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-011-4 AND TOP-002-5 AND REQUEST FOR EXPEDITED ACTION

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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 revised Reliability Standards containing new and enhanced requirements for cold weather operations and preparedness: proposed Reliability Standard EOP-011-4 (Emergency Operations) and proposed Reliability Standard TOP-002-5 (Operations Planning).[4]

The proposed Reliability Standards represent the conclusion of the second phase of work to address the 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.[5] As discussed more fully herein, the proposed Reliability Standards build upon the first and

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[1] 16 U.S.C. § 824o.

[2] 18 C.F.R. § 39.5 (2023).

[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] 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-

second rounds of cold weather Reliability Standards, approved by the Commission in 2021,[6] and 2022,[7] respectively, to further reduce the risks posed by extreme cold weather to the reliability of the Bulk-Power System. Proposed Reliability Standard EOP-011-4 would advance reliability by requiring Balancing Authorities, Transmission Operators, and load shedding entities identified by Transmission Operators to limit the participation of critical natural gas infrastructure loads in the demand response and emergency load shedding programs they oversee, particularly during cold weather conditions when natural gas supply issues for generation have proven to be the most challenging. Proposed Reliability Standard TOP-002-5 would advance reliability through a new requirement addressing how the Balancing Authority will prepare for operations during extreme cold weather conditions. The proposed Reliability Standards address Key Recommendations 1g, 1h, and 1i from the Joint Inquiry Report.[8]

NERC requests that the Commission approve the proposed Reliability Standards EOP-011-4 and TOP-002-5, 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 Standards EOP-011-3 and TOP-002-4; and (iii) the proposed implementation plan (**Exhibit B**).

In light of the risks to reliability posed by the failure to prepare properly for cold weather conditions, demonstrated most recently by the December 2022 Winter Storm Elliott event affecting

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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."

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

7 *N. Am. Elec. Reliability Corp.*, 182 FERC ¶ 61,094 (2023) (approving Reliability Standards EOP-011-3 and EOP-012-1 and directing further revisions) [hereinafter February 2023 Order].

8 Joint Inquiry Report at 190-191, 208-209.

the Eastern Interconnection,[9] NERC respectfully requests that the Commission consider approving the proposed Reliability Standards, associated elements, and the implementation plan on an expedited timeframe.

As required by Section 39.5(a)[10] 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[11] (**Exhibit D**), and a summary of the standard development history (**Exhibit F**). The NERC Board of Trustees adopted the proposed Reliability Standards on October 23, 2023.

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

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9 *See* FERC, NERC, and Regional Entity Joint Staff Inquiry, *December 2022 Winter Storm Elliott Grid Operations: Key Findings and Recommendations* (Sep. 21, 2023), presentation of key findings and recommendations at https://www.ferc.gov/news-events/news/presentation-ferc-nerc-regional-entity-joint-inquiry-winter-storm-elliott [hereinafter December 2022 Winter Storm Elliott Inquiry]. As of the date of this filing, the final report is pending publication.

10 18 C.F.R. § 39.5(a).

11 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).

Reliability Standards enhancements, to be undertaken in two phases of work. Section V provides a 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 summary of the next steps NERC plans to take regarding cold weather reliability risks. Section IX summarizes why NERC requests expedited action in this proceeding.

I. SUMMARY

Multiple events since 2011 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,[12] 2014,[13] 2018,[14] 2021,[15] and 2022.[16] The February 2021 cold weather reliability event in particular proved to be exceptionally severe. The conditions experienced during this event – referred to throughout this filing as 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

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[12] *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.

[13] *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).

[14] *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.

[15] Joint Inquiry Report, supra n. 5.

[16] December 2022 Winter Storm Elliott Inquiry, supra n. 9, Preliminary Recommendation 1 (slide 17) ("Findings support (a) the need for prompt NERC development and implementation of remaining recommended revisions to Reliability Standards from 2021 Key Rec. 1 to strengthen generators' ability to maintain extreme cold weather performance; (b) the need for robust ERO monitoring of implementation of currently-effective and approved cold weather Reliability Standards, to determine if reliability gaps exist.).

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 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 a robust and comprehensive suite of Reliability Standards to address the potential implications for reliability. Over the last several years, NERC has made developing these Reliability Standards a high priority.

In 2021, NERC took an important first step to assure the reliability of the Bulk-Power System in cold weather conditions through the development of 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, which became effective in the United States on April 1, 2023, are advancing the reliability of the Bulk-Power System by 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.

In 2022, NERC developed a second set of cold weather Reliability Standards, Reliability Standards EOP-012-1 and EOP-011-3. Reliability Standards EOP-012-1 and EOP-011-3 represent the conclusion of the first phase of work to address the standards recommendations of the Joint Inquiry Report. Reliability Standards EOP-012-1 and EOP-011-3 contain new and enhanced operations and generator cold weather preparedness requirements and will complement the improved generator cold weather information sharing requirements in Reliability Standards TOP-003-5 and IRO-010-4. The Commission approved Reliability Standards EOP-012-1 and EOP-011-3 in February 2023, with directives to submit further modifications to Reliability Standard EOP-012-1 and the implementation plan by February 2024.[17] Reliability Standard EOP-012-1 will become effective in the United States on October 1, 2024, while the effective date of Reliability Standard EOP-011-3 remains pending Commission approval.[18]

In this petition, NERC submits for Commission approval proposed Reliability Standards EOP-011-4 and TOP-002-5. As discussed herein, proposed Reliability Standards EOP-011-4 and TOP-002-5 address Key Recommendations 1g, 1h, and 1i from the Joint Inquiry Report. Proposed Reliability Standard EOP-011-4 further builds upon the improvements reflected in Reliability Standards EOP-011-2 and EOP-011-3 to require Balancing Authorities, Transmission Operators, and load shedding entities to account for critical natural gas infrastructure loads in the demand response and emergency load shedding programs they oversee, so that deploying these programs

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[17] *See* February 2023 Order at PP 4-11 for a summary of the Commission's directives for standards modifications and implementation plan modifications.

[18] In the February 2023 Order, the Commission deferred approving the effective date of Reliability Standard EOP-011-3 until NERC submits the directed revisions to clarify the applicability of Reliability Standard EOP-012-1. The Commission explained it was taking this action due to the transition of requirements for cold weather preparedness plans and training from EOP-011-3 to EOP-012-1. *See id.* P 59.

in cold weather conditions will not exacerbate natural gas fuel supply issues which can constrain generating unit capacity and thereby threaten the reliability of the Bulk-Power System. Proposed Reliability Standard TOP-002-5 would require Balancing Authorities to implement comprehensive Operating Processes for extreme cold weather periods in their areas. Following Commission approval of proposed Reliability Standards EOP-011-4 and TOP-002-5, NERC will have a comprehensive and robust suite of cold weather Reliability Standards in place, addressing multiple facets of cold weather preparedness and operations. Collectively, these Reliability Standards will provide strong protections for the Bulk-Power System during future winter seasons.

While NERC's cold weather standards development efforts will now focus on refining Reliability Standard EOP-012-1 consistent with the Commission's directives, addressing cold weather reliability risks remains a high priority for NERC. As such, NERC is committed to using all options in its reliability toolkit to address these risks and support entities in their cold weather preparations, including NERC alerts, cold weather preparedness outreach, Reliability Guidelines, and ongoing support and monitoring of entity compliance. NERC is also committed to addressing promptly any recommendations for further NERC action arising from the December 2022 Winter Storm Elliott Inquiry.

NERC respectfully requests that the Commission approve, on an expedited timeframe, the proposed Reliability Standards EOP-011-4 and TOP-002-5 and the associated elements 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:[19]

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III. REGULATORY BACKGROUND

A. Regulatory Framework

By enacting the Energy Policy Act of 2005,[20] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the Bulk-Power System ("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)[21] 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)[22] of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard. Section 39.5(a)[23] 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

[19] Persons to be included on the Commission's service list are indicated with an asterisk. NERC requests waiver of 18 C.F.R. § 385.203(b) to permit the inclusion of more than two people on the service list.

[20] 16 U.S.C. § 824o.

[21] *Id.* § 824o(b)(1).

[22] *Id.* § 824o(d)(5).

[23] 18 C.F.R. § 39.5(a).

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

The Commission 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[24] and Section 39.5(c)[25] 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 develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Standard Processes Manual.[26]

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,[27] and thus satisfy several of the Commission's criteria for approving Reliability Standards.[28] 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

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[24] 16 U.S.C. § 824o(d)(2).

[25] 18 C.F.R. § 39.5(c)(1).

[26] 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.

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

[28] Order No. 672*, supra* note 11, at PP 268, 270.

must adopt, a new or revised Reliability Standard before NERC submits the Reliability Standard to the Commission for approval.

IV. THE NEED FOR ENHANCED RELIABILITY 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.[29] Several notable events since 2011 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 BPS reliability events in 2011,[30] 2014,[31] 2018,[32] and 2021.[33] In December 2022, while the development of the proposed Reliability Standards EOP-011-4 and TOP-002-5 was underway, yet another extreme cold weather event threatened the reliability of the Bulk-Power System.[34]

29 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.

30 *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.

31 *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).

32 *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].

33 Joint Inquiry Report, supra n. 5.

34 December 2022 Winter Storm Elliott Inquiry, supra n. 9.

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.[35] 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, a need that was reinforced again most recently by the December 2022 Winter Storm Elliott Inquiry team.[36]

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,[37] to address the recommendations of the January 2018 Event

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[35] 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.

[36] December 2022 Winter Storm Elliott Inquiry, supra n. 9, at Recommendation 1 ("Findings support (a) the need for prompt NERC development and implementation of remaining recommended revisions to Reliability Standards from 2021 Key Rec. 1 to strengthen generators' ability to maintain extreme cold weather performance; (b) the need for robust ERO monitoring of implementation of currently-effective and approved cold weather Reliability Standards, to determine if reliability gaps exist.").

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

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.[38] 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.
> - 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.

[38] January 2018 Event Report at 80, 84.

- 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.[39]

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. These Reliability Standards became effective in the United States on April 1, 2023.

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,

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

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 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.[40]

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 Reliability

[40] Joint Inquiry Report at 9-10.

Standards EOP-011-3 and EOP-012-1, approved by the Commission in February 2023, and proposed Reliability Standards EOP-011-4 and TOP-002-5, which are discussed in this petition.

1. Overview of the February 2021 Event

As summarized by the Joint Inquiry Report,[41] 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.[42] Supply issues contributed to outages and derates of many gas-powered generating units. The area also experienced periods of freezing participation and snow, which 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.[43]

On February 14, 2021, ERCOT set an all-time winter peak record for system load of 69,871 MW.[44] 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

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

42 *Id.* at 13.

43 *Id.*

44 *Id.*

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.[45]

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.[46] SPP and MISO were able to make up many of their shortfalls by importing power from 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.[47]

2. Key Findings and Recommendations

In the summary of the key findings and causes of the February 2021 Event, the Joint Inquiry team identified that two causes, both triggered by cold weather, lead to the Event, and that these

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45 *Id.* at 14.

46 *Id.*

47 *Id.* at 14-15.

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.[48]

During the February 2021 Event, 1,045 individual generating units, consisting of multiple generation types,[49] 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-up failures, with natural gas fuel supply issues causing the majority (87%) of the fuel issues.[50] 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.[51]

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.[52] 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.[53]

In response to these findings, the Joint Inquiry Report contains several 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

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48 *Id.* at 11-12.

49 *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.

50 *Id.* at 15-16.

51 *Id.*

52 *Id.* at 17.

53 *Id.*

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 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);[54]

- **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);[55]

- **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);[56]

- **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,

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

55 *Id.* at 184.

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

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);[57]

- **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);[58]

- **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);[59] and

- **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).[60]

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,

57 *Id.* at 187.

58 *Id.* at 188.

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

60 *Id.* at 190 (internal citations omitted).

including the participation in demand response programs of natural gas infrastructure loads supplying gas for generation[61] and the inclusion of natural gas production and processing facilities in manual load shedding programs.[62] 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);[63] and

- **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).[64]

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.[65] Related to this observation, the Joint Inquiry Report contains one sub-

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61 *Id.* at 208.

62 *Id.* at 209.

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

64 *Id.* at 208-209.

65 *Id.* at 209.

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)[66]

Reliability Standards EOP-012-1 and EOP-011-3, approved by the Commission in February 2023, represented the conclusion of the first phase of work to address Key Recommendations 1d, 1e, 1f, and 1j, each with a target Winter 2022-2023 completion date, as well as Key Recommendations 1a and 1b, each with a target Winter 2023-2024 completion date. Further work is underway to revise Reliability Standard EOP-012-1 consistent with the Commission's directives in the February 2023 Order and Key Recommendation 1c. NERC intends to file a revised EOP-012 standard by the Commission's February 2024 deadline.

As discussed more fully below, proposed Reliability Standards EOP-011-4 and TOP-002-5 address the Key Recommendations 1g, 1h, and 1i to improve cold weather operations in furtherance of reliability.

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

Recognizing the importance of addressing the recommendations of the Joint Inquiry 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:

66 *Id.* at 209.

- 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.[67]

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 Joint Inquiry Report, consistent with the timelines directed by the NERC Board of Trustees. The first phase of work was completed in September 2022 with the development of Reliability Standards EOP-012-1 and EOP-011-3. The Commission approved these Reliability Standards in February 2023, with directives for further revisions to EOP-012-1 and the associated implementation plan.[68]

The second phase of work began in winter 2022/2023. The Project 2021-07 standard drafting team developed revisions to Reliability Standard TOP-002-4 and the approved, but not yet effective Reliability Standard EOP-011-3 to address Key Recommendations 1g, 1h, and 1i from the Joint Inquiry Report. The first drafts of the proposed Reliability Standards were posted for an initial 45-day formal comment period and ballot from June 5, 2023 through July 20, 2023. Neither proposed standard received the required ballot body approval. On August 23, 2023, 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 subsequent postings under this project. Specifically, the Standards Committee approved shortening the additional formal comment and

[67] 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.

[68] *See* February 2023 Order at PP 4-11 for a summary of the Commission's directives for standards modifications and implementation plan modifications.

ballot period(s) from 45 days to as little as 20 days, with ballot conducted during the last 10 days; and shortening the final ballot from 10 days to as little as 5 days.[69] The proposed Reliability Standards were then posted for an additional formal comment period and ballot that ran from August 24, 2023 through September 12, 2023. The proposed Reliability Standards were posted for final ballot from September 29, 2023 through October 6, 2023 and achieved the following approval percentages:

- Proposed Reliability Standard EOP-011-4: 73.29 % approval / 92.5% quorum;
- Proposed Reliability Standard TOP-002-5: 79.56% approval / 92.11% quorum; and
- Implementation Plan: 80.69% approval / 91.37% quorum.

The NERC Board of Trustees adopted the proposed Reliability Standards on October 23, 2023. 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-011-4 - Emergency Operations and proposed Reliability Standard TOP-002-5 – Operations Planning. The proposed Reliability Standards build upon NERC's prior work with the cold weather Reliability Standards EOP-011-2 and EOP-011-3 and would further advance reliability through improved cold weather operations requirements.

Proposed Reliability Standard EOP-011-4 contains enhanced requirements for Transmission Operator and Balancing Authority Operating Plan(s) to mitigate emergencies in their

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[69] *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.

areas. Consistent with Key Recommendations 1h and 1i of the Joint Inquiry Report, proposed Reliability Standard EOP-011-4 would require each Transmission Operator and Balancing Authority to include provisions in its Operating Plan(s) for mitigating emergencies that account for the critical natural gas infrastructure loads that fuel a significant portion of Bulk-Power System generation. As the Joint Inquiry report observed, de-energizing critical natural gas infrastructure that supplies fuel to generators powering the Bulk-Power System can have adverse impacts on electric system reliability, particularly during the type of cold weather emergency conditions experienced during the February 2021 Event.[70] The proposed Reliability Standard revises current requirements for Transmission Operator Operating Plans to mitigate emergencies so that Transmission Operators will be required to identify and prioritize critical natural gas infrastructure loads in manual and automatic load shedding (particularly underfrequency and undervoltage load shedding) (Requirement R1). The proposed Reliability Standard creates a new requirement for each Transmission Operator to identify relevant entities that are required to assist with load shedding as part of its Operating Plan(s) to mitigate emergencies (Requirement R7). A second new requirement will require those identified entities to develop and implement a load shedding plan that accounts for reliability considerations including the identification and prioritization of critical natural gas infrastructure loads (Requirement R8). The proposed Reliability Standard also requires Balancing Authorities to exclude critical natural gas infrastructure loads from their demand response programs in extreme cold weather periods (Requirement R2).

Proposed Reliability Standard TOP-002-5 contains a new requirement, Requirement R8, which would require each Balancing Authority to develop an extreme cold weather Operating Process for its area, addressing preparations for and operations during extreme cold weather

[70] Joint Inquiry Report at 208-09.

periods. This Operating Process must have, at a minimum, a methodology for identifying the extreme cold weather periods in which it will apply, appropriate to the area; a methodology to determine an adequate reserve margin during the period, considering generating unit operating limitations; and a methodology for developing a five-day hourly forecast that considers weather, demand, resource commitment, and capacity and energy reserve requirements. This new requirement addresses the need for greater specificity about the relative roles of generators and the Balancing Authority in preparing for reliable cold weather operations, consistent with the reliability considerations underlying Key Recommendation 1g.

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. Proposed Reliability Standard EOP-011-4 – Emergency Operations

1. History of the EOP-011 Reliability Standard

The original version of the EOP-011 Reliability Standard, Reliability Standard EOP-011-1 – Emergency Operations, was approved by the Commission in 2015.[71] 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.

NERC developed the currently effective version, Reliability Standard EOP-011-2, to

[71] *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).

address in part Recommendation 1 of the January 2018 Event Report. This standard, which the Commission approved in 2021,[72] revised 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 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. Reliability Standard EOP-011-2 became effective in the United States on April 1, 2023.

In 2022, NERC developed Reliability Standard EOP-011-3 to address in part the first phase key recommendations for standards modifications from the Joint Inquiry Report. The Commission approved Reliability Standard EOP-011-3 in the February 2023 Order.[73] Reliability Standard EOP-011-3 modifies the currently effective Reliability Standard EOP-011-2 by removing Requirement R7 and Requirement R8, which are now in the new generator cold weather preparedness standard Reliability Standard EOP-012-1 as Requirement R3 and Requirement R5, respectively. Additionally, Reliability Standard EOP-011-3 revises Requirement R1 and R2 to address provisions for manual load shed for enhanced reliability in emergency Operating Plans. The effective date for Reliability Standard EOP-011-3 is currently pending before the Commission.[74]

2. Revisions in Proposed Reliability Standard EOP-011-4

Proposed Reliability Standard EOP-011-4 builds upon the modifications in approved, but

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

73 February 2023 Order, *supra* n. 7.

74 *Id.* at P 59.

not yet effective Reliability Standard EOP-011-3 to further advance reliable operations in cold weather conditions. The stated purpose of proposed Reliability Standard EOP-011-4 remains the same as in approved EOP-011-3: "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." The proposed Reliability Standard advances reliability by requiring consideration of the impacts of load shedding during Emergency conditions on the natural gas infrastructure that fuels a significant portion of BES generation, consistent with Recommendations 1h and 1i of the Joint Inquiry Report.

The Joint Inquiry team found that, during the February 2021 Event, natural gas supply issues caused approximately 27% of all outages, derates, and failures to start, and natural gas supply issues comprised the vast majority (87 percent) of total outages due to fuel issues (31.4%).[75] The Joint Inquiry team also found that, at the time of the February 2021 Event, most of the natural gas production and processing facilities surveyed in the ERCOT region in particular were not identified as critical load or otherwise protected from manual load shedding; as a result, the implementation of manual load shed by ERCOT operators contributed to the decline of the production of natural gas.[76] Had additional natural gas supply and transportation been available, the total amount of manual firm load shed needed for reliability may have been reduced.[77] Further, the Joint Inquiry Team identified that at least one natural gas producer participated in a demand response program. A Balancing Authority may rely on demand response as part of an operating plan to mitigate emergencies, including energy emergencies, in its area. If the Balancing Authority

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75 Joint Inquiry Report at 16.

76 *Id.* at 209.

77 *Id.*

sheds loads as part of a demand response program that end up reducing the availability of gas-fired generation, the purpose of the plan would be defeated.[78] Therefore, the Joint Inquiry team recommended that NERC develop a series of requirements to ensure that the relevant entities are taking steps to identify and shield critical natural gas infrastructure in their load shedding plans, 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);[79]

- **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).[80]

To address Key Recommendation 1i, proposed Reliability Standard EOP-011-4 revises Requirement R1 Part 1.2.5 to require each Transmission Operator to include provisions for the consideration of critical natural gas infrastructure loads in manual and automatic load shedding schemes in Operating Plan(s) to mitigate Emergencies in its area. Recognizing that other functional

78 Joint Inquiry Report at 208.

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

80 *Id.* at 208-209 (internal citation omitted).

entities are often called to assist the Transmission Operator in performing load shedding, proposed Reliability Standard EOP-011-4 contains two new requirements, Requirements R7 and R8, to ensure these new requirements for the consideration of critical natural gas infrastructure loads are appropriately implemented for the Loads they represent. Accordingly, the applicability of the proposed Reliability Standard is expanded to include those functional entities with new responsibilities under proposed Requirement R8: the Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area.

To address Key Recommendation 1h, proposed Reliability Standard EOP-011-4 revises Requirement R2 to add a new requirement part, Part 2.2.8, requiring each Balancing Authority to include provisions in their Operating Plans for excluding critical natural gas infrastructure loads which are essential to the reliability of the BES as Interruptible Load, curtailable Load, and demand response during extreme cold weather conditions in the Balancing Authority Area.

The following discussion of the proposed new and revised requirements in proposed Reliability Standard EOP-011-4 are organized by topic area, with revisions pertaining to Transmission Operator Operating Plans (revised Requirement R1, new Requirements R7 and R8) discussed in subsections (a)-(b) below, and Balancing Authority Operating Plans (revised Requirement R2) discussed in subsection (c).

a) Revisions in Requirement R1

Proposed Reliability Standard EOP-011-4 revises Requirement R1 relating to considerations for load shedding schemes in Transmission Operator Operating Plan(s) to mitigate Emergencies in its area. NERC defines an "Operating Plan" as:

> A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating

> Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.[81]

Consistent with Recommendation 1i of the Joint Inquiry Report, proposed Reliability Standard EOP-011-4 Requirement R1 Part 1.2.5 would require each Transmission Operator to identify and prioritize critical natural gas infrastructure loads which are essential to the reliability of the BES as part of manual and automatic load shedding schemes included in Operating Plan(s) to mitigate Emergencies in its Transmission Operator Area. New Requirements R7 and R8, discussed in the following section, would ensure that these considerations are also accounted for by the entities responsible for implementing the load shed. Proposed Reliability Standard EOP-010-4 Requirement R1 revises Reliability Standard EOP-011-3 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. Operator-controlled manual Load shed~~ding~~, <u>undervoltage load shed (UVLS), or underfrequency load shed (UFLS)</u> during an Emergency that accounts for each of the following:

[81] Operating Plan, *Glossary of Terms used in NERC Reliability Standards*, https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

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, UVLS, or UFLS and circuits that serve designated critical loads which are essential to the reliability of the BES;

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;

1.2.5.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity; and

1.2.6. Provisions to determine reliability impacts of:

1.2.6.1. C~~c~~old weather conditions; and

1.2.6.2. E~~e~~xtreme weather conditions.

Under currently effective Reliability Standard EOP-011-2 Requirement R1 Part 1.2.5, Transmission Operators must include in their Operating Plans provisions for operator-controlled manual load shed that minimizes the overlap with automatic load shed and are capable of implemented in a timeframe adequate for mitigating an Emergency. Consistent with Key Recommendation 1j of the Joint Inquiry Report, approved Reliability Standard EOP-011-3 Requirement R1 Part 1.2.5 will add three new requirements regarding load shed: (1) a requirement for the Transmission Operator to include provisions to minimize the overlap of circuits dedicated for manual load shed and those that serve designated critical loads (Requirement R1 Part 1.2.5.2); (2) a requirement for the Transmission Operator to include provisions to minimize of overlap of circuits designated for manual load shed and circuits that are used for underfrequency and undervoltage load shed programs (Requirement R1 Part 1.2.5.3), and (3) a requirement for the

Transmission Operator to include provisions to limit the use of underfrequency or undervoltage load shed circuits for manual load shed to situations where warranted by system conditions (Requirement R1 Part 1.2.5.4).

Consistent with Key Recommendation 1i, proposed Reliability Standard EOP-011-4 further modifies Requirement R1 Part 1.2.5 to include a new requirement, Requirement R1 Part 1.2.5.5, to require the inclusion of provisions for the identification and prioritization of critical natural gas infrastructure loads which are essential to the reliability of the BES. Proposed Reliability Standard EOP-011-4 also further modifies Requirement R1 Part 1.2.5 to include consideration of underfrequency and undervoltage load shed in addition to "operator-controlled manual Load shed" schemes. This revision is appropriate because critical natural gas infrastructure loads must be considered appropriately in the context of automatic load shedding under these schemes, as well as manual load shedding. With respect to automatic load shedding, the proposed standard specifies that undervoltage and underfrequency load shed programs are to be considered. The drafting team determined that it was necessary to specify which automatic load shed programs are to be considered to avoid confusion with other frameworks that involve automatic load shedding, such as Remedial Action Schemes, which are not necessarily used to assist in the mitigation of operating emergencies. Corresponding revisions are proposed in Requirement R2 Part 2.2.9 (Requirement R2 Part 2.2.8 in approved EOP-011-3) pertaining to provisions for Transmission Operator load shed in Balancing Authority Operating Plans.

In the proposed standard, the standard drafting team determined to employ a flexible approach to the required provisions for the identification of critical natural gas infrastructure loads. As noted in Key Recommendation 1i, one method for identifying such loads may include distributing criteria to natural gas infrastructure entities soliciting information to identify critical facilities that would likely affect BES reliability adversely if de-energized.[82] However, other methods may prove equally effective and efficient to provide Transmission Operators with sufficient knowledge to adjust their load shedding schemes as necessary to maximize the availability of natural gas resources and lessen reliability impacts in Emergency conditions. For example, other methods could include relying on identifications of critical natural gas infrastructure that are required by state laws or regulations,[83] or referencing historical information or previous coordination with natural gas suppliers and generators in connection with pre-existing Operating Plans. Regardless of the method chosen, it is expected that ongoing coordination and review will be necessary as changes occur in the electric and natural gas systems.

Similarly, the standard drafting team determined to employ a flexible approach to the required provisions for the prioritization of identified critical natural gas infrastructure loads. This flexibility would allow Transmission Operators to consider and account for the various conditions that may prompt load shed in determining which loads should be shed and when. While the Joint Inquiry Report recommended "protecting" critical natural gas infrastructure Loads from manual and automatic load shed,[84] the standard drafting team determined a more flexible and comprehensive approach, taking into account all relevant factors such as depth, duration, and season for the load shed event, would be more effective to preserve system reliability in Emergency conditions. Therefore, the proposed Reliability Standard refers to "prioritization" of critical natural

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82 Key Recommendation 1i, Joint Inquiry Report at 208-209.

83 As an example, NERC understands that the State of Texas has implemented a scheme for designating critical natural gas facilities where electricity is essential for the supplier to operate, and that operators of such facilities must provide information to their electric service provider as well as ERCOT. *See* Public Utility Commission of Texas, Critical Natural Gas, https://www.puc.texas.gov/industry/electric/cng/default.aspx (last visited Oct. 27, 2023).

84 *See* Key Recommendation 1i, Joint Inquiry Report at 208-209 ("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") (internal citation omitted).)

gas infrastructure loads in load shedding schemes. In the Technical Rationale, the standard drafting team describes an example of such a prioritization approach, depending on the criticality of the particular load in maintaining reliability in that particular area: first, the Transmission Operator would identify and prioritize those critical natural gas infrastructure loads with the highest level of criticality and potential impact to reliability, such that they can be completely excluded from operator-controlled manual load shed and automatic load shed programs; second, the Transmission Operator would identify and prioritize other critical natural gas infrastructure loads not included in automatic load shed programs such that they are shed only if necessary to maintain the system, based on the load shed magnitude; and third, Transmission Operators would identify and prioritize other critical natural gas infrastructure loads included in automatic load shed programs such that they are allocated to the lower frequency, or longer-time delay, steps in a UFLS program, so that they are less likely to be interrupted.[85]

As part of the standard development process, the standard drafting team considered alternative approaches, such as defining the phrase "critical natural gas infrastructure Load." The standard drafting team determined a flexible approach in the standard, compared to a static, continent-wide definition, would be more appropriate given the wide variations in natural gas infrastructure across North America. As discussed further in the Technical Rationale, differences in usage and infrastructure, and even the location of such infrastructure relative to other infrastructure, may result in significant differences in what is considered critical natural gas infrastructure essential for BES reliability in one region or area as compared to another.[86] The flexible approach employed by the proposed standard would allow each Transmission Operator to

85 Technical Rationale, Exhibit C at 6.

86 *Id.* at 5.

consider all relevant information in determining what is a "critical natural gas infrastructure Load" in its footprint. Such information could include the Transmission Operator's governing documents, any guidance established by regulatory authorities in the relevant jurisdiction(s), and other information relevant to its area. Transmission Operators may consult NERC's March 2023 Reliability Guideline, *Natural Gas and Electrical Operational Coordination Considerations*, for further information.[87]

b) Requirements R7 and R8

Proposed Reliability Standard EOP-011-4 Requirements R7 and R8 are new requirements that work together and with Requirement R1 to ensure that, where the Transmission Operator relies on other entities for assisting with the mitigation of operating emergencies in the Transmission Operator Area, that those other entities account for the same load shed considerations for reliability that are required in Transmission Operator Operating Plans. Proposed Requirement R7 is a new requirement that would require each Transmission Owner to identify and notify the relevant entities on an annual basis, so that those entities may develop the load shedding plans required under proposed Requirement R8.

Proposed Reliability Standard EOP-011-4 Requirements R7 and R8 would provide as follows:

> **R7.** Each Transmission Operator shall annually identify and notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding.
>
> **R8.** Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator

[87] NERC, Reliability Guideline *Natural Gas and Electrical Operational Coordination Considerations* (Mar. 2023), available at https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability%20Guideline%20-%20Gas%20and%20Electric%20Operational%20Coord%20Considerations.pdf.

Area shall develop, maintain, and implement a Load shedding plan. The Load shedding plan shall include the following, as applicable:

8.1. Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding during an Emergency that accounts for each of the following:

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

8.1.2. Provisions to minimize the overlap of circuits that are designated for manual, undervoltage, or underfrequency Load shed and circuits that serve designated critical loads which are essential to the reliability of the BES;

8.1.3. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS;

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

8.1.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity.

8.2. Provisions to provide the Load shedding plan to the Transmission Operator for review.

In developing proposed Requirements R7 and R8, the standard drafting team recognized that Transmission Operators are often dependent on Distribution Providers, UFLS-Only Distribution Providers, or Transmission Owners to implement the operator-controlled manual load shedding, underfrequency load shedding, or undervoltage load shedding during an Emergency as required in Requirement R1 Part 1.2.5. Accordingly, the standard drafting team determined that it is necessary to expand the applicability of proposed Reliability Standard EOP-011-4 to these functional entities to address all entities responsible for performing such load shed. This revision is consistent with Joint Inquiry Report Key Recommendation 1i, which recommended that other entities besides the Transmission Operator and Balancing Authority account for critical natural gas infrastructure Loads in their manual and automatic load shedding. The standard drafting team determined to include the Distribution Provider, UFLS-Only Distribution Provider, and the Transmission Owner, as these are the entities often called to assist in implementing manual load shedding, underfrequency load shedding, or undervoltage load shedding. The standard drafting team did not include Planning Coordinators or Transmission Planners, as recommended in Key Recommendation 1i,[88] because these entities are not responsible for performing such load shedding.

Proposed Reliability Standard EOP-011-4 Requirement R7 is a new requirement under which the Transmission Operator must, on an annual basis, identify and notify any Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners that are required to assist with mitigation of operating emergencies in its Transmission Operator Area. The Transmission Operator has the overarching responsibility to mitigate operating emergencies. If a Transmission Operator relies on other functional entities in accomplishing various aspects of manual or automatic load shedding, notice must be provided so those entities can become aware of their responsibilities under Requirement R8.

Proposed Reliability Standard EOP-011-4 Requirement R8 is a new requirement that is applicable to the Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners identified by the Transmission Operator under proposed Requirement R7. Proposed Requirement R8 includes the relevant portions of Requirement R1 Part 1.2.5 that address operator-controlled manual Load shedding or automatic (underfrequency or undervoltage) load shedding. This includes provisions for the consideration of critical natural gas infrastructure loads, discussed

[88] Key Recommendation 1i, Joint Inquiry Report at 208-209 (recommending standards modifications to "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" (internal citations omitted)).

above, in load shedding schemes. The standard drafting team found it appropriate to place these requirements specifically on Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners because they are often the entities performing operator-controlled manual Load shedding or automatic load shedding and have the capability of ensuring that these requirements are appropriately implemented for the loads they represent. These entities must provide the load shedding plan to the Transmission Operator for review.

c) Proposed Revisions in Requirement R2

Proposed Reliability Standard EOP-011-4 also revises Requirement R2 pertaining to Balancing Authority Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies in their respective areas to address Key Recommendation 1h of the Joint Inquiry Report. Specifically, proposed Reliability Standard EOP-011-4 adds a new Requirement R2 Part 2.2.8 to require Balancing Authorities to exclude critical natural gas infrastructure loads which are essential to the reliability of the BES as Interruptible Load, curtailable Load, and demand response during extreme cold weather conditions.

Proposed Reliability Standard EOP-011-4 Requirement R2 revises approved Reliability Standard EOP-011-3 Requirement R2 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. C~~c~~apability and availability;

2.2.3.2. F~~f~~uel supply and inventory concerns;

2.2.3.3. F~~f~~uel switching capabilities; and

2.2.3.4. E~~e~~nvironmental 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 excluding critical natural gas infrastructure loads which are essential to the reliability of the BES, as defined by the Applicable Entity, as Interruptible Load, curtailable Load, and demand response during extreme cold weather periods within each Balancing Authority Area;

2.2.~~8~~9. Provisions for Transmission Operators to implement operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding in accordance with Requirement R1 Part 1.2.5; and

2.2.~~9~~10. Provisions to determine reliability impacts of:

2.2.9.1. C~~c~~old weather conditions; and

2.2.9.2. E~~e~~xtreme weather conditions.

Under proposed Requirement R2 Part 2.2.8, Balancing Authorities must take steps to exclude critical natural gas infrastructure Loads which are essential to the reliability of the BES from their Interruptible Load, curtailable Load, and demand response programs during extreme cold weather periods in the Balancing Authority Area. The phrase "critical natural gas infrastructure Loads which are essential to the reliability of the BES, as defined by the Applicable Entity" is further discussed in the context of the revisions to Requirement R1, above.

The need for limiting the participation of critical natural gas infrastructure loads in load shed programs in extreme cold weather is well documented.[89] However, and as discussed above in the context of proposed Requirement R1, not all natural gas infrastructure loads have the same degree of criticality. Further, natural gas facilities do not have the same limitations and criticality during all seasons and weather conditions. During the standard development process, the standard drafting team considered a requirement that would exclude critical natural gas infrastructure loads in demand response programs generally. However, after further consideration, the standard drafting team determined a more narrowly tailored provision that would bar the participation of such loads only in extreme cold weather conditions would be consistent with the cold weather context of the Joint Inquiry Report. Proposed Requirement R2 Part 2.2.8 strikes an appropriate balance between the need to advance reliability during extreme cold weather conditions, while leaving flexibility for the participation of natural gas infrastructure loads in demand response programs in other seasons and conditions where their participation would not pose the same reliability concerns.

Additionally, and as noted in Section VI.A.2.c, the standard drafting team revised Reliability Standard EOP-011-3 Requirement Part 2.2.8, now Requirement R2 Part 2.2.9 in proposed Reliability Standard EOP-001-4, to account for relevant automatic load shedding schemes (i.e., undervoltage Load shedding and underfrequency Load shedding) in Balancing Authority Operating Plans. This revision was made to address part of Key Recommendation 1i.

In conclusion, proposed Reliability Standard EOP-011-4 would advance the reliability of the Bulk-Power System by requiring consideration of the impacts of load shedding during Emergency conditions on the natural gas infrastructure, consistent with Recommendations 1h and 1i of the Joint Inquiry Report. The Commission should approve the proposed Reliability Standard

89 *See* Joint Inquiry Report at 208.

as just, reasonable, not unduly discriminatory, and in the public interest.

B. Proposed Reliability Standard TOP-002-5 – Operations Planning

1. History of the TOP-002 Reliability Standard

The TOP-002 Reliability Standard addresses operations planning for Transmission Operators and Balancing Authorities. The stated purpose of the standard is "to ensure that Transmission Operators and Balancing Authorities have plans for operating within specified limits." The Commission approved the currently effective version, Reliability Standard TOP-002-4, in 2015.[90]

2. Revisions in Proposed TOP-002-5

Proposed Reliability Standard TOP-002-5 improves upon the currently effective version of the standard and would advance the reliability of the Bulk-Power System through a new requirement addressing how Balancing Authorities prepare for operations during extreme cold weather periods, including resource limitations during such periods, consistent with the reliability considerations underlying Key Recommendation 1g of the Joint Inquiry Report.

In the Report, the Joint Inquiry team highlighted how grid operators were unprepared for the significant generation outages experienced during the Event. The Joint Inquiry team noted that new requirements in two approved Reliability Standards, which were then pending enforceability, would work 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."[91] Specifically, Reliability Standard TOP-003-5 would require Transmission Operators and Balancing Authorities to request in their data specifications information on generator cold weather operating parameters

[90] *Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards*, Order No. 817, 153 FERC ¶ 61,179 (2015).

[91] Joint Inquiry Report at 190-191.

(TOP-003-5 Requirements R1 and R2, respectively), and a new requirement in Reliability Standard EOP-011-2 would require Generator Owners to identify such parameters (EOP-011-2 Requirement R7).[92] To further reduce the potential for surprise, the Joint Inquiry team recommended assigning to each functional entity specific roles in determining the generating unit capacity that can be relied upon during "local forecasted cold weather" under Reliability Standard TOP-003-5. Key Recommendation 1g therefore recommended Reliability Standards modifications as follows:

- **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).[93]

Proposed Reliability Standard TOP-002-5 addresses the reliability considerations underlying this recommendation through the addition of a new requirement, proposed Requirement R8, applicable to the Balancing Authority. Currently effective Reliability Standard

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92 *Id.*.

93 *Id.* at 190 (internal citations omitted).

TOP-002-4 requires each Balancing Authority to have one or more Operating Plans for the next-day that address expected generation resource commitment and dispatch, interchange scheduling, demand patterns, and capacity and energy reserve requirements, including delivery capability. (Requirement R4). Each Balancing Authority is required to notify entities identified in these Operating Plan(s) of their respective roles (Requirement R5), and to provide the Operating Plan(s) to its Reliability Coordinator (Requirement R7) for visibility. Proposed Reliability Standard adds a new requirement, proposed Requirement R8, to advance how the Balancing Authority prepares for operations during extreme cold weather periods in particular. Proposed Requirement R8 would provide as follows:

> **R8.** Each Balancing Authority shall have an extreme cold weather Operating Process for its Balancing Authority Area, addressing preparations for and operations during extreme cold weather periods. The extreme cold weather Operating Process shall include, but is not limited to:
>
> **8.1** A methodology for identifying an extreme cold weather period within each Balancing Authority Area;
>
> **8.2** A methodology to determine an adequate reserve margin during the extreme cold weather period considering the generating unit(s) operating limitations in previous extreme cold weather periods that includes, but is not limited to:
>
> **8.2.1** Capability and availability;
>
> **8.2.2** Fuel supply and inventory concerns;
>
> **8.2.3** Start-up issues;
>
> **8.2.4** Fuel switching capabilities; and
>
> **8.2.5** Environmental constraints.
>
> **8.3** A methodology to determine a five-day hourly forecast during the identified extreme cold weather periods that includes, but is not limited to:
>
> **8.3.1** Expected generation resource commitment and dispatch;
>
> **8.3.2** Demand patterns;
>
> **8.3.3** Capacity and energy reserve requirements, including deliverability capability; and
>
> **8.3.4** Weather forecast.

Proposed Requirement R8 recognizes that there have been several past events during extreme cold weather where load and resource balancing issues have occurred, due to both unexpected generator trips and higher loads than forecasted. Proposed Requirement R8 provides greater specificity regarding the Balancing Authority's responsibilities in extreme cold weather consistent with Key Recommendation 1g of the Joint Inquiry Report. Specifically, proposed Requirement R8 would formalize the Balancing Authority's process to review and respond to oncoming conditions that may affect generation availability and capability, forecasted load, and determining whether additional capability or reserves should be ready to serve loads during extreme cold weather. Proposed Requirement R8 does this by requiring each Balancing Authority to have an Operating Process for extreme cold weather that includes methodologies for assessing relevant operational criteria. NERC defines an "Operating Process" as "A document that identifies general steps for achieving a generic operating goal. An Operating Process includes steps with options that may be selected depending upon Real-time conditions…."[94]

As part of the Operating Process that would be required under proposed Requirement R8, the Balancing Authority must include: (1) a methodology for identifying "extreme cold weather conditions" in the area (Requirement R8 Part 8.1); (2) a methodology for determining an appropriate extreme cold weather reserve margin for the area, considering the types of operating limitations that have been known to limit resource availability in cold weather (Requirement R8 Part 8.2); and (3) a methodology for determining a five-day hourly forecast that accounts for all relevant operational considerations, including resource availability, demand, reserve requirements, and forecasted weather (Requirement R8 Part 8.3).

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[94] Operating Process, NERC Glossary.

In developing this requirement, the standard drafting team determined a flexible approach to developing methodologies based on specified criteria would be appropriate, considering the differences between Balancing Authority footprints, loads, and market constructs. However, to ensure that certain relevant factors are considered, Requirement R8, Parts 8.2 and 8.3 contain criteria, including data requirements, that the Balancing Authority must use as part of its methodologies. The minimum items that must be included in a methodology to determine an adequate reserve margin under proposed Requirement R8 Part 8.2 include factors that are known to impact resource availability in cold weather. These factors are consistent with the cold weather operating parameter information that must be addressed in Balancing Authority data specifications under Reliability Standard TOP-003-5 Requirement R2 Part 2.3, with additional consideration to start-up issues which are known to impact resource availability in cold weather.

