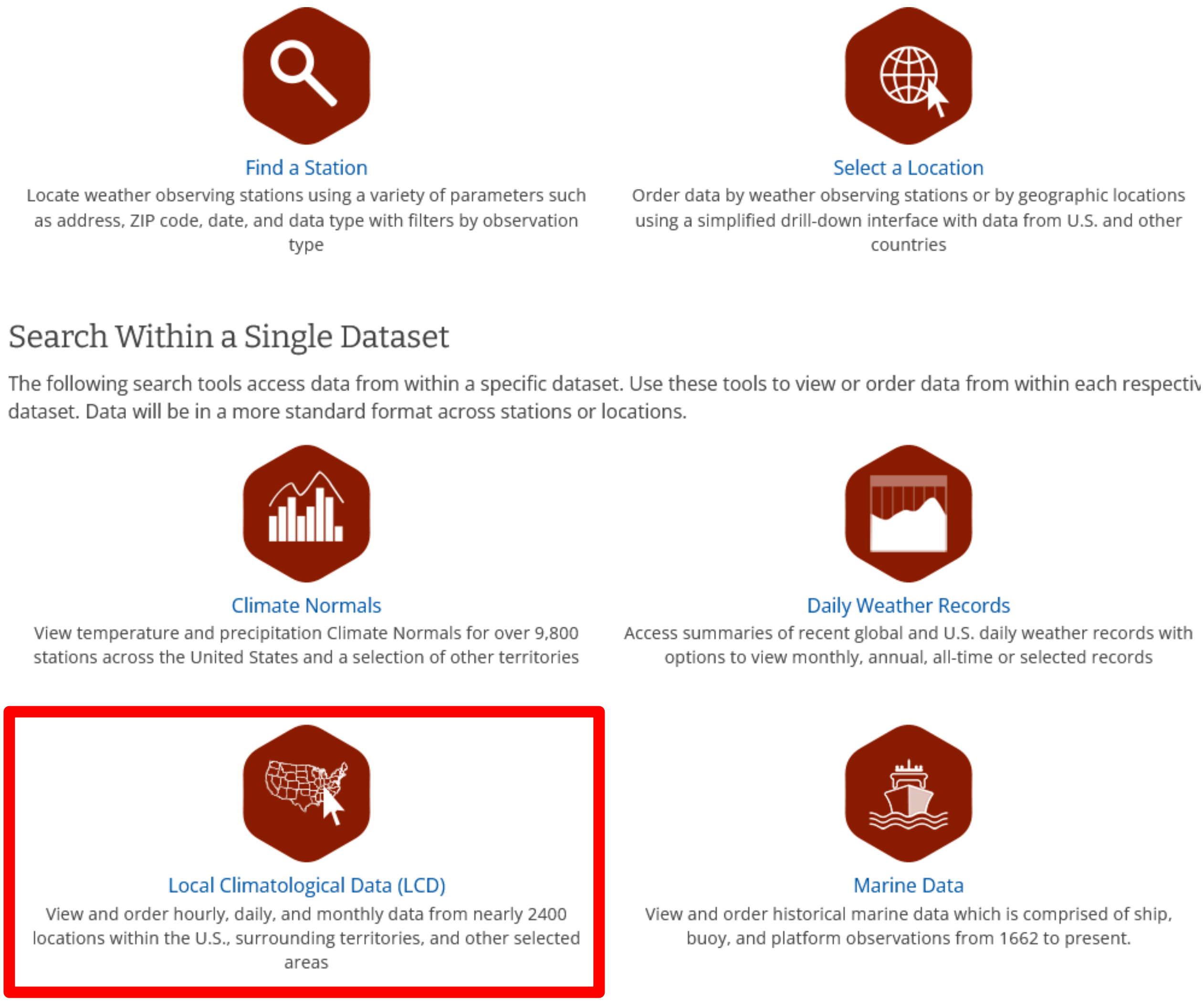
Gathering the Data

Navigate to https://www.ncdc.noaa.gov/cdo-web/

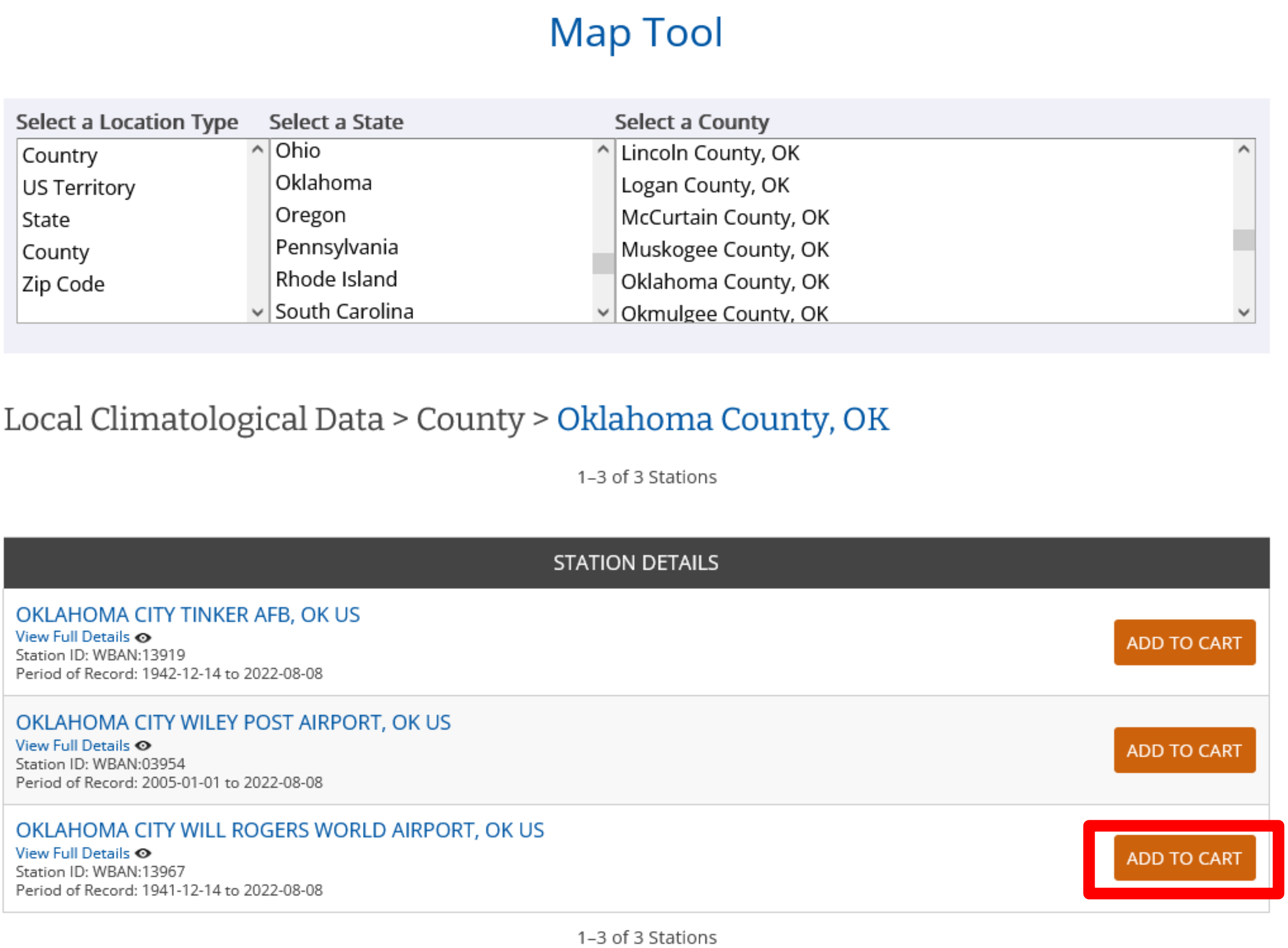
1. Select **Data Tools.**



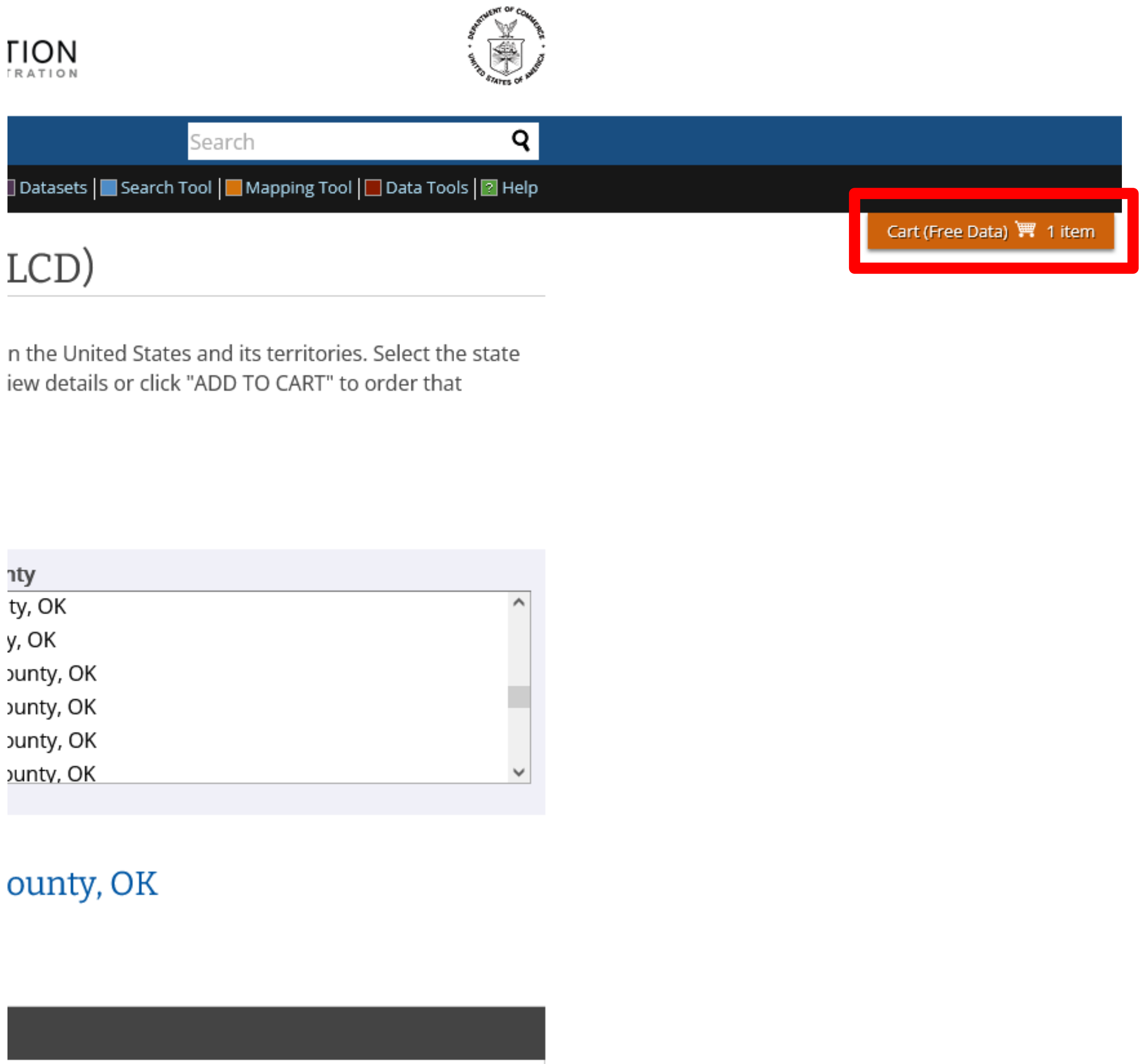
2. Scroll down if necessary and select **Local Climatological Data (LCD).**



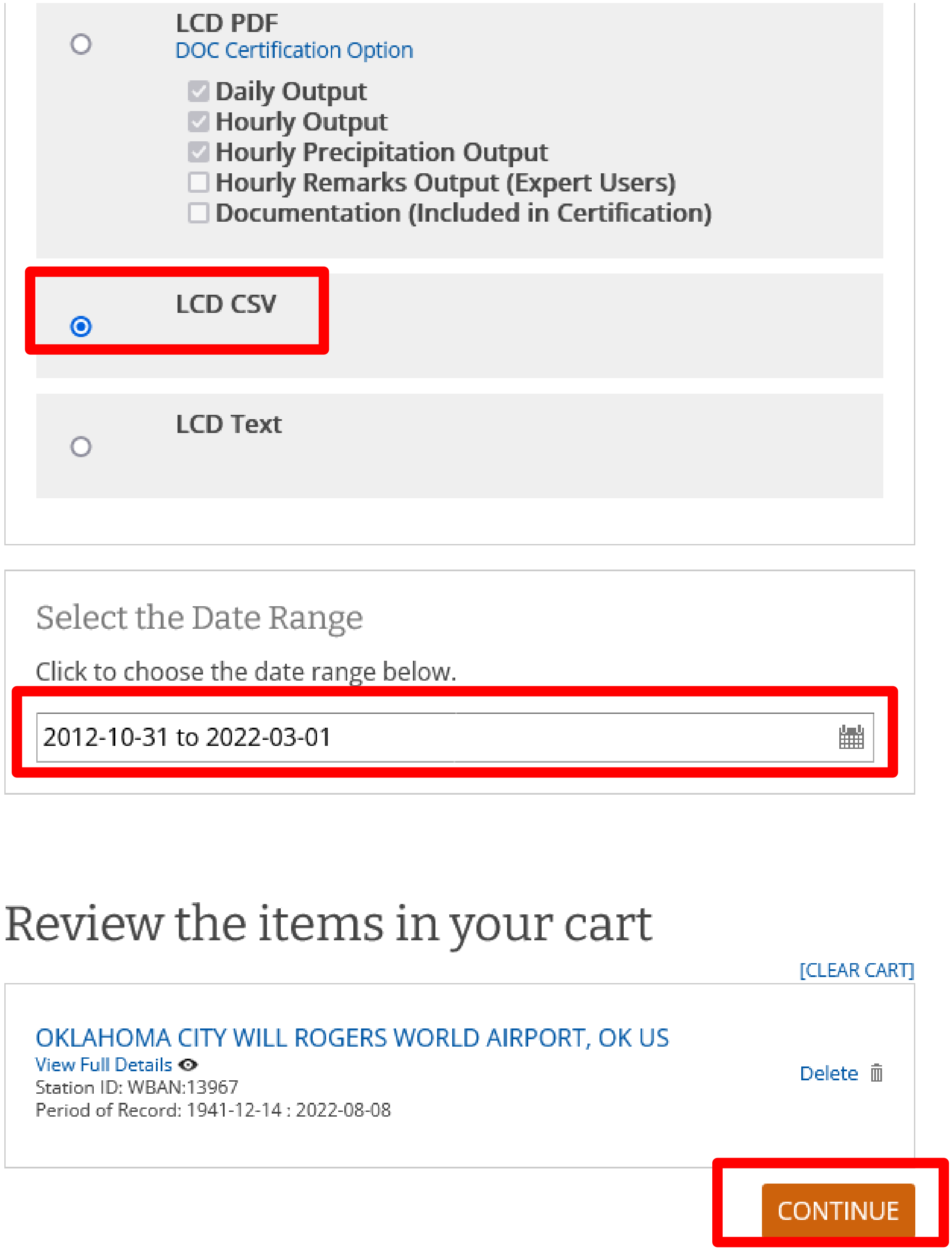
3. Use the selection tool to find a weather station appropriate for your location and click ADD TO CART.



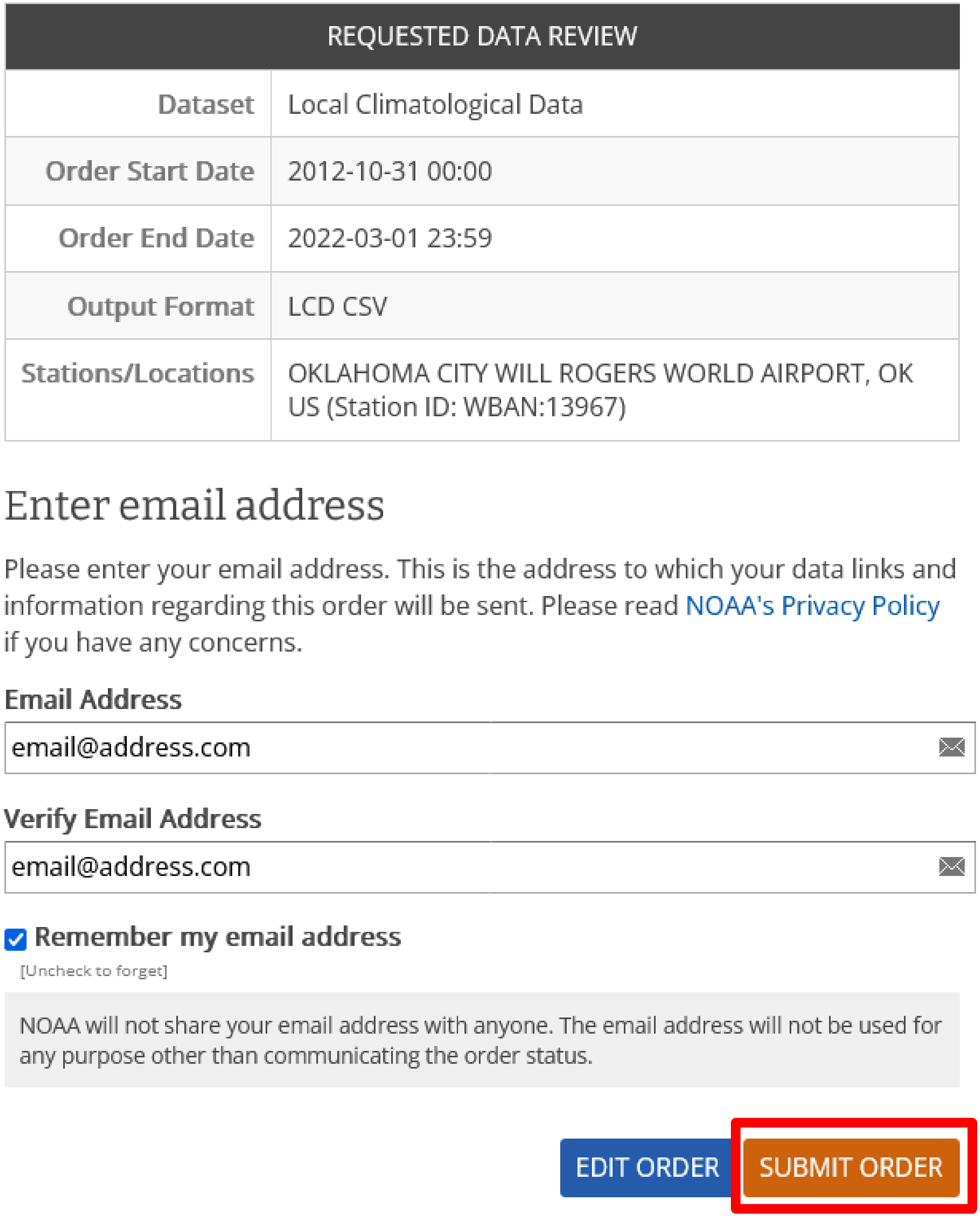
4. Click on the **cart icon** in the upper right-hand portion of the page.