The minimum items that must be included in the five-day hourly forecast include factors generally addressed in Balancing Authority Operating Plans for the next-day (*see* Requirement R4), excluding Interchange scheduling which is typically done in real time on an hourly basis, and with consideration to the weather forecast for the relevant period. In determining the appropriate look-ahead period for the Operating Process, the standard drafting team considered suggestions ranging from seven days to three days. It was determined that seven days was too long of a period, as weather forecasts are not sufficiently reliable for this longer duration, and that three days was too short of a period, as this would not allow the forecast to span a longer holiday weekend. The standard drafting team determined that five days would provide sufficient visibility into projected reserve margin requirements. Due to the criteria being the minimum required, the standard drafting team has included "but not limited to" language to allow the Balancing Authority flexibility to consider other information that it determines is valuable and germane to its methodologies.

Proposed Requirement R8 therefore provides greater specificity about the roles and responsibilities of the Balancing Authority in cold weather and provides a more consistent framework for assessing reserve margin requirements, consistent with the reliability considerations underlying Key Recommendation 1g, while providing flexibility for each Balancing Authority to develop an extreme cold weather Operating Process appropriate to its needs for sustaining an adequate level of reliability during an upcoming extreme cold weather event.

In determining that the above approach was the most appropriate means to address the reliability considerations underlying Key Recommendation 1g, the standard drafting team considered the performance required under the new and revised Reliability Standards addressing cold weather performance, its own experience in cold weather operations, interactions between the markets and reliability functions, and considerations raised by the standard drafting team members and project observers during the standard development process. Based on these considerations, the standard drafting team determined to employ a data-driven approach toward Balancing Authority preparations for cold weather, as reflected in the proposed Requirement R8 for a comprehensive cold weather Operating Process described above. The standard drafting team determined that this approach would be more efficient and effective in addressing the reliability need for informed preparations for cold weather operations.

The standard drafting team did not include a requirement for Generator Owners or Generator Operators to provide the Balancing Authority with the percentage of the total generating unit capacity that the Balancing Authority can rely upon during the local forecasted cold weather as recommended in Key Recommendation 1g. The standard drafting team considered that a Reliability Standard requirement expressly requiring the Generator Owner to provide an estimate of capacity that can be relied upon during local forecasted cold weather based on its understanding of the “full reliability risks” related to its contracts could be calling for the exchange of information that may be speculative in nature and assessed according to methods that may vary highly among Generator Owners, thereby reducing the utility of that information to the Balancing Authority and thus the expected reliability benefit. Against this uncertainty, the standard drafting team considered that Balancing Authorities have access to data involving generator performance during past cold weather events across their areas, including data involving entire classes of units, as well as data from individual Generator Owners regarding their cold weather operating parameters (to include their limitations). This broader data set may allow the Balancing Authority to make more meaningful estimates of expected generator capacity than could be provided by amalgamating potentially inconsistent estimates from individual generating units. The standard drafting team determined that Balancing Authorities are in the best position to estimate their reserve margin needs based on the data set available to them and structured proposed Requirement R8 accordingly. To be clear, the standard drafting team did not determine that individual generator estimates could never be useful, only that the Reliability Standards should not mandate specifically their exchange at this time. If a Balancing Authority would find cold weather capacity estimates or other cold weather information not already specified in the TOP-003 Reliability Standard to be useful to its operations and planning analyses, it may request that information in its data and information specifications to Generator Owners. The Generator Owners would then be required to provide it according to the requirements of that Reliability Standard.

The standard drafting team also determined that it would not include a specific requirement for the Balancing Authority to provide its cold weather capacity evaluations under proposed Requirement R8 to the Reliability Coordinator. In making this determination, the standard drafting team considered that the exchange of this data or information would be addressed best through

Reliability Coordinator data and information specifications. Under the IRO-010 Reliability Standard, Reliability Coordinators may request that Balancing Authorities provide data or information necessary for performing operations planning and real-time functions; Balancing Authorities would then be required to provide the requested data or information to the Reliability Coordinator according to the requirements of the standard. Considering the performance required by that standard, the standard drafting team determined that an additional requirement for the provision of cold weather capacity estimate data specifically was not necessary.

In conclusion, proposed Reliability Standard TOP-002-5 would advance the reliable operation of the Bulk-Power System by providing greater specificity regarding the Balancing Authority's responsibilities in extreme cold weather, consistent with the reliability considerations underlying Key Recommendation 1g of the Joint Inquiry Report. The Commission should approve the proposed Reliability Standard as just, reasonable, not unduly discriminatory, and in the public interest.

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 that proposed Reliability Standard EOP-011-4 would become effective on the first day of the first calendar quarter that is six (6) months after applicable regulatory approval. Reliability Standard EOP-011-3, which is pending Commission action on its enforceability date, would be retired immediately prior to the effective date of the revised Reliability Standards.[95] Transmission Operators and Balancing Authorities would have an additional 30 months to comply with the revised provisions

[95] In the alternative, NERC proposes that the Commission approve the retirement of Reliability Standard EOP-011-2, if such Reliability Standard would be the version of EOP-011 then in effect at the time the proposed EOP-011-4 Reliability Standard would become effective.

specific to underfrequency load shed, undervoltage load shed, and critical gas infrastructure loads in Requirement R1 Part 1.2.5 (Transmission Operator), and Requirement R2 Part 2.2.8 and Part 2.2.9 (Balancing Authority). Newly applicable entities (Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners) that are identified and notified to assist with the mitigation of operating emergencies by their Transmission Operator under Requirement R7[96] will have 30 months to develop a load shedding plan under Requirement R8.

This proposed implementation timeframe reflects consideration of the interaction that will be required between applicable entities and natural gas entities to identify critical natural gas infrastructure loads and account for them as required in manual shedding and underfrequency and undervoltage load shedding schemes. The proposed timeframe also reflects consideration that physical changes may be necessary to comply with the requirements, particularly relating to UFLS circuits. The scope of the necessary changes may not be fully known by an entity at this time. Such physical changes may require time for budgeting, acquiring, and installing new physical equipment.[97] This proposed implementation timeframe also reflects consideration of the fact that the Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner will have obligations under this Reliability Standard for the first time under proposed Requirement R8, and they will need time to develop compliant load shedding plans that are provided to the Transmission

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[96] Transmission Operators will be required to comply with Requirement R7 and perform their first annual identification and notification to these newly applicable entities by the effective date of the standard (i.e. six months following regulatory approval).

[97] While many entities supported the proposed implementation plan, others submitted comments expressing that the proposed timeframe may be too short to implement any physical changes that may be necessary. The standard drafting team considered these comments, the factors identified above, and the history of cold weather events, and determined that 30 months was a reasonable timeframe for implementing any necessary changes. *See* Exhibit F at item 38 (September 2023 Consideration of Comments) at 42-67. The standard drafting team further considered a suggestion to implement separate implementation timeframes; one for when physical changes would be needed, and a second, shorter timeframe for when they would not. In considering this suggestion, the standard drafting team determined that separate implementation timelines for this particular standard would result in significantly more confusion than a straightforward plan with one implementation timeline, but indicated its support for entities becoming compliant sooner if they are able to do so. *See id.* at 66.

Operator for review. With consideration to these factors, the proposed implementation timeline 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.[98]

For proposed Reliability Standard TOP-002-5, NERC proposes that the Reliability Standard become effective on the first day of the first calendar quarter that is eighteen (18) months after applicable regulatory approval. This proposed implementation timeframe reflects consideration of the time needed to develop an extreme cold weather Operating Process, with the required methodologies reflecting the minimum cold weather reliability considerations identified in proposed new Requirement R8. This implementation timeline appropriately balances the urgency in the need to implement the standards against the time allowed for the Balancing Authority who must comply to develop necessary procedures and other relevant capabilities.[99]

While NERC maintains that its proposed implementation period is reasonable considering the above factors, NERC, as with prior versions of the cold weather standards, 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. 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.

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[98] *See* Order No. 672, *supra* n. 11, 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.").

[99] *See* Order No. 672, *supra* n. 11, 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.").

VIII. NEXT STEPS

The proposed Reliability Standards addressed in this petition represent the conclusion of the second phase of work under Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination to address Key Recommendations 1g, 1h, and 1i, each with a target Winter 2023-2024 completion date. Work is currently underway to develop modifications to Reliability Standard EOP-012-1, consistent with the Commission's February 2023 Order. NERC anticipates completing development and filing with the Commission a revised EOP-012 Reliability Standard by the Commission's February 2024 deadline.

Consistent with the Commission's February 2023 Order, NERC will work with Commission staff in the coming months to develop and submit a plan explaining how NERC will gather data and submit an analysis that will allow the Commission to understand the efficacy of, and monitor the ongoing risk posed by: (1) proposed technical, commercial, or operational constraint provisions in EOP-012-1, Requirements R1, R6, and R7; and (2) actual performance of freeze protection measures during future extreme cold weather events.[100] NERC will submit his plan by the Commission's February 2024 deadline.

In addition to the standard development and monitoring work noted above, NERC will also continue its ongoing efforts to support cold weather reliability for the upcoming winter season and beyond. Recent actions to support cold weather preparedness include the following:

- <u>NERC Alerts:</u> In May 2023, NERC issued its first ever Level 3 Alert under its Rules of Procedure containing essential actions addressing cold weather preparedness for extreme weather events.[101] This Level 3 Alert is the third NERC alert issued in the last three years

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100 *See* February 2023 Order at PP 94-96 (directing NERC to submit such a work plan and noting the matters that should be addressed).

101 Section 810.3 of the NERC Rules of Procedure provides that, "When NERC determines it is necessary to place the industry or segments of the industry on formal notice of its findings, analyses, and recommendations, NERC will provide such notification in the form of specific operations or equipment Advisories, Recommendations or Essential Actions." A Level 1 (Advisory) alert is informational in nature, intended to advise of findings and lessons

with specific actions for winter weather preparedness; the first two being Level 2 (advisory) alerts issued in 2021 and 2022. NERC will provide a report to Commission staff describing the actions taken by the responding entities, and the success of those actions taken in correcting the cold weather preparedness issues that were the subject of the alert.

- Webinars and Outreach: NERC hosted a webinar on winter weather preparedness for severe cold weather on September 7, 2023.[102] The Regional Entities also continue to host workshops or similar programs to support winter preparation efforts.

- Small Group Advisory Sessions: NERC hosted a number of small group advisory sessions in 2023 to support entities in achieving compliance with the first series of cold weather Reliability Standards that became effective on April 1, 2023.

- Reliability Guidelines: In June 2023, NERC issued the Reliability Guideline: Generating Unit Winter Weather Readiness – Current Industry Practices (version 4).[103] This guideline provides a general framework for developing an effective winter weather readiness program for generating units across North America.

Cold weather preparedness continues to remain a high priority of NERC, and NERC remains committed to using the different options in its reliability toolkit to advance reliability during future cold weather seasons and to monitor and assess the efficacy of its Reliability Standards to address cold weather reliability risks. NERC is also committed to addressing promptly any recommendations for further NERC action that are recommended in the final report of the joint inquiry team investigating grid operations during the December 2022 Winter Storm Elliott event.

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learned. A Level 2 (Recommendations) alert contains specific actions that NERC is recommending be considered, based on facts and circumstances. A Level 3 (Essential Actions) alert contains specific actions that NERC has determined are essential for certain BPS owners, operators, or users to take to ensure reliability and must be approved by the NERC Board of Trustees prior to issuance.

More information on NERC alerts, including the Level 3 Alert Essential Actions to Industry: Cold Weather Preparations for Extreme Weather Events III, is available on the NERC web page at https://www.nerc.com/pa/rrm/bpsa/Pages/Alerts.aspx.

102 NERC, Preparation for Cold Weather Webinar, Sep. 7, 2023, materials available at https://www.nerc.com/pa/rrm/Pages/Webinars.aspx.

103 NERC, Reliability Guideline: Generating Unit Winter Weather Readiness – Current Industry Practices – Version 4 (Jun. 2023), https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_Generating_Unit_Winter_Weather_Readiness_v4.pdf.

IX. REQUEST FOR EXPEDITED ACTION

NERC respectfully requests that the Commission approve the proposed Reliability Standards and associated elements in an expedited manner. The need for the proposed Reliability Standards has been demonstrated by multiple cold weather reliability events. In recognition of the immense human and economic toll of the February 2021 Event in particular, 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. NERC and its stakeholders recognized the urgency of the need and successfully met the aggressive development timelines directed by the Board. The need for the proposed Reliability Standards was again emphasized by the December 2022 Winter Storm Elliott event.

As discussed in Section VII, NERC's proposed implementation plan 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.[104] 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 and would be consistent with the Commission's expedited consideration of previous cold weather Reliability Standard proposals.[105] For these reasons, NERC respectfully requests that the Commission consider expedited action on NERC's proposals.

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[104] *See* Order No. 672, *supra* n. 11, at P 333.

[105] *See N. Am. Elec. Reliability Corporation*, 176 FERC ¶ 61,119 (2021) (approving Reliability Standards EOP-011-2, IRO-010-4, and TOP-003-5 on an expedited timeline); *see also* February 2023 Order, *supra* n. 7 (approving Reliability Standards EOP-011-3 and EOP-012-1 and directing further revisions, also on an expedited timeline).

X. CONCLUSION

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

- Proposed Reliability Standards EOP-011-4 and TOP-002-5, and the associated elements, as shown in **Exhibit A;**
- the retirement of Reliability Standards EOP-011-3 and TOP-002-4; 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

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Counsel for the North American Electric Reliability Corporation

October 30, 2023

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit A

The Proposed Reliability Standards

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Exhibit A-1

Proposed Reliability Standard EOP-011-4

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Exhibit A-1

Proposed Reliability Standard EOP-011-4

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
45-day formal comment period with ballot –Phase 2	2/28/23 – 4/13/23
20-day comment period and additional ballot – Phase 2	8/24/23 – 9/12/23

Anticipated Actions	Date
8-day final ballot	9/29/23 – 10/6/23
NERC Board of Trustees (Board) adoption	October 2023

A. Introduction

1. **Title:** **Emergency Operations**

2. **Number:** **EOP-011-4**

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

   4.1.4 Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

   4.1.5 UFLS-Only Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

   4.1.6 Transmission Owner identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

5. **Effective Date:** See Implementation Plan for Project 2021-07. As provided therein, each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner that receives notification from the Transmission Operator that it is required to assist in the mitigation of operating Emergencies in the Transmission Operator Area under Requirement R7 shall become compliant with Requirement R8 within 30 calendar months of the notification.

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 shed, undervoltage load shed (UVLS), or underfrequency load shed (UFLS) 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, UVLS, or UFLS and circuits that serve designated critical loads which are essential to the reliability of the BES;

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

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;

1.2.5.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity; and

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 excluding critical natural gas infrastructure loads which are essential to the reliability of the BES, as defined by the Applicable Entity, as Interruptible Load, curtailable Load, and demand response during extreme cold weather periods within each Balancing Authority Area;

2.2.9. Provisions for Transmission Operators to implement operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding in accordance with Requirement R1 Part 1.2.5; and

2.2.10. Provisions to determine reliability impacts of:

2.2.10.1. Cold weather conditions; and

2.2.10.2. 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.

R7. Each Transmission Operator shall annually identify and notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Long-term Planning]*

M7. Each Transmission Operator will have documentation, such as dated emails or other correspondences that it identified and notified Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners annually in accordance with Requirement R7.

R8. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area shall develop, maintain, and implement a Load shedding plan. The Load shedding plan shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

8.1. Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding during an Emergency that accounts for each of the following:

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

8.1.2. Provisions to minimize the overlap of circuits that are designated for manual, undervoltage, or underfrequency Load shed and circuits that serve designated critical loads which are essential to the reliability of the BES;

8.1.3. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS;

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

8.1.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity.

8.2. Provisions to provide the Load shedding plan to the Transmission Operator for review.

M8. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area will have a dated Load shedding plan(s) developed in accordance with Requirement R8 and evidence that the Load shedding plan(s) was provided to its Transmission Operator; evidence such as a review or revision history to indicate that the Load shedding 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 Load shedding plan(s) was implemented for times when an Emergency has occurred, in accordance with 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 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.
- 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.
- The Reliability Coordinator shall maintain evidence of compliance since the last audit for Requirements R3, R5, and R6.
- The Transmission Operator shall maintain evidence of compliance since the last audit for Requirement R7.
- The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner shall retain the current Load shedding plan, evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R8.

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	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	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 #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		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	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 #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			Operator within 30 calendar days.	
R4	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	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 #	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	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	N/A	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities more than one, but fewer than 30 days late.	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities 30 days or more, but fewer than 60 days late.	The Transmission Operator did not identify or notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding. OR The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities 60 days or more late.

R8	N/A	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to maintain it in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to provide it to its Transmission Operator in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner failed to develop a Load shedding plan(s) in accordance with Requirement R8. OR The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to implement it in accordance with Requirement R8.

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	October 26, 2022	Adopted by Board of Trustees	Revised under Project 2021-07
3	February 16, 2023	FERC approved EOP-011-3. *N. Am. Elec. Reliability Corp.*, 182 FERC 61,094	
4	TBD		Revised under Project 2021-07

Attachment 1-EOP-011-4
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.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit A-1

Proposed Reliability Standard EOP-011-4
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
45-day formal comment period with ballot –Phase 2	2/28/23 – 4/13/23
20-day comment period and additional ballot – Phase 2	8/24/23 – 9/12/23

Anticipated Actions	Date
8-day final ballot	9/29/23 – 10/6/23
NERC Board of Trustees (Board) adoption	October 2023

A. Introduction

1. **Title:** **Emergency Operations**

2. **Number:** **EOP-011-~~3~~4**

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

~~**1. Effective Date:** See Implementation Plan for Project 2021-07.~~

   4.1.4 Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

   4.1.5 UFLS-Only Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

   4.1.6 Transmission Owner identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

5. **Effective Date:** See Implementation Plan for Project 2021-07. As provided therein, each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner that receives notification from the Transmission Operator that it is required to assist in the mitigation of operating Emergencies in the Transmission Operator Area under Requirement R7 shall become compliant with Requirement R8 within 30 calendar months of the notification.

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~~shed, undervoltage load shed (UVLS), or underfrequency load shed (UFLS) 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, UVLS, or UFLS and circuits that serve designated critical loads which are essential to the reliability of the BES;

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~~UVLS;

~~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~~.~~;

1.2.5.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity; and

1.2.6. Provisions to determine reliability impacts of:

1.2.6.1. ~~cold~~Cold weather conditions; and

1.2.6.2. ~~extreme~~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~~Capability and availability;

2.2.3.2. ~~fuel~~Fuel supply and inventory concerns;

2.2.3.3. ~~fuel~~Fuel switching capabilities; and

2.2.3.4. ~~environmental~~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 excluding critical natural gas infrastructure loads which are essential to the reliability of the BES, as defined by the Applicable Entity, as Interruptible Load, curtailable Load, and demand response during extreme cold weather periods within each Balancing Authority Area;

~~**2.2.8.**~~**2.2.9.** Provisions for Transmission Operators to implement operator-controlled manual Load ~~shed~~shedding, undervoltage Load shedding, or underfrequency Load shedding in accordance with Requirement R1 Part 1.2.5; and

~~**2.2.9.**~~**2.2.10.** Provisions to determine reliability impacts of:

~~**2.2.9.1.**~~**2.2.10.1.** ~~cold~~Cold weather conditions; and

~~**2.2.9.2.**~~**2.2.10.2.** ~~extreme~~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.

R7. Each Transmission Operator shall annually identify and notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Long-term Planning]*

M7. Each Transmission Operator will have documentation, such as dated emails or other correspondences that it identified and notified Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners annually in accordance with Requirement R7.

R8. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area shall develop, maintain, and implement a Load shedding plan. The Load shedding plan shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

- **8.1.** Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding during an Emergency that accounts for each of the following:
  - **8.1.1.** Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;
  - **8.1.2.** Provisions to minimize the overlap of circuits that are designated for manual, undervoltage, or underfrequency Load shed and circuits that serve designated critical loads which are essential to the reliability of the BES;
  - **8.1.3.** Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS;
  - **8.1.4.** Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions; and
  - **8.1.5.** Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity.
- **8.2.** Provisions to provide the Load shedding plan to the Transmission Operator for review.

M8. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area will have a dated Load shedding plan(s) developed in accordance with Requirement R8 and evidence that the Load shedding plan(s) was provided to its Transmission Operator; evidence such as a review or revision history to indicate that the Load shedding 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 Load shedding plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R8.

C. Compliance

1. Compliance Monitoring Process

~~1.1.~~ Compliance Enforcement Authority

1.1. : "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

1.2. : 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:

1.3. 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	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	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 #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		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	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 #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			Operator within 30 calendar days.	
R4	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	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 #	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	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	N/A	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities more than one, but fewer than 30 days late.	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities 30 days or more, but fewer than 60 days late.	The Transmission Operator did not identify or notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding. OR The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities 60 days or more late.

R8	N/A	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to maintain it in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to provide it to its Transmission Operator in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner failed to develop a Load shedding plan(s) in accordance with Requirement R8. OR The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to implement it in accordance with Requirement R8.

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
~~2~~3	October ~~28,~~26, 2022	Adopted by Board of Trustees~~FERC Approved EOP-011-3 Docket Number RD23-1-000~~	Revised under Project 2021-07
3	February 16,~~2022~~ 2023	FERC approved EOP-011-3. *N. Am. Elec. Reliability Corp.*, 182 FERC 61,094~~Adopted by Board of Trustees~~	~~Revised under Project 2021-07~~
~~3~~4	TBD	~~Effective Date~~	Revised under Project 2021-07

Attachment 1-EOP-011-~~3~~4 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-2

Proposed Reliability Standard TOP-002-5

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit A-2

Proposed Reliability Standard TOP-002-5

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 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)	11/17/2021
SAR posted for comment	11/22/21 – 12/21/21
45-day formal comment period with ballot –Phase 2	2/28/23 – 4/13/23
20-day formal comment period with additional ballot – Phase 2	8/24/23 – 9/12/23

Anticipated Actions	Date
8-day final ballot	9/29/23 – 10/6/23
Board adoption	October 2023

A. Introduction

1. **Title: Operations Planning**
2. **Number: TOP-002-5**
3. **Purpose:** To ensure that Transmission Operators and Balancing Authorities have plans for operating within specified limits.
4. **Applicability:**
   4.1. Transmission Operator
   4.2. Balancing Authority
5. **Effective Date:**
   See Implementation Plan.
6. **Background:**
   See Project 2021-07 project page.

B. Requirements and Measures

R1. Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Each Transmission Operator shall have evidence of a completed Operational Planning Analysis. Such evidence could include, but is not limited to dated power flow study results.

R2. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Transmission Operator shall have evidence that it has an Operating Plan to address potential System Operating Limits (SOLs) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1. Such evidence could include, but it is not limited to plans for precluding operating in excess of each SOL that was identified as a result of the Operational Planning Analysis.

R3. Each Transmission Operator shall notify entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Transmission Operator shall have evidence that it notified entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in the plan(s). Such evidence could include, but is not limited to dated operator logs, or email records.

R4. Each Balancing Authority shall have an Operating Plan(s) for the next day that addresses: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1 Expected generation resource commitment and dispatch;

4.2 Interchange scheduling;

4.3 Demand patterns; and

4.4 Capacity and energy reserve requirements, including deliverability capability.

M4. Each Balancing Authority shall have evidence that it has developed a plan to operate within the criteria identified. Such evidence could include, but is not limited to dated operator logs or email records.

R5. Each Balancing Authority shall notify entities identified in the Operating Plan(s) cited in Requirement R4 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Each Balancing Authority shall have evidence that it notified entities identified in the plan(s) cited in Requirement R4 as to their role in the plan(s). Such evidence could include, but is not limited to dated operator logs or email records.

R6. Each Transmission Operator shall provide its Operating Plan(s) for next day operations identified in Requirement R2 to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M6. Each Transmission Operator shall have evidence that it provided its Operating Plan(s) for next day operations identified in Requirement R2 to its Reliability Coordinator. Such evidence could include, but is not limited to dated operator logs or email records.

R7. Each Balancing Authority shall provide its Operating Plan(s) for next day operations identified in Requirement R4 to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M7. Each Balancing Authority shall have evidence that it provided its Operating Plan(s) for next day operations identified in Requirement R4 to its Reliability Coordinator. Such evidence could include, but is not limited to dated operator logs or email records.

R8. Each Balancing Authority shall have an extreme cold weather Operating Process for its Balancing Authority Area, addressing preparations for and operations during extreme cold weather periods. The extreme cold weather Operating Process shall include, but is not limited to: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

8.1 A methodology for identifying an extreme cold weather period within each Balancing Authority Area;

8.2 A methodology to determine an adequate reserve margin during the extreme cold weather period considering the generating unit(s) operating limitations in previous extreme cold weather periods that includes, but is not limited to:

8.2.1 Capability and availability;

8.2.2 Fuel supply and inventory concerns;

8.2.3 Start-up issues;

8.2.4 Fuel switching capabilities; and

8.2.5 Environmental constraints.

8.3 A methodology to determine a five-day hourly forecast during the identified extreme cold weather periods that includes, but is not limited to:

8.3.1 Expected generation resource commitment and dispatch;

8.3.2 Demand patterns;

8.3.3 Capacity and energy reserve requirements, including deliverability capability; and

8.3.4 Weather forecast.

M8. Each Balancing Authority shall have evidence that it has developed an extreme cold weather Operating Process in accordance with Requirement R8.

C. Compliance

1. **Compliance Monitoring Process**

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

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

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

- Each Transmission Operator and Balancing Authority shall keep data or evidence to show compliance for each applicable Requirement for a rolling 90-calendar days period for analyses, the most recent 90-calendar days for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- The Balancing Authority shall retain the current Operating Process(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 R8.

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	N/A	N/A	N/A	The Transmission Operator did not have an Operational Planning Analysis allowing it to assess whether its planned operations for the next day within its Transmission Operator Area exceeded any of its System Operating Limits (SOLs).
R2	N/A	N/A	N/A	The Transmission Operator did not have an Operating Plan to address potential System Operating Limit (SOL) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1.
R3	The Transmission Operator did not notify one impacted entity or 5% or less of the entities, whichever is greater identified in the	The Transmission Operator did not notify two entities or more than 5% and less than or equal to 10% of the impacted entities, whichever is greater, identified in the	The Transmission Operator did not notify three impacted entities or more than 10% and less than or equal to 15% of the entities, whichever is greater, identified in the	The Transmission Operator did not notify four or more entities or more than 15% of the impacted NERC identified in the Operating Plan(s) as to their role in the plan(s).

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Operating Plan(s) as to their role in the plan(s).	Operating Plan(s) as to their role in the plan(s).	Operating Plan(s) as to their role in the plan(s).	
R4	The Balancing Authority has an Operating Plan, but it does not address one of the criteria in Requirement R4.	The Balancing Authority has an Operating Plan, but it does not address two of the criteria in Requirement R4.	The Balancing Authority has an Operating Plan, but it does not address three of the criteria in Requirement R4.	The Balancing Authority did not have an Operating Plan.
R5	The Balancing Authority did not notify one impacted entity or 5% or less of the entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Balancing Authority did not notify two entities or more than 5% and less than or equal to 10% of the impacted entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Balancing Authority did not notify three impacted entities or more than 10% and less than or equal to 15% of the entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Balancing Authority did not notify four or more entities or more than 15% of the impacted entities identified in the Operating Plan(s) as to their role in the plan(s).
R6	N/A	N/A	N/A	The Transmission Operator did not provide its Operating Plan(s) for next day operations as identified in Requirement R2 to its Reliability Coordinator.
R7	N/A	N/A	N/A	The Balancing Authority did not provide its Operating Plan(s) for next day operations as

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				identified in Requirement R4 to its Reliability Coordinator.
R8	N/A	The Balancing Authority had an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods, but it did not address one of the Requirements or sub-Requirements of R8 Parts 8.1 through 8.3.	The Balancing Authority had an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods, but it did not address two of the Requirements or sub-Requirements of R8 Parts 8.1 through 8.3.	The Balancing Authority did not have an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Extreme Cold Weather Preparedness Technical Rationale and Justification for TOP-002-5

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	August 2, 2006	Adopted by Board of Trustees	Revised
2	November 1, 2006	Adopted by Board of Trustees	Revised
2	June 14, 2007	Fixed typo in R11., (subject to …)	Errata
2a	February 10, 2009	Added Appendix 1 – Interpretation of R11 approved by BOT on February 10, 2009	Interpretation
2a	December 2, 2009	Interpretation of R11 approved by FERC on December 2, 2009	Same Interpretation
2b	November 4, 2010	Added Appendix 2 – Interpretation of R10 adopted by the Board of Trustees	
2b	October 20, 2011	FERC Order issued approving the Interpretation of R10 (FERC’s Order became effective on October 20, 2011)	
2.1b	March 8, 2012	Errata adopted by Standards Committee; (Removed unnecessary language from the Effective Date section. Deleted retired sub-requirements from Requirement R14)	Errata

Version	Date	Action	Change Tracking
2.1b	April 11, 2012	Additional errata adopted by Standards Committee; (Deleted language from retired sub-requirement from Measure M7)	Errata
2.1b	September 13, 2012	FERC approved	Errata
3	May 6, 2012	Revisions under Project 2007-03	Revised
3	May 9, 2012	Adopted by Board of Trustees	Revised
4	April 2014	Revisions under Project 2014-03	Revised
4	November 13, 2014	Adopted by NERC Board of Trustees	Revisions under Project 2014-03
4	November 19, 2015	FERC approved TOP-002-4. Docket No. RM15-16-000. Order No. 817.	
5	TBD	Revisions under Project 2021-07	Revised

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit A-2

Proposed Reliability Standard TOP-002-5
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 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)	11/17/2021
SAR posted for comment	11/22/21 – 12/21/21
45-day formal comment period with ballot –Phase 2	2/28/23 – 4/13/23
20-day formal comment period with additional ballot – Phase 2	8/24/23 – 9/12/23

Anticipated Actions	Date
8-day final ballot	9/29/23 – 10/6/23
Board adoption	October 2023

A. Introduction

1. **Title: Operations Planning**
2. **Number: TOP-002-~~4~~5**
3. **Purpose:** To ensure that Transmission Operators and Balancing Authorities have plans for operating within specified limits.
4. **Applicability:**
   4.1. Transmission Operator
   4.2. Balancing Authority
5. **Effective Date:**
   See Implementation Plan.
6. **Background:**
   ~~See Project 2014-03 project page.~~
   See Project 2021-07 project page.

B. Requirements and Measures

R1. Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Each Transmission Operator shall have evidence of a completed Operational Planning Analysis. Such evidence could include, but is not limited to dated power flow study results.

R2. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Transmission Operator shall have evidence that it has an Operating Plan to address potential System Operating Limits (SOLs) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1. Such evidence could include, but it is not limited to plans for precluding operating in excess of each SOL that was identified as a result of the Operational Planning Analysis.

R3. Each Transmission Operator shall notify entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Transmission Operator shall have evidence that it notified entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in the plan(s). Such

evidence could include, but is not limited to dated operator logs, or ~~e-mail~~email records.

R4. Each Balancing Authority shall have an Operating Plan(s) for the next~~-~~ day that addresses: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1 Expected generation resource commitment and dispatch;

4.2 Interchange scheduling;

4.3 Demand patterns~~.~~; and

4.4 Capacity and energy reserve requirements, including deliverability capability.

M4. Each Balancing Authority shall have evidence that it has developed a plan to operate within the criteria identified. Such evidence could include, but is not limited to dated operator logs or ~~e-mail~~email records.

R5. Each Balancing Authority shall notify entities identified in the Operating Plan(s) cited in Requirement R4 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Each Balancing Authority shall have evidence that it notified entities identified in the plan(s) cited in Requirement R4 as to their role in the plan(s). Such evidence could include, but is not limited to dated operator logs or ~~e-mail~~email records.

R6. Each Transmission Operator shall provide its Operating Plan(s) for next~~-~~ day operations identified in Requirement R2 to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M6. Each Transmission Operator shall have evidence that it provided its Operating Plan(s) for next~~-~~ day operations identified in Requirement R2 to its Reliability Coordinator. Such evidence could include, but is not limited to dated operator logs or ~~e-mail~~email records.

R7. Each Balancing Authority shall provide its Operating Plan(s) for next~~-~~ day operations identified in Requirement R4 to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M7. Each Balancing Authority shall have evidence that it provided its Operating Plan(s) for next~~-~~ day operations identified in Requirement R4 to its Reliability Coordinator. Such evidence could include, but is not limited to dated operator logs or ~~e-mail~~email records.

R8. Each Balancing Authority shall have an extreme cold weather Operating Process for its Balancing Authority Area, addressing preparations for and operations during extreme cold weather periods. The extreme cold weather Operating Process shall include, but is not limited to: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

8.1 A methodology for identifying an extreme cold weather period within each Balancing Authority Area;

8.2 A methodology to determine an adequate reserve margin during the extreme cold weather period considering the generating unit(s) operating limitations in previous extreme cold weather periods that includes, but is not limited to:

8.2.1 Capability and availability;

8.2.2 Fuel supply and inventory concerns;

8.2.3 Start-up issues;

8.2.4 Fuel switching capabilities; and

8.2.5 Environmental constraints.

8.3 A methodology to determine a five-day hourly forecast during the identified extreme cold weather periods that includes, but is not limited to:

8.3.1 Expected generation resource commitment and dispatch;

8.3.2 Demand patterns;

8.3.3 Capacity and energy reserve requirements, including deliverability capability; and

8.3.4 Weather forecast.

M8. Each Balancing Authority shall have evidence that it has developed an extreme cold weather Operating Process in accordance with Requirement R8.

C. Compliance

1. Compliance Monitoring Process

~~1.1.~~ **Compliance Enforcement Authority**

~~1.2.~~1.1. ~~As defined in the NERC Rules of Procedure,~~: "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 NERC~~mandatory and enforceable Reliability Standards in their respective jurisdictions.

~~**1.3. Compliance Monitoring and Assessment Processes**~~

~~As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" 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.~~

~~1.4. Data~~**Evidence Retention**

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

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

- Each Transmission Operator and Balancing Authority shall keep data or evidence to show compliance for each applicable Requirement for a rolling 90-calendar days period for analyses, the most recent 90-calendar days for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

~~If a Transmission Operator or~~ The Balancing Authority ~~is found non-compliant, it~~ shall ~~keep information related to the non-~~retain the current Operating Process(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance ~~until found compliant or the time period specified above, whichever is longer.~~

- ~~The Compliance Enforcement Authority shall keep~~since the last audit ~~records and all requested and submitted subsequent audit records~~ for Requirement R8.

~~**1.5. Additional Compliance Information**~~

~~None.~~

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	N/A	N/A	N/A	The Transmission Operator did not have an Operational Planning Analysis allowing it to assess whether its planned operations for the next day within its Transmission Operator Area exceeded any of its System Operating Limits (SOLs).
R2	N/A	N/A	N/A	The Transmission Operator did not have an Operating Plan to address potential System Operating Limit (SOL) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1.
R3	The Transmission Operator did not notify one impacted entity or 5% or less of the entities, whichever is greater identified in the	The Transmission Operator did not notify two entities or more than 5% and less than or equal to 10% of the impacted entities, whichever is greater, identified in the	The Transmission Operator did not notify three impacted entities or more than 10% and less than or equal to 15% of the entities, whichever is greater, identified in the	The Transmission Operator did not notify four or more entities or more than 15% of the impacted NERC identified in the Operating Plan(s) as to their role in the plan(s).

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Operating Plan(s) as to their role in the plan(s).	Operating Plan(s) as to their role in the plan(s).	Operating Plan(s) as to their role in the plan(s).	
R4	The Balancing Authority has an Operating Plan, but it does not address one of the criteria in Requirement R4.	The Balancing Authority has an Operating Plan, but it does not address two of the criteria in Requirement R4.	The Balancing Authority has an Operating Plan, but it does not address three of the criteria in Requirement R4.	The Balancing Authority did not have an Operating Plan.
R5	The Balancing Authority did not notify one impacted entity or 5% or less of the entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Balancing Authority did not notify two entities or more than 5% and less than or equal to 10% of the impacted entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Balancing Authority did not notify three impacted entities or more than 10% and less than or equal to 15% of the entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Balancing Authority did not notify four or more entities or more than 15% of the impacted entities identified in the Operating Plan(s) as to their role in the plan(s).
R6	N/A	N/A	N/A	The Transmission Operator did not provide its Operating Plan(s) for next day operations as identified in Requirement R2 to its Reliability Coordinator.
R7	N/A	N/A	N/A	The Balancing Authority did not provide its Operating Plan(s) for next day operations as

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				identified in Requirement R4 to its Reliability Coordinator.
R8	N/A	The Balancing Authority had an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods, but it did not address one of the Requirements or sub-Requirements of R8 Parts 8.1 through 8.3.	The Balancing Authority had an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods, but it did not address two of the Requirements or sub-Requirements of R8 Parts 8.1 through 8.3.	The Balancing Authority did not have an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

~~Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.~~

Extreme Cold Weather Preparedness Technical Rationale and Justification for TOP-002-5

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	August 2, 2006	Adopted by Board of Trustees	Revised
2	November 1, 2006	Adopted by Board of Trustees	Revised
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2b	November 4, 2010	Added Appendix 2 – Interpretation of R10 adopted by the Board of Trustees	
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2.1b	March 8, 2012	Errata adopted by Standards Committee; (Removed unnecessary language from the Effective Date section. -Deleted retired sub-requirements from Requirement R14)	Errata
2.1b	April 11, 2012	Additional errata adopted by Standards Committee; (Deleted language from retired sub-requirement from Measure M7)	Errata
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3	May 6, 2012	Revisions under Project 2007-03	Revised
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4	November 13, 2014	Adopted by NERC Board of Trustees	Revisions under Project 2014-03
4	November 19, 2015	FERC approved TOP-002-4. Docket No. RM15-16-000. -Order No. 817.	
5	TBD	Revisions under Project 2021-07	Revised

~~Guidelines and Technical Basis~~

~~Rationale:~~

~~During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.~~

~~Rationale for Definitions:~~
~~Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.~~

~~Rationale for R1:~~
~~Terms deleted in Requirement R1 as they are now contained in the revised definition of Operational Planning Analysis~~

~~Rationale for R2:~~
~~The change to Requirement R2 is in response to NOPR paragraph 42 and in concert with proposed changes made to proposed TOP-001-4~~

~~Rationale for R3:~~
~~Changes in response to IERP recommendation~~

~~Rationale for R4 and R5:~~
~~These Requirements were added to address IERP recommendations~~

~~Rationale for R6 and R7:~~
~~Added in response to SW Outage Report recommendation 1~~

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit B

Implementation Plan

Implementation Plan

Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 – Reliability Standards EOP-011-4 and TOP-002-5

Applicable Standard(s)

- EOP-011-4 Emergency Operations
- TOP-002-5 Operations Planning

Requested Retirement(s)

- EOP-011-3
- TOP-002-4

Prerequisite Standard(s)

- None

Proposed Definition(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 (the "Joint Inquiry 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 outaged megawatts (MW) of load after the August 2003 Northeast blackout and the August 1996 West Coast

[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 Joint Inquiry Report").

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). At the time the Event occurred, the Event was the fourth in the previous 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 Joint Inquiry Report for new or enhanced NERC Reliability Standards. Phase 1 of this project developed Reliability Standards EOP-011-3 and EOP-012-1. This implementation plan addresses Reliability Standards EOP-011-4 and TOP-002-5, which were developed to address the Phase 2 recommendations.

Proposed Reliability Standard EOP-011-4 is a revised Reliability Standard that builds upon changes first made in Reliability Standard EOP-011-3 to address Recommendation 1j of the Joint Inquiry Report regarding minimizing the overlap of manual Load shed and automatic Load shed programs such as underfrequency Load shed (UFLS) and undervoltage Load shed (UVLS). Proposed EOP-011-4 includes new requirements for excluding critical natural gas loads from load shed programs during periods where their participation could adversely impact the BES and for relevant entities to develop Operating Plan(s) addressing load shed considerations in response to Recommendations 1h and 1i of the Joint Inquiry Report.

Proposed Reliability Standard TOP-002-5 is a revised Reliability Standard that would require the Balancing Authority to specifically address extreme cold weather in its Operating Plans, including developing a methodology to determine the number of resources that can reasonably be expected to be available during extreme cold weather conditions. These revisions were developed to address Key Recommendation 1g of the Joint Inquiry Report.

General Considerations

This implementation plan reflects consideration that entities will need time to develop and implement new Requirements as follows:

For proposed Reliability Standard EOP-011-4, this plan reflects consideration of the interaction that will be required between applicable entities and natural gas entities, as well as the fact that several

entities (Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner) will have obligations under this standard for the first time under proposed Requirement R8.

For proposed TOP-002-5, this implementation plan reflects consideration of the time needed to develop and implement a new extreme cold weather Operating Process under proposed Requirement R8.

The implementation timeframe is not intended to extend the timeframe for an entity's existing responsibilities regarding load shedding under EOP-011-2 or EOP-011-3; rather, the additional timeframe is intended to provide additional time to come into compliance with new and revised requirements specific to EOP-011-4.

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.

Reliability Standard EOP-011-4

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 six (6) 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 six (6) 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-011-4 – Requirement R1 Part 1.2.5

Entities shall not be required to comply with the new and revised provisions (i.e., specific to UVLS, UFLS and critical natural gas infrastructure loads) in Requirement R1 Part 1.2.5 until 30 months after the effective date of Reliability Standard EOP-011-4.

Compliance Date for EOP-011-4 – Requirement R2 Part 2.2.8 and Part 2.2.9

Entities shall not be required to comply with the new and revised provisions (i.e., specific to UVLS, UFLS and critical natural gas infrastructure loads) in Requirement R2 Part 2.2.8 and Part 2.2.9 until 30 months after the effective date of Reliability Standard EOP-011-4.

Compliance Date for EOP-011-4 – Requirement R8

Entities shall not be required to comply with Requirement R8 until the later of: (1) 30 calendar months following notification by a Transmission Operator under EOP-011-4 Requirement R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area; or (2) 30 months after the effective date of Reliability Standard EOP-011-4.

Reliability Standard TOP-002-5

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.

Retirement Date

Reliability Standards EOP-011-3 and TOP-002-4

Reliability Standards EOP-011-3 and TOP-002-4 shall be retired immediately prior to the effective date of Reliability Standards EOP-011-4 and TOP-002-5 in the particular jurisdiction in which the revised standards are becoming effective.