5. Select LCD CSV, your desired date range, and then click continue. (Note: date ranges must be less than 10 years, so this process might have to be repeated several times and multiple files combined into one in order to get all data necessary to perform the analysis to determine the Extreme Cold Weather Temperature)



6. Enter and verify your email address and click **Submit Order.** You will receive an email when your request has been processed and is ready to download.



REQUESTED DATA REVIEW	
Dataset	Local Climatological Data
Order Start Date	2012-10-31 00:00
Order End Date	2022-03-01 23:59
Output Format	LCD CSV
Stations/Locations	OKLAHOMA CITY WILL ROGERS WORLD AIRPORT, OK US (Station ID: WBAN:13967)

Enter email address

Please enter your email address. This is the address to which your data links and information regarding this order will be sent. Please read NOAA's Privacy Policy if you have any concerns.

Email Address

email@address.com

Verify Email Address

email@address.com

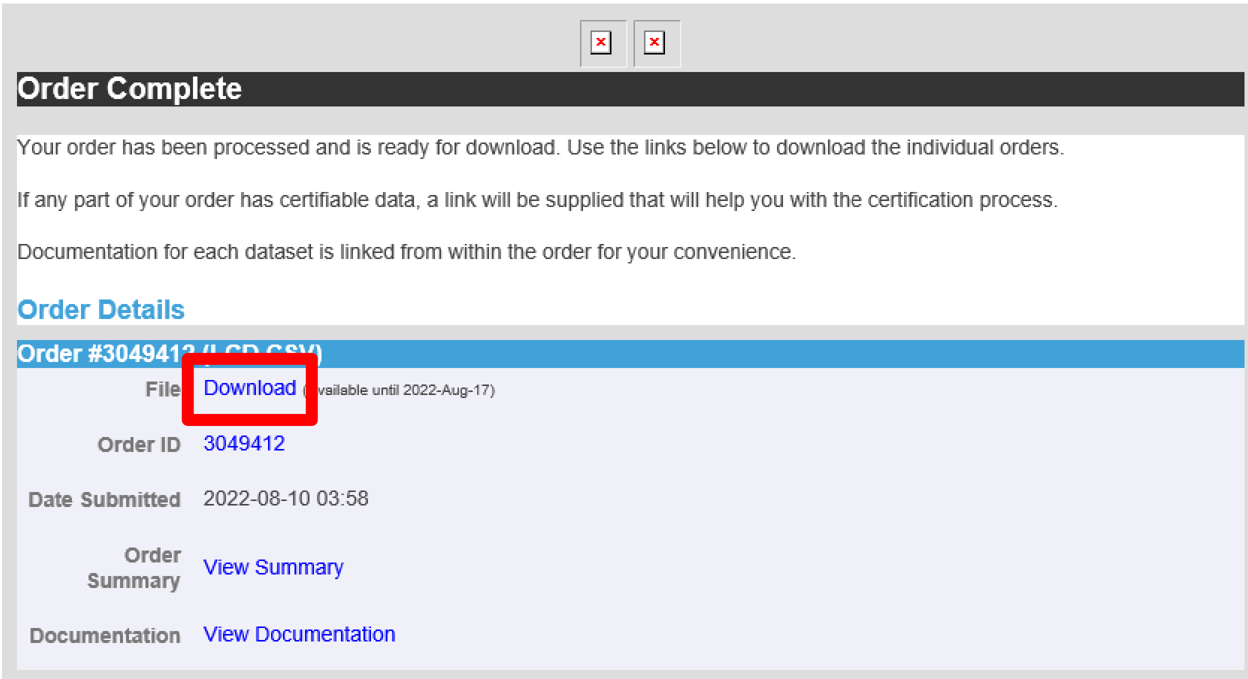
Remember my email address

[Uncheck to forget]

NOAA will not share your email address with anyone. The email address will not be used for any purpose other than communicating the order status.

EDIT ORDER SUBMIT ORDER

7. Click **Download** in the email that you will receive from NOAA to download your dataset.



Analyzing the Data

Option 1

1. Open the .csv file that was downloaded using the previous steps (and combine with other .csv files as necessary to cover the required date range).

2. Add filters to the first row and filter on "Report Type", column C, to only show report type FM-15, this is the standard METAR data.

STATION	DATE	REPORT	SOURCI	AWND	Backup	Backup	Backup	Backup	Backup	Backup	Backup	Backup
72353013967	2012-10-31T00:52:00	FM-15	7									
72353013967	2012-10-31T01:52:00	FM-15	7									
72353013967	2012-10-31T02:52:00	FM-15	7									
72353013967	2012-10-31T03:52:00	FM-15	7									
72353013967	2012-10-31T04:52:00	FM-15	7									
72353013967	2012-10-31T05:52:00	FM-15	7									
72353013967	2012-10-31T06:52:00	FM-15	7									
72353013967	2012-10-31T07:52:00	FM-15	7									
72353013967	2012-10-31T08:52:00	FM-15	7									
72353013967	2012-10-31T09:52:00	FM-15	7									
72353013967	2012-10-31T10:52:00	FM-15	7									
72353013967	2012-10-31T11:52:00	FM-15	7									
72353013967	2012-10-31T12:52:00	FM-15	7									
72353013967	2012-10-31T13:52:00	FM-15	7									
72353013967	2012-10-31T14:52:00	FM-15	7									
72353013967	2012-10-31T15:52:00	FM-15	7									
72353013967	2012-10-31T16:52:00	FM-15	7									
72353013967	2012-10-31T17:52:00	FM-15	7									
72353013967	2012-10-31T18:52:00	FM-15	7									
72353013967	2012-10-31T19:52:00	FM-15	7									
72353013967	2012-10-31T20:52:00	FM-15	7									
72353013967	2012-10-31T21:52:00	FM-15	7									
72353013967	2012-10-31T22:52:00	FM-15	7									
72353013967	2012-10-31T23:52:00	FM-15	7									
72353013967	2012-11-01T00:52:00	FM-15	7									
72353013967	2012-11-01T01:52:00	FM-15	7									
72353013967	2012-11-01T02:52:00	FM-15	7									
72353013967	2012-11-01T03:52:00	FM-15	7									
72353013967	2012-11-01T04:52:00	FM-15	7									
72353013967	2012-11-01T05:52:00	FM-15	7									

3. Select the Date column, column B, by clicking on the column, scroll over to the HourlyDryBulbTemperature column, column AS, and holding down the CTRL key, select that column. Copy and paste both columns into a new sheet named "Clean and Filter".

DATE	HourlyDryBulbTemperature
2012-10-31T00:52:00	52
2012-10-31T01:52:00	51
2012-10-31T02:52:00	50
2012-10-31T03:52:00	47
2012-10-31T04:52:00	46
2012-10-31T05:52:00	46
2012-10-31T06:52:00	44
2012-10-31T07:52:00	48
2012-10-31T08:52:00	52
2012-10-31T09:52:00	57
2012-10-31T10:52:00	61
2012-10-31T11:52:00	65
2012-10-31T12:52:00	67
2012-10-31T13:52:00	68
2012-10-31T14:52:00	71
2012-10-31T15:52:00	71
2012-10-31T16:52:00	70
2012-10-31T17:52:00	66
2012-10-31T18:52:00	62
2012-10-31T19:52:00	59
2012-10-31T20:52:00	54
2012-10-31T21:52:00	51
2012-10-31T22:52:00	52
2012-10-31T23:52:00	52
2012-11-01T00:52:00	53

4. Using the data on the "Clean and Filter" sheet, type **Month** in column C1, type the formula "=mid(A2,6,2)" in cell C2, and copy that formula in column C to the last row of the data set. Then Filter month to only show months 1, 2, 12 (January, February, and December).