Time Period to Address New Designations under EOP-011-4 Requirements R7, R8

Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner that receives notification from the Transmission Operator that it is required to assist in the mitigation of operating Emergencies in the Transmission Operator Area under Requirement R7 shall become compliant with Requirement R8 within 30 calendar months of the notification.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit C

Technical Rationale

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Exhibit C-1

Technical Rationale
Proposed Reliability Standard EOP-011-4

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Extreme Cold Weather Preparedness

Technical Rationale and Justification for EOP-011-4

September 2023

RELIABILITY | RESILIENCE | SECURITY




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Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of 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

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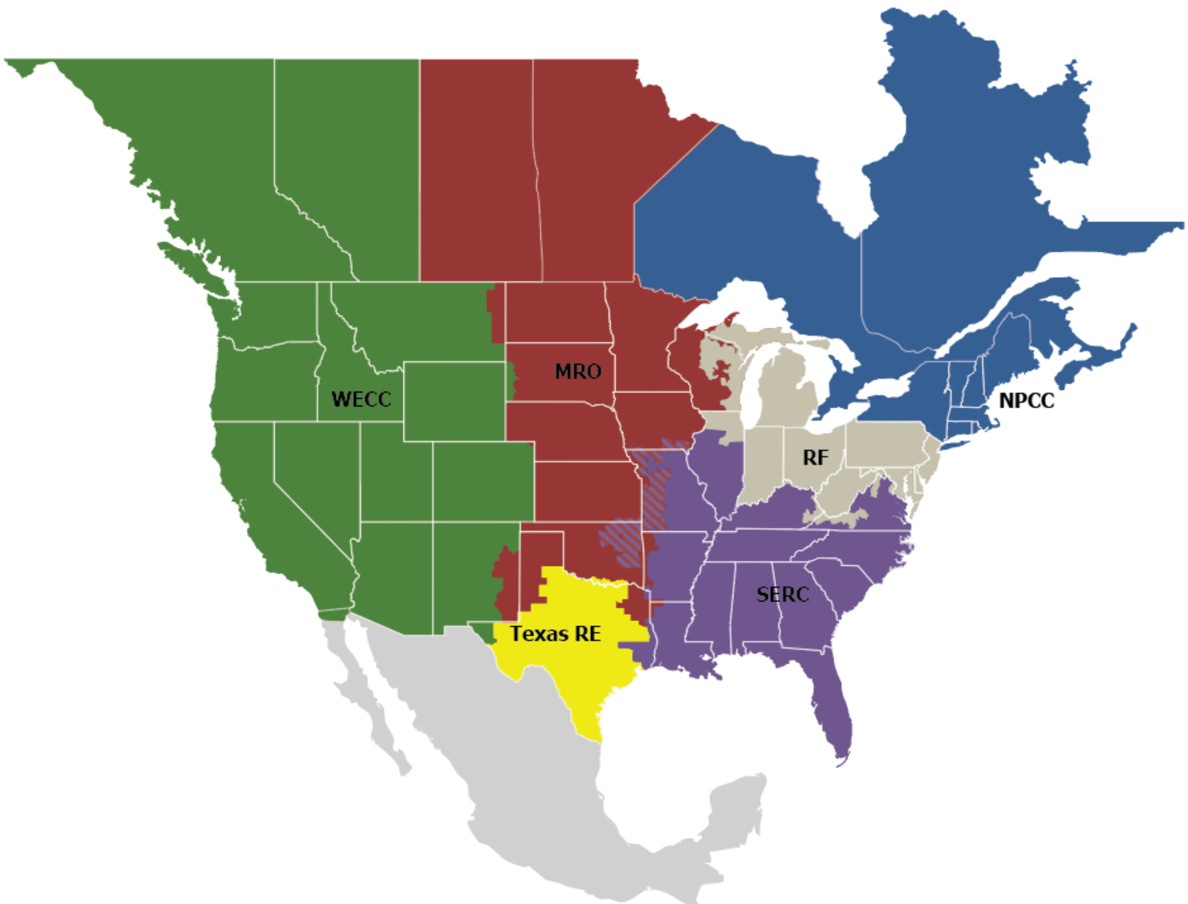

MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

Introduction

This document explains the technical rationale and justification for proposed Reliability Standard EOP-011-4. 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-011-4 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 10 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 was completed by September 30, 2022, and submitted 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-011-4

Requirement R1, R7, and R8

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. *Operator-controlled manual Load shedding undervoltage load shed (UVLS), or underfrequency load shed (UFLS) 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, UVLS, or UFLS and circuits that serve designated critical loads which are essential to the reliability of the BES;*

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

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;*

1.2.5.5. *Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity; and*

1.2.6. *Provisions to determine reliability impacts of:*

1.2.6.1. *Cold weather conditions; and*

1.2.6.2. *Extreme weather conditions.*

R7. *Each Transmission Operator shall annually identify and notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding.*

R8. *Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area shall develop, maintain, and implement a Load shedding plan. The Load shedding plan shall include the following, as applicable:*

8.1. *Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load* *shedding during an Emergency that accounts for each of the following:*

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

8.1.2. *Provisions to minimize the overlap of circuits that are designated for manual, undervoltage, or underfrequency Load shed and circuits that serve designated critical loads which are essential to the reliability of the BES;*

8.1.3. *Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS;*

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

8.1.5. *Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity.*

8.2. *Provisions to provide the Load shedding plan to the Transmission Operator for review.*

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)*

Applicability, Requirement R7 and R8

Expansion of Applicability

In many cases, Transmission Operators are dependent on Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners to implement portions of Requirement R1.2.5. The Project 2021-07 standard drafting team (SDT) determined that it is necessary to expand the Applicability of EOP-011-4 to these Functional Entities in order to address all entities responsible for performing operator-controlled manual Load shedding, UFLS, or UVLS per Key Recommendation 1i. Planning Coordinators and Transmission Planners were purposely excluded from applicability even though they are mentioned in Key Recommendation 1i because they are not responsible for performing operator-controlled manual Load shedding, UFLS, or UVLS.

EOP-011-4 Requirement R7 is a new requirement that was added to require that Transmission Operators annually identify and notify any Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners that are required to assist with mitigation of operating Emergencies in their Transmission Operator Area. The Transmission Operator has the overarching responsibility to mitigate operating Emergencies. If a Transmission Operator relies on other functional entities in accomplishing various aspects of manual Load shedding, UFLS, or UVLS, they must be identified and notified per R7. Those identified and notified entities are subject to Requirement R8. The initial performance of R7 is required upon the effective date of EOP-011-4, which is on the first day of the first calendar quarter that is six 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. This approach to Requirement R7 ensures that newly applicable entities who will be subject to Requirement R8 are identified and notified in a timely manner thus minimizing any delay in implementing Requirement R8. Requirement R7 includes an annual provision to ensure that any additional entities, or changes to existing entities, required to assist with the mitigation of Operating emergencies are appropriately identified and notified on an ongoing basis.

EOP-011-4 Requirement R8 is a new requirement that is specific to Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners identified by the Transmission Operator in Requirement R7. It includes the relevant portions of Requirement R1.2.5 that address operator-controlled manual Load shedding, ULFS or UVLS. The SDT found it appropriate to place these requirements specifically on Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners because many times they are the entities performing operator-controlled manual Load shedding, UFLS or UVLS and have the capability of ensuring that these requirements are appropriately implemented for the Loads they represent. Entities that are subject to R8 have 30 months after being notified by a Transmission Operator in R7 to become compliant with these requirements.

Requirement R1, Part 1.2.5 and Requirement R8, Part 8.1

EOP-011-4 Requirement R1.2.5.5 was added to require Transmission Operators to include provisions to identify and prioritize critical natural gas infrastructure Loads which are essential to the reliability of the BES in their Operating Plan(s). EOP-011-4 Requirement R8.1.5 mirrors this requirement and is applicable to Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners. In addition to the following content, entities are encouraged to review guidance from *Reliability Guideline: Gas and Electrical Operational Coordination Considerations* in developing their approach to identify and prioritize critical natural gas infrastructure loads.

Manual, Undervoltage, and Underfrequency

EOP-011-4 Requirement 1.2.5 was modified to include undervoltage load shed and underfrequency load shed in addition to "operator-controlled manual Load shedding." The addition of UVLS and UFLS throughout Requirement R1.2.5 requires these specific load shed processes to account for minimization of overlap between the different processes. An additional result of this modification is that Requirement R1.2.5.5, which requires the identification and prioritization of critical natural gas Loads, by the Applicable Entity (Distribution Provider or Transmission Owner serving the end-use customer), which are essential to the reliability of the BES, is also applicable to Load shedding, be it manual or UVLS or UFLS. It is important to identify and prioritize critical natural gas Loads not just for the purposes of manual Load shed but also in consideration of Load shedding schemes. This modification does not prohibit the inclusion of critical natural gas Loads in Load shedding, but it does require the prioritization of critical natural gas Loads which are essential to the reliability of the BES. This change was also incorporated into the new EOP-011-4 Requirement R8.1.

Critical Natural Gas Infrastructure Loads

The SDT has elected to add clarifying language in the applicable requirements and expand content in this Technical Rationale document in lieu of making "critical natural gas infrastructure Load" a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may necessarily have been overly broad; and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.

A reasonable application of this term should be informed by the entity's approved governing documents and guidance established by applicable regulatory authorities. A practical example of guidance that provides reasonable direction and flexibility has been developed by the Public Utility Commission of Texas in response to Winter Storm Uri (*Guidance Document for Power Delivery and Restoration During Energy Emergencies*). It is essential for entities to recognize that being overly broad in the application of this term may negatively impact reliability. If everything is critical, then nothing is truly critical.

The various regions covered by NERC requirements will have large variances in natural gas infrastructure that might be considered essential to the reliability of the BES. For example, Texas considers a single forced stoppage of natural gas transportation capacity a "major" event only if it disrupts greater than 200 MMcf per day. The entire state of Vermont used less than 70 times that amount of gas over the course of the entire year in 2021 and would therefore likely consider any infrastructure that moves a small fraction of the Texas quantity of gas "critical." Some locations would consider large gas collection sites (wellheads) as critical while others simply have no gas collection systems. Gas compression stations may be critical in some locations while others, potentially located near large underground high-pressure storage sites, may not be considered as critical. Entities should develop critical load classifications and criteria for prioritizing critical loads for BES reliability based on the unique features of its system.

Identification of Critical Natural Gas Infrastructure Loads

Critical natural gas Loads must be identified so that they can then be prioritized from an operator-controlled manual Load shedding, UFLS, and UVLS perspective. The identification and prioritization of critical natural gas loads requires coordination with natural gas facility owners and operators. This can be accomplished in a number of ways and the SDT did not prescribe specific methods in the drafting of EOP-011-4. Methods may include:

- Distribution of criteria to natural gas infrastructure entities soliciting information to identify critical facilities that would likely adversely affect BES reliability if de-energized;
- Reliance on self-identification of critical gas infrastructure driven by local jurisdictional requirements;
- Use of historical information and coordination with resources and gas suppliers from existing Operating Plans.

The SDT recognizes that entities are dependent upon the cooperation of natural gas facility owners and operators to complete this task. However, it is outside the scope of the SDT to develop methods to compel natural gas owners and operators to cooperate and provide specific information to various entities.

It is also recognized that BES registered entities are not expected to become experts in natural gas infrastructure, nor are natural gas entities expected to become experts in electrical generation. However, the Applicable Entity (Distribution Provider or Transmission Owner serving the end-use customer), in working with natural gas facility owners, is responsible for defining those facilities that are critical to maintain the BES reliability, therefore placing the correct ownership on the entity to make that identification and not on entity that is unfamiliar with the configuration. Those natural gas Loads determined to be critical to the reliability of the BES may also change gradually over time as changes occur in the BES and natural gas supply system, requiring regular review of prioritization schemes. The goal of pre-event planning and emergency response is to promote sufficient knowledge so that discussions of natural gas facility criticality can be conducted prior to and during extreme cold weather events. This allows Reliability Coordinators, Balancing Authorities, Regional Entities, Transmission Operators, Transmission Owners, and Distribution Providers to adjust Load shedding schemes as necessary to maximize availability of natural gas resources and to minimize impacts on the BES.

Prioritization of Critical Natural Gas Infrastructure Loads

The SDT recognizes that it is not reasonable to set a broad expectation of "protecting" critical natural gas Loads as initially recommended in the Joint Inquiry Report. Instead, it is more appropriate for entities to consider how critical natural gas infrastructure Loads are prioritized under various conditions. 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. Continued communication between electricity and natural gas providers is crucial to maintain situational awareness to avoid unintended consequences of Load shedding of critical natural gas infrastructure Loads. Prioritization should take into account the relative criticality of various loads within the natural gas supply chain and their potential impact to BES reliability. For example, critical natural gas Loads such as compression facilities that directly impact gas pipelines serving gas-fired generators should be prioritized above gas production facilities.

Most entities will find it appropriate to completely exclude a subset of the most critical natural gas infrastructure Loads that directly impact BES generators from manual, UFLS, and UVLS. It is recommended to prioritize other critical natural gas Loads so that they are only shed if necessary, based on the Load shed magnitude.

An example method of prioritizing critical natural gas Loads may include:

- Identifying critical natural gas infrastructure Loads with the highest level of criticality and potential impact to BES reliability such that they can be completely excluded from operator-controlled manual Load shed, UFLS and UVLS programs;
- Prioritizing other critical natural gas infrastructure Loads not included in UFLS or UVLS programs such that they are only shed if necessary, based on the Load shed magnitude; and
- Prioritizing other critical natural gas infrastructure Loads included in UFLS or UVLS programs such that they are allocated to the lower frequency, or longer time-delay, steps in a UFLS program to ensure that they are less likely to be interrupted.

Requirement R2

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 excluding critical natural gas infrastructure loads which are essential to the reliability of the BES, as defined by the Applicable Entity, as Interruptible Load, curtailable Load, and demand response during extreme cold weather periods within each Balancing Authority Area;*

2.2.9. *Provisions for Transmission Operators to implement operator-controlled manual Load shedding undervoltage Load shedding, or underfrequency Load shedding in accordance with Requirement R1 Part 1.2.5; and*

2.2.10. *Provisions to determine reliability impacts of:*

2.2.10.1. *cold weather conditions; and*

2.2.10.2. *extreme weather conditions.*

<u>Key Recommendation 1h:</u> 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.

Requirement R2, Part 2.2.8

EOP-011-4 Requirement 2.2.8 was added to address Key Recommendation 1h by prohibiting the use of certain critical natural gas infrastructure loads for demand response. This prohibition does not apply to all natural gas infrastructure loads. Instead, the Balancing Authority is only required to exclude those critical natural gas infrastructure loads which are essential to the reliability of the BES. Additionally, it is recognized that a complete prohibition is not necessary at all times given that the natural gas system does not have the same limitations and criticality during all seasons and weather conditions. For this reason, the SDT has limited the exclusion of these loads from Interruptible Load, curtailable Load, and demand response only to periods of extreme cold weather.

Requirement R2, Part 2.2.9

Key Recommendation 1i requires the Balancing Authorities to include in their Operating Plan(s) for their Balancing Authority Areas provisions for operator-controlled manual Load shedding that identifies and protects critical natural gas infrastructure loads in their respective areas. Further, the recommendation also includes provisions within these operating plans to require manual, UVLS, and UFLS Load shed entities within their respective footprints to protect identified critical natural gas infrastructure loads from manual, UVLS, and UFLS Load shedding.

The current provision, Requirement R2 Part 2.2.9, which references Transmission Operator responsibilities under R1 Part 1.2.5, satisfies the requirements of Key Recommendation 1i with respect to the Balancing Authority. Requirement R1 Part 1.2.5 requires that Transmission Operators have provisions to identify and prioritize critical natural gas infrastructure loads which are essential to the reliability of the BES from a manual Load shedding, UVLS and UFLS Load shedding perspective. The Balancing Authority relies on the Transmission Operator when it directs Load shedding. In addition, as described above, Requirement R8 extends these requirements to the applicable

Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners who are identified in a Transmission Operator's Operating Plan to assist with the mitigation of Operating emergencies. Therefore, the objectives of the recommendation that Load shedding entities identify and protect critical natural gas infrastructure loads are satisfied.

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Exhibit C-2

Technical Rationale
Proposed Reliability Standard TOP-002-5

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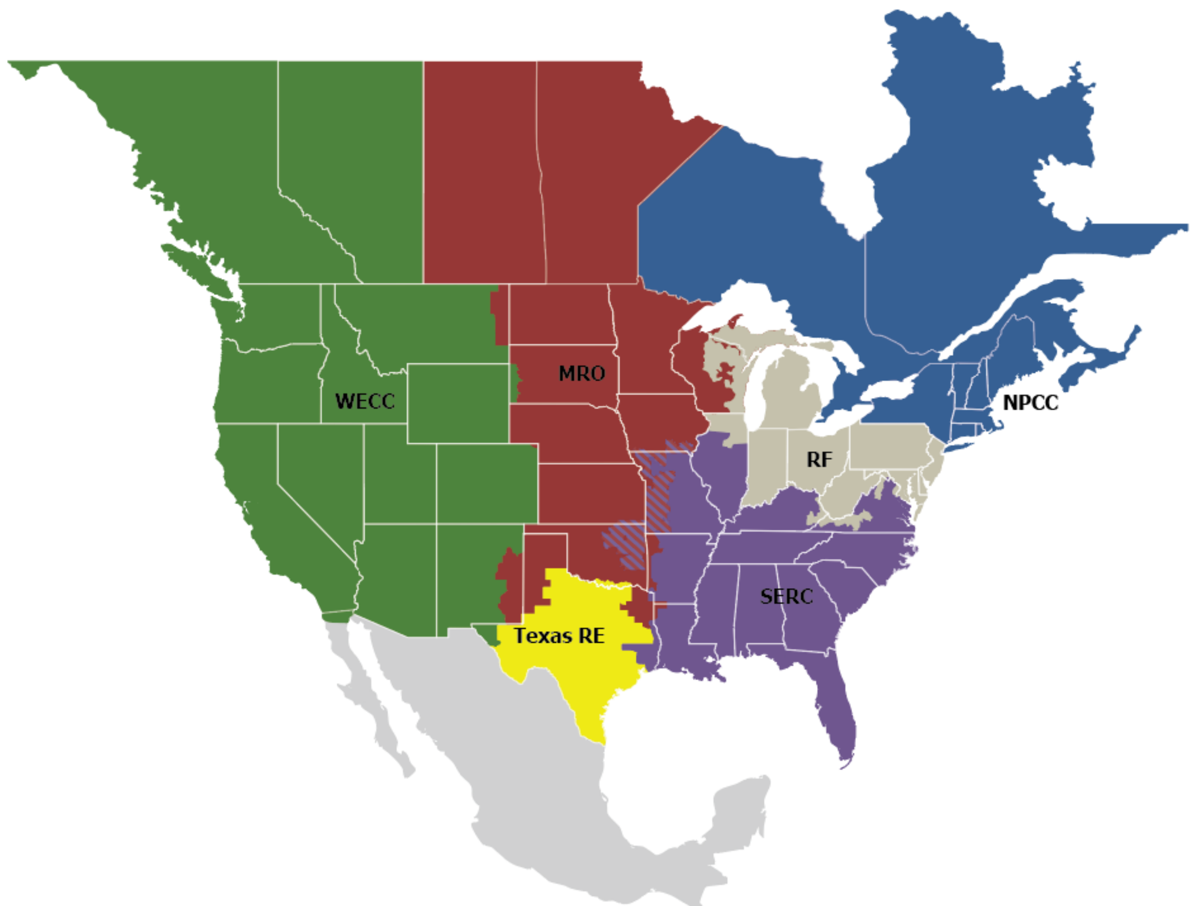

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Introduction

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TOP-002-5

Requirement R8

R8. *Each Balancing Authority shall have an extreme cold weather Operating Process for its Balancing Authority Area, addressing preparations for and operations during extreme cold weather periods. The extreme cold weather Operating Process shall include, but is not limited to:*

8.1 A methodology for identifying an extreme cold weather period within each Balancing Authority Area;

8.2 A methodology to determine an adequate reserve margin during the extreme cold weather period considering the generating unit(s) operating limitations in previous extreme cold weather periods that includes, but is not limited to:

8.2.1 Capability and availability;

8.2.2Fuel supply and inventory concerns

8.2.3 Start-up issues;

8.2.4 Fuel switching capabilities; and

8.2.5 Environmental constraints.

8.3 A methodology to determine a five-day hourly forecast during the identified extreme cold weather periods that includes, but is not limited to:

8.3.1 Expected generation resource commitment and dispatch;

8.3.2 Demand patterns;

8.3.3 Capacity and energy reserve requirements, including deliverability capability; and

8.3.4 Weather forecast.

Key Recommendation 1g: *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.

General Considerations

There have been several past events during extreme cold weather where load and resource balancing issues have occurred, due to both unexpected generator trips and higher loads than forecasted. A proactive Operating Process required prior to the onset of extreme cold weather events would formalize the Balancing Authority's extreme cold weather preparations for those periods, including forecasting load needs and adequate reserve requirements. Initial drafts to incorporate the Operating Process tied the process to the Operating Plan described in Requirement R4. To remove any ambiguity whether a cold weather Operating Process must be developed for all Operating Plans during all seasons, the standard drafting team (SDT) structured Requirement R8 to be stand-alone. Therefore, the Operating Process contained in Requirement R8 will address preparations and operations for extreme cold weather periods and is not required for other seasonal conditions. The Operating Process is specific to extreme cold weather operations to formalize the process to review and respond to oncoming conditions that may affect generation availability and capability, forecasted load, and determining whether additional capability/reserves should be ready to serve loads during extreme cold weather. The content of Requirement R8 is similar to what is required in the Operating Plan in Requirement in R4 with the exception of Interchange Scheduling which is not required here because this function is typically done in real time on an hourly basis. The need for the Balancing Authority to proactively look ahead and forecast their ability to import power from neighboring Control Areas is captured under Parts 8.3.1 and 8.3.3.

The Project 2021-07 SDT does not believe that prescriptive processes must be used for every Balancing Authority to develop their methodology. This is based in part on the differences in the size of Balancing Authorities (for reference, in 2020, 14 Balancing Authorities had peak loads of less than 200 MWs, while two had peak loads of more than 100,000 MWs[1]). The differences between Balancing Authority footprints, loads, and market structures or lack thereof, make a single consistent methodology inappropriate. Requirement R8, Parts R8.2 and R8.3 contain criteria, including data requirements, the Balancing Authority will use as part of its methodologies. Due to the criteria being the minimum required, the SDT team has included "but not limited to" language to allow the Balancing Authority that flexibility in needed information and process that is vital to ensure the methodologies can effectively accomplish the reliability need, and reflect the intent of the standard to require inclusion of the various listed items but not exclude other items that the Balancing Authority may consider valuable and germane to include in its methodologies. The SDT spent considerable time discussing the appropriate look ahead time frame for the Operating Process with suggestions ranging from seven days to three days. It was determined that seven days was too long of a period as weather forecasts are typically not reliable for this longer duration and three days was too short of a period as this would not allow for the forecast to span a longer holiday weekend. Furthermore, the SDT determined that five days would provide sufficient visibility into projected reserve margin requirements.

The SDT developed the proposed requirement to ensure that the Balancing Authorities address the increased uncertainty related to these extreme weather events in a manner appropriate and adequate for their Balancing Authority Area. Each Balancing Authority can develop a methodology consistent with the Requirement they feel provides the best solutions to sustain an adequate level of reliability during an upcoming extreme cold weather event.

[1]Source: OY 2022 BAL-003 Frequency Bias Settings 01 Jun 2022
https://www.nerc.com/comm/OC/RS%20Landing%20Page%20DL/Frequency%20Response%20Standard%20Resources/OY_2022_Frequency_Bias_Annual_Calculations_REVISION_4.26.22.pdf

Technical Rationale from TOP-002-4

This section contains a "cut and paste" of the Technical Rationale components of the former Guidelines and Technical Basis (GTB) as-is from TOP-002-4 standard to preserve any historical references.

Rationale for Definitions:
Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Rationale for R1:
Terms deleted in Requirement R1 as they are now contained in the revised definition of Operational Planning Analysis

Rationale for R2:
The change to Requirement R2 is in response to NOPR paragraph 42 and in concert with proposed changes made to proposed TOP-001-4

Rationale for R3:
Changes in response to IERP recommendation

Rationale for R4 and R5:
These Requirements were added to address IERP recommendations

Rationale for R6 and R7:
Added in response to SW Outage Report recommendation 1

This section contains a "cut and paste" of the "Associated Documents" section as is in TOP-002-4 Standard to preserve any historical references:
Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario, but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow, but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA.

When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of “the Operating Plan document” for compliance purposes.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit D

Order No. 672 Criteria

EXHIBIT D

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-011-4 and TOP-002-5) would advance the reliability of the Bulk-Power System ("BPS") through new and enhanced requirements for cold weather operations and preparedness. Proposed Reliability Standard EOP-011-4 builds upon the improvements reflected in Reliability Standards EOP-011-2 and EOP-011-3 and would advance reliability by requiring Balancing Authorities, Transmission Operators, and load shedding entities account for critical natural gas infrastructure loads in the demand response and emergency load shedding programs they oversee, so that deploying these

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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.").

programs in cold weather conditions will not exacerbate natural gas fuel supply issues and contribute to generator unavailability. Proposed Reliability Standard TOP-002-5 would advance reliability by requiring Balancing Authorities to implement Operating Processes for extreme cold weather periods in their areas.

As discussed more fully in the main section of NERC's petition, the proposed Reliability Standards represent the conclusion of the second phase of work to address the recommendations from FERC, NERC, and the Regional Entity Staff Report on the causes of the February 2021 cold weather event affecting the south central United States.[3] Proposed Reliability Standards EOP-011-4 and TOP-002-5 address Key Recommendations 1g, 1h, and 1i from the Joint Inquiry Report. The proposed Reliability Standards are designed to achieve a specific reliability goal (enhanced requirements for cold weather operations and preparedness), 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-011-4 would apply to Balancing Authorities, Reliability Coordinators, and Transmission Operators, same as the currently-effective and approved versions of the EOP-011 Reliability Standard. Proposed Reliability Standard EOP-011-4 would also add to the standard's applicability

[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.").

Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. Proposed Reliability Standard TOP-002-5 would continue to apply to Transmission Operators and Balancing Authorities. 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.

[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.").

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.

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-011-4 would advance reliability by requiring Balancing Authorities, Transmission Operators, and load shedding entities identified by Transmission Operators to limit the participation of critical natural gas infrastructure loads in the demand response and emergency load shedding programs they oversee, particularly during cold weather conditions when natural gas supply issues for generation have proven to be the most challenging. Proposed Reliability Standard TOP-002-5 would advance reliability through a new requirement addressing how the Balancing Authority will prepare for operations during extreme cold weather conditions. As discussed further in the main petition, both of the proposed Reliability Standards provide flexibility to applicable entities for how they implement the requirements, so that they may take into consideration their unique facts and circumstances.

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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.").

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.").

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]

The proposed Reliability Standards do not reflect a "lowest common denominator" approach. The proposed Reliability Standards would further advance the reliable operation of the Bulk-Power System in cold weather conditions by requiring applicable entities to consider critical natural gas infrastructure loads in the load shedding programs employed during Emergency conditions (EOP-011-4), and by requiring the Balancing Authority to have an extreme cold weather Operating Process for its Balancing Authority Area to address preparations for and operations during extreme cold weather periods. (TOP-002-5).

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

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[8] *See* Order No. 672, *supra* note 1, at P 329 ("The proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice—the so-called 'lowest common denominator'—if such practice does not adequately protect Bulk-Power System reliability. Although the Commission will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect reliability.").

See Order No. 672, *supra* note 1, at P 330 ("A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a 'lowest common denominator' Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk-Power System must bear the cost of complying with each Reliability Standard that applies to it.").

[9] *See* Order No. 672, *supra* note 1, at P 331 ("A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk-Power System, to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or regional model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.").

provide sufficient flexibility to accommodate regional/geographic variations, including climate, generation type, market issues, state rules, and other considerations.

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.

For proposed Reliability Standard EOP-011-4, the proposed implementation plan provides that the proposed Reliability Standards would become effective on the first day of the first calendar quarter that is six (6) months after applicable regulatory approval. Reliability Standard EOP-011-3, which is pending Commission action on its enforceability date, would be retired immediately prior to the effective date of the revised Reliability Standards. Transmission Operators and

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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.").

Balancing Authorities would have an additional 30 months with the revised provisions specific to underfrequency load shed, undervoltage load shed, and critical gas infrastructure loads in Requirement R1 Part 1.2.5 (Transmission Operator), and Requirement R2 Parts 2.2.8 and 2.2.9 (Balancing Authority). Newly applicable entities that are identified and notified to assist with the mitigation of operating emergencies by their Transmission Operator would have 30 months to develop a load shedding plan under Requirement R8.

The proposed implementation plan reflects consideration of the interaction that will be required between applicable entities and natural gas entities to identify critical natural gas infrastructure loads and account for them as required in manual shedding and underfrequency and undervoltage load shedding schemes. The proposed implementation timeframe also reflects consideration of the fact that the Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner will have obligations under this Reliability Standard for the first time under Requirement R8 and will need a reasonable period of time to develop compliant load shedding plans that are provided to the Transmission Operator for review.

Proposed Reliability Standard TOP-002-5 would become effective on the first calendar quarter that is eighteen (18) months after applicable regulatory approval. The proposed implementation timeframe reflects consideration of the time needed to develop an extreme cold weather Operating Process, with the required methodologies reflecting the minimum cold weather reliability considerations identified in Requirement R8. The implementation timeframe balances the urgency in the need to implement the standards against the time allowed for the Balancing authority who must comply to develop the necessary procedures and other relevant capabilities. 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 processes for developing and approving Reliability 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, 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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[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.").

[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-011-4

VRF Justification for EOP-011-4, Requirement R1

The VRF did not change from the previous EOP-011-3 Reliability Standard.

VSL Justification for EOP-011-4, Requirement R1

The VSL did not change from the previous EOP-011-3 Reliability Standard.

VRF Justification for EOP-011-4, Requirement R2

The VRF did not change from the previous EOP-011-3 Reliability Standard.

VSL Justification for EOP-011-4, Requirement R2

The VSL did not change from the previous EOP-011-3 Reliability Standard.

VRF Justification for EOP-011-4, Requirement R3

The VRF did not change from the previous EOP-011-3 Reliability Standard.

VSL Justification for EOP-011-4, Requirement R3

The VSL did not change from the previous EOP-011-3 Reliability Standard.

VRF Justification for EOP-011-4, Requirement R4

The VRF did not change from the previous EOP-011-3 Reliability Standard.

VSL Justification for EOP-011-4, Requirement R4

The VSL did not change from the previous EOP-011-3 Reliability Standard.

VRF Justification for EOP-011-4, Requirement R5

The VRF did not change from the previous EOP-011-3 Reliability Standard.

VSL Justification for EOP-011-4, Requirement R5

The VSL did not change from the previous EOP-011-3 Reliability Standard.

VRF Justification for EOP-011-4, Requirement R6
The VRF did not change from the previous EOP-011-3 Reliability Standard.

VSL Justification for EOP-011-4, Requirement R6
The VSL did not change from the previous EOP-011-3 Reliability Standard.

VRF Justifications for EOP-011-4, Requirement R7	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to the fact that identifying and notifying entities that are required to assist with the mitigation of operating Emergencies through operator-controlled manual Load shedding or automatic Load shedding 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. Therefore, it is in line with the definition of a Lower 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	The assignment of Lower VRF is consistent with the VRF assignments for other requirements in the proposed 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 Lower VRF requirement per the criteria filed with FERC as part of the ERO’s Sanctions Guidelines.
FERC VRF G5 Discussion	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective.

VRF Justifications for EOP-011-4, Requirement R7	
Proposed VRF	**Lower**
Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	Therefore, the VRF reflects the risk of the whole requirement.

VSLs for EOP-011-4, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
N/A	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities more than one, but fewer than 30 days late.	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities 30 days or more, but fewer than 60 days late.	The Transmission Operator did not identify or notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding. OR The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of

			those entities 60 days or more late.

VSL Justifications for EOP-011-4, 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 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-011-4, Requirement R8	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate due to the fact that a lack of a Load shedding plan 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. Therefore, it is in line with the definition of a High 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	The assignment of High VRF is consistent with the VRF assignments for other requirements in the proposed 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 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-011-4, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
N/A	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to maintain it in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to provide it to its Transmission Operator in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner failed to develop a Load shedding plan(s) in accordance with Requirement R8. OR The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to implement it in accordance with Requirement R8.

TOP-002-5

VRF Justification for TOP-002-5, Requirement R1
The VRF did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VSL Justification for TOP-002-5, Requirement R1
The VSL did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VRF Justification for TOP-002-5, Requirement R2
The VRF did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VSL Justification for TOP-002-5, Requirement R2

The VSL did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VRF Justification for TOP-002-5, Requirement R3
The VRF did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VSL Justification for TOP-002-5, Requirement R3
The VSL did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VRF Justification for TOP-002-5, Requirement R4
The VRF did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VSL Justification for TOP-002-5, Requirement R4
The VSL did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VRF Justification for TOP-002-5, Requirement R5
The VRF did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VSL Justification for TOP-002-5, Requirement R5
The VSL did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VRF Justification for TOP-002-5, Requirement R6
The VRF did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VSL Justification for TOP-002-5, Requirement R6
The VSL did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VRF Justification for TOP-002-5, Requirement R7
The VRF did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VSL Justification for TOP-002-5, Requirement R7
The VSL did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VRF Justifications for TOP-002-5, Requirement R8	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that not having an Operating Process to identify cold weather and calculate appropriate demand and reserves while accounting for generating unit operation limitations 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	The assignment of Medium VRF is consistent with the VRF assignments for other requirements in the proposed 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 TOP-002-5, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
N/A	The Balancing Authority had an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods, but it did not address one of the Requirements or sub-Requirements of R8 Parts 8.1 through 8.3.	The Balancing Authority had an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods, but it did not address two of the Requirements or sub-Requirements of R8 Parts 8.1 through 8.3.	The Balancing Authority did not have an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods.

VSL Justifications for TOP-002-5, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed 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.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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-011-4 and TOP-002-5.

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 [hereinafter "Joint Inquiry Report"]. .

- 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.

The Board approved Reliability Standards EOP-011-3 and EOP-012-1 in October 2022.[4] This represented the conclusion of phase 1 of work to address the Joint Inquiry Report recommendations. The Commission approved Reliability Standards EOP-011-3 and EOP-012-1 with directives for further modifications on February 16, 2023.[5]

Proposed Reliability Standards EOP-011-4 and TOP-002-4 represent the conclusion of phase 2.

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.[6] The Standards Committee accepted the SAR on February 25, 2022.

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

On February 22, 2023, the Standards Committee authorized initial of posting of proposed Reliability Standards EOP-011-4 and TOP-002-5, the associated Implementation Plan and other associated documents for a 45-day formal comment period. The initial posting took place from February 28, 2023 through April 13, 2023, with a parallel initial ballot and non-binding poll on

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4 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/Agenda%20highlights%20and%20Mintues%202013/Board_Meeting_October_26_2022_Agenda_Package_ATTENDEE.pdf.

5 *N. Am. Elec. Reliability Corp.*, 182 FERC ¶ 61,094 (2023) (approving Reliability Standards EOP-011-3 and EOP-012-1 and directing further revisions).

6 *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.

the Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") held during the last 10 days of the comment period from April 4, 2023 through April 13, 2023.[7] The initial ballot and non-binding poll results for the proposed Reliability Standards are as follows:

- Proposed Reliability Standard EOP-011-4 received 45.64 percent approval, reaching quorum at 88.69 percent of the ballot pool. The non-binding poll for the associated VRFs and VSLs received 47.06 percent supportive opinions, reaching quorum at 87.91 percent of the ballot pool.[8]
- Proposed Reliability Standard TOP-002-5 received 44.59 percent approval, reaching quorum at 88.65 percent of the ballot pool. The non-binding poll for the associated VRFs and VSLs received 47.49 percent supportive opinions, reaching quorum at 87.08 percent of the ballot pool.[9]
- The Implementation Plan received 44.62 percent approval, reaching quorum at 88.61 percent of the ballot pool.[10]

There were 64 sets of responses, including comments from approximately 152 different individuals and approximately 106 companies, representing all 10 industry segments.[11]

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

On August 23, 2023, the Standards Committee approved a waiver under Sections 4.9 and 4.12 of the Standard Processes Manual to shorten the usual periods for comment and ballot for Project 2021-07. Specifically, the Standards Committee approved shortening the additional formal

[7] *Id.* at item 10.

[8] *Id.* at items 15, 18.

[9] *Id.* at items 16, 19.

[10] *Id.* at item 17.

[11] *Id.* at item 12.

comment and ballot period(s) from 45 days to as little as 20 days, with ballots conducted in the last 10 days; and shortening the final ballot from 10 days to as 5 calendar days.[12]

Proposed Reliability Standards EOP-011-4 and TOP-002-5, the associated Implementation Plan, and other associated documents were posted for a 20-day formal comment period from August 24, 2023 through September 12, 2023, with a parallel additional ballot and non-binding poll held from September 1, 2023 through September 12, 2023.[13] The additional ballot and non-binding poll results for the proposed Reliability Standards are as follows:

- Proposed Reliability Standard EOP-011-4 received 73.4 percent approval, reaching quorum at 90 percent of the ballot pool. The non-binding poll for the associated VRFs and VSLs received 73.89 percent supportive opinions, reaching quorum at 87.78 percent of the ballot pool.[14]
- Proposed Reliability Standard TOP-002-5 received 82.42 percent approval, reaching quorum at 89.61 percent of the ballot pool. The non-binding poll for the associated VRFs and VSLs received 81.29 percent supportive opinions, reaching quorum at 88.06 percent of the ballot pool.[15]
- The Implementation Plan received 79.97 percent approval, reaching quorum at 88.85 percent of the ballot pool.[16]

There were 62 sets of responses, including comments from approximately 152 different individuals and approximately 106 companies, representing all 10 industry segments.[17]

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12 *See* Exhibit F, Complete Record of Development, at item 21.

13 *Id.* at item 36.

14 *Id.* at items 40, 43.

15 *Id.* at items 41, 44.

16 *Id.* at item 42.

17 *Id.* at item 38.

E. Final Ballot

Proposed Reliability Standards EOP-011-4 and TOP-002-5 were posted for an 8-day final ballot period from September 29, 2023 through October 6, 2023.[18] The ballot for the proposed Reliability Standards and associated documents are as follows:

- Proposed Reliability Standard EOP-011-4 reached quorum at 92.5 percent of the ballot pool, receiving affirmative support from 73.29 percent of the voters.[19]
- Proposed Reliability Standard TOP-002-5 reached quorum at 92.11 percent of the ballot pool, receiving affirmative support from 79.56 percent of the voters.[20]
- The Implementation Plan reached quorum at 91.37 percent of the ballot pool, receiving affirmative support from 80.69 percent of the voters.[21]

F. Board of Trustees Adoption

The NERC Board of Trustees adopted proposed Reliability Standards EOP-011-4 and TOP-002-5 on October 23, 2023.[22]

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18 *Id.* at item 58.

19 *Id.* at item 59.

20 *Id.* at item 60.

21 *Id.* at item 61.

22 NERC, *Board of Trustees Agenda Package Oct. 23, 2022,* Agenda Item 1. (Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination), https://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Board_Open_Meeting_October_23_2023_Agenda_Package_ATTENDEE.pdf.

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, October 6, 2023** for the following standards and implementation plan:

- EOP-011-4 – Emergency Operations
- TOP-002-5 – Operations Planning
- Implementation Plan

In response to industry comments, the standard drafting team has made a few clarifying non-substantive changes to EOP-011 and TOP-002. The SDT has provided a summary of these changes in the Consideration of Comments.

The standards will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Background

Extreme cold weather and precipitation affected the south central United States February 8-20, 2021. Many 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.

Phase 1 of the project ran from February – September 2022 and addressed the 4 Key Recommendations identified in the SAR. These standards were presented and approved by the NERC Board in October 2022. Phase 2 of the project began in October 2022 and is addressing the remaining Key Recommendations.

On February 16, 2023, FERC issued an Order Approving Extreme Cold Weather Reliability Standards EOP-011-3 and EOP-012-1 and Directing Modification of Reliability Standard EOP-012-1, *N. Am. Elec. Reliability Corp.*, 182 FERC 61,094 (Feb. 16, 2023). In this order, FERC directed changes to be made to EOP-012-1.[2]

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

[2] eLibrary | File List (ferc.gov)

Draft	Actions	Dates	Results	Consideration of Comments
Phase 2 – Final Ballot of EOP-011-4 and TOP-002-5 **EOP-011-4** **(45)** Clean | **(46)** Redline to Last Posted | **(47)** Redline to Last Approved (EOP-011-3) **TOP-002-5** **(48)** Clean | **(49)** Redline to Last Posted| **(50)** Redline to Last Approved (TOP-002-4) **Implementation Plan** **(51)** Clean | **(52)** Redline **Supporting Materials** **(53)** VRF/VSL Justifications **Technical Rationale** **EOP-011-4** **(54)** Clean | **(55)** Redline to Last Posted **TOP-002-5** **(56)** Clean | **(57)** Redline to Last Posted	**Final Ballot** **(58)** Info Vote	09/29/23 - 10/06/23	**Ballot Results** **(59)** EOP-011-4 **(60)** TOP-002-5 **(61)** Implementation Plan	
Phase 2 - Draft 2 of EOP-011-4 and TOP-002-5	Additional Ballots and Non-binding Polls		**Ballot Results** **(40)** EOP-011-4	

EOP-011-4 **(22)** Clean | **(23)** Redline to Last Posted | **(24)** Redline to Last Approved (EOP-011-3) **TOP-002-5** **(25)** Clean | **(26)** Redline to Last Posted | **(27)** Redline to Last Approved (TOP-002-4) **Implementation Plan** **(28)** Clean | **(29)** Redline **Supporting Materials** **(30)** Unofficial Comment Form (Word) **(31)** VRF/VSL Justifications **Technical Rationale** **EOP-011-4** **(32)** Clean | **(33)** Redline to Last Posted **TOP-002-5** **(34)** Clean | **(35)** Redline to Last Posted	Ballots Open Reminder **(39)** Info Vote	09/01/23 - 09/12/23	**(41)** TOP-002-5 **(42)** Implementation Plan **Non-Binding Poll Results** **(43)** EOP-011-4 **(44)** TOP-002-5	**(38)** Consideration of Comments
	Comment Period **(36)** Info Submit Comments	08/24/23 - 09/12/23	**(37)**Comments Received	
Waiver **(20)** Waiver I **(21)** Meeting Minutes	Standards Committee accepted the waiver on August 23, 2023.			
Phase 2 - Draft 1 EOP-011-4 **(1)** Clean | **(2)** Redline to EOP-011-3 TOP-002-5 **(3)** Clean | **(4)** Redline to Last Approved **(5)** Implementation Plan **Supporting Materials** **(6)** Unofficial Comment Form (Word) **(7)** VRF/VSL Justifications Technical Rationales **(8)** EOP-011-4 **(9)** TOP-002-5	Initial Ballots and Non-binding Polls **(13)** Ballot Open Reminder **(14)** Info Vote	04/04/23 - 04/13/23	**Ballot Results** **(15)** EOP-011-4 **(16)** TOP-002-5 **(17)** Implementation Plan **Non-Binding Poll Results** **(18)** EOP-011-4 **(19)** TOP-002-5	
	Join Ballot Pools	02/28/23 - 03/29/23		
	Comment Period **(10)** Info Submit Comments	02/28/23 - 04/13/23	**(11)**Comments Received	**(12)** Consideration of Comments

Standard Authorization Request (SAR) **(viii)** Clean | **(ix)** Redline	The Standards Committee Executive Committee accepted the SAR on February 25, 2022			
Drafting Team Nominations Supporting Materials **(vi)** Unofficial Nomination Form (Word)	Nomination Period **(vii)** Info Submit Nominations	11/22/21 – 12/21/21		
(i) **Standard Authorization Request** **Supporting Materials** **(ii)** Unofficial Comment Form (Word)	Comment Period **(iii)** Info Submit Comments	11/22/21 – 12/21/21	**(iv)** Comments Received	**(v)**Summary Response to Comments

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 initial draft of the proposed standard for a formal 45-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
45-day formal comment period with ballot –Phase 2	February 2023

Anticipated Actions	Date
45-day additional ballot – Phase 2	June 2023
10-day final ballot	September 2023
NERC Board of Trustees (Board) adoption	October 2022

A. Introduction

1. **Title:** **Emergency Operations**
2. **Number:** **EOP-011-4**
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

   4.1.4 Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

   4.1.5 UFLS-Only Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

   4.1.6 Transmission Owner identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area
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 or automatic 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);

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;

1.2.5.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads; and

1.2.5.6. Provisions for the identification of Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners required to mitigate operating Emergencies in its Transmission Operator Area.

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 excluding critical natural gas infrastructure loads as Interruptible Load, curtailable Load, and demand response during periods when it would adversely impact the reliable operation of the BES;

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

2.2.10. Provisions to determine reliability impacts of:

2.2.10.1. Cold weather conditions; and

2.2.10.2. 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.

R7. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner identified in a Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area shall develop, maintain and implement one or more Operating Plan(s). The Operating Plan(s) shall be provided to the Transmission Operator. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

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

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

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

7.1.3. 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);

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

7.1.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads.

M7. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner identified in a Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area will have a dated Operating Plan(s) developed in accordance with Requirement R7 and evidence that the Operating Plan was provided to its Transmission Operator; 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 R7.

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.
- The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner 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 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 #	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.

R7	Real-time Operations, Operations Planning, Long-term Planning	High	N/A	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed an Operating Plan(s) but failed to maintain it.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed an Operating Plan(s) but failed to provide it to its Transmission Operator.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner failed to develop an Operating Plan(s). OR The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed an Operating Plan(s) but failed to implement it.

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
4	TBD		Revised under Project 2021-07

Attachment 1-EOP-011-4
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 initial draft of the proposed standard for a formal 45-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
45-day formal comment period with ballot –Phase 2	February 2023

Anticipated Actions	Date
45-day additional ballot – Phase 2	June 2023
10-day final ballot	September 2023
NERC Board of Trustees (Board) adoption	October 2022

A. Introduction

1. **Title:** **Emergency Operations**

2. **Number:** **EOP-011-~~3~~4**

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

   4.1.4 Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

   4.1.5 UFLS-Only Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

   4.1.6 Transmission Owner identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

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 or automatic 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~~.~~;

1.2.5.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads; and

1.2.5.6. Provisions for the identification of Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners required to mitigate operating Emergencies in its Transmission Operator Area.

1.2.6. Provisions to determine reliability impacts of:

1.2.6.1. ~~cold~~Cold weather conditions; and

1.2.6.2. ~~extreme~~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~~Capability and availability;

2.2.3.2. ~~fuel~~Fuel supply and inventory concerns;

2.2.3.3. ~~fuel~~Fuel switching capabilities; and

2.2.3.4. ~~environmental~~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 excluding critical natural gas infrastructure loads as Interruptible Load, curtailable Load, and demand response during periods when it would adversely impact the reliable operation of the BES;

~~**2.2.8.**~~**2.2.9.** Provisions for Transmission Operators to implement operator-controlled manual Load shed in accordance with Requirement R1 Part 1.2.5; and

~~**2.2.9.**~~**2.2.10.** Provisions to determine reliability impacts of:

~~**2.2.9.1.**~~**2.2.10.1.** ~~cold~~Cold weather conditions; and

~~**2.2.9.2.**~~**2.2.10.2.** ~~extreme~~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.

R7. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner identified in a Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area shall develop, maintain and implement one or more Operating Plan(s). The Operating Plan(s) shall be provided to the Transmission Operator. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

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

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

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

7.1.3. 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);

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

7.1.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads.

M7. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner identified in a Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area will have a dated Operating Plan(s) developed in accordance with Requirement R7 and evidence that the Operating Plan was provided to its Transmission Operator; 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 R7.

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.
- The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner 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 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 #	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.

R7	Real-time Operations, Operations Planning, Long-term Planning	High	N/A	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed an Operating Plan(s) but failed to maintain it.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed an Operating Plan(s) but failed to provide it to its Transmission Operator.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner failed to develop an Operating Plan(s). OR The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed an Operating Plan(s) but failed to implement it.

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
4	TBD		Revised under Project 2021-07

Attachment 1-EOP-011-~~3~~4 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 is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the initial draft of the proposed standard for a formal 45-day comment and ballot period.

Completed Actions	Date
45-day formal or informal comment period with ballot	February 2023

Anticipated Actions	Date
45-day formal or informal comment period with additional ballot	June 2023
10-day final ballot	September 2023
Board adoption	October 2023

A. Introduction

1. **Title: Operations Planning**

2. **Number: TOP-002-5**

3. **Purpose:** To ensure that Transmission Operators and Balancing Authorities have plans for operating within specified limits.

4. **Applicability:**

   4.1. Transmission Operator

   4.2. Balancing Authority

5. **Effective Date:**

   See Implementation Plan.

6. **Background:**

   See Project 2021-07 project page.

B. Requirements and Measures

R1. Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Each Transmission Operator shall have evidence of a completed Operational Planning Analysis. Such evidence could include but is not limited to dated power flow study results.

R2. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Transmission Operator shall have evidence that it has an Operating Plan to address potential System Operating Limits (SOLs) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1. Such evidence could include but it is not limited to plans for precluding operating in excess of each SOL that was identified as a result of the Operational Planning Analysis.

R3. Each Transmission Operator shall notify entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Transmission Operator shall have evidence that it notified entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in the plan(s). Such evidence could include but is not limited to dated operator logs, or e-mail records.

R4. Each Balancing Authority shall have an Operating Plan(s) for the next day that addresses: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1 Expected generation resource commitment and dispatch;

4.2 Interchange scheduling;

4.3 Demand patterns; and

4.4 Capacity and energy reserve requirements, including deliverability capability.

M4. Each Balancing Authority shall have evidence that it has developed a plan to operate within the criteria identified. Such evidence could include but is not limited to dated operator logs or email records.

R5. Each Balancing Authority shall notify entities identified in the Operating Plan(s) cited in Requirement R4 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Each Balancing Authority shall have evidence that it notified entities identified in the plan(s) cited in Requirement R4 as to their role in the plan(s). Such evidence could include but is not limited to dated operator logs or email records.

R6. Each Transmission Operator shall provide its Operating Plan(s) for next day operations identified in Requirement R2 to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M6. Each Transmission Operator shall have evidence that it provided its Operating Plan(s) for next day operations identified in Requirement R2 to its Reliability Coordinator. Such evidence could include but is not limited to dated operator logs or email records.

R7. Each Balancing Authority shall provide its Operating Plan(s) for next day operations identified in Requirement R4 to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M7. Each Balancing Authority shall have evidence that it provided its Operating Plan(s) for next day operations identified in Requirement R4 to its Reliability Coordinator. Such evidence could include but is not limited to dated operator logs or email records.

R8. Each Balancing Authority shall have an extreme cold weather Operating Process, as part of its Operating Plan developed in Requirement R4, addressing preparations for and operations during extreme cold weather periods. The extreme cold weather Operating Process shall include: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

8.1 A methodology for identifying an extreme cold weather period within each Balancing Authority Area;

8.2 A methodology that determines an appropriate reserve margin during the extreme cold weather period considering the generating unit(s) operating limitations in previous extreme cold weather periods including:

8.2.1 Capability and availability;

8.2.2 Fuel supply and inventory concerns;

8.2.3 Start-up issues;

8.2.4 Fuel switching capabilities; and

8.2.5 Environmental constraints.

8.3 A methodology to determine a five-day hourly forecast during the identified extreme cold weather periods that includes:

8.3.1 Expected generation resource commitment and dispatch;

8.3.2 Interchange scheduling;

8.3.3 Demand patterns;

8.3.4 Capacity and energy reserve requirements, including deliverability capability; and

8.3.5 Weather forecast.

M8. Each Balancing Authority shall have evidence that it has developed an extreme cold weather Operating Process in accordance with Requirement R8.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Assessment Processes

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" 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.

1.3. Data Retention

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

Each Transmission Operator and Balancing Authority shall keep data or evidence to show compliance for each applicable Requirement for a rolling 90-calendar days period for analyses, the most recent 90-calendar days for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Operator or Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

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

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Medium	N/A	N/A	N/A	The Transmission Operator did not have an Operational Planning Analysis allowing it to assess whether its planned operations for the next day within its Transmission Operator Area exceeded any of its System Operating Limits (SOLs).
R2	Operations Planning	Medium	N/A	N/A	N/A	The Transmission Operator did not have an Operating Plan to address potential System Operating Limit (SOL) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
For the Requirement R3 and R5 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.						
R3	Operations Planning	Medium	The Transmission Operator did not notify one impacted entity or 5% or less of the entities, whichever is greater identified in the Operating Plan(s) as to their role in the plan(s).	The Transmission Operator did not notify two entities or more than 5% and less than or equal to 10% of the impacted entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Transmission Operator did not notify three impacted entities or more than 10% and less than or equal to 15% of the entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Transmission Operator did not notify four or more entities or more than 15% of the impacted NERC identified in the Operating Plan(s) as to their role in the plan(s).
R4	Operations Planning	Medium	The Balancing Authority has an Operating Plan but it does not address one of the criteria in Requirement R4.	The Balancing Authority has an Operating Plan but it does not address two of the criteria in Requirement R4.	The Balancing Authority has an Operating Plan but it does not address three of the criteria in Requirement R4.	The Balancing Authority did not have an Operating Plan.
R5	Operations Planning	Medium	The Balancing Authority did not notify one impacted entity or 5% or less	The Balancing Authority did not notify two entities or more than 5% and	The Balancing Authority did not notify three impacted entities or	The Balancing Authority did not notify four or more entities or more than

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			of the entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	less than or equal to 10% of the impacted entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	more than 10% and less than or equal to 15% of the entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	15% of the impacted entities identified in the Operating Plan(s) as to their role in the plan(s).
R6	Operations Planning	Medium	N/A	N/A	N/A	The Transmission Operator did not provide its Operating Plan(s) for next day operations as identified in Requirement R2 to its Reliability Coordinator.
R7	Operations Planning	Medium	N/A	N/A	N/A	The Balancing Authority did not provide its Operating Plan(s) for next day operations as identified in Requirement R4 to its Reliability Coordinator.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R8	Operations Planning	Medium	N/A	The Balancing Authority had an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods, but it did not address one of the parts of Requirement R8 Parts 8.1 through 8.3.	The Balancing Authority had an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods, but it did not address two of the parts of Requirement R8 Parts 8.1 through 8.3.	The Balancing Authority did not have a cold weather Operating Process addressing preparations for and operations during extreme cold weather periods.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	August 2, 2006	Adopted by Board of Trustees	Revised
2	November 1, 2006	Adopted by Board of Trustees	Revised
2	June 14, 2007	Fixed typo in R11., (subject to …)	Errata
2a	February 10, 2009	Added Appendix 1 – Interpretation of R11 approved by BOT on February 10, 2009	Interpretation
2a	December 2, 2009	Interpretation of R11 approved by FERC on December 2, 2009	Same Interpretation
2b	November 4, 2010	Added Appendix 2 – Interpretation of R10 adopted by the Board of Trustees	
2b	October 20, 2011	FERC Order issued approving the Interpretation of R10 (FERC's Order became effective on October 20, 2011)	
2.1b	March 8, 2012	Errata adopted by Standards Committee; (Removed unnecessary language from the Effective Date section. Deleted retired sub-requirements from Requirement R14)	Errata
2.1b	April 11, 2012	Additional errata adopted by Standards Committee; (Deleted language from retired sub-requirement from Measure M7)	Errata
2.1b	September 13, 2012	FERC approved	Errata
3	May 6, 2012	Revisions under Project 2007-03	Revised

Version	Date	Action	Change Tracking
3	May 9, 2012	Adopted by Board of Trustees	Revised
4	April 2014	Revisions under Project 2014-03	Revised
4	November 13, 2014	Adopted by NERC Board of Trustees	Revisions under Project 2014-03
4	November 19, 2015	FERC approved TOP-002-4. Docket No. RM15-16-000. Order No. 817.	
5	TBD	Revisions under Project 2021-07	Revised

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 initial draft of the proposed standard for a formal 45-day comment and ballot period.

Completed Actions	Date
45-day formal or informal comment period with ballot	February 2023

Anticipated Actions	Date
45-day formal or informal comment period with additional ballot	June 2023
10-day final ballot	September 2023
Board adoption	October 2023

A. Introduction

1. **Title: Operations Planning**
2. **Number: TOP-002-~~4~~5**
3. **Purpose:** To ensure that Transmission Operators and Balancing Authorities have plans for operating within specified limits.
4. **Applicability:**
   - **4.1.** Transmission Operator
   - **4.2.** Balancing Authority
5. **Effective Date:**

   See Implementation Plan.
6. **Background:**

   ~~See Project 2014-03 project page.~~

   See Project 2021-07 project page.

B. Requirements and Measures

R1. Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Each Transmission Operator shall have evidence of a completed Operational Planning Analysis. Such evidence could include but is not limited to dated power flow study results.

R2. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Transmission Operator shall have evidence that it has an Operating Plan to address potential System Operating Limits (SOLs) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1. Such evidence could include but it is not limited to plans for precluding operating in excess of each SOL that was identified as a result of the Operational Planning Analysis.

R3. Each Transmission Operator shall notify entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Transmission Operator shall have evidence that it notified entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in the plan(s). Such evidence could include but is not limited to dated operator logs, or e-mail records.

R4. Each Balancing Authority shall have an Operating Plan(s) for the next~~-~~ day that addresses: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1 Expected generation resource commitment and dispatch;

4.2 Interchange scheduling;

4.3 Demand patterns~~.~~; and

4.4 Capacity and energy reserve requirements, including deliverability capability.

M4. Each Balancing Authority shall have evidence that it has developed a plan to operate within the criteria identified. Such evidence could include but is not limited to dated operator logs or ~~e-mail~~email records.

R5. Each Balancing Authority shall notify entities identified in the Operating Plan(s) cited in Requirement R4 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Each Balancing Authority shall have evidence that it notified entities identified in the plan(s) cited in Requirement R4 as to their role in the plan(s). Such evidence could include but is not limited to dated operator logs or ~~e-mail~~email records.

R6. Each Transmission Operator shall provide its Operating Plan(s) for next~~-~~ day operations identified in Requirement R2 to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M6. Each Transmission Operator shall have evidence that it provided its Operating Plan(s) for next~~-~~ day operations identified in Requirement R2 to its Reliability Coordinator. Such evidence could include but is not limited to dated operator logs or ~~e-mail~~email records.

R7. Each Balancing Authority shall provide its Operating Plan(s) for next~~-~~ day operations identified in Requirement R4 to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M7. Each Balancing Authority shall have evidence that it provided its Operating Plan(s) for next~~-~~ day operations identified in Requirement R4 to its Reliability Coordinator. Such evidence could include but is not limited to dated operator logs or ~~e-mail~~email records.

R8. Each Balancing Authority shall have an extreme cold weather Operating Process, as part of its Operating Plan developed in Requirement R4, addressing preparations for and operations during extreme cold weather periods. The extreme cold weather Operating Process shall include: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

8.1 A methodology for identifying an extreme cold weather period within each Balancing Authority Area;

8.2 A methodology that determines an appropriate reserve margin during the extreme cold weather period considering the generating unit(s) operating limitations in previous extreme cold weather periods including:

8.2.1 Capability and availability;

8.2.2 Fuel supply and inventory concerns;

8.2.3 Start-up issues;

8.2.4 Fuel switching capabilities; and

8.2.5 Environmental constraints.

8.3 A methodology to determine a five-day hourly forecast during the identified extreme cold weather periods that includes:

8.3.1 Expected generation resource commitment and dispatch;

8.3.2 Interchange scheduling;

8.3.3 Demand patterns;

8.3.4 Capacity and energy reserve requirements, including deliverability capability; and

8.3.5 Weather forecast.

M8. Each Balancing Authority shall have evidence that it has developed an extreme cold weather Operating Process in accordance with Requirement R8.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Assessment Processes

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" 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.

1.3. Data Retention

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

Each Transmission Operator and Balancing Authority shall keep data or evidence to show compliance for each applicable Requirement for a rolling 90-calendar days period for analyses, the most recent 90-calendar days for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Operator or Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

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

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Medium	N/A	N/A	N/A	The Transmission Operator did not have an Operational Planning Analysis allowing it to assess whether its planned operations for the next day within its Transmission Operator Area exceeded any of its System Operating Limits (SOLs).
R2	Operations Planning	Medium	N/A	N/A	N/A	The Transmission Operator did not have an Operating Plan to address potential System Operating Limit (SOL) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
For the Requirement R3 and R5 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.						
R3	Operations Planning	Medium	The Transmission Operator did not notify one impacted entity or 5% or less of the entities, whichever is greater identified in the Operating Plan(s) as to their role in the plan(s).	The Transmission Operator did not notify two entities or more than 5% and less than or equal to 10% of the impacted entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Transmission Operator did not notify three impacted entities or more than 10% and less than or equal to 15% of the entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Transmission Operator did not notify four or more entities or more than 15% of the impacted NERC identified in the Operating Plan(s) as to their role in the plan(s).
R4	Operations Planning	Medium	The Balancing Authority has an Operating Plan but it does not address one of the criteria in Requirement R4.	The Balancing Authority has an Operating Plan but it does not address two of the criteria in Requirement R4.	The Balancing Authority has an Operating Plan but it does not address three of the criteria in Requirement R4.	The Balancing Authority did not have an Operating Plan.
R5	Operations Planning	Medium	The Balancing Authority did not notify one impacted entity or 5% or less	The Balancing Authority did not notify two entities or more than 5% and	The Balancing Authority did not notify three impacted entities or	The Balancing Authority did not notify four or more entities or more than

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			of the entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	less than or equal to 10% of the impacted entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	more than 10% and less than or equal to 15% of the entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	15% of the impacted entities identified in the Operating Plan(s) as to their role in the plan(s).
R6	Operations Planning	Medium	N/A	N/A	N/A	The Transmission Operator did not provide its Operating Plan(s) for next-~~-~~day operations as identified in Requirement R2 to its Reliability Coordinator.
R7	Operations Planning	Medium	N/A	N/A	N/A	The Balancing Authority did not provide its Operating Plan(s) for next day operations as identified in Requirement R4 to its Reliability Coordinator.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R8	Operations Planning	Medium	N/A	The Balancing Authority had an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods, but it did not address one of the parts of Requirement R8 Parts 8.1 through 8.3.	The Balancing Authority had an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods, but it did not address two of the parts of Requirement R8 Parts 8.1 through 8.3.	The Balancing Authority did not ~~provide its~~have a cold weather Operating ~~Plan(s)~~Process addressing preparations for ~~next-day~~and operations ~~as identified in Requirement R4 to its Reliability Coordinator~~during extreme cold weather periods.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-~~-~~ day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	August 2, 2006	Adopted by Board of Trustees	Revised
2	November 1, 2006	Adopted by Board of Trustees	Revised
2	June 14, 2007	Fixed typo in R11., (subject to …)	Errata
2a	February 10, 2009	Added Appendix 1 – Interpretation of R11 approved by BOT on February 10, 2009	Interpretation
2a	December 2, 2009	Interpretation of R11 approved by FERC on December 2, 2009	Same Interpretation
2b	November 4, 2010	Added Appendix 2 – Interpretation of R10 adopted by the Board of Trustees	
2b	October 20, 2011	FERC Order issued approving the Interpretation of R10 (FERC's Order became effective on October 20, 2011)	
2.1b	March 8, 2012	Errata adopted by Standards Committee; (Removed unnecessary language from the Effective Date section. Deleted retired sub-requirements from Requirement R14)	Errata
2.1b	April 11, 2012	Additional errata adopted by Standards Committee; (Deleted language from retired sub-requirement from Measure M7)	Errata
2.1b	September 13, 2012	FERC approved	Errata
3	May 6, 2012	Revisions under Project 2007-03	Revised

Version	Date	Action	Change Tracking
3	May 9, 2012	Adopted by Board of Trustees	Revised
4	April 2014	Revisions under Project 2014-03	Revised
4	November 13, 2014	Adopted by NERC Board of Trustees	Revisions under Project 2014-03
4	November 19, 2015	FERC approved TOP-002-4. Docket No. RM15-16-000. Order No. 817.	
5	TBD	Revisions under Project 2021-07	Revised

~~Guidelines and Technical Basis~~

~~Rationale:~~

~~During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.~~

~~Rationale for Definitions:~~

~~Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.~~

~~Rationale for R1:~~

~~Terms deleted in Requirement R1 as they are now contained in the revised definition of Operational Planning Analysis~~

~~Rationale for R2:~~

~~The change to Requirement R2 is in response to NOPR paragraph 42 and in concert with proposed changes made to proposed TOP-001-4~~

~~Rationale for R3:~~

~~Changes in response to IERP recommendation~~

~~Rationale for R4 and R5:~~

~~These Requirements were added to address IERP recommendations~~

~~Rationale for R6 and R7:~~

~~Added in response to SW Outage Report recommendation 1~~

Implementation Plan

Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination – Reliability Standards EOP-011-4 and TOP-002-5

Applicable Standard(s)

- EOP-011-4 Emergency Operations
- TOP-002-5 Operations Planning

Requested Retirement(s)

- EOP-011-3
- TOP-002-4

Prerequisite Standard(s)

- None

Proposed Definition(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 (the "Joint Inquiry 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 outaged megawatts (MW) of load after the August 2003 Northeast blackout and the August 1996 West Coast

[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 Joint Inquiry Report").

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 Joint Inquiry Report for new or enhanced NERC Reliability Standards. Phase 1 of this project developed Reliability Standards EOP-011-3 and EOP-012-1. This implementation plan addresses Reliability Standards EOP-011-4 and TOP-002-5, which were developed to address the Phase 2 recommendations.

Proposed Reliability Standard EOP-011-4 is a revised Reliability Standard that builds upon changes first made in Reliability Standard EOP-011-3 to address Recommendation 1j of the Joint Inquiry Report regarding minimizing the overlap of manual Load shed and automatic Load shed programs such as underfrequency Load shed (UFLS) and undervoltage Load shed (UVLS). Proposed EOP-011-4 includes new requirements for excluding critical natural gas loads from load shed programs during periods where their participation could adversely impact the BES and for relevant entities to develop Operating Plan(s) addressing load shed considerations in response to Recommendations 1h and 1l of the Joint Inquiry Report.

Proposed Reliability Standard TOP-002-5 is a revised Reliability Standard that would require the Balancing Authority to specifically address extreme cold weather in its Operating Plans, including developing a methodology to determine the number of resources that can reasonably be expected to be available during extreme cold weather conditions. These revisions were developed to address Key Recommendation 1g of the Joint Inquiry Report.

General Considerations

This implementation plan reflects consideration that entities will need time to develop, implement, and maintain enhanced cold weather plans and freeze protection measures, as follows:

For proposed Reliability Standard EOP-011-4, this plan reflects consideration of the interaction that will be required between applicable entities and natural gas entities, as well as the fact that several entities (Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner) will have obligations under this standard for the first time under proposed Requirement R7.

For proposed TOP-002-5, this implementation plan reflects consideration of the time needed to develop and implement a new extreme cold weather Operating Process under proposed Requirement R8.

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.

Reliability Standard EOP-011-4

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.

Reliability Standard TOP-002-5

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 12 months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

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

Retirement Date

Reliability Standards EOP-011-3 and TOP-002-4

Reliability Standards EOP-011-3 and TOP-002-4 shall be retired immediately prior to the effective date of Reliability Standards EOP-011-4 and TOP-002-5 in the particular jurisdiction in which the revised standards are becoming effective.

Unofficial Comment Form

Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on **Phase 2 of Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination** by **8 p.m. Eastern, Thursday, April 13, 2023.**

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

Extreme cold weather and precipitation affected the south central United States February 8-20, 2021. Many 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 Event was most severe February 15-18, 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

EOP-011-4 (Questions 1-4)

Recommendation 1h states: 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.

1. Proposed EOP-011-4 Requirement R2 was drafted to address recommendation 1h. Do the changes in EOP-011-4 Requirement R2 provide sufficient clarity in regards to limiting critical natural gas infrastructure participation in demand response?

   ☐ Yes
   ☐ No

   Comments:

Recommendation 1i states: 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' (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.**

2. The standard drafting team (SDT) made changes to the applicability section based on the recommendation above (additional clarity included in the technical rationale). Do you believe these are the correct Functional Entities to include? If not, please provide details and any other Functional Entities be added with justification.

   ☐ Yes
   ☐ No

   Comments:

3. Is the implementation timeframe for EOP-011-4 Requirement R7 reasonable given that it is applicable to Functional Entities who were not previously included in Applicability for EOP-011-3?

   ☐ Yes
   ☐ No

   Comments:

4. Do the changes in EOP-011 provide sufficient clarity and flexibility in regards to the treatment of critical natural gas infrastructure in operator-controlled manual Load shedding and automatic load shedding?

   ☐ Yes
   ☐ No

   Comments:

TOP-002-5 (Questions 5-6)

Recommendation 1g of the Report states: 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)**

As explained by the Report on the 2021 event, Key Recommendation 1g was intended to "take the next logical step [after TOP-003-5 and EOP-011-2 changes take effect in April 2023] and eliminate doubt about which entity is responsible to provide information or act on information," preventing BAs and RCs from being surprised during extreme cold weather events (See Report at pp 189-190). The SDT would like feedback on the first bulleted subpart of Key Recommendation 1g, which, in essence,

recommends a requirement that the GOs/GOPs provide the BA with the generating units MWs, including MWh the GO/GOP reasonably believes that it can rely upon during the local forecasted cold weather.

5. Please comment on whether information pertaining to the generating unit's MWs, including MWhs the GO/GOP reasonably believes that the BA can rely upon during local forecasted cold weather, would be useful to your operations during local forecasted cold weather. Alternatively, is there a better way for the BA to develop assumptions related to cold weather needs to address this specific metric rather than asking for this information from the GO/GOPs? Please provide comments and revisions to the draft language.

   ☐ Yes
   ☐ No

   Comments:

6. Recommendation 1g, bullets 2 and 3 of the Report suggests that each Balancing Authority should be required to use the data provided by the Generator Owner/Generator Operator to determine total generating capacity that can be relied upon during "local forecasted cold weather," and utilize such information 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." The SDT proposes a new Requirement R8 in TOP-002 that requires a Balancing Authority to create an extreme cold weather Operating Process within its Operating Plan to formalize the Balancing Authority's analysis functions and Real-time monitoring of its Balancing Authority Area during extreme cold weather. Do you agree the language in proposed Requirement R8 of TOP-002 addresses the intent of and is the appropriate manner in which to satisfy Recommendation 1g? Please provide the reasoning or justification for your position in the comments.

   ☐ Yes
   ☐ No

   Comments:

General (Questions 7-10)

7. The SDT proposes that the modifications in EOP-011-4, and TOP-002-5 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:

8. Do you agree with the implementation plan proposed by the SDT? 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:

9. Is there any part of the proposed requirements, as currently drafted, that is unclear? If so, how would you make it clearer?

☐ Yes
☐ No

Comments:

10. Provide any additional comments for the SDT to consider, including the provided technical rationale document, if desired.

Comments:

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Justifications

Project 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-011-4

VRF Justification for EOP-011-4, Requirement R1

The VRF did not change from the previous EOP-011-3 Reliability Standard.

VSL Justification for EOP-011-4, Requirement R1

The VSL did not change from the previous EOP-011-3 Reliability Standard.

VRF Justification for EOP-011-4, Requirement R2

The VRF did not change from the previous EOP-011-3 Reliability Standard.

VSL Justification for EOP-011-4, Requirement R2

The VSL did not change from the previous EOP-011-3 Reliability Standard.

VRF Justification for EOP-011-4, Requirement R3

The VRF did not change from the previous EOP-011-3 Reliability Standard.

VSL Justification for EOP-011-4, Requirement R3

The VSL did not change from the previous EOP-011-3 Reliability Standard.

VRF Justification for EOP-011-4, Requirement R4

The VRF did not change from the previous EOP-011-3 Reliability Standard.

VSL Justification for EOP-011-4, Requirement R4

The VSL did not change from the previous EOP-011-3 Reliability Standard.

VRF Justification for EOP-011-4, Requirement R5

The VRF did not change from the previous EOP-011-3 Reliability Standard.

VSL Justification for EOP-011-4, Requirement R5

The VSL did not change from the previous EOP-011-3 Reliability Standard.

VRF Justification for EOP-011-4, Requirement R6
The VRF did not change from the previous EOP-011-3 Reliability Standard.

VSL Justification for EOP-011-4, Requirement R6
The VSL did not change from the previous EOP-011-3 Reliability Standard.

VRF Justifications for EOP-011-4, Requirement R7	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of High is appropriate due to the fact that not having an Operating Plan for Operator-controlled manual or automatic Load shedding while taking into account overlap or circuits and the identification and prioritization of designated critical natural gas infrastructure loads 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. Therefore, it is in line with the definition of a High 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	The assignment of High VRF is consistent with the VRF assignments for other requirements in the proposed 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	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.

VRF Justifications for EOP-011-4, Requirement R7	
Proposed VRF	**Medium**
Definitions of VRFs	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for EOP-011-4, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
N/A	The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed an Operating Plan(s), but failed to maintain it.	The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed an Operating Plan(s), but failed to provide it to its Transmission Operator.	The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner failed to develop an Operating Plan(s). OR The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed an Operating Plan(s), but failed to implement it.

VSL Justifications for EOP-011-4, 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.

VSL Justifications for EOP-011-4, Requirement R7	
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.

TOP-002-5

VRF Justification for TOP-002-5, Requirement R1
The VRF did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VSL Justification for TOP-002-5, Requirement R1
The VSL did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VRF Justification for TOP-002-5, Requirement R2
The VRF did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VSL Justification for TOP-002-5, Requirement R2
The VSL did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VRF Justification for TOP-002-5, Requirement R3
The VRF did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VSL Justification for TOP-002-5, Requirement R3
The VSL did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VRF Justification for TOP-002-5, Requirement R4
The VRF did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VSL Justification for TOP-002-5, Requirement R4
The VSL did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VRF Justification for TOP-002-5, Requirement R5
The VRF did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VSL Justification for TOP-002-5, Requirement R5
The VSL did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VRF Justification for TOP-002-5, Requirement R6
The VRF did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VSL Justification for TOP-002-5, Requirement R6
The VSL did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VRF Justification for TOP-002-5, Requirement R7
The VRF did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VSL Justification for TOP-002-5, Requirement R7

The VSL did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VRF Justifications for TOP-002-5, Requirement R8	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that not having an Operating Process to identify cold weather and calculate appropriate demand and reserves while accounting for Generating unit operation limitations 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	The assignment of Medium VRF is consistent with the VRF assignments for other requirements in the proposed 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 TOP-002-5, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
N/A	The Balancing Authority had an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods, but it did not address one of the parts of Requirement R8 Parts 8.1 through 8.3.	The Balancing Authority had an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods, but it did not address two of the parts of Requirement R8 Parts 8.1 through 8.3.	The Balancing Authority did not have a cold weather Operating Process addressing preparations for and operations during extreme cold weather periods.

VSL Justifications for TOP-002-5, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed 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.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Extreme Cold Weather Preparedness

Technical Rationale and Justification for EOP-011-4

February 2023

RELIABILITY | RESILIENCE | SECURITY




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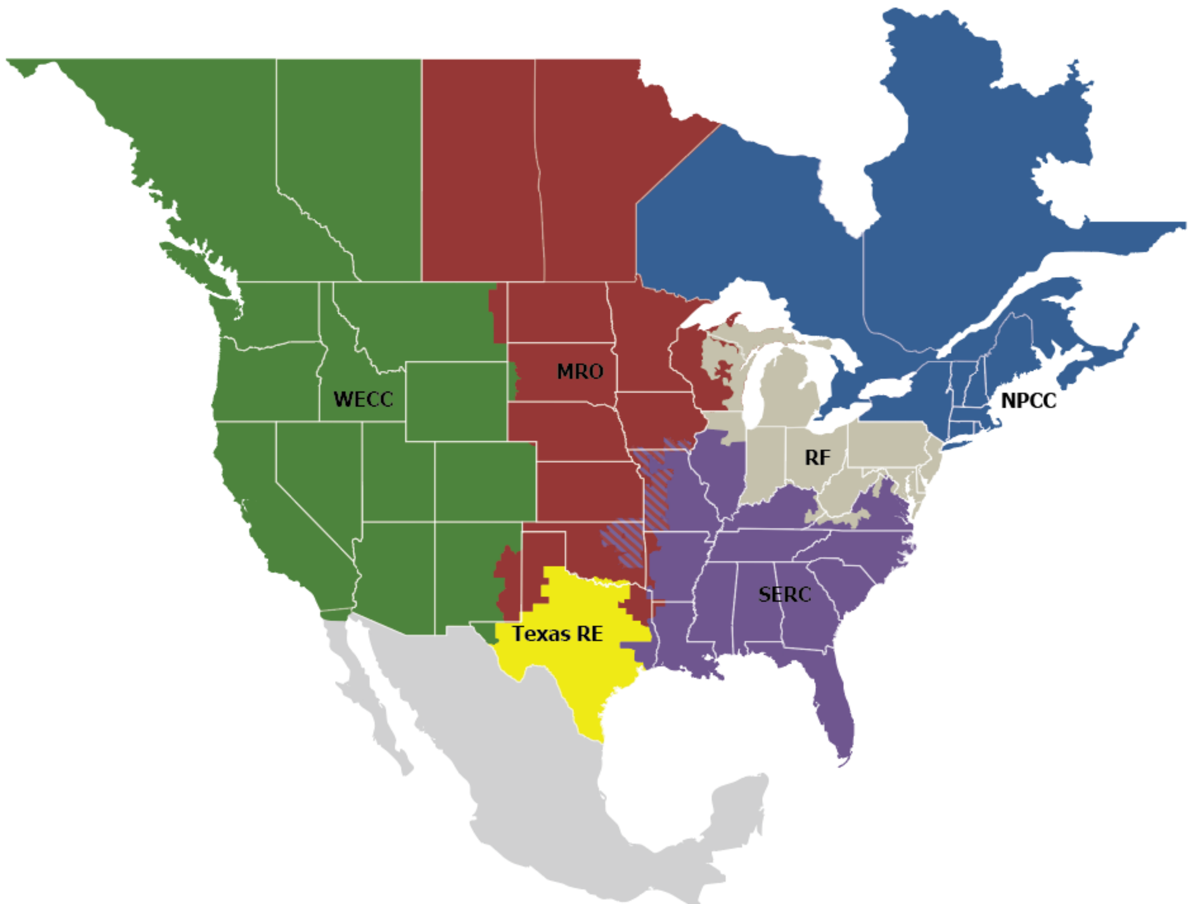
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of 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-011-4. 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-011-4 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.

Applicability

4.1. *Functional Entities:*

4.1.1 *Balancing Authority*

4.1.2 *Reliability Coordinator*

4.1.3 *Transmission Operator*

4.1.4 *Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area*

4.1.5 *UFLS-Only Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area*

4.1.6 *Transmission Owner identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area*

Requirement R1 and R7

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 or automatic 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);*

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;*

1.2.5.5. *Provisions for the identification and prioritization of designated critical natural gas infrastructure loads; and*

1.2.5.6. *Provisions for the identification of Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners required to mitigate operating Emergencies in its Transmission Operator Area.*

1.2.6. *Provisions to determine reliability impacts of:*

1.2.6.1. *Cold weather conditions; and*

1.2.6.2. *Extreme weather conditions.*

R7. *Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner identified in a Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area shall develop, maintain and implement one or more Operating Plan(s). The Operating Plan(s) shall be provided to the Transmission Operator. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

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

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

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

7.1.3. *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);*

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

7.1.5. *Provisions for the identification and prioritization of designated critical natural gas infrastructure loads.*

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)*

Applicability, Requirement R1.2.5.6 and Requirement R7

Expansion of Applicability

In many cases, Transmission Operators (TOP) are dependent on Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners to implement portions of Requirement R1.2.5. The SDT determined that is necessary to expand the Applicability of EOP-011-4 to these Functional Entities to address all entities responsible for performing operator-controlled or automatic load shedding per Key Recommendation 1i.

EOP-011-4 Requirement R1.2.5.6 is a new requirement that was added to require that Transmission Operators identify any Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners required to mitigate operating Emergencies in their Transmission Operator Area. The Transmission Operator has the overarching responsibility to mitigate operating Emergencies. If a Transmission Operator relies on other Functional Entities to accomplish various aspects of manual or automatic Load shedding, they must be identified in the TOP's Operating Plan(s).

EOP-011-4 Requirement R7 is a new requirement that is specific to Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners identified by the Transmission Operator in Requirement R1.2.5.6. It includes the relevant portions EOP-011-4 R1.2.5 that address operator-controlled or automatic load shedding. The SDT found it appropriate to place these requirements specifically on Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners because many times they are the entities performing operator-controlled manual or automatic Load shedding and have the capability of ensuring that these requirements are appropriately implemented for the Loads they represent.

Requirement R1, Part 1.2.5 and Requirement R7, Part 7.1

Identify and Prioritize Critical Natural Gas Loads

EOP-011-4 Requirement R1.2.5.5 was added to require Transmission Operators to include provisions to identify and prioritize critical natural gas loads in their Operating Plan(s). EOP-011-4 Requirement R7.1.5 mirrors this requirement and is applicable to Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners. In addition to the following content, entities are encouraged to review guidance from Reliability Guideline: Gas and Electrical Operational Coordination Considerations (add hyperlink).

Manual AND Automatic

EOP-011-4 Requirement 1.2.5 was modified to include "automatic Load shedding" in addition to "operator-controlled manual Load shedding." The result of this modification is that Requirement R1.2.5.5, which requires the identification and prioritization of critical natural gas Loads, is also applicable to automatic Load shedding. It is important to identify and prioritize critical natural gas Loads not just for the purposes of manual Load shed but also in consideration of automatic Load shedding schemes. This modification does not prohibit the inclusion of critical natural gas Loads in automatic Load shedding, but it does require the prioritization of critical natural gas Loads. This change was also incorporated into the new EOP-011-4 Requirement R7.1.

Identification of Critical Natural Gas Loads

Critical natural gas loads must be identified so that they can then be prioritized from an operator-controlled manual and automatic Load shedding perspective. The identification of critical natural gas loads can be accomplished in several ways and the SDT did not prescribe specific methods in the drafting of EOP-011-4. Methods may include:

- Distribution of criteria to natural gas infrastructure entities soliciting information to identify critical facilities that would likely adversely affect BES reliability if de-energized;
- Reliance on self-identification of critical gas infrastructure driven by local jurisdictional requirements;
- Use of historical info and coordination with resources and gas suppliers from existing Operating Plans.

Prioritization of Critical Natural Gas Loads

The SDT recognizes that it is not reasonable to set a broad expectation of "protecting" critical natural gas Loads as initially recommended in the Joint Inquiry Report. Instead, it is more appropriate for entities to consider how critical natural gas infrastructure loads are prioritized under various conditions. 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. Prioritization should consider the relative criticality of various loads within the natural gas supply chain as compared to their potential impact to BES reliability. For example, critical natural gas loads such as compression facilities that directly impact gas pipelines serving gas-fired generators should be prioritized above gas production facilities.

Most entities will find it appropriate to completely exclude a subset of the most critical natural gas infrastructure Loads that directly impact BES generators from manual and automatic Load shed. It is recommended to prioritize other critical natural gas Loads so that they are only shed if necessary, based on the Load shed magnitude.

An example method of prioritizing critical natural gas loads may include:

- Identifying critical natural gas Loads with the highest level of criticality and potential impact to BES reliability such that they can be completely excluded from operator-controlled manual Load shed and automatic Load shed programs;
- Prioritizing other critical natural gas Loads not included in automatic Load shed programs such that they are only shed if necessary, based on the Load shed magnitude; and
- Prioritizing other critical natural gas Loads included in automatic Load shed programs such that they are allocated to the lower frequency, or longer time-delay, steps in a UFLS program to ensure that they are less likely to be interrupted.

Requirement R2

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 excluding critical natural gas infrastructure loads as Interruptible Load, curtailable Load, and demand response during periods when it would adversely impact the reliable operation of the BES;*

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

2.2.10. *Provisions to determine reliability impacts of:*

2.2.10.1. *Cold weather conditions; and*

2.2.10.2. *Extreme weather conditions.*

<u>Key Recommendation 1h:</u> 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.

Requirement R2, Part 2.2.8

EOP-011-4 Requirement 2.2.8 was added to require Balancing Authorities to include provisions to identify and prioritize critical natural gas loads in their Operating Plan(s), similar to EOP-011-4 Requirements R1.2.5 and R7.1.5

applicable to Transmission Operators, Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners. The Technical Rationale verbiage above regarding the identification and prioritization of critical natural gas Loads applicable to Requirements R1.2.5 and R7.1.5 is also applicable to Requirement R2.2.8.