5. You can then filter by HourlyDryBulbTemperature (Column B) to find and address bad data as appropriate. Now Select, Copy, and Paste the remaining data to a new sheet named ECWT.

	A	B	C	D
1	DATE	HourlyDryBulbTemperatur	Month	
747	2012-12-01T00:52:00	58	12	
748	2012-12-01T01:52:00	58	12	
749	2012-12-01T02:52:00	59	12	
750	2012-12-01T03:52:00	59	12	
751	2012-12-01T04:52:00	58	12	
752	2012-12-01T05:52:00	59	12	
753	2012-12-01T06:52:00	58	12	
754	2012-12-01T07:52:00	60	12	
755	2012-12-01T08:52:00	61	12	
756	2012-12-01T09:52:00	63	12	
757	2012-12-01T10:52:00	66	12	
758	2012-12-01T11:52:00	71	12	
759	2012-12-01T12:52:00	74	12	
760	2012-12-01T13:52:00	75	12	
761	2012-12-01T14:52:00	77	12	
762	2012-12-01T15:52:00	76	12	
763	2012-12-01T16:52:00	73	12	
764	2012-12-01T17:52:00	67	12	
765	2012-12-01T18:52:00	64	12	
766	2012-12-01T19:52:00	63	12	
767	2012-12-01T20:52:00	58	12	
768	2012-12-01T21:52:00	61	12	
769	2012-12-01T22:52:00	52	12	
770	2012-12-01T23:52:00	50	12	
771	2012-12-02T00:52:00	48	12	
772	2012-12-02T01:52:00	46	12	
773	2012-12-02T02:52:00	45	12	
774	2012-12-02T03:52:00	43	12	
775	2012-12-02T04:52:00	44	12	
776	2012-12-02T05:52:00	43	12	

6. Using Excel's built in Percentile function, the Extreme Cold Weather Temperature (ECWT) can now be determined. While on the ECWT sheet, in a blank cell use the function "=PERCENTILE.INC()" and select all temperature data in Column B (HourlyDryBulbTemperature) on the "ECWT" sheet and use 0.002 for the percentile value. The formula will look similar to this, "=PERCENTILE.INC(B:B,0.002)" (using 0.002 for the second argument in this function returns the two-tenths percentile temperature of the hourly temperatures measured in the dataset used).

   <u>This value should be representative of the Extreme Cold Weather Temperature based on the given dataset.</u>

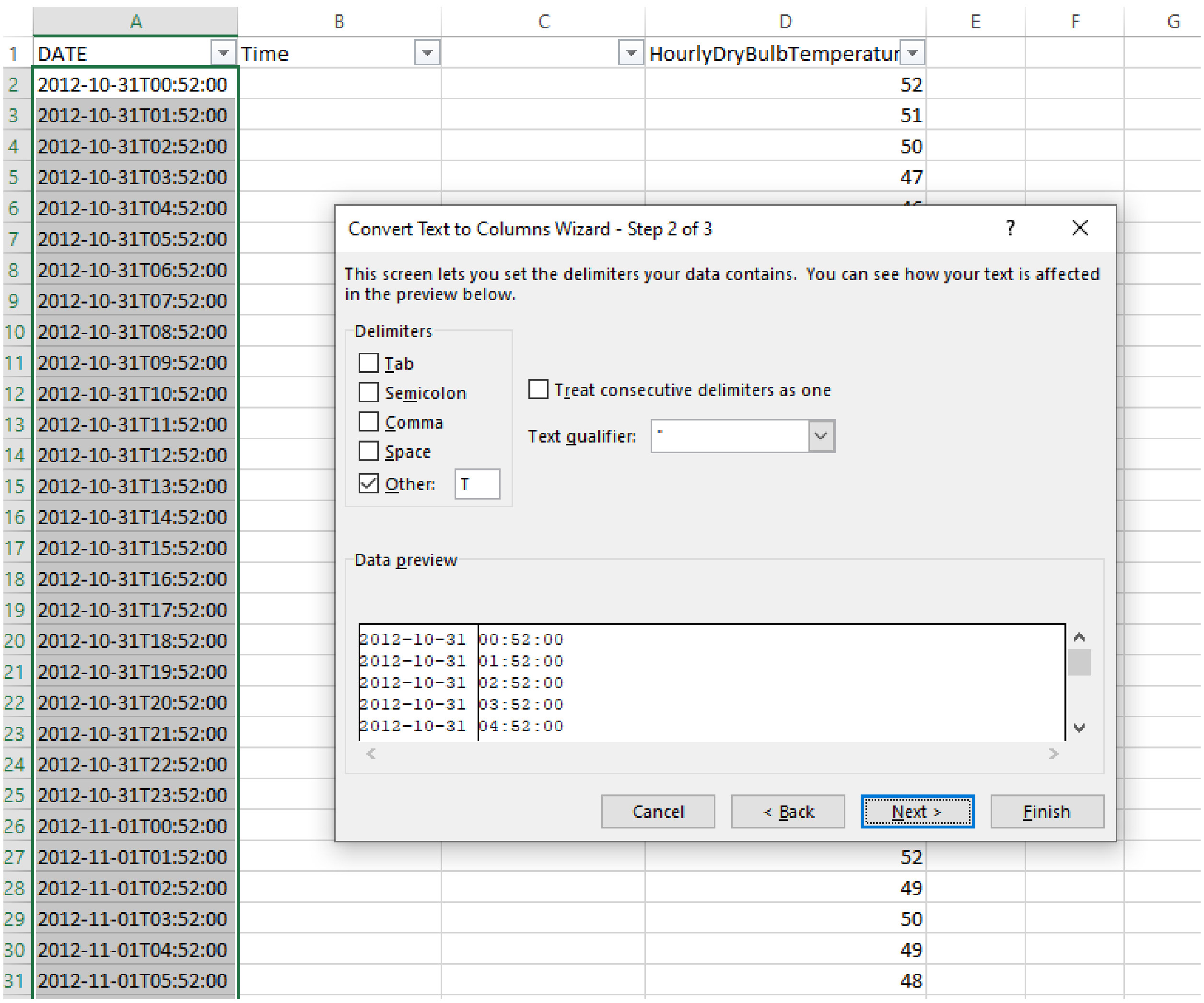
E5 | =PERCENTILE.INC(B:B,0.002)

	A	B	C	D	E	F	G
1	DATE	HourlyDryBulbTemperature	Month				
2	2012-12-01T00:52:00	58	12				
3	2012-12-01T01:52:00	58	12				
4	2012-12-01T02:52:00	59	12		ECWT		
5	2012-12-01T03:52:00	59	12		2		
6	2012-12-01T04:52:00	58	12				
7	2012-12-01T05:52:00	59	12				
8	2012-12-01T06:52:00	58	12				
9	2012-12-01T07:52:00	60	12				
10	2012-12-01T08:52:00	61	12				
11	2012-12-01T09:52:00	63	12				
12	2012-12-01T10:52:00	66	12				
13	2012-12-01T11:52:00	71	12				
14	2012-12-01T12:52:00	74	12				
15	2012-12-01T13:52:00	75	12				
16	2012-12-01T14:52:00	77	12				
17	2012-12-01T15:52:00	76	12				
18	2012-12-01T16:52:00	73	12				
19	2012-12-01T17:52:00	67	12				

Option 2

These next few steps demonstrate how to view the distribution of temperatures from the data set and obtain the Extreme Cold Weather Temperature by a slightly different method.

1. On the "Clean and Filter" sheet, insert two new columns between column A and column B. Select column A and use Excel's *Text to Columns* feature and selected the delimited option and use the letter "T" to split the date data into a date component and a time component by hitting "Next" and "Finish".