It is important to stress that in the verbiage above applicable to R1.2.5 and R7.1.5, and the Key Recommendation 1h and Recommendation 28 from the Joint Inquiry Report, it is recognized that "critical" is situational, i.e. depending on the local conditions, and may change during the course of a severe weather event. That is, during an event, any element of natural gas processing and delivery may become "critical". Continued communication between electricity and natural gas providers is crucial to maintain situational awareness to avoid unintended consequences of load shedding of critical natural gas loads.

It is also recognized that BES registered entities are not expected to become experts in natural gas infrastructure, nor are natural gas entities expected to become experts in electrical generation. Those natural gas loads determined to be critical may also change more gradually over time as changes occur in the BES and natural gas supply system, requiring regular review of prioritization schemes. The goal of pre-event planning and emergency response is to promote sufficient knowledge so that discussions of natural gas facility criticality can be conducted prior to and during severe cold weather to allow Reliability Coordinators, Balancing Authorities, Regional Entities, Transmission Operators, Transmission Owners, and Distribution Providers to adjust load shedding schemes as necessary to maximize availability of natural gas resources and minimize impact on the BES.

Requirement R2, Part 2.2.9

Key Recommendation 1i requires the Balancing Authorities to include in their Operating Plan(s) for their Balancing Authority Areas provisions for operator-controlled manual load shedding that identifies and protects critical natural gas infrastructure loads in their respective areas. Further, the recommendation also includes provisions within these operating plans to require manual and automatic load shed entities within their respective footprints to protect identified critical natural gas infrastructure loads from manual and automatic load shedding.

The current provision R2 Part 2.2.9, which references Transmission Operator responsibilities under R1 Part 1.2.5., satisfies the requirements of Key Recommendation 1i with respect to the Balancing Authority. Requirement R1 Part 1.2.5 identifies and protects critical natural gas infrastructure loads from manual and automatic load shedding within the Transmission Operator's Operating Plan(s), which the Balancing Authority relies on when it directs load-shedding provisions (*See* Requirement R2 Part 2.2.9). In addition, as described above, Requirement R7 applicable to the Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner, identifies and protects critical natural gas infrastructure loads from manual and automatic load shedding, and are essential in the implementation of a Transmission Operator's Operating Plan(s). Therefore, the objectives of the recommendation that load-shedding entities identify and protect critical natural gas infrastructure loads are satisfied within the Transmission Operator's Operating Plan(s).

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Extreme Cold Weather Preparedness

Technical Rationale and Justification for TOP-002-5

February 2023

RELIABILITY | RESILIENCE | SECURITY




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

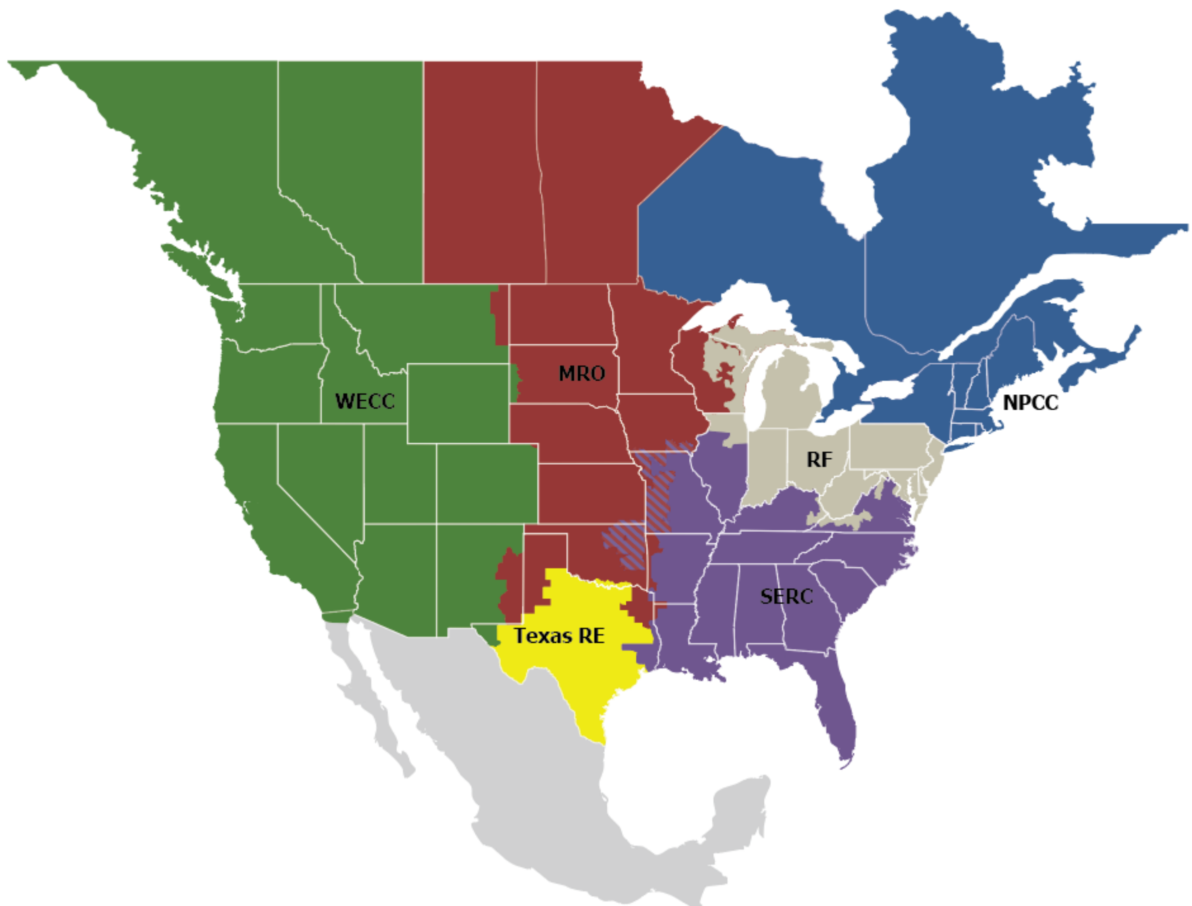
Table of Contents

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 TOP-002-5. 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 TOP-002-5 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.

TOP-002-5

Requirement R8

R8. *Each Balancing Authority shall have an extreme cold weather Operating Process, as part of its Operating Plan developed in Requirement R4, addressing preparations for and operations during extreme cold weather periods. The extreme cold weather Operating Process shall include: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

8.1 *A methodology for identifying an extreme cold weather period within each Balancing Authority Area;*

8.2 *A methodology that determines an appropriate reserve margin during the extreme cold weather period considering the generating unit(s) operating limitations in previous extreme cold weather periods including:*

8.2.1 *Capability and availability;*

8.2.2 *Fuel supply and inventory concerns;*

8.2.3 *Start-up issues;*

8.2.4 *Fuel switching capabilities; and*

8.2.5 *Environmental constraints.*

8.3 *A methodology to determine a five-day hourly forecast during the identified extreme cold weather periods that includes:*

8.3.1 *Expected generation resource commitment and dispatch;*

8.3.2 *Interchange scheduling;*

8.3.3 *Demand patterns;*

8.3.4 *Capacity and energy reserve requirements, including deliverability capability; and*

8.3.5 *Weather forecast.*

<u>Key Recommendation 1g:</u> 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 “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.

General Considerations

In reviewing TOP-003, the SDT determined that the current standards provide Transmission Operators and Balancing Authorities with sufficient flexibility to request whatever data is needed from the Generator Owners to fulfill their operational and planning responsibilities. As such, the SDT focused their edits on TOP-002 to ensure the Balancing Authority had an appropriate extreme cold weather Operating Process in place to ensure reliability during these extreme events.

There have been several past events during extreme cold weather where Load and resource balancing issues have occurred, due to both unexpected generator trips and higher Loads than forecasted. A proactive Operating Process required prior to the onset of extreme cold weather events would formalize the Balancing Authority’s extreme cold weather preparations within their Operating Plan for those periods, including forecasting Load needs and reserve requirements. The Operating Process is specific to extreme cold weather operations to formalize the process to review and respond to oncoming conditions that may affect generation availability and capability, forecasted Load, and determining whether additional capability/reserves should be ready to serve Loads during extreme cold weather.

The SDT does not believe that prescriptive processes must be used for every Balancing Authority to develop their methodology. This is based in part on the differences in the size of Balancing Authorities (for reference, in 2020, 14 Balancing Authorities had peak Loads of less than 200 MWs, while two had peak Loads of more than 100,000 MWs[1]). The differences between Balancing Authority footprints, Loads, and market structures or lack thereof, make a single consistent methodology inappropriate.

The SDT developed the proposed requirement to ensure that the Balancing Authorities address the increased uncertainty related to these extreme weather events in a manner appropriate for their Balancing Authority Area. Each Balancing Authority can develop a methodology consistent with the Requirement they feel provides the best solutions to sustain an adequate level of reliability during an upcoming extreme cold weather event.

[1] Source: OY 2022 BAL-003 Frequency Bias Settings 01 Jun 2022
https://www.nerc.com/comm/OC/RS%20Landing%20Page%20DL/Frequency%20Response%20Standard%20Resources/OY_2022_Frequency_Bias_Annual_Calculations_REVISION_4.26.22.pdf

Technical Rationale through TOP-002-4

Rationale for Definitions:

Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Rationale for R1:

Terms deleted in Requirement R1 as they are now contained in the revised definition of Operational Planning Analysis

Rationale for R2:

The change to Requirement R2 is in response to NOPR paragraph 42 and in concert with proposed changes made to proposed TOP-001-4

Rationale for R3:

Changes in response to Independent Experts Review Project (IERP) recommendation

Rationale for R4 and R5:

These Requirements were added to address IERP recommendations

Rationale for R6 and R7:

Added in response to SW Outage Report recommendation 1

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

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

Formal Comment Period Open through April 13, 2023
Ballot Pools Forming through March 29, 2023

Now Available

A formal comment period is open through **8 p.m. Eastern, Thursday, April 13, 2023** for the following:

- EOP-011-4 – Emergency Operations
- TOP-002-5 – Operations Planning
- Implementation Plan

This posting does not include EOP-012-2. The drafting team is holding this standard back to make revisions based on FERC Order Approving Extreme Cold Weather Reliability Standards EOP-011-3 and EOP-012-1 and Directing Modification of Reliability Standard EOP-012-1, N. Am. Elec. Reliability Corp., 182 FERC ¶ 61,094 (Feb. 16, 2023). An initial posting for EOP-012-2 will occur at a future date.

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

Reminder Regarding Corporate RBB Memberships
Under the NERC Rules of Procedure, each entity and its affiliates is collectively permitted one voting membership per Registered Ballot Body Segment. Each entity that undergoes a change in corporate structure (such as a merger or acquisition) that results in the entity or affiliated entities having more than the one permitted representative in a particular Segment must withdraw the duplicate membership(s) prior to joining new ballot pools or voting on anything as part of an existing ballot pool. Contact ballotadmin@nerc.net to assist with the removal of any duplicate registrations.

Ballot Pools
Ballot pools are being formed through **8 p.m. Eastern, Wednesday, March 29, 2023.** 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 **April 4-13, 2023**.

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
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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 | Phase 2 - Draft 1
Comment Period Start Date:	2/28/2023
Comment Period End Date:	4/13/2023
Associated Ballots:	2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 EOP-011-4 IN 1 ST 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 Implementation Plan IN 1 OT 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 TOP-002-5 IN 1 ST

There were 64 sets of responses, including comments from approximately 152 different people from approximately 106 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

See the unofficial comment form for additional information: https://www.nerc.com/pa/Stand/Project202107ExtremeColdWeatherDL/2021-07_Cold_Weather_Phase%202_Unofficial_Comment_Form_02282023.docx

1. Proposed EOP-011-4 Requirement R2 was drafted to address recommendation 1h. Do the changes in EOP-011-4 Requirement R2 provide sufficient clarity in regards to limiting critical natural gas infrastructure participation in demand response?

See the unofficial comment form for additional information: https://www.nerc.com/pa/Stand/Project202107ExtremeColdWeatherDL/2021-07_Cold_Weather_Phase%202_Unofficial_Comment_Form_02282023.docx

2. The standard drafting team (SDT) made changes to the applicability section based on the recommendation above (additional clarity included in the technical rationale). Do you believe these are the correct Functional Entities to include? If not, please provide details and any other Functional Entities be added with justification.

3. Is the implementation timeframe for EOP-011-4 Requirement R7 reasonable given that it is applicable to Functional Entities who were not previously included in Applicability for EOP-011-3?

4. Do the changes in EOP-011 provide sufficient clarity and flexibility in regards to the treatment of critical natural gas infrastructure in operator-controlled manual Load shedding and automatic load shedding?

See the unofficial comment form for additional information: https://www.nerc.com/pa/Stand/Project202107ExtremeColdWeatherDL/2021-07_Cold_Weather_Phase%202_Unofficial_Comment_Form_02282023.docx

5. Please comment on whether information pertaining to the generating unit's MWs, including MWhs the GO/GOP reasonably believes that the BA can rely upon during local forecasted cold weather, would be useful to your operations during local forecasted cold weather. Alternatively, is there a better way for the BA to develop assumptions related to cold weather needs to address this specific metric rather than asking for this information from the GO/GOPs? Please provide comments and revisions to the draft language.

6. Recommendation 1g, bullets 2 and 3 of the Report suggests that each Balancing Authority should be required to use the data provided by the Generator Owner/Generator Operator to determine total generating capacity that can be relied upon during "local forecasted cold weather," and utilize such information 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." The SDT proposes a new Requirement R8 in TOP-002 that requires a Balancing Authority to create an extreme cold weather Operating Process within its Operating Plan to formalize the Balancing Authority's analysis functions and Real-time monitoring of its Balancing Authority Area during extreme cold weather. Do you agree the language in proposed Requirement R8 of TOP-002 addresses the intent of and is the appropriate manner in which to satisfy Recommendation 1g? Please provide the reasoning or justification for your position in the comments.

7. The SDT proposes that the modifications in EOP-011-4, EOP-012-2, and TOP-002-5 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.

8. Do you agree with the implementation plan proposed by the SDT? 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.

9. Is there any part of the proposed requirements, as currently drafted, that is unclear? If so, how would you make it clearer?

10. Provide any additional comments for the SDT to consider, including the provided technical rationale document, if desired.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
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
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
Public Utility District No. 1 of Chelan County	Diane E Landry	1		CHPD	Meaghan Connell	Public Utility District No. 1 of Chelan County	5	WECC
					Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC
					Glen Pruitt	Public Utility District No. 1 of Chelan County	6	WECC
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	5	WECC

						Utilities (Tacoma, WA)		
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,RF,SERC,Texas RE,WECC	ACES Collaborators	Bob Soloman	Hoosier Energy Electric Cooperative	1	RF
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Ryan Strom	Buckeye Power, Inc.	5	RF
					Dave Hartman	Arizona Electric Power Cooperative	1	WECC
					Scott Brame	NC Electric Membership Corporation	3,4,5	SERC
					Jordan Mcclellan	Southern Illinois Power Cooperative	1	SERC
Eversource Energy	Joshua London	1		Eversource	Joshua London	Eversource Energy	1	NPCC
					Vicki O'Leary	Eversource Energy	3	NPCC
MRO	Jou Yang	1,2,3,4,5,6	MRO	MRO NSRF	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Chris Bills	City of Independence, Power and Light Department	5	MRO
					Fred Meyer	Algonquin Power Co.	3	MRO
					Christopher Bills	City of Independence Power & Light	3,5	MRO
					Larry Heckert	Alliant Energy Corporation Services, Inc.	4	MRO
					Marc Gomez	Southwestern Power Administration	1	MRO
					Matthew Harward	Southwest Power Pool, Inc. (RTO)	2	MRO

					Bryan Sherrow	Board of Public Utilities	1	MRO
					Terry Harbour	Berkshire Hathaway Energy - MidAmerican Energy Co.	1	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Jamison Cawley	Nebraska Public Power District	1,3,5	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Shonda McCain	Omaha Public Power District	6	MRO
					George E Brown	Pattern Operators LP	5	MRO
					George Brown	Acciona Energy USA	5	MRO
					Jaimin Patel	Saskatchewan Power Cooperation	1	MRO
					Kimberly Bentley	Western Area Power Administration	1,6	MRO
					Jay Sethi	Manitoba Hydro	1,3,5,6	MRO
					Michael Ayotte	ITC Holdings	1	MRO
Entergy	Julie Hall	6		Entergy	Oliver Burke	Entergy - Entergy Services, Inc.	1	SERC
					Jamie Prater	Entergy	5	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	5	RF

						Solutions		
					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	RF
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Jim Howell, Jr.	Southern Company - Southern Company Generation	5	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Alain Mukama	Hydro One Networks, Inc.	1	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC

Randy Buswell	Vermont Electric Power Company	1	NPCC
James Grant	NYISO	2	NPCC
John Pearson	ISO New England, Inc.	2	NPCC
Harishkumar Subramani Vijay Kumar	Independent Electricity System Operator	2	NPCC
Randy MacDonald	New Brunswick Power Corporation	2	NPCC
Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
David Burke	Orange and Rockland	3	NPCC
Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
Salvatore Spagnolo	New York Power Authority	1	NPCC
Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
David Kwan	Ontario Power Generation	4	NPCC
Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
Glen Smith	Entergy Services	4	NPCC
Sean Cavote	PSEG	4	NPCC
Jason Chandler	Con Edison	5	NPCC
Tracy MacNicoll	Utility Services	5	NPCC
Shivaz Chopra	New York Power Authority	6	NPCC

					Vijay Puran	New York State Department of Public Service	6	NPCC
					ALAN ADAMSON	New York State Reliability Council	10	NPCC
					David Kiguel	Independent	7	NPCC
					Joel Charlebois	AESI	7	NPCC
					John Hastings	National Grid	1	NPCC
					Michael Jones	National Grid USA	1	NPCC
Tim Kelley	Tim Kelley		WECC	SMUD	Ryder Couch	Sacramento Municipal Utility District	5	WECC
					Foung Mua	Sacramento Municipal Utility District	4	WECC
					Wei Shao	Sacramento Municipal Utility District	1	WECC
					Nicole Looney	Sacramento Municipal Utility District	3	WECC
					Charles Norton	Sacramento Municipal Utility District	6	WECC

See the unofficial comment form for additional information: https://www.nerc.com/pa/Stand/Project202107ExtremeColdWeatherDL/2021-07_Cold_Weather_Phase%202_Unofficial_Comment_Form_02282023.docx

1. Proposed EOP-011-4 Requirement R2 was drafted to address recommendation 1h. Do the changes in EOP-011-4 Requirement R2 provide sufficient clarity in regards to limiting critical natural gas infrastructure participation in demand response?

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	No
Document Name	

Comment

The changes proposed do not speak to or provide sufficient clarity to how TOPs will acquire the information necessary to properly identify and prioritize those critical gas infrastructure facilities such that their sources of electrical power can be determined – thereby allowing them to be properly considered within any automatic or manual load shedding program. There needs to be provisions indicating that the entities that are the owners and operators of critical natural gas infrastructure facilities will provide lists and addresses of those facilities such that TOPs can properly identify them and their source of electrical power. Without requirements for the gas infrastructure entities to supply and maintain a list of these facilities to the TOPs, we would not be in a position to reliably identify them nor prioritize them.

Likes 1	Platte River Power Authority, 1, Archie Marissa
Dislikes 0	

Response

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

BPA believes the recurring label of "critical natural gas infrastructure" is vague and undefined. Will there be a term created and placed in the NERC Glossary? Further, what specifically designates any one particular natural gas infrastructure as “critical” versus another as “non-critical”? Are electrical transmission / distribution entities being asked to designate natural gas infrastructure as critical or non-critical? BPA, as large Transmission entity, does not possess the information to make those determinations. BPA seeks clarity pertaining to what, if any, authorities are in place (or expected to be put in place) for BA, TO, TOP, DP, or UFLS-only DP to request/demand natural gas companies provide Critical Information about their facilities? BPA views this as potential overreach to require entities to do something BPA, as a Transmission entity, lacks the information or authority to do.

Likes 2	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.; Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	

Response

Donna Wood - Tri-State G and T Association, Inc. - 1

Answer	No
Document Name	

Comment

The changes do not identify how or who will be responsible for determining and identifying the critical natural gas infrastructure.

Likes 1	Platte River Power Authority, 1, Archie Marissa
Dislikes 0	

Response

Lindsey Mannion - ReliabilityFirst - 10

Answer	No
Document Name	

Comment

RF has concerns regarding consistent identification of critical natural gas infrastructure. The Technical Rationale document states "the identification of critical natural gas loads can be accomplished in several ways and the SDT did not prescribe specific methods in the drafting of EOP-011-4" but does goes on to provide some examples of methods. However, the current draft appears to leave open the possibility that the BA, TOP, TO, and DP/DP-UFLS may disagree on whether any given load is a "designated critical natural gas infrastructure load."

Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	

Response

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	

Comment

MRO NSRF requests that the term "critical natural gas infrastructure load" be defined. Additionally, MRO NSRF would request that the definition, at a minimum, state "critical natural gas infrastructure load" is natural gas infrastructure load that if rendered unavailable would adversely impact generator output and would affect the reliable operation of the Bulk Electric System. The definition of BES Cyber Asset (included below) can be looked to for language similar to what MRO NSRF is requesting.

BES Cyber Asset

A Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one or more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the reliable operation of the Bulk Electric System. Redundancy of affected Facilities, systems, and equipment shall not be considered when determining adverse impact. Each BES Cyber Asset is included in one or more BES Cyber Systems.

Recommendation 1i states: 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' (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.**

Likes 2	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.; Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	

Response

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1

Answer	No
Document Name	

Comment

AEPC has signed on to ACES comments below:

The text of Requirement R2.2.8 requires the Balancing Authority to include provisions in their Operating Plan(s); however, the published Technical Rationale document does not align with the Requirement text.

Excerpt from published Technical Rationale (emphasis added):

"EOP-011-4 Requirement 2.2.8 was added to require Balancing Authorities to include provisions to identify and prioritize critical natural gas loads in their Operating Plan(s), similar to EOP-011-4 Requirements R1.2.5 and R7.1.5 applicable to Transmission Operators, Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners. The Technical Rationale verbiage above regarding the identification and prioritization of critical natural gas Loads applicable to Requirements R1.2.5 and R7.1.5 is also applicable to Requirement R2.2.8."

Which is it? Is the Balancing Authority required to identify and prioritize or merely to include provisions in their Operating Plan(s) to exclude critical natural gas infrastructure loads?

While it is recognized that coordination of load shedding schemes may be (and likely will be) necessary at the Balancing Authority level, it should not be incumbent upon the Balancing Authority to identify critical natural gas infrastructure loads. Critical loads should be identified at a single operating level to prevent duplication and/or conflicting identifications. It is our recommendation that this identification of critical natural gas infrastructure loads should occur at the TOP level.

Thus, we recommend modifying the text of this requirement as follows:

"2.2.9. Provisions for excluding critical natural gas infrastructure loads, as identified by the TOP, from load shedding schemes (i.e., Interruptible Load, curtailable Load, or demand response) during periods when it would adversely impact the reliable operation of the BES;

Likes 0	
Dislikes 0	

Response

Gerry Adamski - Cogentrix Energy Power Management, LLC - 5

Answer	No
Document Name	

Comment

Where generation is continuing their efforts to increase their layers of freeze protection measures, enough is *not* being done to minimize the risk and improve reliability with the emphasis on fuel. Not just natural gas but a complete diversity to ensure the US power grid has all necessary fuels for generation in any extreme condition. While electric demand is increasing, reliable generation resources are decreasing. The focus for renewables need to continue, but a review of current trends need to be weighed against the reliability and the increasing demands for today and the future. IPPs are forced to make business decisions based on market/tariff agreements during volatile conditions that can and does impact the livelihood for generation facilities. During extreme weather conditions reliability should become the priority and the market aspects or penalties should be removed from the equation. The RC, BA, TOP should be working together with congress to ensure the fuels are available and the grid is diverse enough for its reliable operation.

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10

Answer	No
Document Name	

Comment

WECC believes the use of the term "critical" is ambiguous and formally undefined. Requirement 2 as written specifies the BA must exclude critical natural gas infrastructure loads from consideration as interruptible load, curtailable Load and demand response. Requirement 1 allows (requires) the TOP to identify the critical natural gas infrastruction loads. The FERC recommendation contained a description of "critical natural gas infrastructure loads" as "natural gas production, processing and intrastate and interstate pipeline facility loads which, if deenergized, could adversely affect provision of natural gas to bulk-power system natural gas-fired generation." If this description is to be used by the TOP's when identifying the critical natural gas infrastructucture loads WECC feels it should be added to the NERC Glossary of Terms or stated explicitly in the standard.

Also WECC believes it is not clear if the description provided would only apply to BES Generation Facilities that are defined as applicable in Section 4.2.1 of EOP-012-1 or considered for any BES Generation as the description implies.

The technical rational describes the consideration of “critical” gas infrastructure to be considered on a priority scale with some “critical” loads being a higher priority than other “critical” loads. WECC believes this aglso makes the use of the term “critical” ambiguous.

It was noted that EOP-011-4 does not contain any requirement for the TOP to provide the list of identified critical natural gas infrastructure loads to the Balancing Authority that must consider them in Requirement 2. This could be addressed by modification of the BA Data Specifications of TOP-003-4. But since this would be relatively unchanging information it might be preferable to specify its distribution in EOP-011-4.

WECC recommends the standard include more specific direction for identification of critical natural gas infrastructure loads for the TOP and to require communication of this information to all BA’s which share its footprint. Alternately in line with the variable priorities discussed in the technical rational consider deleting the term “critical” and simply addressing the prioritization of natural gas infrastructure providing service to BES generation.

Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	

Response

Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis

Answer	No
Document Name	

Comment

In addition to PJM supporting the IRC SRC comments, PJM requests striking the language: 'during periods when it would adversely impact the reliable operation of the BES;' from R2.2.8. This is due to balancing Load and generation during emergency conditions and the concern with any possible interruption of natural gas fired resources. There is also a potential to impact other Balancing Authority Areas since critical natural gas infrastructure would most likely extend beyond the host Balancing Authority's footprint.

Likes 0	
Dislikes 0	

Response

Nazra Gladu - Manitoba Hydro - 1

Answer	No
Document Name	

Comment

In support of MRO NSRF comments.

Likes 0	
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
For the purpose of this standard, WEC Energy Group suggests stating that "critical natural gas infrastructure load" is natural gas infrastructure that if rendered unavailable would adversely impact generator output and would affect the reliable operation of the Bulk Electric System.	
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 addition of R2.2.8 seems repetitive since the BA is required in R2.2.9 (previously R2.2.8) to have provisions to implement manual load shed in accordance with R1.2.5 which already states the requirement to minimize the overlap of critical loads in manual load shed circuits. The SDT should consider adding "or automatic" to R2.2.9 to correspond to the language of "or automatic" being added to R1.2.5. Additionally R1.2.5 could be read to include Operator Controlled Automatic Load-shed. The SDT should consider modifying R1.2.5 as follows to clearly identify both in the sub-requirement: R1.2.5. Operator Controlled manual load shedding and automatic load shedding during an Emergency that accounts for each of the following: Recommended change: 2.2.9 Provisions for Transmission Operators to implement operator-controlled manual or automatic Load shed in accordance with Requirement R1 Part 1.2.5; and If the requirement remains, ISO-NE would support an addition to the NERC Glossary of Terms for "Critical Natural Gas Infrastructure"	
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

WAPA requests that the term “critical natural gas infrastructure” be defined. Additionally, WAPA would request that the definition, at a minimum, state “critical natural gas infrastructure” is natural gas infrastructure that if rendered unavailable would adversely impact generator output and would affect the reliable operation of the Bulk Electric System.

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

We would like the SDT to clarify if the critical natural gas infrastructure loads to be identified are only in reference to electric generation or if it relates to all natural gas delivery.

We believe the term “critical natural gas infrastructure loads” should be further explained / bounded within the standard, perhaps in a footnote(s). The technical rationale document for EOP-011-4 states that “the SDT did not prescribe specific methods [for identifying critical natural gas infrastructure loads] in the drafting of EOP-011-4”, and notes three possible methods. The rationale document also suggests that a prioritization criteria be developed for critical natural gas infrastructure loads under various conditions. Recommendation 1i suggests that manual and automatic load shed entities 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. As written, R1 (part 1.2.5.5) and R2 (Part 2.2.8) could result in a wide range of interpretations.

Likes 0	
Dislikes 0	

Response

Lori Frisk - Allete - Minnesota Power, Inc. - 1

Answer	No
Document Name	

Comment

Minnesota Power supports MRO’s NERC Standards Review Form (NSRF) comments.

Likes 0	
Dislikes 0	

Response

Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	2021-07_Cold_Weather_Phase 2_Unofficial_Comment_Form_SRC_04-12-23 - Clean.docx
Comment	

As written, Requirement R2 does not provide sufficient clarity. To provide adequate clarity, the ISO/RTO Council (IRC) **Standards Review Committee (SRC)[1] recommends the term "critical natural gas infrastructure load" be defined**. The definition should be:

· **Flexible** – to recognize that some Responsible Entities may already be subject to an approved definition for their jurisdiction (*see* proposed language below):

o ***Critical Natural Gas Infrastructure Load*** *- Shall have the meaning established by the Responsible Entity's approved governing documents or by the applicable regulatory authorities, or, if no applicable definition exists, is defined as electric loads that are involved in natural gas production, processing, or transmission or distribution, both intrastate and interstate, which if curtailed will impact the delivery of natural gas to bulk-power system natural gas-fired generation.*

· **Results-based and premised on reliability** - to minimize adverse impacts to the reliable operation of the Bulk Electric System. Portions of the definition for *BES Cyber Asset* may serve as a useful reference for appropriate language.

o ***BES Cyber Asset*** *- A Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one or more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the reliable operation of the Bulk Electric System. Redundancy of affected Facilities, systems, and equipment shall not be considered when determining adverse impact. Each BES Cyber Asset is included in one or more BES Cyber Systems*.

Finally, the **SRC requests the standard acknowledge that the ability to identify critical natural gas infrastructure loads requires the cooperation of natural gas providers, which are outside of NERC's jurisdiction, and other Registered Entities, such as DPs**. The ability of Responsible Entities to comply with the Standard should not depend on the extent to which natural gas providers are willing to work with Responsible Entities to identify critical natural gas infrastructure loads. Additionally, the obligations of Responsible Entities should be limited to *known* critical natural gas infrastructure loads. Consequently, the SRC recommends that Requirement 2.2.8 be limited to known critical natural gas infrastructure loads, as follows:

"Provisions for excluding *known* critical natural gas infrastructure loads as Interruptible Load, curtailable Load, and demand response during periods when it would adversely impact the reliable operation of the BES;"

[1] For purposes of these comments, the IRC SRC includes the following entities: CAISO (with the exception of our response to question 5), ERCOT (with the exception of our responses to questions 3, 5 and 8), IESO, ISO-NE, MISO, NYISO, PJM and SPP.

Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	No
Document Name	

Comment	
The text of Requirement R2.2.8 requires the Balancing Authority to include provisions in their Operating Plan(s); however, the published Technical Rationale document does not align with the Requirement text. Excerpt from published Technical Rationale (emphasis added): "EOP-011-4 Requirement 2.2.8 was added to require Balancing Authorities to include provisions to identify and prioritize critical natural gas loads in their Operating Plan(s), similar to EOP-011-4 Requirements R1.2.5 and R7.1.5 applicable to Transmission Operators, Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners. The Technical Rationale verbiage above regarding the identification and prioritization of critical natural gas Loads applicable to Requirements R1.2.5 and R7.1.5 is also applicable to Requirement R2.2.8." Which is it? Is the Balancing Authority required to identify and prioritize or merely to include provisions in their Operating Plan(s) to exclude critical natural gas infrastructure loads? While it is recognized that coordination of load shedding schemes may be (and likely will be) necessary at the Balancing Authority level, it should not be incumbent upon the Balancing Authority to identify critical natural gas infrastructure loads. Critical loads should be identified at a single operating level to prevent duplication and/or conflicting identifications. It is our recommendation that this identification of critical natural gas infrastructure loads should occur at the TOP level. Thus, we recommend modifying the text of this requirement as follows: "2.2.9. Provisions for excluding critical natural gas infrastructure loads, as identified by the TOP, from load shedding schemes (i.e., Interruptible Load, curtailable Load, or demand response) during periods when it would adversely impact the reliable operation of the BES;"	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) in response to this question.	
Likes 0	
Dislikes 0	
Response	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	

Comment	
PacifiCorp requests that the term “critical natural gas infrastructure” be defined. Additionally, PacifiCorp would request that the definition, at a minimum, state “critical natural gas infrastructure” is natural gas infrastructure that if rendered unavailable would adversely impact generator output and would affect the reliable operation of the Bulk Electric System. The definition of BES Cyber Asset (included below) can be looked to for language similar to what PacifiCorp is requesting. **BES Cyber Asset** A Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one or more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the reliable operation of the Bulk Electric System. Redundancy of affected Facilities, systems, and equipment shall not be considered when determining adverse impact. Each BES Cyber Asset is included in one or more BES Cyber Systems.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
AEP believes the revisions provide clarity.	
Likes 0	
Dislikes 0	

Response	
Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Yes, CenterPoint Energy Houston Electric, LLC (CEHE) agrees that the proposed EOP-011-4 Requirement R2 language provides sufficient clarity in regards to limiting critical natural gas infrastructure participation in demand response.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon supports EEI's comments	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon supports EEI comments.	
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 that the proposed EOP-011-4 Requirement R2 language provides sufficient clarity in regards to limiting critical natural gas infrastructure participation in demand response.	
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 comments that the language in proposed EOP-011-4, Requirement R2, provides sufficient clarity in regards to limiting critical natural gas infrastructure participation in demand response systems. However, Southern Company would point out a potential gap in the standard concerning TO/DP exclusion of Critical Natural Gas Infrastructure loads in their Demand Response Programs.

Language for the use of and provision for excluding Critical Natural Gas Infrastructure loads as demand response to mitigate Energy Emergencies within the Balancing Authority Area is only present in the R2 requirements for BA. R1 requirements for TOP and R7 requirements for TO/DP only require provisions for the identification and prioritization of Critical Natural Gas Infrastructure loads, not the exclusion from Demand Response Programs. As written, the standard gives the BA no authority to require that TOs or DPs develop their Demand Response programs in this manner and the BA Operating Plans(s) can only accommodate what is provided by the TOP, TO, and DP.

To close this gap Southern Company would suggest that parallel requirements to R2.2.8 be placed upon the TOP, TO, and DP to exclude any identified designated critical natural gas infrastructure loads in their Demand Response Program offered for use in the BA Operating Plan(s) to mitigate Energy Emergencies during periods when it would adversely impact the reliable operation of the BES. The Commission should clarify that critical natural gas infrastructure can participate in Demand Response Programs such as real-time pricing which do not restrict the natural gas facilities from operating during energy emergencies.

Recommendation 1i states: 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' (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.

Likes 0	
Dislikes 1	Platte River Power Authority, 1, Archie Marissa
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	
BHP is not a BA.	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
BHP is not a BA.	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	Yes
Document Name	
Comment	

BHP is not a BA.	
Likes 0	
Dislikes 0	
Response	
Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
Answer	Yes
Document Name	
Comment	
BHP is not a BA.	
Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Comments: *The SDT may want to consider defining the term "Critical Natural Gas Infrastructure Load" while recognizing that some Responsible Entities may already have an approved definition in place for their jurisdiction (see proposed language below):* *Critical Natural Gas Infrastructure Load - Shall have the meaning established by the Responsible Entity's approved governing documents or by the applicable regulatory authorities, or, if no applicable definition exists, is defined as any natural gas infrastructure load, if de-energized, could adversely impact BES reliability".*	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	Yes

Document Name	
Comment	
PNM is in agreement that there is sufficient clarity regarding EOP-011-4 R2 and is in agreemetn with 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 Constellation Segements 5 and 6	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, 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 the comments of the Edison Electric Institue (EEI) to question #1,	
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 language in proposed EOP-011-4, Requirement R2, provides sufficient clarity in regards to limiting critical natural gas infrastructure participation in demand response systems.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
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	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma,	

WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
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	
Marc Sedor - Seminole Electric Cooperative, Inc. - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
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	
Tracy MacNicoll - Utility Services, Inc. - 4	
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	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Ken Habgood - Seminole Electric Cooperative, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE appreciates and supports the standard drafting team's (SDT) efforts in address the Joint Inquiry report for Winter Storm Uri. Texas RE is concerned, however, that Balancing Authorities (BAs), the entities responsible for developing Operating Plans in EOP-011-4 R2 may lack sufficient information to properly design those plans. As an initial matter, Texas RE notes that there is no provision for the BA receiving information regarding critical natural gas infrastructure loads. Texas RE recommends an explicit requirement for the BA to receive the critical natural gas infrastructure load information. Texas RE is also concerned the BAs may not receive information on the criticality of natural gas loads in multiple TOP Areas. If the natural gas infrastructure is in TOP Area 1 but affects units in TOP Area 2, it is unclear how TOP Area 2 would recognize the impact.

Moreover, while Texas RE understands the need for flexibility, Texas RE is also concerned the phrase "when it would adversely impact the reliable operation of the BES" does not fully meet the recommendation objective to "prohibit use" of critical natural gas infrastructure loads for demand response. As noted in the February 2021 Cold Weather Outages in Texas and the South Central United States Joint Inquiry Report ("Joint Inquiry"), BA operating plans may include natural gas infrastructure loads in demand response programs. In contrast, however, designated critical natural gas infrastructure loads which, "if de-energized, would adversely affect BES natural gas-fired generation" should be prohibited from participating in demand response programs. (Joint Inquiry, at 207). The proposed EOP-011-4 R2.2.2.8 language appears to permit critical natural gas infrastructure to participate in demand response programs if it would not adversely impact reliability. However, as the Joint Inquiry defines "critical natural gas infrastructure loads" as "natural gas infrastructure loads which, if de-energized, could adversely affect the provision of natural gas to BES-fired natural gas-fired generating units, thereby adversely affecting BES reliability," the inclusion of critical natural gas infrastructure should, by definition, adversely impact BES reliability. Instead of effectively creating a hollow provision and potential confusion, Texas RE recommends either removing this phrase "when in would adversely impact . . . BES" and/or clarify that non-critical natural gas infrastructure loads may be properly included in BA-developed demand response programs.

Texas RE recommends the requirement apply to any manual or automatic load shed programs. The term "Interruptible Load" references the inactive function LSE. The other terms, curtailable Load and demand response, are not defined.

Likes 0	
Dislikes 0	

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	
Document Name	

Comment

See comments submitted by the Edison Electric Institute

Likes 0	
Dislikes 0	

Response

Carl Pineault - Hydro-Qu?bec Production - 5

Answer	
Document Name	

Comment

No comments

Likes 0	

Dislikes 0	
Response	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	
Document Name	
Comment	
N/A to Hydro One	
Likes 0	
Dislikes 0	
Response	

See the unofficial comment form for additional information: https://www.nerc.com/pa/Stand/Project202107ExtremeColdWeatherDL/2021-07_Cold_Weather_Phase%202_Unofficial_Comment_Form_02282023.docx

2. The standard drafting team (SDT) made changes to the applicability section based on the recommendation above (additional clarity included in the technical rationale). Do you believe these are the correct Functional Entities to include? If not, please provide details and any other Functional Entities be added with justification.

Scott McGough - Georgia System Operations Corporation - 3	
Answer	No
Document Name	
Comment	
The NERC Reliabilty Standard for Undervoltage Load Shedding, PRC-010-2 references “UVLS entities” as an applicable entity. GSOC suggests considering UVLS entities be a Functional entity that would apply under “automatic Load shedding” for R7.	
Likes 0	
Dislikes 0	
Response	

Ken Habgood - Seminole Electric Cooperative, Inc. - 4	
Answer	No
Document Name	
Comment	
Should not include the additional functional entities as proposed in 4.1.4, 4.1.5 and 4.1.6. This is adding extra layers of coordination and processes that will be complex and difficult due to multiple DPs trying to coordinate in multiple TOs area .. This would be burdensome on the TOP as well.	
Likes 0	
Dislikes 0	
Response	

Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
Should not include the additional functional entities as proposed in 4.1.4, 4.1.5 and 4.1.6. This is adding extra layers of coordination and processes	

that will be complex and difficult due to multiple DPs trying to coordinate in multiple TOs area .. This would be burdensome on the TOP as well.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	

We don't believe that the proposed changes to the applicability section sufficiently address recommendation 1i. The recommendation references the roles of the Planning Coordinator and Transmission Planner in regard to automatic load shedding (e.g., underfrequency load shedding, undervoltage load shedding), but those entities have not been addressed. While the entities added (DP, UFLS-Only DP, TO) have a role in implementing automatic load shedding programs developed by the PC or TP, we believe the drafting team should consider changes to the PRC-006 (Automatic Underfrequency Load Shedding) and PRC-010 (Undervoltage Load Shedding) standards to more fully address recommendation 1i.

We question the addition of "or automatic" in R1, Part 1.2.5. We suggest the following restructuring for 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 for identifying any other entities (DP, TO) that help execute manual Load shedding during an Emergency;

1.2.5.3. Provisions for the periodic identification and prioritization of designated critical loads, including critical natural gas infrastructure loads;

1.2.5.4. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that serve designated critical loads, including critical natural gas infrastructure loads;

1.2.5.5. Provisions for periodic coordination with the appropriate UFLS Entities and UVLS Entities to obtain information on their circuits that are utilized for automatic underfrequency load shed (UFLS) or automatic undervoltage load shed (UVLS); and

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

Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	No
Document Name	

Comment	
SRP supports TPWR comments.	
Likes 0	
Dislikes 0	
Response	
Marc Sedor - Seminole Electric Cooperative, Inc. - 3	
Answer	No
Document Name	
Comment	
Should not include the additional functional entities as proposed in 4.1.4, 4.1.5 and 4.1.6. This is adding extra layers of coordination and processes that will be complex and difficult due to multiple DPs trying to coordinate in multiple TOs area .. This would be burdensome on the TOP as well.	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	
Tacoma Power requests additional clarity on the applicability section. For EOP-011-4 Requirements 1.2.5.5 and 1.2.5.6, does the SDT intend for TOPs to account for all distribution providers in their Operating Plans (even non-BES providers), or is it limited to registered Distribution Providers only? Additionally, is the TOP responsible for identifying critical natural gas infrastructure loads that are located on non-registered distribution provider networks? If this Standard is requiring TOPs to account for non-registered distribution providers, then there may be difficulty collecting this information, since these providers aren't subject to NERC jurisdiction.	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	

Answer	No
Document Name	
Comment	
Should not include the additional functional entities as proposed in 4.1.4, 4.1.5 and 4.1.6. This is adding extra layers of coordination and processes that will be complex and difficult due to multiple DPs trying to coordinate in multiple TOs area .. This would be burdensome on the TOP as well.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Regardless of DP, TO or UFLS-Only DP applicability, BPA believes those entities do not have the legal authority to require natural gas companies to identify and disclose information pertaining to their critical natural gas facilities (locations, etc.). Natural gas entities are not NERC Registered entities. BPA seeks clarity on how this information could be obtained if a natural gas entity refuses to provide its information.	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
While AEP does not object to the three entities which have been added as Functional Entities in 4.1.4 through 4.1.6, we believe natural gas owners and operators would need to be added as well. Please see our response to Question 4 regarding their omission.	
Likes 0	
Dislikes 0	
Response	

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

ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) in response to this question.