2. Add in column C, add the date in column A to time in column B, and copy this formula for all rows of the data set.

C2 =A2+B2

	A	B	C	D
1	DATE	Time	Date/Time	HourlyDryBulbTemperatur
2	10/31/2012	0:52:00	10/31/2012 0:52	52
3	10/31/2012	1:52:00	10/31/2012 1:52	51
4	10/31/2012	2:52:00	10/31/2012 2:52	50
5	10/31/2012	3:52:00	10/31/2012 3:52	47
6	10/31/2012	4:52:00	10/31/2012 4:52	46
7	10/31/2012	5:52:00	10/31/2012 5:52	46
8	10/31/2012	6:52:00	10/31/2012 6:52	44
9	10/31/2012	7:52:00	10/31/2012 7:52	48
10	10/31/2012	8:52:00	10/31/2012 8:52	52
11	10/31/2012	9:52:00	10/31/2012 9:52	57
12	10/31/2012	10:52:00	10/31/2012 10:52	61
13	10/31/2012	11:52:00	10/31/2012 11:52	65
14	10/31/2012	12:52:00	10/31/2012 12:52	67
15	10/31/2012	13:52:00	10/31/2012 13:52	68
16	10/31/2012	14:52:00	10/31/2012 14:52	71
17	10/31/2012	15:52:00	10/31/2012 15:52	71
18	10/31/2012	16:52:00	10/31/2012 16:52	70
19	10/31/2012	17:52:00	10/31/2012 17:52	66
20	10/31/2012	18:52:00	10/31/2012 18:52	62
21	10/31/2012	19:52:00	10/31/2012 19:52	59
22	10/31/2012	20:52:00	10/31/2012 20:52	54
23	10/31/2012	21:52:00	10/31/2012 21:52	51

3. Type Month in cell E1, and in cell E2 use the formula "=month(C2)". Copy the formula for all rows of the data set, then filter based on month, only selecting 1,2,12 for the desired months. Then copy remaining data from column C and column D to a sheet named Histogram.

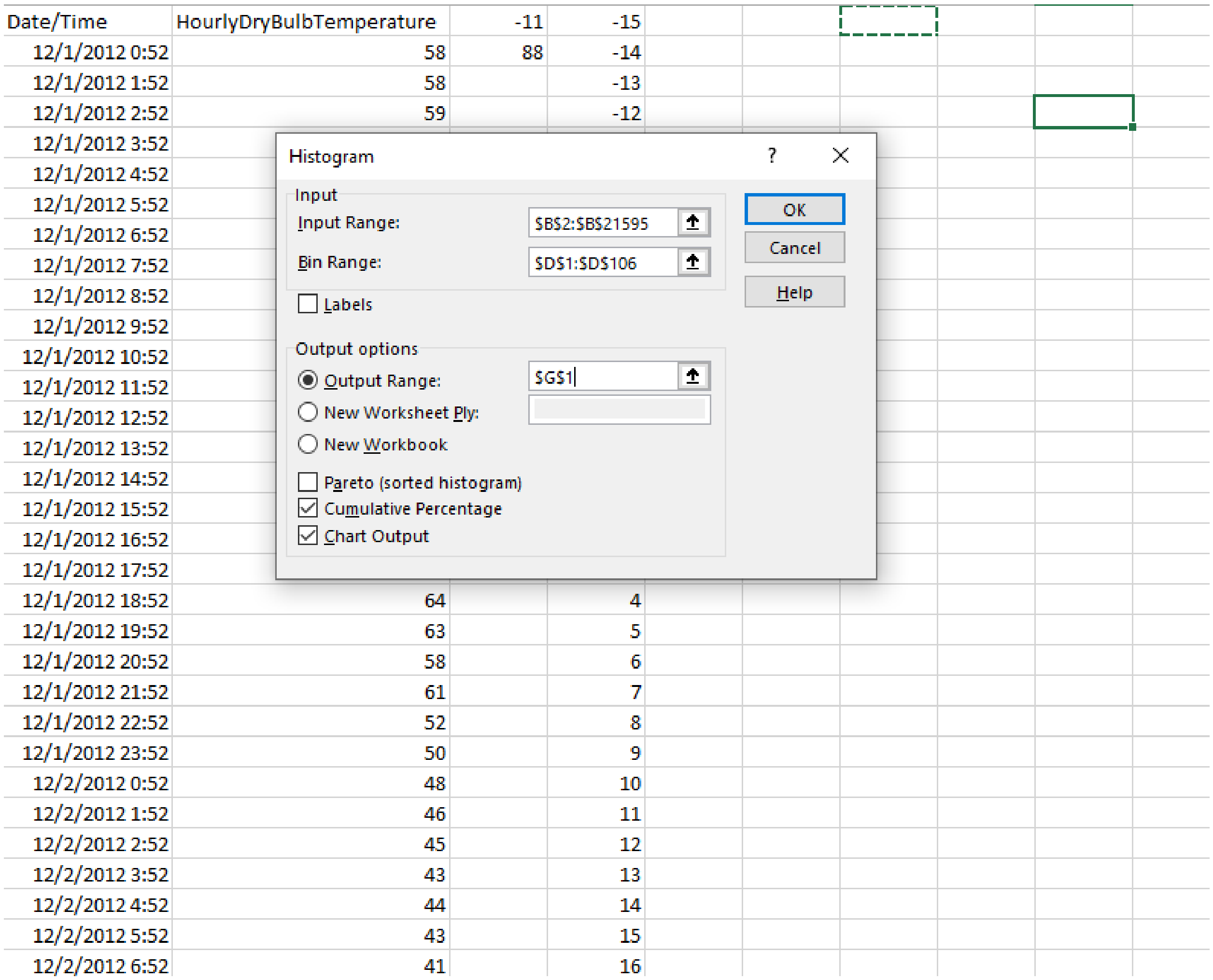
E747 =MONTH(C747)

	A	B	C	D	E	F	G
1	DATE	Time	Date/Time	HourlyDryBulbTemperatur	month		
747	12/1/2012	0:52:00	12/1/2012 0:52	58	12		
748	12/1/2012	1:52:00	12/1/2012 1:52	58	12		
749	12/1/2012	2:52:00	12/1/2012 2:52	59	12		
750	12/1/2012	3:52:00	12/1/2012 3:52	59	12		
751	12/1/2012	4:52:00	12/1/2012 4:52	58	12		
752	12/1/2012	5:52:00	12/1/2012 5:52	59	12		
753	12/1/2012	6:52:00	12/1/2012 6:52	58	12		
754	12/1/2012	7:52:00	12/1/2012 7:52	60	12		
755	12/1/2012	8:52:00	12/1/2012 8:52	61	12		
756	12/1/2012	9:52:00	12/1/2012 9:52	63	12		
757	12/1/2012	10:52:00	12/1/2012 10:52	66	12		
758	12/1/2012	11:52:00	12/1/2012 11:52	71	12		
759	12/1/2012	12:52:00	12/1/2012 12:52	74	12		
760	12/1/2012	13:52:00	12/1/2012 13:52	75	12		
761	12/1/2012	14:52:00	12/1/2012 14:52	77	12		
762	12/1/2012	15:52:00	12/1/2012 15:52	76	12		
763	12/1/2012	16:52:00	12/1/2012 16:52	73	12		
764	12/1/2012	17:52:00	12/1/2012 17:52	67	12		
765	12/1/2012	18:52:00	12/1/2012 18:52	64	12		

4. On the Histogram sheet, enter "=min(B:B)" in cell C1, and "=max(B:B)" in cell C2. This will give you the minimum and maximum temperatures in the dataset. We will use the temperatures to set range for this histogram. In Column D start with a value, a few degrees below the min, then list every degree to a few degrees above the max.

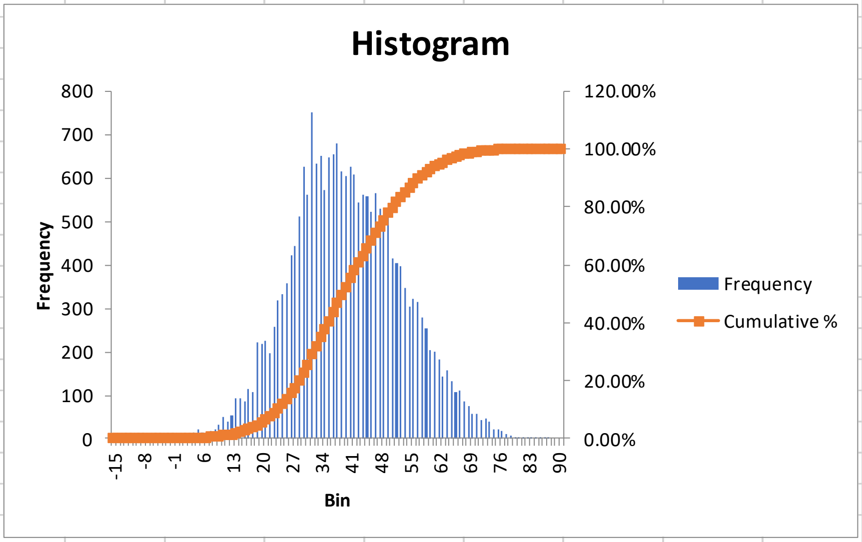
Date/Time	HourlyDryBulbTemperature	-11	-15	
12/1/2012 0:52	58	88	-14	
12/1/2012 1:52	58		-13	
12/1/2012 2:52	59		-12	
12/1/2012 3:52	59		-11	
12/1/2012 4:52	58		-10	
12/1/2012 5:52	59		-9	
12/1/2012 6:52	58		-8	
12/1/2012 7:52	60		-7	
12/1/2012 8:52	61		-6	
12/1/2012 9:52	63		-5	
12/1/2012 10:52	66		-4	
12/1/2012 11:52	71		-3	
12/1/2012 12:52	74		-2	
12/1/2012 13:52	75		-1	
12/1/2012 14:52	77		0	
12/1/2012 15:52	76		1	
12/1/2012 16:52	73		2	
12/1/2012 17:52	67		3	
12/1/2012 18:52	64		4	
12/1/2012 19:52	63		5	
12/1/2012 20:52	58		6	
12/1/2012 21:52	61		7	
12/1/2012 22:52	52		8	
12/1/2012 23:52	50		9	
12/2/2012 0:52	48		10	
12/2/2012 1:52	46		11	
12/2/2012 2:52	45		12	
12/2/2012 3:52	43		13	
12/2/2012 4:52	44		14	
12/2/2012 5:52	43		15	
12/2/2012 6:52	41		16	
12/2/2012 7:52	38		17	
12/2/2012 8:52	44		18	

5. In the Data Analysis ToolPak in excel, select histogram. Select all dry bulb temperatures for your Input Range. Select all the Temperatures in column D for our Bin Range. Select an empty cell for your Output Range. Check the Cumulative Percentage and Chart Output boxes.