Additionally, ERCOT would like to highlight that assigning real-time operational tasks to TOs would require modifications to COM, IRO, and TOP Reliability Standards to ensure these entities have the communications infrastructure and compliance responsibilities necessary to reliably receive and execute real-time operating instructions. ERCOT continues to encourage the use of proper registration, Coordinated Functional Registration agreements, or Regional Standards to address scenarios in which one functional entity might be better suited to perform tasks typically carried out by a different functional entity. ERCOT discourages the creation of ambiguous obligations for a functional entity, such as a TO, to perform tasks typically reserved for a different functional entity, such as a TOP or a DP.

Likes 0	
Dislikes 0	
Response	

Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	

The SRC[1] thanks the SDT for adopting its recommendation made during Project 2021-07 Phase 1 (Draft #1). SRC agrees with the proposed additions to the applicability section, as these functional entities (i.e., Distribution Provider, UFLS-only Distribution Provider and Transmission Owners) have important roles to play in protecting critical natural gas infrastructure loads from load shed.

That said, the SRC is concerned with the use of the proposed language, “Operating Plan,” in the Applicability section and in Requirement R7, as it may be construed to assign UFLS-Only Distribution Providers and Transmission Owners real-time operational tasks that they are not equipped to handle. Therefore, SRC recommends the language “to mitigate operating Emergencies” in applicability sections 4.1.5 and 4.1.6 be revised to read “to assist with mitigating operating Emergencies,” and that the language in R7 be modified as indicated below. Other clarifications to Requirement R7 are also proposed in the SRC’s response to Question 9.

R7. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner identified in a Transmission Operator’s Operating Plan(s) to *assist with* mitigat*ing* operating Emergencies in its Transmission Operator Area shall, *in consultation with the Transmission Operator, develop, maintain, implement, and provide to the Transmission Operator an Operator-controlled manual, or automatic Load shedding program, that accounts for each of the following, as applicable:* [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]

[1] For purposes of these comments, the IRC SRC includes the following entities: CAISO (with the exception of our response to question 5), ERCOT (with the exception of our responses to questions 3, 5 and 8), IESO, ISO-NE, MISO, NYISO, PJM and SPP.

Likes 0	
Dislikes 0	

Response	
Tracy MacNicoll - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Recommend specifically identifying that the Operating Plans that make a TO/DP/DP-UFLS applicable are those referenced in R1. Curently written, this could be interpereted as any TO/DP/DP-UFLS that is part of a TOP Operating Plan to mitigate operating Emergencies is applicable to EOP-011-4. See applicability section of PRC-023 as an example.	
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	
This seems to be the correct entities to include in the applicability section The SDT should consider adding automatic to EOP-011 R7.1.2. As in R1.2.5.2, the sub-requirements only call for the minimization of overlap between MANUAL load shed circuits and designated critical loads. Adding automatic to R7.1.2 would emphasize the minimization of overlap for both manual and automatic load shed circuits, while not prohibiting the overlap where it may be necessary as stated in the technical rationale. Although the intent is there, the standard doesn't explicitly address that potential overlap. Recommend adding automatic to R7.1.2 The proposed R1.2.5.5 is specific to "critical gas infrastructure load". The SDT should consider that this be rewritten to be more generic to encompass all "designated critical loads" and not just for gas infrastructure? Does this make sense to specifically call it out in a separate requirement. The SDT should consider whether or not to include a new term in the NERC Glossary of "Designated Critical Load" which would define what the minimum standard critical loads are, including, but not limited to critical gas infrastructure, critical fuel delivery infrastructure, off-site nuclear feeds, public safety, public health, etc. A recommendation for language is provided in ISO-NE's response to Question 4.	
Likes 0	
Dislikes 0	

Response	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
In support of MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI agrees that TOs, DPs and UFLS-Only DPs are the correct Functional Entities.	
Likes 0	
Dislikes 0	
Response	

Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco on behalf of Constellation Segements 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 is in agreement that with the three additions to the functional entities.	
Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
There is a concern with the use of the proposed language, "Operating Plan," in Requirement R7 as it may denote real-time operational tasks to UFLS-Only Distribution Providers and Transmission Owners that they are not equipped to handle. IESO recommends that "Operating Plan" be replaced with "Load Shedding Procedures".	
Likes 0	
Dislikes 0	

Response	
Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
Answer	Yes
Document Name	
Comment	
BHP is not a BA.	
Likes 0	
Dislikes 0	

Response	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	Yes
Document Name	
Comment	
BHP is not a BA.	
Likes 0	
Dislikes 0	

Response	
Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
BHP is not a BA.	
Likes 0	
Dislikes 0	

Response

Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	
BHP is not a BA.	
Likes 0	
Dislikes 0	
Response	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
TO, DP, and DP-UFLS appear to be the correct Functional Entities, but RF recommends considering a requirement for the TOP to notify identified TO, DP, or DP-UFLS Functional Entities. This could be accomplished by revising R1 Part 1.2.5.6 to state "Provisions for the identification and notification of…" or by adding a separate requirement analogous to EOP-005-3 R2.	
Likes 0	
Dislikes 0	
Response	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
Some clarification may be beneficial in regards to whether this is the expectation for natural gas transmission and distribution facilities, or does this expectation also include natural gas production facilities (wells, processing plants, etc).	
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 believes that the language as written is overly broad as to the applicability of DPs. Therefore, Southern Company would suggest language changes in the Applicability section 4.1.4 to include only DPs with identified Critical Natural Gas Infrastructure loads as Applicable Functional Entities:

"4.1.4 Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area **as serving one or more Critical Natural Gas Infrastructure loads** "

Southern Company would also add the following language to clarify R7 to specify that the operating plans now required by the TOs and DPs are to achieve the goal of implementing portions of the TOPs requirements in R1.2.5 as stated in the EOP-011-4 Technical Rationale:

"Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner identified in a Transmission Operator's Operating Plan(s) **as implementing portions of its Requirements in R1.2.5** to mitigate operating Emergencies in its Transmission Operator Area shall develop, maintain and implement one or more Operating Plan(s). The Operating Plan(s) shall be provided to the Transmission Operator. The Operating Plan(s) shall include the following, as applicable:"

Alternately, R7 could be narrowed such that the DP does not need to develop and Operating Plan so long as the DP communicates to the TOP how the load is served and that no Critical Natural Gas Infrastructure loads are part of any load shed or Demand Response programs. Suggested modifications to R7 are as follows:

"Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner identified in a Transmission Operator's Operating Plan(s) **which serves one or more Critical Natural Gas Infrastructure loads shall communicate to the Transmission Operator how the load(s) is served and verify that the load(s) is not included in the Distribution Provider's manual or automatic load shed programs and that the load(s) is not in a Demand Response Program which would restrict operation during an Energy Emergency.**"

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 that the TOs, DPs and UFLS-Only DPs are the correct Functional Entities.

Likes 0	

Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon supports EEI's comments	
Likes 0	
Dislikes 0	
Response	
Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Yes, CEHE agrees that the TOs, DPs, and UFLS-Only DPs are the correct Functional Entities.	
Likes 0	
Dislikes 0	
Response	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	Yes
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

LaTroy Brumfield - American Transmission Company, LLC - 1

Answer	Yes
Document Name	

Comment

ATC agrees with the changes made by the SDT to the applicable entities as these are the entities that have the information the TOP or BA needs to develop appropriate plans. In addition, these are typically the entities with the direct relationships with the end-use customer natural gas infrastructure loads. It is also important to note that successfully complying with the standard requires cooperation from these end-use customers, who have no regulatory obligation to provide this information.

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

None.

Likes 0	
Dislikes 0	

Response

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6

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 Collaborators

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC

Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Lori Frisk - Allete - Minnesota Power, Inc. - 1	
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	
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	

Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
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	
Teresa Krabe - Lower Colorado River Authority - 5	
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	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, 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	

Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD	
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	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
Answer	
Document Name	
Comment	
PJM supports the IRC SRC comments.	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	

Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE agrees with the changes to the applicability section of EOP-011-4. Texas RE recommends that TP/PC also be included so planners will be made aware of critical natural gas infrastructure loads during planning analyses and understand which loads to drop in order to plan effectively (and not exacerbate an operational issue).

Likes 0	
Dislikes 0	

Response

3. Is the implementation timeframe for EOP-011-4 Requirement R7 reasonable given that it is applicable to Functional Entities who were not previously included in Applicability for EOP-011-3?

Dave Krueger - SERC Reliability Corporation - 10	
Answer	No
Document Name	
Comment	

On behalf of the SERC Generator Working Group (GWG)

We believe the intent is that those loads have been identified within 18 months is reasonable. However, if those critical loads need to be removed, that may not be possible, if, for example, a new feeder must be built. Request clarity that the intent is the former, not latter.

Likes 0	
Dislikes 0	
Response	

LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	

ATC does not agree that the implementation timeframe for EOP-011-4 Requirement 7 is reasonable. TOPs that are not vertically integrated utilities, like ATC, will need to rely on a number of Distribution Providers to provide information related to prioritization of designated critical natural gas infrastructure. As such, 18 months is not enough time to gather all of the information, modify load shed plans, and train system operators on the new plans. An implementation timeframe of 24 to 36 months would be more realistic.

Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

Eighteen months would not be sufficient for the new Functional Entities (4.1.4 through 4.1.6) to become compliant with their EOP-011 obligations. Additional time will be needed to develop accurate lists of critical gas infrastructure and install Distribution SCADA network equipment to allow load shed to take to place as per R7. AEP instead recommends an implementation period of 36 months.

To ensure the success of any implementation period used, AEP believes it would be beneficial if the RTOs provided natural gas providers a registration system that Functional Entities could use to comply with R7.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	No
Document Name	

Comment

FE supports EEI Comments which state:

EEI could support 18 months to identify critical natural gas infrastructure, however, 18 months is insufficient for TOs, DPs and UFLS Only DPs to either move those loads to other feeders or in many cases to entirely exclude those feeders from their load shedding programs and find other suitable offsetting loads in their place. Often this work requires both engineering and field crew support to fully accomplish. The effort will likely require 36 months to fully implement. For this reason, we suggest a phased approach that provides 18 months to identify the critical natural gas infrastructure and 18 additional months to make system and field changes.

Likes 0	
Dislikes 0	

Response

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

BPA disagrees with 18 months as a feasible timeframe to implement EOP-011-4. BPA believes these revisions would require identification of all critical natural gas facilities across BPA's very large transmission network footfrint, which spans the entire Pacific Northwest. BPA believes this could potentially require removal and/or installation of new UFLS relays at all substation locations surrounding that natural gas critiacal load. BPA believes the amount of work required to achieve this, including design and construction activities, could take up to 5+ years. BPA recommends a longer, phased in approach, similar to PRC-005 (PSMP) or PRC-002 (Equipment Monitoring).

Likes 0	
Dislikes 0	

Response

Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	No
Document Name	
Comment	
Request 36 months	
Likes 0	
Dislikes 0	
Response	

Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
No,CEHE could support the 18 month implementation timeframe; however, CEHE also supports the comments as submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	

Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon supports EEI's comments	
Likes 0	
Dislikes 0	
Response	

Kinte Whitehead - Exelon - 3	

Answer	No
Document Name	
Comment	
Exelon supports EEI comments.	
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	
As drafted, Southern Company agrees with EEI comments that 18 months is insufficient for DPs to document and implement a plan to identify, designate, and prioritize critical natural gas infrastructure loads. If the standard was narrowed as suggested in our comments for Question 2, for DPs to verify the exclusion of gas infrastructure loads from their manual and automatic load shed programs, Southern Company believes 18 months may be sufficient time.	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
This will be a very difficult implementation time frame for the Distribution Provider to meet. Suggest at least a 48month implementation.	
Likes 0	
Dislikes 0	
Response	
Lindsey Mannion - ReliabilityFirst - 10	

Answer	No
Document Name	
Comment	

RF recommends the implementation plan specify the timeframe allotted for a TO, DP, or DP-UFLS newly identified in a TOP Operating Plan to develop its own Operating Plan following notification by the TOP.

Likes 0	
Dislikes 0	
Response	

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	
Comment	

MRO NSRF is supportive of 18 months; MRO NSRF does not want to see the implementation period go beyond 18 months to ensure all impacted entities have updated load shed plans in place in time for the 2025-2026 Winter Season.

Additionally, MRO NSRF refers the Standard Drafting team to Recommendation 28 of *The February 2021 Cold Weather Outages in Texas and the South Central United States* report. The MRO NSRF encourages the standard drafting team to consider how the content of this recommendation can be taken into account. Recommendation 28 states that various entities "should jointly conduct a study to establish guidelines to assist natural gas infrastructure entities in identifying critical natural gas infrastructure loads…" Recommendation 28 also states that "This Recommendation is necessary to support Key Recommendation 1i, regarding the protection of critical natural gas infrastructure loads."

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 below:

There is not a separate implementation phase for a newly identified DP, DP-UPFL, and/or TO. As an example, if the standard goes into effect 1/1/2025 and the TOP now identifies a DP in its Operational Plan on 1/1/2025 (per proposed Requirement R1.2.5.6), the current language and Implementation

Plan seems to indicate that the DP must immediately have a plan implemented on the same day. Thus, we recommend a phased-in compliance approach for Requirement R7.

Furthermore, there is no provision in Requirement R7 for how long a newly identified DP, DP-UFLS, or TO has to develop their Operating Plan(s) in the future. In other words, if at some point in the future the TOP revises their Operating Plan(s) to now include a previously unidentified DP, the verbiage in R7 seems to indicate that the DP would be required to develop an Operating Plan on the same day. We recommend modifying the text of Requirement R7 as follows:

“R7. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner identified in a Transmission Operator’s Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area shall develop, maintain, and implement one or more Operating Plan(s) within six (6) calendar months of being notified by the Transmission Operator. The Operating Plan(s) shall be provided to the Transmission Operator. The Operating Plan(s) shall include the following, as applicable:”

Likes 0	
Dislikes 0	

Response

Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC

Answer	No
Document Name	

Comment

PNM supports EEI's suggested phased approach that provides 18 months to identify the critical natural gas infrastructure and 18 additional months to make system and field changes.

Likes 0	
Dislikes 0	

Response

Marcus Bortman - APS - Arizona Public Service Co. - 6

Answer	No
Document Name	

Comment

APS agrees with EEI and supports a phased approach that provides 18 months to identify the critical natural gas infrastructure and 18 additional months to make system and field changes. The 18-month time frame is sufficient to identify natural gas infrastructure. However, it is insufficient for TOs, DPs, and UFLS Only DPs to either move those loads to other feeders or to entirely exclude those feeders from their load shedding programs and find other suitable offsetting loads in their place. This work often requires both engineering and field crew support to fully accomplish and will likely require 36 months to fully implement.

Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.

Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, 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 the comments of the Edison Electric Institue (EEI) to question #3,	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI could support 18 months to identify critical natural gas infrastructure, however, 18 months is insufficient for TOs, DPs and UFLS Only DPs to either move those loads to other feeders or in many cases to entirely exclude those feeders from their load shedding programs and find other suitable offsetting loads in their place. Often this work requires both engineering and field crew support to fully accomplish. The effort will likely require 36 months to fully implement. For this reason, we suggest a phased approach that provides 18 months to identify the critical natural gas infrastructure and 18 additional months to make system and field changes.	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
In support of MRO NSRF comments.	

Likes 0	
Dislikes 0	

Response

Alain Mukama - Hydro One Networks, Inc. - 1,3

Answer	No
Document Name	

Comment

A phased in implementation time would be more reasonable, 25-50-75-100% on an annual basis starting after 12 months as larger Transmission Entities need a longer implementation period. Under R7 7.1.4 it is not clear what is meant by this sub-requirement and what the impact to implementation may be. It is not clear if this is implying some type of dynamic selection of load based on system conditions or something else so clarity on the intent of this would be helpful.

Likes 0	
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group

Answer	No
Document Name	

Comment

WEC Energy Group does not agree that the implementation timeframe for EOP-011-4 R7 is reasonable. The 18-month implementation timeframe is insufficient to identify all critical natural gas infrastructure and to modify all impacted operator-controlled or manual load shed plans. The 18 months would be sufficient for identification, and an additional 18 months would be necessary for development of new and/or the modification of existing load shed plans to ensure that they are adequately avoiding critical natural gas infrastructure while also meeting the reliability needs of the load shed process. It is also important to remember that this process is contingent on cooperation from natural gas customers, who have no regulatory obligation to provide this information. WEC Energy Group also holds that since natural gas customers must self-identify their critical natural gas infrastructure, the language in the standard should take this into account.

Likes 0	
Dislikes 0	

Response

Marc Sedor - Seminole Electric Cooperative, Inc. - 3

Answer	No
Document Name	

Comment	
Request 36 months	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Given our concerns with Draft 1, it's difficult to comment on the reasonableness of an 18 month implementation timeframe. Our sense is that a longer implementation period (perhaps 24 to 30 months) would be more reasonable for some entities given the expanded entity applicability and need to develop and implement a process for identifying "critical natural gas infrastructure loads".	
Likes 0	
Dislikes 0	
Response	
Lori Frisk - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Tracy MacNicoll - Utility Services, Inc. - 4	
Answer	No
Document Name	
Comment	

18 months for the identification of applicable circuits is appropriate, however the implementation of adding those circuits to a load shedding program requires an additional 12-18 months (especially for R7.1.5 critical natural gas infrastructure loads)

Likes 0	
Dislikes 0	

Response

Kristine Ward - Seminole Electric Cooperative, Inc. - 1

Answer	No
Document Name	

Comment

Request 36 months

Likes 0	
Dislikes 0	

Response

Ken Habgood - Seminole Electric Cooperative, Inc. - 4

Answer	No
Document Name	

Comment

Request 36 months

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

There is not a separate implementation phase for a newly identified DP, DP-UPFL, and/or TO. As an example, if the standard goes into effect 1/1/2025 and the TOP now identifies a DP in its Operational Plan on 1/1/2025 (per proposed Requirement R1.2.5.6), the current language and Implementation

Plan seems to indicate that the DP must immediately have a plan implemented on the same day. Thus, we recommend a phased-in compliance approach for Requirement R7.

Furthermore, there is no provision in Requirement R7 for how long a newly identified DP, DP-UFLS, or TO has to develop their Operating Plan(s) in the future. In other words, if at some point in the future the TOP revises their Operating Plan(s) to now include a previously unidentified DP, the verbiage in R7 seems to indicate that the DP would be required to develop an Operating Plan on the same day. We recommend modifying the text of Requirement R7 as follows:
"R7. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner identified in a Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area shall develop, maintain, and implement one or more Operating Plan(s) within six (6) calendar months of being notified by the Transmission Operator. The Operating Plan(s) shall be provided to the Transmission Operator. The Operating Plan(s) shall include the following, as applicable:"

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

ERCOT recommends a 24-month implementation timeframe to allow for the coordination, budget revisions, staffing changes, and systems upgrades that may be necessary to accomplish the new tasks.

Likes 0	
Dislikes 0	

Response

Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6

Answer	No
Document Name	

Comment

PacifiCorp is supportive of 18 months; PacifiCorp does not want to see the implementation period go beyond 18 months to ensure all impacted entities have updated load shed plans in place in time for the 2025-2026 Winter Season.

Additionally, PacifiCorp refers the Standard Drafting team to Recommendation 28 of *The February 2021 Cold Weather Outages in Texas and the South Central United States* report. PacifiCorp encourages the standard drafting team to consider how the content of this recommendation can be taken into account. Recommendation 28 states that various entities "should jointly conduct a study to establish guidelines to assist natural gas infrastructure entities in identifying critical natural gas infrastructure loads…" Recommendation 28 also states that "This Recommendation is necessary to support Key Recommendation 1i, regarding the protection of critical natural gas infrastructure loads."

Likes 0	
Dislikes 0	

Response

Scott McGough - Georgia System Operations Corporation - 3

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

None.

Likes 0	
Dislikes 0	

Response

Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF

Answer	Yes
Document Name	

Comment

Southern Indiana Gas & Electric Company (SIGE) agrees that the 18 month implementation timeframe is reasonable.

Likes 0	
Dislikes 0	

Response
Kimberly Turco - Constellation - 6

Answer	Yes
Document Name	

Comment
Constellation has no additional comments. Kimberly Turco on behalf of Constellation Segements 5 and 6

Likes 0	
Dislikes 0	

Response
Alison MacKellar - Constellation - 5

Answer	Yes
Document Name	

Comment
Constellation has no additional comments. Alison Mackellar on behalf of Constellation Segments 5 and 6

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	
An 18 month implementation timeframe may be appropriate assuming the NERC Standard is approved through FERC on the same general timetable as the Phase 1 Standards, FERC approval approx. Feb 2024, with effective date of October 1, 2025 which would be prior to the 2025 winter period. However, the SDT should consider that based on the current status of the SDT through Phase 2 with this version of EOP-011 already at the first ballot, a 12 month timeframe might be appropriate so that if FERC were to approve the Standard in 2023, there would be the possibility of the effective date being prior to the 2024 winter period, or at least near the start of the 2024 winter period. If Phase 2 Standards revisions were to be adopted before October 1, 2023, the effective date would aling with the expected Effective date of the Phase 1 EOP-011 and EOP-012 which could eliminate a potential risk of compliance with multiple versions of the same Standard. ISO-NE does not support any implementation timeframe that goes beyond the start of the 2025-2026 Winter.	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	
The SRC[1] supports an implementation timeframe of 18 months to ensure Requirement R7 is effective in time for the 2025-2026 winter season [1] For purposes of these comments, the IRC SRC includes the following entities: CAISO (with the exception of our response to question 5), ERCOT (with the exception of our responses to questions 3, 5 and 8), IESO, ISO-NE, MISO, NYISO, PJM and SPP.	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
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	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
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	
Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
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	
Joshua London - Eversource Energy - 1, Group Name Eversource	
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, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD	

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	

Teresa Krabe - Lower Colorado River Authority - 5

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	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
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	

Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	
Document Name	

Comment

See comments submitted by the Edison Electric Institute

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10

Answer	
Document Name	

Comment

WECC has no comment on the implementation timeline, and leaves it to the entities that have to implement the requirements to provide feedback.

Likes 0	
Dislikes 0	

Response

Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis

Answer	
Document Name	

Comment

PJM supports the IRC SRC comments.

Likes 0	
Dislikes 0	

Response	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	

4. Do the changes in EOP-011 provide sufficient clarity and flexibility in regards to the treatment of critical natural gas infrastructure in operator-controlled manual Load shedding and automatic load shedding?

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	No
Document Name	
Comment	

EOP-011-4, R2.2.8 states “Provisions for excluding critical natural gas infrastructure loads as Interruptible Load, curtailable Load, and demand response during periods when it would adversely impact the reliable operation of the BES”. So if it is “critical,” which is not a defined term, it must be excluded from any manual /automatic load shed. This seems to remove flexibility. The flexibility will only show up if it is not classified as “critical” which defeats the purpose of this revision.

Likes 0	
Dislikes 0	
Response	

Scott McGough - Georgia System Operations Corporation - 3	
Answer	No
Document Name	
Comment	

R1: GSOC agrees with the SDT’s recommendation to protect critical natural gas infrastructure loads from automatic Load shedding. However, GSOC has concerns introducing automatic Load shedding requirements within EOP-011-4 under requirements R1.2.5 thereby indicating that it would be applicable to the TOP when the TOP is not responsible for automatic Load shedding schemes. Automatic Load shedding design requirements and corresponding applicable entities are addressed in their respective NERC Reliability Standards PRC-006-5 and PRC-010-2 which includes PC, TP, TO, DP, UVLS entities, and UFLS-Only DP. Alternatively, rather than introducing any automatic Load shedding requirements within EOP-011-4, R1.2.5, GSOC recommends revisions to PRC-006 and PRC-010, accordingly, to introduce new design requirements for “identification and prioritization of designtated critical natural gas infrastructure loads”. In doing so, the appropriate subject matter experts responsible for these schemes and requirements would become more aware of this issue and address this concern accordingly. As long as R7 still contains requirements for addressing automatic Load shedding by the responsible entities, the TOP can still identify the appropriate entities required to mitigate operating Emergencies in its Transmission Operator Area under R1.2.5.6 without introducing automatic Load shedding within R1.2.5.

R7: The Extreme Cold Weather Preparedness Technical Rationale and Justification for EOP-011-4 document indicates “automatic Load shedding” was introduced to align with sub-requirement “*Provisions for the identification and prioritization of designated critical natural gas infrastructure loads*” to be applicable to automatic Load shedding. For clarity, GSOC recommends separating “Operator-controlled manual Load shedding” from “automatic Load shedding” requirements such that R7.1 only addresses “Operator-controlled manual Load shedding”. In addition, requirements 7.1.1 through 7.1.5 and a new R7.2 would only address “automatic Load shedding” (thereby requiring the removal “or automatic” from 7.1. The new R7.2 could read as: “*R7.2 Automatic Load shedding during an Emergency that accounts for provisions for the identification and prioritization of designated critical natural gas infrastructure loads.*”

Likes 0	

Dislikes 0	

Response

Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6

Answer	No
Document Name	

Comment

PacifiCorp acknowledges that the proposed language offers sufficient flexibility; however, it lacks clarity. As highlighted in our response to Question #1, we request that the term "critical natural gas infrastructure" be defined.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) in response to this question.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Requirement R1.2.5.6 requires the Transmission Operator to include “provisions for the identification of Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners required to mitigate operating Emergencies in its Transmission Operator Area” and Requirement R7 requires the affected entities to develop, maintain, and implement an Operating Plan; however, there is no requirement for the TOP to notify the affected entities. How then will the entities identified in the TOP’s Operating Plan(s) know that Requirement R7 is now applicable to them? Therefore, we recommend including a requirement for the TOP to notify the affected entities. We propose adding Requirement 1.2.5.7 utilizing the following text.

“R1.2.5.7. The TOP shall notify the entities identified pursuant to the application of 1.2.5.6 within 30 days of the latest approved revision date or by the effective date of the Operating Plan; whichever is later."

Lastly, we recommend that the identification of designated critical natural gas infrastructure loads should be performed at a single operating level, specifically by the TOP. Thus, we recommend the removal of Requirement R7.1.5.

Likes 0	
Dislikes 0	

Response

Bobbi Welch - Midcontinent ISO, Inc. - 2

Answer	No
Document Name	

Comment

As described in SRC's response to Question 1, the SRC believes the proposed language provides flexibility, but not clarity.

Likes 0	
Dislikes 0	

Response

Lori Frisk - Allete - Minnesota Power, Inc. - 1

Answer	No
Document Name	

Comment

Minnesota Power supports MRO's NERC Standards Review Forum (NSRF) comments.

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

We don't believe the Draft 1 standard provides sufficient clarity in regards to the treatment of critical natural gas infrastructure with respect to operator-controlled manual Load shedding and automatic load shedding. See responses to Questions 1-2.

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	
WAPA acknowledges that the proposed language offers sufficient flexibility; however, it lacks clarity. As highlighted in our response to Question #1, we request that the term "critical natural gas infrastructure" be defined.	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	No
Document Name	
Comment	
SRP supports TPWR comments. In addtion, on Question 1, it feels like there is a word missing in the 1h recommendation. Also, what is that is being prohibited in the BA's operating plan? Lastly, how is "critical natural gas infrastructure" defined and what does "demand response of critical natural gas infrstructure load" mean? Or how is "demand response" interpreted here?	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	No
Document Name	
Comment	

IID recommends that the SDT develop a definition or guidance for what is considered critical natural gas infrastructure loads in either the Technical Rationale or other Implementation Guidance specific to EOP-011. Furthermore, IID recommends registration of natural gas infrastructure owners and operators.

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 SDT should consider that the current and proposed language of EOP-011 does not require an entity to minimize the overlap between critical gas infrastructure loads or a designated critical load and automatic load shed circuits. Although the intent is there with the addition of "automatic" in R1.2.5, the standard doesn't explicitly address the potential overlap of critical loads on automatic load shed circuits as it does for manual load shed circuits. Recommend adding automatic to R1.2.5.2. to close that loop.

Recommended change:

1.2.5.2. Provisions to minimize the overlap of circuits that are designated for manual and **automatic** load shed and circuits that serve designated critical loads, **including designated critical gas infrastructure loads**

The proposed R1.2.5.5 is specific to "critical gas infrastructure load". The SDT should consider that this be be removed is the above proposal is used or be rewritten to be more generic to encompass all "designated critical loads" and not just for gas infrastructure? Does it make sense to specifically call out one specific critical load and not others in a separate requirement.

The SDT should consider whether or not to include a new term(s) in the NERC Glossary of "Designated Critical Load" and/or "Critical Natural Gas Infrastructure" which would define what the minimum standard critical loads are, including, but not limited to critical gas infrastructure, critical fuel delivery infrastructure, off-site nuclear station service, public safety, public health, etc

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

The proposed changes in EOP-011 do not provide sufficient clarity. Tacoma Power understands that the SDT does not want to limit or prescribe a single identification method to entities. However, not providing any examples in the Technical Rationale results in lack of clarity, and leaves the definition for the critical natural gas infrastructure loads to each entity. The application of this definition will be inconsistent between entities and auditors. For example, some entities may miss identifying a critical load simply because the entity has a different threshold or definition of what is considered "critical." Tacoma Power recommends that the SDT develop a definition or guidance for what is considered critical natural gas infrastructure loads in either the Technical Rationale or other Implementation Guidance specific to EOP-011.

Tacoma Power recognizes that the Reliability Guideline, "Natural Gas and Electrical Operational Coordination Considerations," includes guidance on identification of critical natural gas system components and dual-fuel supplier components that could assist with R1.2.5.5. However, Tacoma Power is concerned about the application of this guideline in the absence of a clear definition of what is considered a critical natural gas infrastructure load. Below is a summary of how application of this guideline and lack of a definition can result in confusion or inconsistency.

The Requirement R1.2.5.5 is not clear if critical natural gas infrastructure is focused solely on electric generation load, or if as specified in Chapter 2 of the Reliability Guideline, that non-electric generation load is also considered a "critical" natural gas load. For example, would a natural gas meter at a hospital be considered "critical"? Or is the scope of R1.2.5.5 limited only to major or bulk transmission of natural gas and pipelines that supply natural gas power plants?

Additionally, R1.2.5.5 and the Reliability Guideline is not clear on the responsibilities of a BA or TOP that does not have natural gas generation in their footprint or service territory. For example, if a TOP has a substation that powers a natural gas pipeline which eventually serves a natural gas power plant physically located in the TOP footprint, but the plant is not connected to the TOP's/TO's system nor is the plant within their BA's BAA. This situation exists within Tacoma Power's footprint and as written, the compliance obligations for meeting R1.2.5.5 are not clear.

Lastly, the Reliability Guideline proposes that electric transmission and distribution owners reach out to regulatory entities, natural gas companies and organizations, and secondary fuel suppliers. Reaching out to this many organizations and agencies, as well as receiving their responses, may be unattainable in the proposed implementation timeline and will be difficult to maintain the coordination. As capured by the MRO NSRF comments, these organizations are not subject to NERC Standards and as a result, may not respond or prioritize coordination with TOPs. Tacoma Power recommends utilizing a note similar to CIP-013 R2 to address this concern. This note should specify compliance with R1.2.5.5 does not include the natural gas companies' or fuel suppliers' performance and adherence to the TOP requests.

Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group

Answer	No
Document Name	

Comment

WEC Energy Group acknowledges that the proposed language offers sufficient flexibility; however, it lacks clarity. As highlighted in our response to Question #1, we request that the term "critical natural gas infrastructure load" be defined.

Likes 0	
Dislikes 0	

Response

Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
In support of MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, 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 the comments of the Edison Electric Institue (EEI) to question #4,	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	
APS believes that clarification is needed because responsible entities do not have the visibility to identify such loads, so they are reliant on natural gas facilities owners, however, natural gas facility owners have no regulatory obligation to self-identify their facilities as critical. To address this concern, APS suggests modifications to Requirement 1, subpart 1.2.5.5 and Requirement R7, subpart 7.1.5 as follows: Requirement 1, subpart 1.2.5.5: Provisions for the identification and prioritization of designated critical natural gas infrastructure loads**, as identified by the responsible natural gas infrastructure owner/operator**; and	

Requirement R7, subpart 7.1.5: Provisions for the identification and prioritization of designated critical natural gas infrastructure loads**, as identified by the responsible natural gas infrastructure owner/operator**.	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	No
Document Name	
Comment	
Please refer back to WECC's comments on question 1. WECC believes the is enough flexibility, but not enough clarity.	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD	
Answer	No
Document Name	
Comment	
The changes in EOP-011 do not provide sufficient clarity because the term “critical natural gas infrastructure” is not defined. The SDT should create this definition so that it is clear to entities how to identify these types of loads.	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	

Comment	
AEPC has signed on to ACES comments below: Requirement R1.2.5.6 requires the Transmission Operator to include “provisions for the identification of Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners required to mitigate operating Emergencies in its Transmission Operator Area” and Requirement R7 requires the affected entities to develop, maintain, and implement an Operating Plan; however, there is no requirement for the TOP to notify the affected entities. How then will the entities identified in the TOP’s Operating Plan(s) know that Requirement R7 is now applicable to them? Therefore, we recommend including a requirement for the TOP to notify the affected entities. We propose adding Requirement 1.2.5.7 utilizing the following text. “R1.2.5.7. The TOP shall notify the entities identified pursuant to the application of 1.2.5.6 within 30 days of the latest approved revision date or by the effective date of the Operating Plan; whichever is later. Lastly, we recommend that the identification of designated critical natural gas infrastructure loads should be performed at a single operating level, specifically by the TOP. Thus, we recommend the removal of Requirement R7.1.5.	
Likes 0	
Dislikes 0	
Response	

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
MRO NSRF acknowledges that the proposed language offers sufficient flexibility; however, it lacks clarity. As highlighted in our response to Question #1, we request that the term "critical natural gas infrastructure load" be defined.	
Likes 0	
Dislikes 0	
Response	

Lindsey Mannion - ReliabilityFirst - 10	
Answer	No
Document Name	
Comment	
Reference comment on question 1. Additionally, while EOP-011 does address the overlap between circuits designated for operator-controlled manual or automatic Load shedding and those used for UFLS/UVLS, RF recommends requirements to prioritize certain circuits for the implementation of UFLS and/or UVLS fall under PRC-006 and PRC-010. It is not clear in the current draft of EOP-011 that the “provisions for the identification and prioritization of designated critical natural gas infrastructure loads” also apply to UFLS and UVLS programs.	

Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Again, the changes do not identify how or who will be responsible for determining and identifying the critical natural gas infrastructure.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Please see BPA's response to Q1 and Q3 above.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
Coordination between the Electric industry and the Gas Industry in terms of communication and operational obligations must be sufficient to fully apply the intent of EOP-011-4. Until clear guidance of communication and the coordination can be provided – either through standard modification or assigned entity responsibility – FirstEnergy cannot support the proposed treatment of critical natural gas infrastructure in manual Load shedding and	

automatic load shedding.	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
The changes do not provide sufficient clarity of what constitutes critical natural gas infrastructure. ATC requests that the term “critical natural gas infrastructure” be defined. Additionally, ATC requests that the definition, at a minimum, state “critical natural gas infrastructure” is natural gas infrastructure that if rendered unavailable would adversely impact the reliable operation of the Bulk Electric System. *With the addition of “automatic” to R1.2.5, the standard unintentionally conflicts with the new NERC paradigm that recognizes the role of the Planning Coordinator (PC) in the design and implementation of UFLS under PRC-006 and the PC and the Transmission Planning in the design and implantation of UVLS under PRC-010. Years ago, the load shedding requirements for the operating horizon listed both manual and automatic load shedding. However, automatic load shedding was removed due to recognition that the TOP and/or the BA do not design or implement automatic load shedding schemes. With the reintroduction of the term “automatic”, this standard will now require the TOP and/or BA to be directly involved in the design and deployment of automatic load shedding schemes developed by these other entities. If the intention of the SDT is to capture automated schemes developed with a TOP or BA EMS to aid the manual load shedding process, additional language is needed to ensure the appropriate scope is understood by all parties either auditing this standard or seeking to be compliant under this standard.*	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	Yes
Document Name	
Comment	
We would like to see a requirement for the RC to identify the overlap requirements for MLS and UFLS.	
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 changes to EOP-011 provide sufficient clarity and flexibility in regard to the treatment of critical natural gas infrastructure in operator-controlled manual Load shedding and automatic load shedding.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco on behalf of Constellation Segements 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 agrees that there is sufficient clarity and flexibility for critical natural gas loads in regards to load shedding.	
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 would suggest language changes that would require coordination between natural gas facility owners and the responsible functional entities to identify Critical Natural Gas Infrastructure loads. Southern Company would modify requirement R7, subpart 7.1.5 to the following:

"7.1.5 Provisions for the identification and prioritization of designated critical natural gas infrastructure loads, as identified by the responsible natural gas infrastructure owner/operator in coordination with the applicable Functional Entity.

TOP-002-5 (Questions 5-6)

Recommendation 1g of the Report states: 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)**

As explained by the Report on the 2021 event, Key Recommendation 1g was intended to "take the next logical step [after TOP-003-5 and

EOP-011-2 changes take effect in April 2023] and eliminate doubt about which entity is responsible to provide information or act on information," preventing BAs and RCs from being surprised during extreme cold weather events (See Report at pp 189-190). The SDT would like feedback on the first bulleted subpart of Key Recommendation 1g, which, in essence, recommends a requirement that the GOs/GOPs provide the BA with the generating units MWs, including MWh the GO/GOP reasonably believes that it can rely upon during the local forecasted cold weather.

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 that the proposed language in R1.2.5.5 and R7.1.5 provides sufficient clarity and flexibility in regards to the treatment of critical natural gas infrastructure in operator-controlled manual Load shedding and automatic load shedding.

Likes 0	
Dislikes 0	

Response

Kinte Whitehead - Exelon - 3

Answer	Yes
Document Name	

Comment

Exelon supports EEI comments.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	Yes
Document Name	

Comment

Exelon supports EEI's comments	
Likes 0	
Dislikes 0	
Response	
Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Yes, CEHE agrees that the proposed changes to EOP-011 provide sufficient clarity and flexibility in regard to the treatment of critical natural gas infrastructure in operator-controlled manual Load shedding and automatic load shedding.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
AEP agrees that clarity and flexibility have been added to EOP-011, however we still believe registration of natural gas infrastructure owner and operators themselves, with the RTOs in an official capacity, would add more clarity and improve overall system reliability associated with natural gas service to generating facilities. Because the proposed revisions do not include natural gas owners and operators as new Functional Entities, AEP has chosen to vote Negative on EOP-011-4. The word “critical”, as used in lower case to qualify both loads and natural gas infrastructure loads, is subjective and subject to interpretation. This will likely result in an inconsistent application of the term across entities. AEP suggests that clarity be provided as to how to properly identify loads, including natural gas infrastructure loads, as “critical.” Similar to our response to Question #3, we believe it would beneficial to have a criteria of critical levels similar to that used by Transmission Planning to illustrate the different risk levels. Potential examples might include 1) generation on-site backup, 2) critical to generation supply for loss of one site 3) becomes critical if electrical supply were lost at two sites in area (indicates a combination), and 4) critical to generation supply for loss of three sites and so forth. The criteria used could also capture risk to one RTO area as opposed to affecting multiple RTO regions via the interstate pipeline system. We believe it would be beneficial for NERC to work directly with FERC and gas suppliers to develop this set of criteria to assist in properly identifying risk. AEP believes clarity is needed regarding scenarios when the Distribution Provider and the Transmission Operator are not within the same company. For those situations, it is unclear how self-identification would occur and what their obligations might be.	

Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
Answer	Yes
Document Name	
Comment	
Yes. The changes in EOP-011 and the supporting technical rationale provide sufficient clarify and flexibility.	
Likes 0	
Dislikes 0	
Response	
Ken Habgood - Seminole Electric Cooperative, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tracy MacNicoll - Utility Services, Inc. - 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

David Jendras Sr - Ameren - Ameren Services - 3

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Marc Sedor - Seminole Electric Cooperative, Inc. - 3

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

Teresa Krabe - Lower Colorado River Authority - 5	
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	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt

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

Claudine Bates - Black Hills Corporation - 6

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
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	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Carl Pineault - Hydro-Qu?bec Production - 5

Answer	
Document Name	

Comment

No comments

Likes 0	
Dislikes 0	

Response

Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis

Answer	
Document Name	

Comment

PJM supports the IRC SRC comments.

Likes 0	
Dislikes 0	

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	
Document Name	

Comment

See comments submitted by the Edison Electric Institute

Likes 0	
Dislikes 0	

Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE recommends the requirement apply to any manual or automatic load shed programs. The term “Interruptible Load” references the inactive LSE function. The other terms, curtailable Load and demand response, are not defined.	
Likes 0	
Dislikes 0	
Response	

See the unofficial comment form for additional information: https://www.nerc.com/pa/Stand/Project202107ExtremeColdWeatherDL/2021-07_Cold_Weather_Phase%202_Unofficial_Comment_Form_02282023.docx

5. Please comment on whether information pertaining to the generating unit's MWs, including MWhs the GO/GOP reasonably believes that the BA can rely upon during local forecasted cold weather, would be useful to your operations during local forecasted cold weather. Alternatively, is there a better way for the BA to develop assumptions related to cold weather needs to address this specific metric rather than asking for this information from the GO/GOPs? Please provide comments and revisions to the draft language.

Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
No, CEHE supports the comments as submitted by Edison Electric Institute and agrees the GO/GOP would be the best source for the reliable projections.	
Likes 0	
Dislikes 0	
Response	

Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon supports EEI's comments	
Likes 0	
Dislikes 0	
Response	

Kinte Whitehead - Exelon - 3	
Answer	No
Document Name	
Comment	
Exelon supports EEI comments.	

Likes 0	
Dislikes 0	
Response	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	No
Document Name	
Comment	
Southern Indiana Gas & Electric Company (SIGE) supports Edison Electric Institute's comment and agrees the GO/GOP would be the best source for the most reliable projections.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Southern Company agrees with EEI comments that The GO/GOP would be the source for the most reliable projections. Southern Company would add that providing the MWhs is not helpful. The anticipated schedule for the 5-day period would be more useful, along with additional MWhs available above the projected schedule, only if availability limitations exist.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
BHP as TOP, amount of MWh is not useful for BHP as a TOP. More interested in if a unit is or is not available which we would have through new cold weather standards with TOP-003-5.	

Likes 0	
Dislikes 0	

Response

Micah Runner - Black Hills Corporation - 1

Answer	No
Document Name	

Comment

BHP as TOP, amount of MWh is not useful for BHP as a TOP. More interested in if a unit is or is not available which we would have through new cold weather standards with TOP-003-5.

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt

Answer	No
Document Name	

Comment

BHP as TOP, amount of MWh is not useful for BHP as a TOP. More interested in if a unit is or is not available which we would have through new cold weather standards with TOP-003-5.

Likes 0	
Dislikes 0	

Response

Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller

Answer	No
Document Name	

Comment

BHP as TOP, amount of MWh is not useful for BHP as a TOP. More interested in if a unit is or is not available which we would have through new cold weather standards with TOP-003-5.

Likes 0	
Dislikes 0	

Response

Gerry Adamski - Cogentrix Energy Power Management, LLC - 5

Answer	No
Document Name	

Comment

The requested generator data is only as good as the availability of the natural gas supply. More needs to be done to ensure supply meets and or exceeds demand and or increase generation of other available resources to make the industry and generation reliable.

In addition, BAs, particularly in organized markets, need greater certainty from the GOs as to the need for their resources during projected periods of extreme cold weather. In this regard, market operators need to be held accountable for a greater level of precision in load forecasting so that gas supply can be procured in advance more thoughtfully and not as a result of wildly inaccurate estimates. Where is the added accountability on the market operators for improving its processes? A significant amount of the 'emergency' in December 2022 could have been averted by better load forecasting and generation scheduling practices at the ISO/RTO level.

Likes 0	
Dislikes 0	

Response

Marcus Bortman - APS - Arizona Public Service Co. - 6

Answer	No
Document Name	

Comment

APS believes that information pertaining to the generating unit's MWs the GO/GOP reasonably believes that the BA can rely upon during local forecasted cold weather would be useful to our operations during local forecasted cold weather. APS does not believe that information pertaining to the generating unit's MWhs the GO/GOP reasonably believes that the BA can rely upon during local forecasted cold weather would be useful to our operations during local forecasted cold weather. APS agrees that the GO/GOP would be the source for the most reliable projections.

Likes 0	
Dislikes 0	

Response

Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, 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	
The GO/GOP would be the source for the most reliable projections.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
The GO/GOP would be the source for the most reliable projections.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren perfers not to make assumptions on the performance of generators during cold weather events. We believe that MISO may be better suited to provide this information.	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	No
Document Name	
Comment	

Capability of generating units is necessary for BAs to develop Operating Plans, regardless of weather conditions. It is the responsibility of the GO/GOP to understand and communicate this information to the BA. The GO/GOP would be the source for the most reliable projections	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
This information is already required to be provided with the update to TOP-003-5.	
Likes 0	
Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
Capability of generating units is necessary for BAs to develop Operating Plans, regardless of weather conditions. It is the sole responsibility of the GO/GOP to understand and communicate this information to the BA.	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
The proposed approach is unlikely to result in useful information. While owners and operators of some simpler facilities with hard cutoff protection, such	

as wind turbines, may be able to forecast cold weather performance with some degree of certainty, more complex facilities, such as thermal generation facilities, have many, many variables that impact cold weather performance and make it difficult for owners and operators to accurately forecast cold weather performance.

Older units may have had several retrofits that make a design limit highly inaccurate. A thorough, recently conducted engineering analysis can provide more accuracy than original design limits; however, even these types of analyses will lose accuracy over time as generating units suffer degradation and are retrofitted. Even recent historical performance will become less dependable over time and is inherently limited to temperatures actually observed. Historical performance data also may not capture the impact of maintenance or upgrades undertaken to address previous performance failures.

In addition to the limitations of performance limit calculations, there are also inherent inaccuracies in the temperature forecasts used to attempt to determine the limits that may apply during an upcoming event, as these forecasts may be based on information from weather stations many miles away from a given generating facility. Fuel supply and inventory information also depend on natural gas suppliers providing timely and accurate notifications to GOs and GOPs. RCs and BAs ultimately depend on information that other entities provide to them and will continue to encounter scenarios where unit performance does not conform to provided limits and where units suddenly identify fuel constraints as an event unfolds because their fuel provider did not provide sufficient advance notice of fuel supply constraints.

Given these inherent inaccuracies and uncertainties in availability forecasts, a forecast from a GO or GOP that a unit is going to be fully or partially unavailable would only be useful to a BA if the unavailability is certain; forecasts based on potential risks or potential unavailability are not typically useful to BAs. Generating units preemptively coming offline because of anticipated cold weather is counterproductive unless there is a need to protect equipment. All of this taken together means that information pertaining to a generating unit's MWs, including MWhs, the GO/GOP reasonably believes that the BA can rely upon during local forecasted cold weather would not be useful to the operations of ERCOT during local forecasted cold weather.

A more effective approach would be to require GO/GOPs to provide BAs with data about specific constraints that might limit the capabilities of their units, such as known fuel and emissions constraints, and allow each BA the leeway to develop its own approach and assumptions related to cold weather needs based on its past experiences and the unique characteristics of its Balancing Authority Area.

Likes 0	
Dislikes 0	

Response

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1

Answer	No
Document Name	

Comment

It does not seem practical for plants to guess at what they expect they can do during cold weather. They already have to plan to fully perform during expected cold weather based on past history. Why would anyone expect, or rely on, anything other than 100% performance. That is what we design the system to (Ten Year Site plans, long term forecasts, etc.).

The standard appears to only penalize an entity if they have another Winter Storm Uri, which we of course do not want it to happen again. It seems unnecessary to double the size of all our generators and transmission lines so we can operate to the unforeseen failure of so many things all at once. We are making progress, but this standard has many ways to meet an entities needs and very few ways to succeed short of another Uri and not having any issues.

Likes 0	
Dislikes 0	

Response

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1

Answer	No
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 Collaborators

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Julie Hall - Entergy - 6, Group Name Entergy

Answer	Yes
Document Name	

Comment

MISO is Entergy's Balancing Authority.

Likes 0	

Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

None.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	Yes
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Melanie Wong - Seminole Electric Cooperative, Inc. - 5

Answer	Yes
Document Name	

Comment

Capability of generating units is necessary for BAs to develop Operating Plans, regardless of weather conditions. It is the sole responsibility of the GO/GOP to understand and communicate this information to the BA.

Likes 0	
Dislikes 0	

Response

Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
The expected generation is important for performing an accurate Operational Planning Analysis, OPA. BA's determine generation resource commitment based on generation limitation derates and outages in the outage management system, per TOP-003 and IRO-010. Due to the recent additions in TOP-003 and IRO-010 to specifically identify cold weather limitations of generators this is already integrated into OPAs and real-time assessments.	
Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
SDT may want to consider that it may be useful to areas where wholesale electricity markets are not operating, to propose a requirement to have the GO/GOP to provide its BA with a reasonable forecast pertaining to its generating unit(s)' forecasted MW/MWh output during local forecasted cold weather so the BA can use this information when developing its five-day hourly forecast for their BA footprint.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	
PNM's assessment is that MW forcasting from generators should come from the GO/GOP. PNM supports EEI comments that the GO/GOP would be the source for the most reliable projections.	
Likes 0	
Dislikes 0	

Response	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco on behalf of Constellation Segements 5 and 6	
Likes 0	
Dislikes 0	

Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
In support of MRO NSRF comments.	
Likes 0	
Dislikes 0	

Response	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	

Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group

Answer	Yes
Document Name	

Comment

The BA already has the tools and the authority necessary to plan for generating unit MWH. There is no need for another process, except to define “critical natural gas infrastructure load” and add it to the plan.

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

We believe this data would be beneficial and should be supplied by the GO/GOP to the BA.

Likes 0	
Dislikes 0	

Response

Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen

Answer	Yes
Document Name	

Comment

No Additional Comments

Likes 0	
Dislikes 0	

Response

Marc Sedor - Seminole Electric Cooperative, Inc. - 3	
Answer	Yes
Document Name	
Comment	
Capability of generating units is necessary for BAs to develop Operating Plans, regardless of weather conditions. It is the sole responsibility of the GO/GOP to understand and communicate this information to the BA.	
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	
WAPA believes it would be useful to BA operations to have the GO/GOP, in accordance with the BA's documented methodology, provide a reasonable five-day hourly forecast of MW or MWh output for each generating unit during local forecasted cold weather so the BA can incorporate this information into the five-day hourly forecast for their BA footprint. WAPA believes what is critical to making this work is a framework similar to that for load forecasting. GOs/GOPs should not be penalized for failure to predict their energy output with complete accuracy. There should be some recognition that new factors can emerge or existing factors (including the weather forecast) change in real-time, thereby altering the energy output forecast. WAPA recommends the GO/GOPs provide their BA with a reasonable forecast to work with. WAPA supports a framework that would ask GO/GOPs to provide their forecasted energy output information to the BA as: 1. GO/GOPs are in the best position to provide an educated forecast for their units' performance. Not ony does the GO/GOP have superior past performance data (over that of the BA) to perform this analysis, they also have superior knowledge of how their unit will likely perform under projected conditions 2. BAs receiving a more accurate output forecast would be in an improved position to increase the accuracy of their dispatch and unit commitment. Without this information, the BA must employ manual methods (e.g. phone calls) to gather this information anecdotally.	
Likes 0	
Dislikes 0	
Response	
Devon Tremont - Taunton Municipal Lighting Plant - 1	

Answer	Yes
Document Name	

Comment

Response to the question regarding MW/MWh data being useful to operations: This question will receive varied responses depending on the functional registrations of the respondent, but as a GO/GOP/TO/DP, this information would be useful to us as we will use this information as an indication of potential Emergency situations, assuming that we will be receiving notice prior to cold weather event rather than just prior to the season. As a GO/GOP in ISO-NE territory, we would consider self-scheduling some or all of our thermal resource's capability to mitigate the impact of a potential pay-for-performance (ISO-NE market construct that is triggered when reserve deficient) event. As a DP, this will allow us to better prepare for manual load shedding, such as calling in additional staff to prepare for rotation and restoration of outages

Likes 0	
Dislikes 0	

Response

Bobbi Welch - Midcontinent ISO, Inc. - 2

Answer	Yes
Document Name	

Comment

The SRC[1] believes it would be useful for GO/GOPs to provide their BAs with a reasonable forecast of their generating unit(s)' MW/MWh output during local forecasted cold weather so the BA can use this information when developing its five-day hourly forecast for its BA footprint.

In the absence of a generator output forecast, the Balancing Authority might attempt to create its own forecast using the information it has available, such as historical generator performance; however, this would only represent a BA's best guess, which would still be less informed and less accurate than a forecast created by a GO/GOP for its own unit(s).

The SRC proposes that the GO/GOP would provide the BA with an hourly forecast of their expected energy output for the following reasons:

1. **GO/GOPs are in the best position to prepare an educated forecast for their generating units' output.** The GO/GOP will have more detailed past performance data than the BA will have, along with superior knowledge of how their unit will likely perform under expected weather conditions. The GO/GOP will also have more intimate knowledge of their fuel supply and inventory, start-up concerns, environmental limitations, and other factors listed in Part 8.2.

2. **A BA that receives a more accurate output forecast will be in an improved position to increase the accuracy and strategy of its unit commitment and dispatch.** With the information from the GO/GOP described above, the BA will be in an improved position to determine when to deploy the generating units in its footprint. In addition, it will minimize the burden on the BA to employ manual methods, such as phone calls, to gather this information anecdotally.

In order for this approach to function properly, it is critical that this requirement be established under a framework like that used for load forecasting. Specifically, GO/GOPs should not be penalized for failure to predict their energy output with complete accuracy. There should be some recognition that new factors will emerge and existing factors, such as the weather forecast, will change in real-time, thereby causing the actual energy output realized to diverge from the forecasted output

[1] For purposes of these comments, the IRC SRC includes the following entities: CAISO (with the exception of our response to question 5), ERCOT (with the exception of our responses to questions 3, 5 and 8), IESO, ISO-NE, MISO, NYISO, PJM and SPP.

Likes 0	
Dislikes 0	

Response

Ken Habgood - Seminole Electric Cooperative, Inc. - 4

Answer	Yes
Document Name	

Comment

Capability of generating units is necessary for BAs to develop Operating Plans, regardless of weather conditions. It is the sole responsibility of the GO/GOP to understand and communicate this information to the BA.

Likes 0	
Dislikes 0	

Response

Dave Krueger - SERC Reliability Corporation - 10

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

Likes 0	

Dislikes 0	

Response

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD

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

Teresa Krabe - Lower Colorado River Authority - 5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
Answer	
Document Name	
Comment	
Abstain	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
NA	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	

Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	
Document Name	
Comment	
No comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
Answer	
Document Name	
Comment	
PJM supports the IRC SRC comments.	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	
Document Name	
Comment	

No comments

Likes 0	
Dislikes 0	

Response

Alain Mukama - Hydro One Networks, Inc. - 1,3

Answer	
Document Name	

Comment

N/A to Hydro One

Likes 0	
Dislikes 0	

Response

Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6

Answer	
Document Name	

Comment

PacifiCorp holds that through existing processes, BAs possess the needed means to collect all information necessary to make determinations about generation availability during local forcasted cold weather.

Currently, PacifiCorp sees a reliability gap between what Generator Owners (GOs) /Generator Operators (GOPs) offer into the market and the amount of energy (MWh) that shows up in real-time. PacifiCorp's Risk Assessment Team analyzes this gap and attempts to close it using the information we have available; e.g. historical generator performance, to develop a "best guess" forecast for generator output. At best, our guess is uncertain.

Rather than requiring the BA to put on the hat of a generator and attempt to make an educated guess on their behalf, what we would like to see is something akin to what is done with load forecasting. PacifiCorp supports a framework that would ask GO/GOPs to provide their forecasted energy output information to the BA for the following reasons:

1. GO/GOPs are in the best position to provide an educated forecast for their units' performance. Not ony does the GO/GOP have superior past performance data (over that of the BA) to perform this analysis, they also have superior knowledge of how their unit will likely perform under projected conditions; e.g. if a GO/GOP has been told by their natural gas supplier that there is a 50% chance that their natural gas supply will be curtailed, the GO/GOP could incorporate this information into their energy output forecast.

2. BAs receiving a more accurate output forecast would be in an improved position to increase the accuracy of their dispatch and unit commitment.

Without this information, the BA must employ manual methods (e.g. phone calls) to gather this information anecdotally.

What is critical to making this work is a framework similar to that for load forecasting. GOs/GOPs should not be penalized for failure to predict their energy output with complete accuracy. There should be some recognition that new factors can emerge or existing factors change in real-time, thereby altering the energy output forecast. PacifiCorp recommends the GO/GOPs provide their BA with a reasonable forecast to work with.

Likes 0	
Dislikes 0	

Response

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	
Document Name	Q5-6.PNG

Comment

The MRO NSRF believes it would be useful to BA operations to have the GO/GOP, in accordance with the BA's documented methodology, provide a reasonable five-day hourly forecast of MW or MWh output for each generating unit during local forecasted cold weather so the BA can incorporate this information into the five-day hourly forecast for their BA footprint.

The MRO NSRF believes what is critical to making this work is a framework similar to that for load forecasting. GOs/GOPs should not be penalized for failure to predict their energy output with complete accuracy. There should be some recognition that new factors can emerge or existing factors (including the weather forecast) change in real-time, thereby altering the energy output forecast. The MRO NSRF recommends the GO/GOPs provide their BA with a reasonable forecast to work with.

Currently, MRO NSRF sees a reliability gap between what Generator Owners (GOs) /Generator Operators (GOPs) offer into the market and the amount of energy (MWh) that shows up in real-time. In part this is due to the fact that generators do not know in advance how many hours they will be dispatched to run, thereby making it difficult for them to reflect when they expect to "run out of fuel" in their forecast.

A MRO NSRF member's Risk Assessment Team analyzes this gap and attempts to close it using the information we have available; e.g. historical generator performance, to develop a "best guess" forecast for generator output. That said, our "best guess" is still uncertain.

Rather than requiring the BA to put on the hat of a generator and attempt to make an educated guess on their behalf, what we would like to see is something akin to what is done with load forecasting. The MRO NSRF supports a framework that would ask GO/GOPs to provide their forecasted energy output information to the BA for the following reasons:

1. GO/GOPs are in the best position to provide an educated forecast for their units' performance. Not only does the GO/GOP have superior past performance data (over that of the BA) to perform this analysis, they also have superior knowledge of how their unit will likely perform under projected weather conditions; e.g. if a GO/GOP has been told by their natural gas supplier that there is a 50% chance that their natural gas supply will be curtailed, the GO/GOP could incorporate this information into their energy output forecast.
2. BAs receiving a more accurate output forecast would be in an improved position to increase the accuracy of their dispatch and unit commitment.

With the information from the GO/GOP described above, the BA will be in an improved position to determine when to deploy the generating units in their footprint. In addition, it will reduce the need for the BA to employ manual methods (e.g. phone calls) to gather this information anecdotally.	
Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	
Response	

6. Recommendation 1g, bullets 2 and 3 of the Report suggests that each Balancing Authority should be required to use the data provided by the Generator Owner/Generator Operator to determine total generating capacity that can be relied upon during “local forecasted cold weather,” and utilize such information 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.” The SDT proposes a new Requirement R8 in TOP-002 that requires a Balancing Authority to create an extreme cold weather Operating Process within its Operating Plan to formalize the Balancing Authority’s analysis functions and Real-time monitoring of its Balancing Authority Area during extreme cold weather. Do you agree the language in proposed Requirement R8 of TOP-002 addresses the intent of and is the appropriate manner in which to satisfy Recommendation 1g? Please provide the reasoning or justification for your position in the comments.

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	No
Document Name	
Comment	
We are of the opinion that the analysis is not needed. If we come up negative, we already have a Capacity Emergency Procedure. It does not have to be a stand alone “Cold Weather” Capacity Emergency Plan.	
Likes 0	
Dislikes 0	
Response	

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) in response to this question.	
Likes 0	
Dislikes 0	
Response	

Ken Habgood - Seminole Electric Cooperative, Inc. - 4	
Answer	No
Document Name	
Comment	

Per TOP-003 R4., BAs are already required to develop Operating Plans for the next-day that address expected generation resource commitment and dispatch, which require knowledge of generating units' capabilities, regardless of the weather conditions. The proposed R8 is redundant and unnecessary, as what it requires is already addressed in TOP-003-5 and TOP-002-4. Further, R8.3 is now requiring development of an Operating Plan, although it doesn't explicitly state it but it includes the same elements required in R4 with the addition of a weather forecast, for a five-day period, but only during an extreme cold weather period.

Likes 0	
Dislikes 0	

Response

Bobbi Welch - Midcontinent ISO, Inc. - 2

Answer	No
Document Name	

Comment

Requirement R8 as written only partially addresses the intent of Recommendation 1g

While Requirement R8 addresses a *portion* of the intent of Recommendation 1g (bullets 2 and 3), the SRC believes it is insufficient to achieve the overall intent of Recommendation 1g without a corresponding requirement for GO/GOPs to provide BAs with their output forecasts (bullet 1).

Without a corresponding requirement for the GO/GOP to provide its BA with an expected output forecast for its unit(s), there may be a reliability gap in terms of what the BA can generate to comply with Parts 8.2 and 8.3 as described in the SRC's response to Question #5.

The GO/GOP is in a superior position to provide the information listed in Part 8.2. Therefore, for the BA to develop a methodology that considers these operating limitations, there must be an equal and opposite requirement for the GO/GOP to provide this information to the BA. The time horizon for the GO/GOP requirement must mirror the proposed BA requirement for Part 8.3; i.e. an *hourly* generator output forecast for *five days* into the future.

There is a mismatch in time horizons for the Operating Process (R8) and Operating Plan (R4)

The SRC supports the proposal of a flexible, methodology-based approach to identifying an extreme cold weather period; however, the SRC believes the proposed language in Requirement R8 conflicts with the language in Requirement R4.

Under the proposed language, R8 and R4 both reference the Operating Plan; however, R4 contemplates the Operating Plan as applying to next-day operations only, while R8, Part 8.3 specifically requires a "five-day hourly forecast." To rectify this mismatch, the SRC proposes the following modification:

R8. Each Balancing Authority shall have an extreme cold weather Operating Process, *to inform* its Operating Plan developed in Requirement R4, addressing preparations for and operations during extreme cold weather periods. The extreme cold weather Operating Process shall include: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

Likes 0	
Dislikes 0	

Response

Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
Per TOP-003 R4., BAs are already required to develop Operating Plans for the next-day that address expected generation resource commitment and dispatch, which require knowledge of generating units' capabilities, regardless of the weather conditions. The proposed R8 is redundant and unnecessary, as what it requires is already addressed in TOP-003-5 and TOP-002-4. Further, R8.3 is now requiring development of an Operating Plan, although it doesn't explicitly state it but it includes the same elements required in R4 with the addition of a weather forecast, for a five-day period, but only during an extreme cold weather period.	
Likes 0	
Dislikes 0	
Response	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
There are redundancies between this language and TOP-003-5 and EOP-011-2. This language also adds additional data requirements not included in TOP-003-5. TOP-003-5 does not include data related to generation start failure. TOP-002-5, R8 part 8.2.3 (Start-up issues) is not included in TOP-003-5.	
Likes 0	
Dislikes 0	
Response	

Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	No
Document Name	
Comment	
SRP supports TPWR comments.	
Likes 0	
Dislikes 0	

Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Most of the requirements in R8, such as reserve margin, fall under the responsibility of our BA which is MISO.	
Likes 0	
Dislikes 0	
Response	
Marc Sedor - Seminole Electric Cooperative, Inc. - 3	
Answer	No
Document Name	
Comment	
Per TOP-003 R4., BAs are already required to develop Operating Plans for the next-day that address expected generation resource commitment and dispatch, which require knowledge of generating units' capabilities, regardless of the weather conditions. The proposed R8 is redundant and unnecessary, as what it requires is already addressed in TOP-003-5 and TOP-002-4. Further, R8.3 is now requiring development of an Operating Plan, although it doesn't explicitly state it but it includes the same elements required in R4 with the addition of a weather forecast, for a five-day period, but only during an extreme cold weather period.	
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	
Including a requirement for a BA to have a methodology to identify an Extreme Cold Weather period in their area seems to be a good fit for the recommendation. Proposed Requirement 8.3.1 states, "expected generation resource commitment and dispatch" with regards to a five-day hourly forecast. Generation resource commitments are typically done as a function of the markets and are done in the day-ahead time horizon. While some baseload generation is	

capable of being projected, many other intermittent and self-scheduled peaking facilities are much more difficult to accurately project, especially beyond a couple days.

The SDT should consider changing requirement 8.3.1 to “Anticipated available resources” as resource commitment and dispatch are typically viewed as operating day or day-ahead activities.

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

For TOP-002-5 Requirement 8.3, Tacoma Power is unsure whether this Requirement is for the BAA or for each generating unit. Tacoma Power recommends modifying the Requirement 8.3 to specify whether it’s applied to BAA or each generating unit. For example, “A methodology to determine a five-day hourly forecast **within each Balancing Authority Area** during the identified extreme cold weather periods that includes...”

Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	

Response

Marcus Bortman - APS - Arizona Public Service Co. - 6

Answer	No
Document Name	

Comment

APS agrees that much on the language in R8. However, a key element in Recommendation 1g bullets 2 is missing, which is that each “Balancing Authority should be required to use the data provided by the Generator Owner/Generator Operator.” We recommend the following edits to R8 in bold:

Each Balancing Authority shall have an extreme cold weather Operating Process, as part of its Operating Plan, developed in Requirement R4, **that in combination with its own evaluation, utilizing resource capability and fuel availability data provided by the responsible GO/GOP**, **addresses** preparations for and operations during extreme cold weather periods. The extreme cold weather Operating Process shall include: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

Likes 0	

Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	No
Document Name	
Comment	
IWECC believes the proposed language is relatively clear and auditable but there is some question about when this cold weather operating process should be implemented and appear in the daily operating plan. An auditor may expect to see it addressed in a daily plan during December but probably would not expect it to appear in the plan for July. But there is a possibility that unless it was addressed in the process, some auditors would expect to see a forecast and determination of cold weather considerations included in every operating plan. The requirements for when, or what triggers, the process should be included in the subrequirements for R8 to reduce the chance of an unreasonable audit approach	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD	
Answer	No
Document Name	
Comment	
SMUD agrees with the comment provided by Tacoma Power. It is unclear whether TOP-002-5 Requirement 8.3 applies to the BA Area or to each generating unit.	
Likes 0	
Dislikes 0	
Response	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	No
Document Name	
Comment	

Operational Planning Analyses are conducted using temperature forecasts and expected generation resource commitment and dispatch. The process during cold weather would be no different than any other OPA. Generation limitations are identified as outages or derates in the outage management system, per TOP-003 and IRO-010.

Likes 0	
Dislikes 0	

Response

Lindsey Mannion - ReliabilityFirst - 10

Answer	No
Document Name	

Comment

As currently proposed, R8 states that each Balancing Authority's "extreme cold weather Operating Process" is to be "part of its Operating Plan developed in Requirement R4." However, R4 requires Operating Plan(s) for "the next day," implying that these Operating Plans may vary from day to day throughout the year. RF recommends R8 be revised to state that the "extreme cold weather Operating Process" is "to support the development of the Operating Plan(s) pursuant to R4." An Operating Plan developed for a day in July is unlikely to need to include an extreme cold weather Operating Process, but Operating Plans for days that may fall during extreme cold weather periods should be developed in accordance with the Operating Process, which must be available for use when needed.

Likes 0	
Dislikes 0	

Response

Melanie Wong - Seminole Electric Cooperative, Inc. - 5

Answer	No
Document Name	

Comment

Per TOP-003 R4., BAs are already required to develop Operating Plans for the next-day that address expected generation resource commitment and dispatch, which require knowledge of generating units' capabilities, regardless of the weather conditions. The proposed R8 is redundant and unnecessary, as what it requires is already addressed in TOP-003-5 and TOP-002-4. Further, R8.3 is now requiring development of an Operating Plan, although it doesn't explicitly state it but it includes the same elements required in R4 with the addition of a weather forecast, for a five-day period, but only during an extreme cold weather period.

Likes 0	

Dislikes 0	
Response	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	

Without requiring the GO/GOP to provide an expected output forecast for its unit(s) as described in our response to Question #5, PacifiCorp sees a real reliability gap in terms of what the BA will be able to generate to satisfy Parts 8.2 and 8.3 (below). The GO/GOP is in a far superior position to provide the information listed in Parts 8.2.1 - 8.2.5 to that of the BA. Therefore, for the BA to develop a methodology that considers those operating limitations, there must be an equal and opposite requirement on the GO/GOP to provide these limitations to the BA. The time horizon for the GO/GOP requirement must mirror the proposed BA requirement for Part 8.3; i.e. an hourly generator output forecast for five days into the future.

8.2 A methodology that determines an appropriate reserve margin during the extreme cold weather period considering the generating unit(s) operating limitations in previous extreme cold weather periods including:

8.2.1 Capability and availability;

8.2.2 Fuel supply and inventory concerns;

8.2.3 Start-up issues;

8.2.4 Fuel switching capabilities; and

8.2.5 Environmental constraints

8.3 A methodology to determine a five-day hourly forecast during the identified extreme cold weather periods that includes:

8.3.1 Expected generation resource commitment and dispatch.

8.3.2 Interchange scheduling;

8.3.3 Demand patterns;

8.3.4 Capacity and energy reserve requirements, including deliverability capability; and

8.3.5 Weather forecast

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	
However, without requiring the GO/GOP to provide an expected output forecast for its unit(s) as described in response to Question #5, there is a real reliability gap in terms of what the BA will be able to generate to satisfy Parts 8.2 and 8.3 (below). The GO/GOP is in a far superior position to provide the information listed in Parts 8.2.1 - 8.2.5 to that of the BA. Therefore, for the BA to develop a methodology that considers those operating limitations, there must be an equal and opposite requirement on the GO/GOP to provide these limitations to the BA. The time horizon for the GO/GOP requirement must mirror the proposed BA requirement for Part 8.3.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
The BA already has the authority under the standards to require the GO/GOP to report any fuel supply and inventory concerns. In addition, R3 of EOP-012 requires a cold weather preparedness plan which includes "generating unit(s) operating limitation in cold weather to include:...Fuel supply and inventory concerns".	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	

Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
In support of MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI agrees the language in Requirement R8 appropriately addresses the intent of Recommendation 1g bullets 2 and 3.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco on behalf of Constellation Segements 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 is in agreement with that language in R8.	
Likes 0	
Dislikes 0	
Response	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	Yes
Document Name	
Comment	
Additional resources should be utilized to offset the demand for natural gas if that industry cannot meet demand. The 'all the eggs in one basket' approach is problematic and suggests a more thoughtful resource balance is necessary to mitigate these effects.	
Likes 0	
Dislikes 0	
Response	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
The MRO NSRF believes that while the proposed language for Requirement R8 of TOP-002 is appropriate to address the intent of Recommendation 1g relative to the BA's role (bullets 2 and 3) , it is insufficient to achieve the overall intent of Recommendation 1g without a corresponding requirement for GO/GOPs to provide the information described under bullet 1. Without requiring the GO/GOP to provide an expected output forecast for its unit(s) as described in our response to Question #5, MRO NSRF sees a	

real reliability gap in terms of what the BA will be able to generate to satisfy Parts 8.2 and 8.3 (below). The GO/GOP is in a far superior position to provide the information listed in Parts 8.2.1 - 8.2.5 to that of the BA. Therefore, for the BA to develop a methodology that considers those operating limitations, there must be an equal and opposite requirement on the GO/GOP to provide these limitations to the BA. The time horizon for the GO/GOP requirement must mirror the proposed BA requirement for Part 8.3; i.e. an hourly generator output forecast for five days into the future.

Likes 0	
Dislikes 0	

Response

Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller

Answer	Yes
Document Name	

Comment

BHP is not a BA.

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt

Answer	Yes
Document Name	

Comment

BHP is not a BA.

Likes 0	
Dislikes 0	

Response

Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
BHP is not a BA.	
Likes 0	
Dislikes 0	
Response	

Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	
BHP is not a BA,	
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 comments that the language in Requirement R8 appropriately addresses the intent of Recommendation 1g bullets 2 and 3.	
Likes 0	
Dislikes 0	
Response	

Kinte Whitehead - Exelon - 3	
Answer	Yes

Document Name	
Comment	
Exelon supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon supports EEI's comments	
Likes 0	
Dislikes 0	
Response	
Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Yes.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	

N/A

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

None.

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 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	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	

Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, 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	

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
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	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	
Document Name	
Comment	
N/A to Hydro One	
Likes 0	
Dislikes 0	

Response	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	

Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
Answer	
Document Name	
Comment	
PJM supports the IRC SRC comments.	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE noticed the use of the term “extreme cold weather period,” which is not defined in the NERC Glossary. EOP-012-1 introduced the term “Extreme Cold Weather Temperature,” and it is unclear how or whether these two terms work together. Specifically, would an “extreme cold weather period” only include time periods in which Extreme Cold Weather Temperatures (i.e., 0.2 percentile temperatures) would be reached, conditions which approach, but do not reach those extremes but could have reliability impacts, operating conditions before and after such periods, and, if so, for how long? The SDT may wish to clarify these relationships.

It is unclear what the expectation is for BAs that cover a large geographic area that is subject to significant differences in weather. Would the Operating Process only apply to the part of the area that is subject to the extreme cold weather? Texas RE notes that reserve margin is generally not considered in sub-areas of a Balancing Authority Area.

Texas RE recommends defining the term “reserve margin” in Requirement Part 8.2. Texas RE understands that the intent of the recommendation 1g was to provide clear delineation of responsibilities and estimates of generation availability so that BAs and Reliability Coordinators (RCs) can perform real-time monitoring and managing of generating resources as part of its capacity and energy operating plans. If the SDT retains the concept of a “reserve margin” to perform this function, Texas RE believes it is appropriate to better clarify that relationship.

Texas RE inquires whether the expectation is to create the five-day hourly forecast that goes beyond the “extreme cold weather period’ per Requirement part 8.2. For example, the cold weather period defined by the BA is 24 hours of consecutive freezing weather across the entire Balancing Authority Area but is only forecasted for 2 days. Texas RE understands the current language to indicate there would need to be a five-day forecast the day ahead of the forecasted temperature (per the Operating Plan), the first day of the forecasted temperature Operating Plan and then the Operating Plan developed on second day of forecasted extreme cold weather would include the five-day forecast. Is this the SDT’s intent?

Likes 0	
Dislikes 0	

Response

Donna Wood - Tri-State G and T Association, Inc. - 1

Answer	
Document Name	

Comment

NA

Likes 0	
Dislikes 0	

Response

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	
Document Name	
Comment	
To simplify the requirement and maintain consistency with the intent of the rest of TOP-002, BPA recommends removing the "five-day hourly forecast" requirement of R8.3. BPA suggests the intent of Recommendation 1g would be satisfied by modifying R8.3 to state: **"A methodology to include the extreme cold weather reserve margin determined in R8.2 when creating the Balancing Authority Operating Plan for the next-day addressed by R4."**	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	
Document Name	
Comment	
MISO is Entergy's Balancing Authority.	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
Answer	
Document Name	
Comment	
Abstain	
Likes 0	
Dislikes 0	
Response	

7. The SDT proposes that the modifications in EOP-011-4, EOP-012-2, and TOP-002-5 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.

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	No
Document Name	

Comment

See our response to Q3. Until we gain full understanding of the assigned obligations related to identifying and implementing these recommendations and the TOP and BAs response toward these modifications, FirstEnergy cannot determine the cost effectiveness of these proposals.

Likes 0	
Dislikes 0	

Response

Melanie Wong - Seminole Electric Cooperative, Inc. - 5

Answer	No
Document Name	

Comment

The coordination efforts between multiple DPs in multiple TOs area and the staffing needed to create plans, process, implement and manage is burdensome and costly to the TOPs, DPs and TOs.

Likes 0	
Dislikes 0	

Response

Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD

Answer	No
Document Name	

Comment

The addition of R8 in TOP-002-05 is redundant. The OPA process does not change based on the weather. Requirement R4 requires an Operating Plan, whether that plan is to mitigate impacts in a cold weather scenario or extreme summer temperatures is irrelevant.

Likes 0	
Dislikes 0	

Response

Claudine Bates - Black Hills Corporation - 6

Answer	No
Document Name	

Comment

BHP will not comment on cost effectiveness.

Likes 0	
Dislikes 0	

Response

Micah Runner - Black Hills Corporation - 1

Answer	No
Document Name	

Comment

BHP will not comment on cost effectiveness.

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt

Answer	No
Document Name	

Comment

BHP will not comment on cost effectiveness.

Likes 0	
Dislikes 0	

Response	
Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
Answer	No
Document Name	
Comment	
BHP will not comment on cost effectiveness.	
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 below: We believe that the identification of critical natural gas infrastructure loads should be performed at a single operating level. To require the TO, DP, DP-UFLS, TOP, and BA to all perform the same identification function(s) seems redundant and inefficient. Please see our comments for questions 3, and 4 above for additional details.	
Likes 0	
Dislikes 0	

Response	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	No
Document Name	
Comment	
Their needs to be a documented plan for generating facilities to recoup the cost for modifications and upgrades of freeze protection measures and additional layers of freeze protection measures.	
Likes 0	

Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
Until these recommendations are implemented WEC Energy Group is unable to make a determination as to the cost effectiveness of the modifications.	
Likes 0	
Dislikes 0	
Response	
Marc Sedor - Seminole Electric Cooperative, Inc. - 3	
Answer	No
Document Name	
Comment	
The coordination efforts between multiple DPs in multiple TOs area and the staffing needed to create plans, process, implement and manage is burdensome and costly to the TOPs, DPs and TOs.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Depending on the number of identified items that require physical changes and engineering updates, these standard changes may require multiple projects on the distribution system. These projects will involve equipment that may have supply chain challenges that will add time and expense to the process.	
Likes 0	

Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
The coordination efforts between multiple DPs in multiple TOs area and the staffing needed to create plans, process, implement and manage is burdensome and costly to the TOPs, DPs and TOs.	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
The SRC is concerned that TOP-002-5 as written is not the most cost-effective approach since it lacks a corresponding requirement for the GO/GOP to provide the BA with their MW/MWh output forecast. Historically, SRC members (as registered BAs) have incurred additional costs when implementing BA requirements when there is not a corresponding requirement for other Responsible Entities (e.g., GOs and GOPs), to provide the BA with the information needed for the BA to perform its compliance obligation(s). This increases the overall cost of compliance, as the BA must develop and employ alternative processes to obtain the data needed (e.g., modifications to a FERC tariff, revisions to membership agreements, engagement in regional rulemaking processes, etc.). In addition to the cost of delays, there may also be costs associated with the BA receiving lower quality data than if the obligation to provide data had been enshrined in a Reliability Standard or other regulatory rule.	
Likes 0	
Dislikes 0	
Response	
Ken Habgood - Seminole Electric Cooperative, Inc. - 4	
Answer	No
Document Name	
Comment	

The coordination efforts between multiple DPs in multiple TOs area and the staffing needed to create plans, process, implement and manage is burdensome and costly to the TOPs, DPs and TOs.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

We believe that the identification of critical natural gas infrastructure loads should be performed at a single operating level. To require the TO, DP, DP-UFLS, TOP, and BA to all perform the same identification function(s) seems redundant and inefficient.

Please see our comments for questions 3, and 4 above for additional details.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) in response to this question.

Likes 0	
Dislikes 0	

Response

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1

Answer	No
Document Name	

Comment

On the surface this may seem as a low cost option; however, if you delve deeper into the reason for the need for the standards, we would have to overbuild the BES for extreme events like Uri. This does not appear as cost effective. While Electricity is a critical commodity, there is a time when we will have to shed firm load. It will be during an extreme event. No one wants to, but we cannot build, economically, the infrastructure to keep this from happening.

Likes 0	
Dislikes 0	

Response

Dave Krueger - SERC Reliability Corporation - 10

Answer	Yes
Document Name	

Comment

Question should be updated to remove EOP-012

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

None.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	Yes
Document Name	

Comment

Constellation has no additional comments. Kimberly Turco on behalf of Constellation Segements 5 and 6	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
In support of MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	Yes
Document Name	
Comment	
We would like to see a longer implementation period with a phased in approach, 25% per 12 month period starting after 12 months to ensure a more cost effective implementation.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	

Comment	
Constellation has no additional comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	Yes
Document Name	
Comment	
In New England, we do not anticipate severe cost increases in complying with the proposed standard revisions as our plants are built with cold weather in mind. We believe that the BA will incur the greatest cost implications in complying with R8.3 as an hourly forecast can be very involved for large systems.	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
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	
LaTroy Brumfield - American Transmission Company, LLC - 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	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD	
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	

Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, 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	

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	

Teresa Krabe - Lower Colorado River Authority - 5

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	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
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	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	
Document Name	
Comment	
CEHE Abstains from Question 7.	
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 does not think this answer will be known until everything is fully implemented.	

Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	
Document Name	
Comment	
No comment.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
Answer	
Document Name	
Comment	
PJM supports the IRC SRC comments.	
Likes 0	
Dislikes 0	

Response	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	
Document Name	
Comment	
No comments	
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	
No Comments	
Likes 0	
Dislikes 0	
Response	

8. Do you agree with the implementation plan proposed by the SDT? 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.

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT recommends a 24-month implementation timeframe to account for the coordination, budget revisions, staffing changes, and systems upgrades necessary to accomplish the new tasks. New forecasts and tools often require multiple projects to acquire the necessary input data and to process and display that data to users. This often requires extensive testing as well.	
Likes 0	
Dislikes 0	
Response	

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	No
Document Name	
Comment	
There is not a separate implementation phase for a newly identified DP, DP-UPFL, and/or TO. As an example, if the standard goes into effect 1/1/2025 and the TOP now identifies a DP in its Operational Plan on 1/1/2025 (per proposed Requirement R1.2.5.6), the current language and Implementation Plan seems to indicate that the DP must immediately have a plan implemented on the same day. Thus, we recommend a phased-in compliance approach for Requirement R7. Per our recommendation for modifying R7 in response to Question 3, we recommend a phased-in implementation plan for this standard. It is our recommendation that the phased-in compliance date be no earlier than six (6) calendar months after the effective date of R1.	
Likes 0	
Dislikes 0	
Response	

Ken Habgood - Seminole Electric Cooperative, Inc. - 4	
Answer	No
Document Name	
Comment	

For EOP-011, propose 36 months. The coordination and agreements between multiple DPs and multiple DP's in multiple TOs areas, could possibly take a significant amount of time. For TOP-002, propose 18 months to remain consistent with other revisions.

Likes 0	
Dislikes 0	

Response

Bobbi Welch - Midcontinent ISO, Inc. - 2

Answer	No
Document Name	

Comment

The SRC[1] supports an 18-month implementation timeframe for EOP-011.

In addition, the SRC supports an 18-month implementation timeframe for TOP-002. (This would extend the proposed 12-month timeframe to 18 months (assuming the SDT adopts the SRC's recommendation for the GO/GOP to provide the MW/MWh output forecast as described in the SRC's response to Questions 5 and 6).

This would align the implementation timeframe for all Phase 2 requirements to 18 months, ensuring all requirements would be in place prior to the Winter 2025-2026 season

[1] For purposes of these comments, the IRC SRC includes the following entities: CAISO (with the exception of our response to question 5), ERCOT (with the exception of our responses to questions 3, 5 and 8), IESO, ISO-NE, MISO, NYISO, PJM and SPP.

Likes 0	
Dislikes 0	

Response

Kristine Ward - Seminole Electric Cooperative, Inc. - 1

Answer	No
Document Name	

Comment

For EOP-011, propose 36 months. The coordination and agreements between multiple DPs and multiple DP's in multiple TOs areas, could possibly take a significant amount of time. For TOP-002, propose 18 months to remain consistent with other revisions.