6. The output from this will provide a listing of percentile rankings for the listed temperatures, as well as a graph output of the distribution of temperatures contained in this dataset. The "Bin" column shows the temperature, "Frequency" shows how many times that temperature occurred within he dataset, and "Cumulative %" shows the percentile ranking for each temperature. Choose the temperature at or closest to the 0.2 percentile level.

Bin	*Frequency*	*Cumulative %*
-15	0	0.00%
-14	0	0.00%
-13	0	0.00%
-12	0	0.00%
-11	1	0.00%
-10	0	0.00%
-9	2	0.01%
-8	0	0.01%
-7	1	0.02%
-6	4	0.04%
-5	4	0.06%
-4	4	0.07%
-3	1	0.08%
-2	4	0.10%
-1	6	0.13%
0	5	0.15%
1	3	0.16%
2	11	**0.21%**
3	5	0.24%
4	13	0.30%
5	22	0.40%
6	14	0.46%
7	12	0.52%
8	17	0.60%
9	23	0.70%
10	32	0.85%
11	50	1.08%
12	39	1.26%
13	53	1.51%
14	93	1.94%
15	92	2.37%
16	86	2.76%



Standards Announcement

Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination

Final Ballot Open through September 30, 2022

Now Available

A final ballot is open through **8 p.m. Eastern, Friday, September 30, 2022** for the following standards and implementation plan:

- EOP-011-3 – Emergency Operations
- EOP-012-1 – Extreme Cold Weather Preparedness and Operations
- Implementation Plan

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 standards will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Standards Development Process

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

For more information or assistance, contact Senior Standards Developer, Alison Oswald (via email) or at 404-446-9668

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: 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination EOP-011-3 FN 2 ST
Voting Start Date: 9/23/2022 8:58:13 AM
Voting End Date: 9/30/2022 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 301
Total Ballot Pool: 314
Quorum: 95.86
Quorum Established Date: 9/23/2022 9:23:29 AM
Weighted Segment Value: 83.64

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	65	0.813	15	0.188	0	6	3
Segment: 2	7	0.7	5	0.5	2	0.2	0	0	0
Segment: 3	68	1	53	0.898	6	0.102	0	5	4
Segment: 4	19	1	10	0.833	2	0.167	0	4	3
Segment: 5	75	1	52	0.788	14	0.212	0	8	1
Segment: 6	49	1	36	0.837	7	0.163	0	4	2
Segment: 7	1	0.1	1	0.1	0	0	0	0	0
Segment: 8	0	0	0	0	0	0	0	0	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	6	0.5	5	0.5	0	0	0	1	0
Totals:	314	6.3	227	5.269	46	1.031	0	28	13

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	Ameren - Ameren Services	Tamara Evey		Negative	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Negative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski	Brandon Smith	Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Arkansas Electric Cooperative Corporation	Jennifer Loiacano		None	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		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Micah Runner	Jennifer Malon	Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Negative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Negative	N/A
1	Dairyland Power Cooperative	Steve Ritscher		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Affirmative	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
1	Edison International - Southern California Edison Company	Jose Avendano Mora		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Allen Klassen	Alan Kloster	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Eversource Energy	Quintin Lee		Negative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Gainesville Regional Utilities	David Owens	LaKenya VanNorman	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Sheraz Majid		Negative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Negative	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	Joe McClung		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Negative	N/A
1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Lower Colorado River Authority	James Baldwin		Affirmative	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	Minnkota Power Cooperative Inc.	Theresa Allard		Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	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		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Negative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Ohio Valley Electric Corporation	Scott Cunningham		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer	Gul Khan	Affirmative	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle Longo		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Kyle Down		Negative	N/A
1	Public Utility District No. 1 of Chelan County	Diane Landry		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		None	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Chris Hofmann		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seattle City Light	Michael Jang		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Abstain	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Taunton Municipal Lighting Plant	Devon Tremont		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Negative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	N/A
1	VELCO -Vermont Electric Power Company, Inc.	Randy Buswell		Negative	N/A
1	Western Area Power Administration	sean erickson	Kimberly Bentley	Affirmative	N/A
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
2	California ISO	Darcy O'Connell		Negative	N/A
2	Independent Electricity System Operator	Leonard Kula		Negative	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		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Tom Foster	Elizabeth Davis	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	AEP	Kent Feliks		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Negative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Austin Energy	Michael Dieringer		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Negative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs	Jennifer Malon	Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Abstain	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Negative	N/A
3	CPS Energy	Glenn Pressler		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Schroeder		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Negative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		None	N/A
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Alan Kloster	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Abstain	N/A
3	Florida Municipal Power Agency	Carl Turner	LaKenya VanNorman	Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Imperial Irrigation District	Glen Allegranza	Denise Sanchez	Affirmative	N/A
3	JEA	Marilyn Williams		None	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Steve Marshall		None	N/A
3	Lincoln Electric System	Sam Christensen		Affirmative	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Ronald Bauer		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	LaKenya VanNorman	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	William Berry		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Affirmative	N/A
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	maria pardo		Negative	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		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Abshier		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Negative	N/A
3	WEC Energy Group, Inc.	Christine Kane		Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	American Public Power Association	John McCaffrey		Abstain	N/A
4	Austin Energy	Jun Hua		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
4	DTE Energy	patricia ireland		None	N/A
4	Electricities of North Carolina	Marcus Freeman		None	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Abstain	N/A
4	Florida Municipal Power Agency	Dan O'Hagan	LaKenya VanNorman	Affirmative	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain	N/A
4	Indiana Municipal Power Agency	Jack Alvey	Scott Berry	Negative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Adam Lee		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Northern California Power Agency	Marty Hostler		Abstain	N/A
4	Oklahoma Municipal Power Authority	Michael Watt		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		None	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Ken Habgood		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Negative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	Acciona Energy North America	Krys Rootham		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	N/A
5	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Negative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Negative	N/A
5	Basin Electric Power Cooperative	Amanda Wangler		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Black Hills Corporation	Derek Silbaugh	Jennifer Malon	Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Negative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Cogentrix Energy Power Management, LLC	Gerry Adamski		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Haizhen Wang		Affirmative	N/A
5	Constellation	Alison Mackellar		Negative	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	CPS Energy	Robert Stevens		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Decatur Energy Center LLC	Shannon Ferdinand		Negative	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		Negative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Enel Green Power	Natalie Johnson		Abstain	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Robert Loy		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Florida Municipal Power Agency	Chris Gowder	LaKenya VanNorman	Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	Greybeard Compliance Services, LLC	Michael Gabriel		Abstain	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	Invenergy LLC	Rhonda Jones		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Jason Fortik		Affirmative	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	Mark Spencer		Abstain	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
5	NB Power Corporation	David Melanson		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	NextEra Energy	Summer Esquerre		Negative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Northern California Power Agency	Jeremy Lawson		Negative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Negative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	OTP - Otter Tail Power Company	Tammy Kubela		Affirmative	N/A
5	Pacific Gas and Electric Company	Frank Lee	Michael Johnson	Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Negative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		Affirmative	N/A
5	Sacramento Municipal Utility District	Nicole Goi	Tim Kelley	Affirmative	N/A
5	Salt River Project	Jennifer Bennett		Affirmative	N/A
5	Santee Cooper	Marty Watson		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Abstain	N/A
5	Southern Company - Southern Company Generation	James Howell		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	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	Tennessee Valley Authority	M Lee Thomas		None	N/A
5	TransAlta Corporation	Ashley Scheelar		Negative	N/A
5	Tri-State G and T Association, Inc.	Ryan Walter		Negative	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Negative	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt	Amy Casuscelli	Affirmative	N/A
6	AEP	JT Kuehne		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	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		Abstain	N/A
6	Black Hills Corporation	Claudine Bates		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Negative	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Michael Foley		Affirmative	N/A
6	Constellation	Kimberly Turco		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Kenya Streeter		None	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Jennifer Flandermeyer	Alan Kloster	Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Abstain	N/A
6	Florida Municipal Power Agency	Jade Bulitta	LaKenya VanNorman	Affirmative	N/A
6	Florida Municipal Power Pool	Aaron Casto	LaKenya VanNorman	Affirmative	N/A
6	Great River Energy	Donna Stephenson		Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Invenergy LLC	Colin Chilcoat		Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Negative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Manitoba Hydro	Simon Tanapat-Andre		Affirmative	N/A
6	Muscatine Power and Water	Nick Burns		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A

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		Negative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	Powerex Corporation	Raj Hundal		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia		Negative	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Israel Perez		Affirmative	N/A
6	Santee Cooper	Glenda Horne		Affirmative	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.	Erin Spence		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Tennessee Valley Authority	Armando Rodriguez		Affirmative	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
7	Oxy - Occidental Chemical	Venona Greaff		Affirmative	N/A
10	Midwest Reliability Organization	William Steiner		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	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

Ballot Name: 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination EOP-012-1 FN 3 ST
Voting Start Date: 9/23/2022 8:57:28 AM
Voting End Date: 9/30/2022 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 3
Total # Votes: 300
Total Ballot Pool: 314
Quorum: 95.54
Quorum Established Date: 9/23/2022 9:23:49 AM
Weighted Segment Value: 79.04

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	87	1	55	0.797	14	0.203	0	12	6
Segment: 2	7	0.6	3	0.3	3	0.3	0	0	1
Segment: 3	68	1	48	0.814	11	0.186	0	6	3
Segment: 4	19	1	15	0.938	1	0.063	0	3	0
Segment: 5	77	1	46	0.667	23	0.333	0	7	1
Segment: 6	49	1	33	0.786	9	0.214	0	4	3
Segment: 7	1	0.1	1	0.1	0	0	0	0	0
Segment: 8	0	0	0	0	0	0	0	0	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	6	0.5	5	0.5	0	0	0	1	0
Totals:	314	6.2	206	4.901	61	1.299	0	33	14

BALLOT POOL MEMBERS

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski	Brandon Smith	Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Arkansas Electric Cooperative Corporation	Jennifer Loiacano		None	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	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Micah Runner		Negative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		None	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	N/A
1	Colorado Springs Utilities	Mike Braunstein		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Affirmative	N/A
1	Dairyland Power Cooperative	Steve Ritscher		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Negative	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
1	Edison International - Southern California Edison Company	Jose Avendano Mora		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Alan Kloster	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Negative	N/A
1	Gainesville Regional Utilities	David Owens	LaKenya VanNorman	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Negative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		Affirmative	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	Joe 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		Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Nazra Gladu		Affirmative	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	Andy Kurriger		Negative	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		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Negative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Negative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Ohio Valley Electric Corporation	Scott Cunningham		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer	Gul Khan	Abstain	N/A
1	Orlando Utilities Commission	Aaron Staley		Abstain	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Affirmative	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Platte River Power Authority	Matt Thompson		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle Longo		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Kyle Down		Abstain	N/A
1	Public Utility District No. 1 of Chelan County	Diane Landry		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Negative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Chris Hofmann		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Negative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seattle City Light	Michael Jang		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		None	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	Taunton Municipal Lighting Plant	Devon Tremont		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Negative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	N/A
1	VELCO -Vermont Electric Power Company, Inc.	Randy Buswell		Abstain	N/A
1	Western Area Power Administration	sean erickson		Negative	N/A
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
2	California ISO	Darcy O'Connell		Negative	N/A
2	Independent Electricity System Operator	Leonard Kula		None	N/A
2	ISO New England, Inc.	John Pearson	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Negative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Tom Foster	Elizabeth Davis	Negative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	AEP	Kent Feliks		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Michael Dieringer		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs		Negative	N/A
3	Bonneville Power Administration	Ken Lanehome		Abstain	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Negative	N/A
3	CPS Energy	Glenn Pressler		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Schroeder		Negative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Negative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Entergy	James Keele		Negative	N/A
3	Evergy	Marcus Moor	Alan Kloster	Affirmative	N/A
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	Florida Municipal Power Agency	Carl Turner	LaKenya VanNorman	Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Imperial Irrigation District	Glen Allegranza	Denise Sanchez	Affirmative	N/A
3	JEA	Marilyn Williams		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Steve Marshall		None	N/A
3	Lincoln Electric System	Sam Christensen		Affirmative	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Ronald Bauer		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Negative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera	Shelly Dineen	Negative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney	James Mearns	Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	LaKenya VanNorman	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Abstain	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	William Berry		Abstain	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Affirmative	N/A
3	Platte River Power Authority	Wade Kiess		None	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	maria pardo		Abstain	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		Affirmative	N/A
3	Santee Cooper	James Poston		Negative	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		None	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Abshier		Negative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Negative	N/A
3	WEC Energy Group, Inc.	Christine Kane		Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	American Public Power Association	John McCaffrey		Abstain	N/A
4	Austin Energy	Jun Hua		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
4	DTE Energy	patricia ireland		Affirmative	N/A
4	Electricities of North Carolina	Marcus Freeman		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Florida Municipal Power Agency	Dan O'Hagan	LaKenya VanNorman	Affirmative	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain	N/A
4	Indiana Municipal Power Agency	Jack Alvey		Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Adam Lee		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Northern California Power Agency	Marty Hostler	James Mearns	Abstain	N/A
4	Oklahoma Municipal Power Authority	Michael Watt		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Negative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Ken Habgood		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	Acciona Energy North America	Krys Rootham		Negative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
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	Basin Electric Power Cooperative	Amanda Wangler		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Black Hills Corporation	Derek Silbaugh	Jennifer Malon	Negative	N/A
5	Bonneville Power Administration	Scott Winner		Abstain	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Cogentrix Energy Power Management, LLC	Gerry Adamski		Negative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Haizhen Wang		Affirmative	N/A
5	Constellation	Alison Mackellar		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Negative	N/A
5	CPS Energy	Robert Stevens		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Decatur Energy Center LLC	Shannon Ferdinand		Negative	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Negative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		Negative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Enel Green Power	Natalie Johnson		Negative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Robert Loy		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Florida Municipal Power Agency	Chris Gowder	LaKenya VanNorman	Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	Greybeard Compliance Services, LLC	Michael Gabriel		Negative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	Invenergy LLC	Rhonda Jones		Negative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Jason Fortik		Affirmative	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	Mark Spencer		Negative	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
5	NB Power Corporation	David Melanson		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Negative	N/A
5	NextEra Energy	Summer Esquerre		Negative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Northern California Power Agency	Jeremy Lawson	James Mearns	Abstain	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Negative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	OTP - Otter Tail Power Company	Tammy Kubela		Affirmative	N/A
5	Pacific Gas and Electric Company	Frank Lee	Michael Johnson	Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Negative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		Negative	N/A
5	Sacramento Municipal Utility District	Nicole Goi	Tim Kelley	Affirmative	N/A
5	Salt River Project	Jennifer Bennett		Affirmative	N/A
5	Santee Cooper	Marty Watson		Negative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		None	N/A
5	Southern Company - Southern Company Generation	James Howell		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Negative	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	Tenaska, Inc.	Mark Young		Negative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Affirmative	N/A
5	TransAlta Corporation	Ashley Scheelar		Abstain	N/A
5	Tri-State G and T Association, Inc.	Ryan Walter		Negative	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Negative	N/A
5	Vistra Energy	Dan Roethemeyer		Negative	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP	JT Kuehne		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	Claudine Bates		Negative	N/A
6	Bonneville Power Administration	Andrew Meyers		Abstain	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Con Ed - Consolidated Edison Co. of New York	Michael Foley		Affirmative	N/A
6	Constellation	Kimberly Turco		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	N/A
6	Duke Energy	John Sturgeon		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Jennifer Flandermeyer	Alan Kloster	Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
6	Florida Municipal Power Agency	Jade Bulitta	LaKenya VanNorman	Affirmative	N/A
6	Florida Municipal Power Pool	Aaron Casto	LaKenya VanNorman	Affirmative	N/A
6	Great River Energy	Donna Stephenson		Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Invenergy LLC	Colin Chilcoat		Negative	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Manitoba Hydro	Simon Tanapat-Andre		Affirmative	N/A
6	Muscatine Power and Water	Nick Burns		Negative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet	James Mearns	Abstain	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Negative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	Powerex Corporation	Raj Hundal		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Negative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Israel Perez		Affirmative	N/A
6	Santee Cooper	Glenda Horne		Negative	N/A
6	Snohomish County PUD No. 1	John Liang		Negative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Erin Spence		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	Tennessee Valley Authority	Armando Rodriguez		Affirmative	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
7	Oxy - Occidental Chemical	Venona Greaff		Affirmative	N/A
10	Midwest Reliability Organization	William Steiner		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	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

Ballot Name: 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination Implementation Plan FN 3 OT
Voting Start Date: 9/23/2022 8:57:42 AM
Voting End Date: 9/30/2022 8:00:00 PM
Ballot Type: OT
Ballot Activity: FN
Ballot Series: 3
Total # Votes: 297
Total Ballot Pool: 312
Quorum: 95.19
Quorum Established Date: 9/23/2022 9:23:44 AM
Weighted Segment Value: 87.89

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	86	1	63	0.926	5	0.074	0	13	5
Segment: 2	7	0.5	3	0.3	2	0.2	0	1	1
Segment: 3	68	1	53	0.93	4	0.07	0	8	3
Segment: 4	18	1	13	0.929	1	0.071	0	4	0
Segment: 5	77	1	53	0.803	13	0.197	0	8	3
Segment: 6	49	1	35	0.897	4	0.103	0	7	3
Segment: 7	1	0.1	1	0.1	0	0	0	0	0
Segment: 8	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: 9	0	0	0	0	0	0	0	0	0
Segment: 10	6	0.3	3	0.3	0	0	0	3	0
Totals:	312	5.9	224	5.185	29	0.715	0	44	15

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	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski	Brandon Smith	Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Arkansas Electric Cooperative Corporation	Jennifer Loiacano		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Micah Runner		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		None	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Affirmative	N/A
1	Dairyland Power Cooperative	Steve Ritscher		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Affirmative	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
1	Edison International - Southern California Edison Company	Jose Avendano Mora		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Evergy	Kevin Frick	Alan Kloster	Affirmative	N/A
1	Eversource Energy	Quintin Lee		Abstain	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Gainesville Regional Utilities	David Owens	LaKenya VanNorman	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Negative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		Affirmative	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	Joe 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		Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Lower Colorado River Authority	James Baldwin		Affirmative	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	Minnkota Power Cooperative Inc.	Theresa Allard	Nikki Carson-Marquis	Affirmative	N/A
1	Muscatine Power and Water	Andy 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		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Negative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	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	Ohio Valley Electric Corporation	Scott Cunningham		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer	Gul Khan	Affirmative	N/A
1	Orlando Utilities Commission	Aaron Staley		Abstain	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle Longo		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Kyle Down		Abstain	N/A
1	Public Utility District No. 1 of Chelan County	Diane Landry		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Negative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Chris Hofmann		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Negative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		None	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	Taunton Municipal Lighting Plant	Devon Tremont		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	N/A
1	VELCO -Vermont Electric Power Company, Inc.	Randy Buswell		Abstain	N/A
1	Western Area Power Administration	sean erickson		Abstain	N/A
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
2	California ISO	Darcy O'Connell		Abstain	N/A
2	Independent Electricity System Operator	Leonard Kula		None	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		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Tom Foster	Elizabeth Davis	Negative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Negative	N/A
3	AEP	Kent Feliks		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Michael Dieringer		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Abstain	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	CPS Energy	Glenn Pressler		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Schroeder		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
3	Duke Energy	Lee Schuster		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	Alan Kloster	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	Florida Municipal Power Agency	Carl Turner	LaKenya VanNorman	Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Imperial Irrigation District	Glen Allegranza	Denise Sanchez	Affirmative	N/A
3	JEA	Marilyn Williams		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Steve Marshall		None	N/A
3	Lincoln Electric System	Sam Christensen		Affirmative	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Ronald Bauer		Affirmative	N/A
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		Affirmative	N/A
3	New York Power Authority	David Rivera	Shelly Dineen	Negative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney	James Mearns	Abstain	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Ocala Utility Services	Neville Bowen	LaKenya VanNorman	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		Abstain	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	William Berry		Abstain	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Affirmative	N/A
3	Platte River Power Authority	Wade Kiess		None	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	maria pardo		Abstain	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		Affirmative	N/A
3	Santee Cooper	James Poston		Negative	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		None	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Negative	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 Abshier		Negative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	American Public Power Association	John McCaffrey		Abstain	N/A
4	Austin Energy	Jun Hua		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
4	DTE Energy	patricia ireland		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Florida Municipal Power Agency	Dan O'Hagan	LaKenya VanNorman	Affirmative	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain	N/A
4	Indiana Municipal Power Agency	Jack Alvey		Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Adam Lee		Affirmative	N/A
4	Northern California Power Agency	Marty Hostler	James Mearns	Abstain	N/A
4	Oklahoma Municipal Power Authority	Michael Watt		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Negative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Ken Habgood		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Abstain	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	Acciona Energy North America	Krys Rootham		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
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	Basin Electric Power Cooperative	Amanda Wangler		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
5	Black Hills Corporation	Derek Silbaugh	Jennifer Malon	Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Cogentrix Energy Power Management, LLC	Gerry Adamski		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Haizhen Wang		Affirmative	N/A
5	Constellation	Alison Mackellar		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	CPS Energy	Robert Stevens		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Decatur Energy Center LLC	Shannon Ferdinand		None	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Enel Green Power	Natalie Johnson		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	LaKenya VanNorman	Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Greybeard Compliance Services, LLC	Michael Gabriel		Negative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	Invenergy LLC	Rhonda Jones		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Jason Fortik		Affirmative	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	Mark Spencer		Negative	N/A
5	National Grid USA	Elizabeth Spivak		Affirmative	N/A
5	NB Power Corporation	David Melanson		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Negative	N/A
5	NextEra Energy	Summer Esquerre		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Northern California Power Agency	Jeremy Lawson	James Mearns	Abstain	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Negative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	OTP - Otter Tail Power Company	Tammy Kubela		None	N/A
5	Pacific Gas and Electric Company	Frank Lee	Michael Johnson	Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Negative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		Negative	N/A
5	Sacramento Municipal Utility District	Nicole Goi	Tim Kelley	Affirmative	N/A
5	Salt River Project	Jennifer Bennett		Affirmative	N/A
5	Santee Cooper	Marty Watson		Negative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		None	N/A
5	Southern Company - Southern Company Generation	James Howell		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Negative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Tenaska, Inc.	Mark Young		Negative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Affirmative	N/A
5	TransAlta Corporation	Ashley Scheelar		Abstain	N/A
5	Tri-State G and T Association, Inc.	Ryan Walter		Negative	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Negative	N/A
5	Vistra Energy	Dan Roethemeyer		Negative	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP	JT Kuehne		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	Claudine Bates		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Abstain	N/A
6	Cleco Corporation	Robert Hirchak		Abstain	N/A
6	Con Ed - Consolidated Edison Co. of New York	Michael Foley		Affirmative	N/A
6	Constellation	Kimberly Turco		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	John Sturgeon		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Jennifer Flandermeyer	Alan Kloster	Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
6	Florida Municipal Power Agency	Jade Bulitta	LaKenya VanNorman	Affirmative	N/A
6	Florida Municipal Power Pool	Aaron Casto	LaKenya VanNorman	Affirmative	N/A
6	Great River Energy	Donna Stephenson		Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Invenergy LLC	Colin Chilcoat		Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Manitoba Hydro	Simon Tanapat-Andre		Affirmative	N/A
6	Muscatine Power and Water	Nick Burns		Abstain	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet	James Mearns	Abstain	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	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	Joseph Neglia		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Negative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Israel Perez		Affirmative	N/A
6	Santee Cooper	Glenda Horne		Negative	N/A
6	Snohomish County PUD No. 1	John Liang		Negative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Erin Spence		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	Tennessee Valley Authority	Armando Rodriguez		Affirmative	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
7	Oxy - Occidental Chemical	Venona Greaff		Affirmative	N/A
10	Midwest Reliability Organization	William Steiner		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	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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Exhibit G

Standard Drafting Team Roster, Project 2021-07
Extreme Cold Weather Grid Operations, Preparedness, and Coordination

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Standard Drafting Team Roster

Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination

	Name	Entity
Chair	Kenneth Luebbert	Evergy, Inc.
Vice Chair	Matthew Harward	Southwest Power Pool, Inc.
Members	Venona Greaff	Oxy
	Derek Kassimer	ReliabilityFirst
	Jonathan Davidson	City Utilities of Springfield
	David McRee	Duke Energy
	Thor Angle	Puget Sound Energy
	Keith Smith	Orsted Onshore North American
	Chad Wiseman	Newfoundland & Labrador Hydro
	Bradley Pabian	Louisville Gas & Electric and Kentucky Utilities
	Collin Martin	Oncor Electric Delivery, LLC
	Jill Loewer	Utility Services
	David Kezell	Electric Reliability Council of Texas, Inc. (ERCOT)
	Ryan Salisbury	Oklahoma Gas & Electric
	David Deerman	Southern Company Services
PMOS Liaison	Michael Brytowski	Great River Energy
	Kirk Rosener	CPS Energy
NERC Staff	Alison Oswald – Senior Standards Developer	North American Electric Reliability Corporation

	Name	Entity
	Lauren Perotti – Legal	North American Electric Reliability Corporation