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Depending on the number of identified items that require physical changes and engineering updates, this may not be possible in an 18 month period. The SDT should consider a phased approach to this implementation plan.	
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	
Recommend aligning the implementation plans for EOP-011-4 and TOP-002-5 to 18 months.	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	No
Document Name	
Comment	
IID recommends an 18-month implementation plan.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	

Answer	No
Document Name	
Comment	
Ameren recommends extending the implementation plan for TOP-002-5 be extended to 18 months.	
Likes 0	
Dislikes 0	
Response	
Marc Sedor - Seminole Electric Cooperative, Inc. - 3	
Answer	No
Document Name	
Comment	
For EOP-011, propose 36 months. The coordination and agreements between multiple DPs and multiple DP's in multiple TOs areas, could possibly take a significant amount of time. For TOP-002, propose 18 months to remain consistent with other revisions.	
Likes 0	
Dislikes 0	
Response	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
We would propose for EOP-011-4 that R7 has a later implementation date than R1 to afford those entities identified by their TOPs sufficient time to prepare and comply.	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	

Answer	No
Document Name	
Comment	
Tacoma Power supports MRO NSRF comments on the implementation timeframe.	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group proposes that the implementation timeframe for TOP-002-5 be extended from 12 months to 18 months	
Likes 0	
Dislikes 0	
Response	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	No
Document Name	
Comment	
A phased in implementation approach, 25% per 12 month period, starting after 12 months.	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	

Comment	
In support of MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	
As stated in response to question #3, APS supports a phased approach for EOP-011-4 Requirement R7 that provides 18 months to identify the critical natural gas infrastructure and 18 additional months to make system and field changes. The 18-month time frame is sufficient to identify natural gas infrastructure. However, it is insufficient for TOs, DPs, and UFLS Only DPs to either move those loads to other feeders or to entirely exclude those feeders from their load shedding programs and find other suitable offsetting loads in their place. This work often requires both engineering and field crew support to fully accomplish and will likely require 36 months to fully implement.	
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 below: There is not a separate implementation phase for a newly identified DP, DP-UPFL, and/or TO. As an example, if the standard goes into effect 1/1/2025 and the TOP now identifies a DP in its Operational Plan on 1/1/2025 (per proposed Requirement R1.2.5.6), the current language and Implementation Plan seems to indicate that the DP must immediately have a plan implemented on the same day. Thus, we recommend a phased-in compliance approach for Requirement R7. Per our recommendation for modifying R7 in response to Question 3, we recommend a phased-in implementation plan for this standard. It is our recommendation that the phased-in compliance date be no earlier than six (6) calendar months after the effective date of R1.	
Likes 0	
Dislikes 0	

Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Tri-State suggests a 48month implementation plan.	
Likes 0	
Dislikes 0	
Response	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	No
Document Name	
Comment	
For EOP-011, propose 36 months. The coordination and agreements between multiple DPs and multiple DP's in multiple TOs areas, could possibly take a significant amount of time. For TOP-002, propose 18 months to remain consistent with other revisions.	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
Implementation timeframe should be extended to at least 24 months to allow sufficient time to collect and incorporate the data. An implementation period of 36 months will allow for sufficient time to train all system operators on the updated plans.	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
As stated in our response to Question #3, eighteen months would not be sufficient for these new Functional Entities to become compliant with their EOP-011 obligations. AEP instead recommends an implementation period of 36 months for EOP-011.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
See our response to Q3. Until we gain full understanding of the assigned obligations related to identifying and implementing these recommendations and the TOP and BAs response toward these modifications, FirstEnergy cannot support the implementation plan for TOP-002-5.	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	No
Document Name	
Comment	
On behalf of the SERC GWG See above for R7. There is no timeframe issued for newly identified Distribution Providers, UFLS-Only DPs, or Transmission Owners to implement/respond to the TOP plan.	
Likes 0	
Dislikes 0	

Response

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Add language to align implementation plan timeframes to 18 months.	
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	

An 18 month implementation timeframe may be appropriate assuming the NERC Standard is approved through FERC on the same general timetable as the Phase 1 Standards, FERC approval approx. Feb 2024, with effective date of October 1, 2025 which would be prior to the 2025 winter period.

However, the SDT should consider that based on the current status of the SDT through Phase 2 with this version of EOP-011 already at the first ballot, a 12 month timeframe might be appropriate so that if FERC were to approve the Standard in 2023, there would be the possibility of the effective date being prior to the 2024 winter period, or at least near the start of the 2024 winter period.

If Phase 2 Standards revisions were to be adopted before October 1, 2023, the effective date would aling with the expected Effective date of the Phase 1 EOP-011 and EOP-012 which could eliminate a potential risk of compliance with multiple versions of the same Standard.

ISO-NE does not support any implementation timeframe that goes beyond the start of the 2025-2026 Winter.

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5

Answer	Yes
Document Name	

Comment

Constellation has no additional comments.

Alison Mackellar 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

EEI supports the proposed 12 month implementation plan for TOP-002-5.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	Yes
Document Name	

Comment

Constellation has no additional comments.

Kimberly Turco on behalf of Constellation Segements 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 is in support of a 12 month implementation timeframe for TOP-002-5.	
Likes 0	
Dislikes 0	
Response	

Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
Answer	Yes
Document Name	
Comment	
Date on SDT timeline states NERC Board of Trustees adoption is October 2022, shouldn't that be 2023?	
Likes 0	
Dislikes 0	
Response	

Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	Yes
Document Name	
Comment	

Date on SDT timeline states NERC Board of Trustees adoption is October 2022, shouldn't that be 2023?

Likes 0	
Dislikes 0	

Response

Micah Runner - Black Hills Corporation - 1

Answer	Yes
Document Name	

Comment

Date on SDT timeline states NERC Board of Trustees adoption is October 2022, shouldn't that be 2023?

Likes 0	
Dislikes 0	

Response

Claudine Bates - Black Hills Corporation - 6

Answer	Yes
Document Name	

Comment

Date on SDT timeline states NERC Board of Trustees adoption is October 2022, shouldn't that be 2023?

Likes 0	
Dislikes 0	

Response

Lindsey Mannion - ReliabilityFirst - 10

Answer	Yes
Document Name	

Comment

12 months for TOP-003 and 18 months for EOP-011 seem reasonable. Please refer to comments on question 3.

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 EEI comments.

Likes 0	
Dislikes 0	

Response

Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	Yes
Document Name	

Comment

Yes, CEHE supports the proposed 12 month implementation plan for the TOP-002-5.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	Yes
Document Name	

Comment

Exelon supports EEI's comments

Likes 0	
Dislikes 0	

Response	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon supports EEI comments.	
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 the proposed 12 month implementation plan for the TOP-002-5.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA agrees with the Implementation Plan for TOP-002-5 but disagrees with the Implementation Plan for EOP-011-4. Please also see BPA's response to question 3.	
Likes 0	
Dislikes 0	
Response	

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
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	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, 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	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD	
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	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
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	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
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	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
Answer	
Document Name	
Comment	
PJM supports the IRC SRC comments.	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	
Document Name	
Comment	
WECC leaves comment on the implementation plan to those entities that have to implement the standards.	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	

Answer	
Document Name	

Comment
See comments submitted by the Edison Electric Institute

Likes 0	
Dislikes 0	

Response

9. Is there any part of the proposed requirements, as currently drafted, that is unclear? If so, how would you make it clearer?

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
While the proposed requirements we feel are clear, until we gain full understanding of the assigned obligations related to identifying and implementing these recommendations and the TOP and BAs response toward these modifications, FirstEnergy cannot support these modifications.	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	No
Document Name	
Comment	
Exelon supports EEI comments.	
Likes 0	
Dislikes 0	
Response	

Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon supports EEI's comments	
Likes 0	
Dislikes 0	
Response	

Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
No.	
Likes 0	
Dislikes 0	
Response	

Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	No
Document Name	
Comment	
PNM believes that changes are described sufficiently.	
Likes 0	
Dislikes 0	
Response	

Kimberly Turco - Constellation - 6	
Answer	No

Document Name	

Comment

Constellation has no additional comments.

Kimberly Turco on behalf of Constellation Segements 5 and 6

Likes 0	
Dislikes 0	

Response

Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, 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 the comments of the Edison Electric Institue (EEI) to question #9,

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment

EEI agrees that the proposed changes to EOP-011 and TOP-002-5 are sufficiently clear.

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5

Answer	No
Document Name	
Comment	

Constellation has no additional comments.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	

Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Julie Hall - Entergy - 6, Group Name Entergy

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Melanie Wong - Seminole Electric Cooperative, Inc. - 5

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD

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	

Micah Runner - Black Hills Corporation - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
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	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Marc Sedor - Seminole Electric Cooperative, Inc. - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Devon Tremont - Taunton Municipal Lighting Plant - 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	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ken Habgood - Seminole Electric Cooperative, Inc. - 4	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
On behalf of the SERC GWG For R7: The requirement states “The Operating Plan(s) shall be provided to the Transmission Operator.” Should this be “as requested by the Transmission Operator”? Does the TOP really want to be flooded with every DP’s full operating plan?	
Likes 0	

Dislikes 0	

Response

LaTroy Brumfield - American Transmission Company, LLC - 1

Answer	Yes
Document Name	

Comment

As metioned in the response to question 4, the standard does not define what is meant by "critical natural gas infrastructure". ATC requests that the term "critical natural gas infrastructure" be defined.

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 would clarify language in EOP-011-4 R1.2.5 that currently could be confusing regarding operator controlled MLS and automatic UFLS/UVLS as follows:

"Operator-controlled **Manual Load Shed and/or Automatic Load Shed** during an Emergency that accounts for each of the following:"
Southern Company would also suggest language modifications to TOP-002-5 R8 to reduce confusion in the BA having a process and having next day plans as follows:

"Each Balancing Authority shall have an extreme cold weather Operating Process, **which it uses in developing** its **next day** Operating Plan **consistent with** Requirement R4, addressing preparations for and operations during extreme cold weather periods."

Likes 0	
Dislikes 0	

Response

Lindsey Mannion - ReliabilityFirst - 10

Answer	Yes
Document Name	

Comment	
Please refer to comments on questions 1 and 4.	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
More clarification is needed on the phrase “minimize the overlap” in EOP-011 Requirements 7.1.2 and 7.1.3.. How will an entity determine if it has minimized the overlap enough to satisfy an auditor and meet the expectation of the requirement?	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
See previous comments.	
Likes 0	
Dislikes 0	
Response	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	Yes
Document Name	
Comment	

See earlier comments	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD	
Answer	Yes
Document Name	
Comment	
The term “critical natural gas infrastructure” needs to be defined with a formal definition.	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
Please see the response to question 1. WECC believes that more clarity to EOP--11-4 on identification of "critical" natural gas ficility load is possible.	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	

APS believes that clarification is needed in EOP-011-4 because responsible entities do not have the visibility to identify such loads, so they are reliant on natural gas facilities owners, however, natural gas facility owners have no regulatory obligation to self-identify their facilities as critical. To address this concern, APS suggests modifications to Requirement 1, subpart 1.2.5.5 and Requirement R7, subpart 7.1.5 as follows:

Requirement 1, subpart 1.2.5.5:

Provisions for the identification and prioritization of designated critical natural gas infrastructure loads**, as identified by the responsible natural gas infrastructure owner/operator**; and

Requirement R7, subpart 7.1.5:

Provisions for the identification and prioritization of designated critical natural gas infrastructure loads**, as identified by the responsible natural gas infrastructure owner/operator**.

Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	

Response

Alain Mukama - Hydro One Networks, Inc. - 1,3

Answer	Yes
Document Name	

Comment

We would like more clarification on what is a “Designated Critical Load”. Many standards have overlapping definitions so a clear definition of what this means would support a consistent application.

Likes 0	
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group

Answer	Yes
Document Name	

Comment

Please refer to the comments in response to Question #10.

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	
See previous comments submitted on TOP-002 Requirement 8.3 and definition of critical natural gas infrastructure in EOP-011 R1.2.5.5.	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	

Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	

The SDT should consider that the current and proposed language of EOP-011 R1 does not prevent an entity from having critical gas infrastructure loads or a designated critical load from being included in its automatic load shed circuits. Although the intent is there, the standard doesn't explicitly address that potential overlap. Recommend adding automatic to R1.2.5.2

The proposed R1.2.5.5 is specific to "critical gas infrastructure load". The SDT should consider that this be rewritten to be more generic to encompass all "designated critical loads" and not just for gas infrastructure? Does this make sense to specifically call it out in a separate requirement.

The SDT should consider whether or not to include a new term in the NERC Glossary of "Designated Critical Load" which would define what the standard critical loads are, including, but not limited to critical gas infrastructure, critical fuel delivery infrastructure, off-site nuclear feeds, public safety, public health, etc.

These specifics could be called out in the sub requirement as well.

Suggested R1.2.5 Language for additions of "automatic" to 1.2.5.2 and the specific critical loads to 1.2.5.5.

Option 1:

1.2.5. {C}Operator-controlled manual load shedding or automatic 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 and automatic 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.;

1.2.5.5. Provisions for the identification and prioritization of designated critical loads, including;

1.2.5.5.1. Natural gas infrastructure,

1.2.5.5.2. Other fuel supply infrastructure,

1.2.5.5.3. Public safety and public health infrastructure

1.2.5.6. {C}Provisions for the identification of Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners required to mitigate operating Emergencies in its Transmission Operator Area.

Option 2 for R1.2.5.5 with "Designated Critical Load" glossary term:

1.2.5.5 Provisions for the identification and prioritization of designated critical loads

The SDT should consider the above recommendations be incorporated into R7 for the DP and UFLS-Only DP Requirement as well since the same comments apply.

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

Define "critical natural gas infrastructure" as be used in the requirement

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	Yes
Document Name	

Comment

See previous question responses.

Likes 0	
Dislikes 0	
Response	

Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	

In order to streamline R1, the SRC recommends that Part 1.2.5.5 be consolidated with Part 1.2.5.2 as follows:

1.2.5.2 Provisions to *identify and* minimize the overlap of circuits that are designated for manual *or automatic* Load shed and circuits that serve designated critical loads*, including known critical natural gas infrastructure loads*;

EOP-011, Requirement R7

The SRC is concerned with the use of the proposed language "Operating Plan," in Requirement R7, as it may be read to assign UFLS-Only Distribution Providers and Transmission Owners real-time operational tasks that they are not equipped to handle. Therefore, the SRC recommends R7 be modified as indicated below:

R7. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner identified in a Transmission Operator's Operating Plan(s) to *assist with* mitigating operating Emergencies in its Transmission Operator Area shall, *in consultation with the Transmission Operator, develop, maintain, and implement, and provide to the Transmission Operator an Operator-controlled manual, or automatic Load shedding program, that accounts for each of the following,* as applicable:[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]

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

7.2. Provisions to *identify and* minimize the overlap of circuits that are designated for manual *or automatic* Load shed and circuits that serve designated critical loads, *including known critical natural gas infrastructure loads*;

7.3. 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*

7.4. 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	

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

Document Name	
Comment	
See our previous comments.	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) in response to this question. Additionally, ERCOT refers the SDT to its response to question 2 to highlight the need to clarify the obligations of TOs and other applicable entities.	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	
Document Name	

Comment

See comments submitted by the Edison Electric Institute

Likes 0	
Dislikes 0	

Response

Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis

Answer	
Document Name	

Comment

PJM supports the IRC SRC comments.

Likes 0	
Dislikes 0	

Response	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	

10. Provide any additional comments for the SDT to consider, including the provided technical rationale document, if desired.

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	
ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) in response to this question.	
Likes 0	
Dislikes 0	
Response	

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	
Document Name	
Comment	
We believe the proposed modifications are a good first attempt at meeting the identified key recommendations; however, we also believe that there are a few key areas that need additional review and clarification. Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	

Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	
Document Name	
Comment	
If the SDT does not accept the SRC's recommendation to define the term "*critical natural gas infrastructure load,"* as discussed in the SRC's response to Question 1, the SRC requests the SDT include guidance on implementing this concept in the technical rationale for 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 RSC	
Answer	
Document Name	
Comment	
Please consider updating TOP-002-5 Section C. Compliance with the most recent NERC wording used for Section C. Compliance.	
Likes 0	
Dislikes 0	
Response	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	
Document Name	
Comment	
No comments.	
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	

Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	
Document Name	
Comment	
In Technical Rationale for EOP-011-4, the word “load” is both capitalized and not capitalized throughout the document. IID recommends the SDT check the capitalization of “load” and ensure it’s consistent throughout the document	
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	
No Additional Comments	
Likes 0	
Dislikes 0	
Response	

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	
Document Name	
Comment	
In the Technical Rationale for EOP-011-4, the word “load” is both capitalized and not capitalized throughout the document. Tacoma Power recommends the SDT check the capitalization of “load” and ensure it’s consistent throughout the document.	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	
Document Name	
Comment	

- There appears to be a correlation between EOP-011-4 R1 and EOP-001-4 R7, however there does not appear to be a similar correlation referencing obligations for others for EIP-011-4 R2.
- EOP-011-4 R2 is redundant with TOP-002-5 R8. Suggest language modifications to TOP-002-5 R8 to reduce confusion in the BA having a process and having next day plans.
- In EOP-011-4 R7.1, DP is being obligated to respond to implementing a TOP's timeframe for which it may not be capable. It is the TOP which should be obligated to be capable of meeting the TOP's timeframe.

Likes 0	
Dislikes 0	
Response	

Alison MacKellar - Constellation - 5	
Answer	
Document Name	
Comment	

Constellation has no additional comments.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	

Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	
Document Name	
Comment	

Gas is important for generation but generation is also important. Non-BES connected distributed generation should also be identified that would provide support to the BES.

Likes 0	
Dislikes 0	

Response
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment
Please consider updating TOP-002-5 Section C. Compliance with the most recent NERC wording used for the compliance section.

Likes 0	
Dislikes 0	

Response
Carl Pineault - Hydro-Qu?bec Production - 5

Answer	
Document Name	

Comment
No comments

Likes 0	
Dislikes 0	

Response
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis

Answer	
Document Name	

Comment
PJM supports the IRC SRC comments.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6	
Answer	
Document Name	
Comment	

Constellation has no additional comments.

Kimberly Turco on behalf of Constellation Segements 5 and 6

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	
Document Name	
Comment	

No additional comments

Likes 0	
Dislikes 0	

Response

Romel Aquino - Edison International - Southern California Edison Company - 3	
Answer	
Document Name	
Comment	

See comments submitted by the Edison Electric Institute

Likes 0	
Dislikes 0	

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	
AEPC signed on to ACES comments: We believe the proposed modifications are a good first attempt at meeting the identified key recommendations; however, we also believe that there are a few key areas that need additional review and clarification. Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	

Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	
Document Name	
Comment	
EOP-011 R1.2.5.5 should be removed and the requirement "Provisions for the identification and prioritization of designated critical natural gas infrastructure loads" be a DP only responsibility(R7.1.5.). TOP’s do not know what natural gas customers they serve and where ‘critical natural gas infrstructure’ loads are found on the distribution system, and sharing of customer information from DP to TOP may not always be allowed.	

Likes 0	
Dislikes 0	

Response

Lindsey Mannion - ReliabilityFirst - 10

Answer	
Document Name	

Comment

ReliabilityFirst appreciates the Standard Drafting Team's diligent work on this project.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	
Document Name	

Comment

Exelon supports EEI's comments

Likes 0	
Dislikes 0	

Response

Kinte Whitehead - Exelon - 3

Answer	
Document Name	

Comment

Exelon supports EEI comments.

Likes 0	
Dislikes 0	

Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	
Document Name	
Comment	
ATC does not believe that critical natural gas infrasture loads require its own sub-requirement for R1.2.5, since it is a subset of "designated critical loads."	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Project Name:	2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 - Draft 1
Comment Period Start Date:	2/28/2023
Comment Period End Date:	4/13/2023
Associated Ballots:	2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 EOP-011-4 IN 1 ST 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 Implementation Plan IN 1 OT 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 TOP-002-5 IN 1 ST

There were 64 sets of responses, including comments from approximately 152 different people from approximately 106 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 Director, Standards Development Latrice Harkness (via email) or at (404) 858-8088.

Questions

See the unofficial comment form for additional information: https://www.nerc.com/pa/Stand/Project202107ExtremeColdWeatherDL/2021-07_Cold_Weather_Phase%202_Unofficial_Comment_Form_02282023.docx

1. Proposed EOP-011-4 Requirement R2 was drafted to address recommendation 1h. Do the changes in EOP-011-4 Requirement R2 provide sufficient clarity in regards to limiting critical natural gas infrastructure participation in demand response?

See the unofficial comment form for additional information: https://www.nerc.com/pa/Stand/Project202107ExtremeColdWeatherDL/2021-07_Cold_Weather_Phase%202_Unofficial_Comment_Form_02282023.docx

2. The standard drafting team (SDT) made changes to the applicability section based on the recommendation above (additional clarity included in the technical rationale). Do you believe these are the correct Functional Entities to include? If not, please provide details and any other Functional Entities be added with justification.

3. Is the implementation timeframe for EOP-011-4 Requirement R7 reasonable given that it is applicable to Functional Entities who were not previously included in Applicability for EOP-011-3?

4. Do the changes in EOP-011 provide sufficient clarity and flexibility in regards to the treatment of critical natural gas infrastructure in operator-controlled manual Load shedding and automatic load shedding?

See the unofficial comment form for additional information: https://www.nerc.com/pa/Stand/Project202107ExtremeColdWeatherDL/2021-07_Cold_Weather_Phase%202_Unofficial_Comment_Form_02282023.docx

5. Please comment on whether information pertaining to the generating unit's MWs, including MWhs the GO/GOP reasonably believes that the BA can rely upon during local forecasted cold weather, would be useful to your operations during local forecasted cold

weather. Alternatively, is there a better way for the BA to develop assumptions related to cold weather needs to address this specific metric rather than asking for this information from the GO/GOPs? Please provide comments and revisions to the draft language.

6. Recommendation 1g, bullets 2 and 3 of the Report suggests that each Balancing Authority should be required to use the data provided by the Generator Owner/Generator Operator to determine total generating capacity that can be relied upon during "local forecasted cold weather," and utilize such information 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." The SDT proposes a new Requirement R8 in TOP-002 that requires a Balancing Authority to create an extreme cold weather Operating Process within its Operating Plan to formalize the Balancing Authority's analysis functions and Real-time monitoring of its Balancing Authority Area during extreme cold weather. Do you agree the language in proposed Requirement R8 of TOP-002 addresses the intent of and is the appropriate manner in which to satisfy Recommendation 1g? Please provide the reasoning or justification for your position in the comments.

7. The SDT proposes that the modifications in EOP-011-4, EOP-012-2, and TOP-002-5 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.

8. Do you agree with the implementation plan proposed by the SDT? 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.

9. Is there any part of the proposed requirements, as currently drafted, that is unclear? If so, how would you make it clearer?

10. Provide any additional comments for the SDT 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
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
Public Utility District No. 1 of Chelan County	Diane E Landry	1		CHPD	Meaghan Connell	Public Utility District No. 1 of Chelan County	5	WECC
					Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC

					Glen Pruitt	Public Utility District No. 1 of Chelan County	6	WECC
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	1,3,4,5,6	MRO,RF,SERC,Texas RE,WECC	ACES Collaborators	Bob Soloman	Hoosier Energy Electric Cooperative	1	RF
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO

					Ryan Strom	Buckeye Power, Inc.	5	RF
					Dave Hartman	Arizona Electric Power Cooperative	1	WECC
					Scott Brame	NC Electric Membership Corporation	3,4,5	SERC
					Jordan Mcclellan	Southern Illinois Power Cooperative	1	SERC
Eversource Energy	Joshua London	1		Eversource	Joshua London	Eversource Energy	1	NPCC
					Vicki O'Leary	Eversource Energy	3	NPCC
MRO	Jou Yang	1,2,3,4,5,6	MRO	MRO NSRF	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Chris Bills	City of Independence, Power and Light Department	5	MRO
					Fred Meyer	Algonquin Power Co.	3	MRO
					Christopher Bills	City of Independence Power & Light	3,5	MRO

					Larry Heckert	Alliant Energy Corporation Services, Inc.	4	MRO
					Marc Gomez	Southwestern Power Administration	1	MRO
					Matthew Harward	Southwest Power Pool, Inc. (RTO)	2	MRO
					Bryan Sherrow	Board of Public Utilities	1	MRO
					Terry Harbour	Berkshire Hathaway Energy - MidAmerican Energy Co.	1	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Jamison Cawley	Nebraska Public Power District	1,3,5	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Shonda McCain	Omaha Public Power District	6	MRO

					George E Brown	Pattern Operators LP	5	MRO
					George Brown	Acciona Energy USA	5	MRO
					Jaimin Patel	Saskatchewan Power Cooperation	1	MRO
					Kimberly Bentley	Western Area Power Administration	1,6	MRO
					Jay Sethi	Manitoba Hydro	1,3,5,6	MRO
					Michael Ayotte	ITC Holdings	1	MRO
Entergy	Julie Hall	6		Entergy	Oliver Burke	Entergy - Entergy Services, Inc.	1	SERC
					Jamie Prater	Entergy	5	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

					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	RF
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Jim Howell, Jr.	Southern Company - Southern Company Generation	5	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC

					Alain Mukama	Hydro One Networks, Inc.	1	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
					Randy Buswell	Vermont Electric Power Company	1	NPCC
					James Grant	NYISO	2	NPCC
					John Pearson	ISO New England, Inc.	2	NPCC
					Harishkumar Subramani Vijay Kumar	Independent Electricity System Operator	2	NPCC

Randy MacDonald	New Brunswick Power Corporation	2	NPCC
Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
David Burke	Orange and Rockland	3	NPCC
Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
Salvatore Spagnolo	New York Power Authority	1	NPCC
Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
David Kwan	Ontario Power Generation	4	NPCC
Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
Glen Smith	Entergy Services	4	NPCC
Sean Cavote	PSEG	4	NPCC

					Jason Chandler	Con Edison	5	NPCC
					Tracy MacNicoll	Utility Services	5	NPCC
					Shivaz Chopra	New York Power Authority	6	NPCC
					Vijay Puran	New York State Department of Public Service	6	NPCC
					ALAN ADAMSON	New York State Reliability Council	10	NPCC
					David Kiguel	Independent	7	NPCC
					Joel Charlebois	AESI	7	NPCC
					John Hastings	National Grid	1	NPCC
					Michael Jones	National Grid USA	1	NPCC
Tim Kelley	Tim Kelley		WECC	SMUD	Ryder Couch	Sacramento Municipal Utility District	5	WECC
					Foung Mua	Sacramento Municipal Utility District	4	WECC

					Wei Shao	Sacramento Municipal Utility District	1	WECC
					Nicole Looney	Sacramento Municipal Utility District	3	WECC
					Charles Norton	Sacramento Municipal Utility District	6	WECC

See the unofficial comment form for additional information: https://www.nerc.com/pa/Stand/Project202107ExtremeColdWeatherDL/2021-07_Cold_Weather_Phase%202_Unofficial_Comment_Form_02282023.docx

1. Proposed EOP-011-4 Requirement R2 was drafted to address recommendation 1h. Do the changes in EOP-011-4 Requirement R2 provide sufficient clarity in regards to limiting critical natural gas infrastructure participation in demand response?

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	No
Document Name	

Comment

The changes proposed do not speak to or provide sufficient clarity to how TOPs will acquire the information necessary to properly identify and prioritize those critical gas infrastructure facilities such that their sources of electrical power can be determined – thereby allowing them to be properly considered within any automatic or manual load shedding program. There needs to be provisions indicating that the entities that are the owners and operators of critical natural gas infrastructure facilities will provide lists and addresses of those facilities such that TOPs can properly identify them and their source of electrical power. Without requirements for the gas infrastructure entities to supply and maintain a list of these facilities to the TOPs, we would not be in a position to reliably identify them nor prioritize them.

Likes 1	Platte River Power Authority, 1, Archie Marissa
Dislikes 0	

Response

Thank you for your comment. Additional content has been added to the Technical Rationale to address this topic. The identification and prioritization of critical natural gas loads requires coordination with natural gas facility owners and operators. The SDT recognizes that entities are dependent upon the cooperation of natural gas facility owners and operators to complete this task. However, it is outside the scope of the SDT to develop methods to compel natural gas owners and operators to cooperate and provide specific information to various entities.

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA believes the recurring label of "critical natural gas infrastructure" is vague and undefined. Will there be a term created and placed in the NERC Glossary? Further, what specifically designates any one particular natural gas infrastructure as “critical” versus another as “non-critical”? Are electrical transmission / distribution entities being asked to designate natural gas infrastructure as critical or non-critical? BPA, as large Transmission entity, does not possess the information to make those determinations. BPA seeks clarity pertaining to what, if any, authorities are in place (or expected to be put in place) for BA, TO, TOP, DP, or UFLS-only DP to request/demand natural gas companies provide Critical Information about their facilities? BPA views this as potential overreach to require entities to do something BPA, as a Transmission entity, lacks the information or authority to do.	
Likes 2	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.; Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making “critical natural gas infrastructure load” a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad; and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint. The identification and prioritization of critical natural gas loads requires coordination with natural gas facility owners and operators. The SDT recognizes that entities are dependent upon the cooperation of natural gas facility owners and operators to complete this task. However, it is outside the scope of the SDT to develop methods to compel natural gas owners and operators to cooperate and provide specific information to various entities.	
Donna Wood - Tri-State G and T Association, Inc. - 1	

Answer	No
Document Name	
Comment	
The changes do not identify how or who will be responsible for determining and identifying the critical natural gas infrastructure.	
Likes 1	Platte River Power Authority, 1, Archie Marissa
Dislikes 0	
Response	
Thank you for your comment. Additional content has been added to the Technical Rationale to address this topic.	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	No
Document Name	
Comment	
RF has concerns regarding consistent identification of critical natural gas infrastructure. The Technical Rationale document states “the identification of critical natural gas loads can be accomplished in several ways and the SDT did not prescribe specific methods in the drafting of EOP-011-4” but does goes on to provide some examples of methods. However, the current draft appears to leave open the possibility that the BA, TOP, TO, and DP/DP-UFLS may disagree on whether any given load is a “designated critical natural gas infrastructure load.”	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	
Thank you for your comment. Additional content has been added to the Technical Rationale to address these topics.	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No

Document Name	
Comment	

MRO NSRF requests that the term “critical natural gas infrastructure load” be defined. Additionally, MRO NSRF would request that the definition, at a minimum, state “critical natural gas infrastructure load” is natural gas infrastructure load that if rendered unavailable would adversely impact generator output and would affect the reliable operation of the Bulk Electric System. The definition of BES Cyber Asset (included below) can be looked to for language similar to what MRO NSRF is requesting.

BES Cyber Asset

A Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one or more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the reliable operation of the Bulk Electric System. Redundancy of affected Facilities, systems, and equipment shall not be considered when determining adverse impact. Each BES Cyber Asset is included in one or more BES Cyber Systems.

Recommendation 1i states: 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’ (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.**

Likes 2	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.; Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making “critical natural gas infrastructure load” a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad; and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	

AEPC has signed on to ACES comments below:

The text of Requirement R2.2.8 requires the Balancing Authority to include provisions in their Operating Plan(s); however, the published Technical Rationale document does not align with the Requirement text.

Excerpt from published Technical Rationale (emphasis added):

“EOP-011-4 Requirement 2.2.8 was added to require Balancing Authorities to include provisions to identify and prioritize critical natural gas loads in their Operating Plan(s), similar to EOP-011-4 Requirements R1.2.5 and R7.1.5 applicable to Transmission Operators, Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners. The Technical Rationale verbiage above regarding the identification and prioritization of critical natural gas Loads applicable to Requirements R1.2.5 and R7.1.5 is also applicable to Requirement R2.2.8.”

Which is it? Is the Balancing Authority required to identify and prioritize or merely to include provisions in their Operating Plan(s) to exclude critical natural gas infrastructure loads?

While it is recognized that coordination of load shedding schemes may be (and likely will be) necessary at the Balancing Authority level, it should not be incumbent upon the Balancing Authority to identify critical natural gas infrastructure loads. Critical loads should be identified at a single operating level to prevent duplication and/or conflicting identifications. It is our recommendation that this identification of critical natural gas infrastructure loads should occur at the TOP level. Thus, we recommend modifying the text of this requirement as follows: “2.2.9. Provisions for excluding critical natural gas infrastructure loads, as identified by the TOP, from load shedding schemes (i.e., Interruptible Load, curtailable Load, or demand response) during periods when it would adversely impact the reliable operation of the BES;	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The Technical Rationale has been modified to more appropriately address the language in R2.2.8 and R2.2.9.	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	No
Document Name	
Comment	
Where generation is continuing their efforts to increase their layers of freeze protection measures, enough is *not* being done to minimize the risk and improve reliability with the emphasis on fuel. Not just natural gas but a complete diversity to ensure the US power grid has all necessary fuels for generation in any extreme condition. While electric demand is increasing, reliable generation resources are decreasing. The focus for renewables need to continue, but a review of current trends need to be weighed against the reliability and the increasing demands for today and the future. IPPs are forced to make business decisions based on market/tariff agreements during volatile conditions that can and does impact the livelihood for generation facilities. During extreme weather conditions reliability should become the priority and the market aspects or penalties should be removed from the equation. The RC, BA, TOP should be working together with congress to ensure the fuels are available and the grid is diverse enough for its reliable operation.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	No
Document Name	
Comment	

WECC believes the use of the term “critical” is ambiguous and formally undefined. Requirement 2 as written specifies the BA must exclude critical natural gas infrastructure loads from consideration as interruptible load, curtailable Load and demand response. Requirement 1 allows (requires) the TOP to identify the critical natural gas infrastruction loads. The FERC recommendation contained a description of “critical natural gas infrastructure loads” as “natural gas production, processing and intrastate and interstate pipeline facility loads which, if deenergized, could adversely affect provision of natural gas to bulk-power system natural gas-fired generation.” If this description is to be used by the TOP’s when identifying the critical natural gas infrastructucture loads WECC feels it should be added to the NERC Glossary of Terms or stated explicitly in the standard.

Also WECC believes it is not clear if the description provided would only apply to BES Generation Facilities that are defined as applicable in Section 4.2.1 of EOP-012-1 or considered for any BES Generation as the description implies.

The technical rational describes the consideration of “critical” gas infrastructure to be considered on a priority scale with some “critical” loads being a higher priority than other “critical” loads. WECC believes this aglso makes the use of the term “critical” ambiguous.

It was noted that EOP-011-4 does not contain any requirement for the TOP to provide the list of identified critical natural gas infrastructure loads to the Balancing Authority that must consider them in Requirement 2. This could be addressed by modification of the BA Data Specifications of TOP-003-4. But since this would be relatively unchanging information it might be preferable to specify its distribution in EOP-011-4.

WECC recommends the standard include more specific direction for identification of critical natural gas infrastructure loads for the TOP and to require communication of this information to all BA's which share its footprint. Alternately in line with the variable priorities discussed in the technical rational consider deleting the term "critical" and simply addressing the prioritization of natural gas infrastructure providing service to BES generation.	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making "critical natural gas infrastructure load" a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint. The SDT discussed and declined to create a separate provision that would require Transmission Operators to provide a listing of critical natural gas infrastructure loads to the Balancing Authority. If necessary, this could be obtained by the Balancing Authority though their Data Specifications.	
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
Answer	No
Document Name	
Comment	
In addition to PJM supporting the IRC SRC comments, PJM requests striking the language: 'during periods when it would adversely impact the reliable operation of the BES;' from R2.2.8. This is due to balancing Load and generation during emergency conditions and the concern with any possible interruption of natural gas fired resources. There is also a potential to impact other Balancing Authority Areas since critical natural gas infrastructure would most likely extend beyond the host Balancing Authority's footprint.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. The SDT discussed whether the exclusion of critical natural gas infrastructure loads as Interruptible Load, curtailable Load, and demand response should be limited to certain situations or be a complete prohibition. The SDT determined that a complete prohibition is not necessary at all times given that the natural gas system does not have the same limitations and criticality during all seasons and weather conditions. The SDT has limited the exclusion of these loads from Interruptible Load, curtailable Load, and demand response only to periods of extreme cold weather. Entities should note that the proposed Standard represents a minimum requirement which can be exceeded by individual entities if deemed appropriate.	
Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
In support of MRO NSRF comments.	
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	

For the purpose of this standard, WEC Energy Group suggests stating that "critical natural gas infrastructure load" is natural gas infrastructure that if rendered unavailable would adversely impact generator output and would affect the reliable operation of the Bulk Electric System.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making "critical natural gas infrastructure load" a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	No
Document Name	
Comment	
The addition of R2.2.8 seems repetitive since the BA is required in R2.2.9 (previously R2.2.8) to have provisions to implement manual load shed in accordance with R1.2.5 which already states the requirement to minimize the overlap of critical loads in manual load shed circuits. The SDT should consider adding "or automatic" to R2.2.9 to correspond to the language of "or automatic" being added to R1.2.5. Additionally R1.2.5 could be read to include Operator Controlled Automatic Load-shed. The SDT should consider modifying R1.2.5 as follows to clearly identify both in the sub-requirement: R1.2.5. Operator Controlled manual load shedding and automatic load shedding during an Emergency that accounts for each of the following: Recommended change: 2.2.9 Provisions for Transmission Operators to implement operator-controlled manual or automatic Load shed in accordance with Requirement R1 Part 1.2.5; and	

If the requirement remains, ISO-NE would support an addition to the NERC Glossary of Terms for "Critical Natural Gas Infrastructure"	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has incorporated these suggestions into the latest draft.	
Kimberly Bentley - Kimberly Bentley On Behalf of: Sean Erickson, Western Area Power Administration, 1, 6; - Kimberly Bentley	
Answer	No
Document Name	
Comment	
WAPA requests that the term "critical natural gas infrastructure" be defined. Additionally, WAPA would request that the definition, at a minimum, state "critical natural gas infrastructure" is natural gas infrastructure that if rendered unavailable would adversely impact generator output and would affect the reliable operation of the Bulk Electric System.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making "critical natural gas infrastructure load" a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	

We would like the SDT to clarify if the critical natural gas infrastructure loads to be identified are only in reference to electric generation or if it relates to all natural gas delivery. We believe the term "critical natural gas infrastructure loads" should be further explained / bounded within the standard, perhaps in a footnote(s). The technical rationale document for EOP-011-4 states that "the SDT did not prescribe specific methods [for identifying critical natural gas infrastructure loads] in the drafting of EOP-011-4", and notes three possible methods. The rationale document also suggests that a prioritization criteria be developed for critical natural gas infrastructure loads under various conditions. Recommendation 1i suggests that manual and automatic load shed entities 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. As written, R1 (part 1.2.5.5) and R2 (Part 2.2.8) could result in a wide range of interpretations.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making "critical natural gas infrastructure load" a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.	
Lori Frisk - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Form (NSRF) comments.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	2021-07_Cold_Weather_Phase 2_Unofficial_Comment_Form_SRC_04-12-23 - Clean.docx
Comment	

As written, Requirement R2 does not provide sufficient clarity. To provide adequate clarity, the ISO/RTO Council (IRC) **Standards Review Committee (SRC)[1] recommends the term "critical natural gas infrastructure load" be defined**. The definition should be:

· **Flexible** – to recognize that some Responsible Entities may already be subject to an approved definition for their jurisdiction (*see* proposed language below):

o ***Critical Natural Gas Infrastructure Load*** *- Shall have the meaning established by the Responsible Entity's approved governing documents or by the applicable regulatory authorities, or, if no applicable definition exists, is defined as electric loads that are involved in natural gas production, processing, or transmission or distribution, both intrastate and interstate, which if curtailed will impact the delivery of natural gas to bulk-power system natural gas-fired generation.*

· **Results-based and premised on reliability** - to minimize adverse impacts to the reliable operation of the Bulk Electric System. Portions of the definition for *BES Cyber Asset* may serve as a useful reference for appropriate language.

o ***BES Cyber Asset*** *- A Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one or more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the reliable operation of the Bulk Electric System. Redundancy of affected Facilities, systems, and equipment shall not be considered when determining adverse impact. Each BES Cyber Asset is included in one or more BES Cyber Systems*.

Finally, the **SRC requests the standard acknowledge that the ability to identify critical natural gas infrastructure loads requires the cooperation of natural gas providers, which are outside of NERC's jurisdiction, and other Registered Entities, such as DPs**. The ability of Responsible Entities to comply with the Standard should not depend on the extent to which natural gas providers are willing to work with Responsible Entities to identify critical natural gas infrastructure loads. Additionally, the obligations of Responsible Entities should be limited

to *known* critical natural gas infrastructure loads. Consequently, the SRC recommends that Requirement 2.2.8 be limited to known critical natural gas infrastructure loads, as follows: "Provisions for excluding *known* critical natural gas infrastructure loads as Interruptible Load, curtailable Load, and demand response during periods when it would adversely impact the reliable operation of the BES;" [1] For purposes of these comments, the IRC SRC includes the following entities: CAISO (with the exception of our response to question 5), ERCOT (with the exception of our responses to questions 3, 5 and 8), IESO, ISO-NE, MISO, NYISO, PJM and SPP.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making "critical natural gas infrastructure load" a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint. The identification and prioritization of critical natural gas loads requires coordination with natural gas facility owners and operators. The SDT recognizes that entities are dependent upon the cooperation of natural gas facility owners and operators to complete this task. However, it is outside the scope of the SDT to develop methods to compel natural gas owners and operators to cooperate and provide specific information to various entities.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	No
Document Name	
Comment	
The text of Requirement R2.2.8 requires the Balancing Authority to include provisions in their Operating Plan(s); however, the published Technical Rationale document does not align with the Requirement text.	

Excerpt from published Technical Rationale (emphasis added): “EOP-011-4 Requirement 2.2.8 was added to require Balancing Authorities to include provisions to identify and prioritize critical natural gas loads in their Operating Plan(s), similar to EOP-011-4 Requirements R1.2.5 and R7.1.5 applicable to Transmission Operators, Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners. The Technical Rationale verbiage above regarding the identification and prioritization of critical natural gas Loads applicable to Requirements R1.2.5 and R7.1.5 is also applicable to Requirement R2.2.8.” Which is it? Is the Balancing Authority required to identify and prioritize or merely to include provisions in their Operating Plan(s) to exclude critical natural gas infrastructure loads? While it is recognized that coordination of load shedding schemes may be (and likely will be) necessary at the Balancing Authority level, it should not be incumbent upon the Balancing Authority to identify critical natural gas infrastructure loads. Critical loads should be identified at a single operating level to prevent duplication and/or conflicting identifications. It is our recommendation that this identification of critical natural gas infrastructure loads should occur at the TOP level. Thus, we recommend modifying the text of this requirement as follows: “2.2.9. Provisions for excluding critical natural gas infrastructure loads, as identified by the TOP, from load shedding schemes (i.e., Interruptible Load, curtailable Load, or demand response) during periods when it would adversely impact the reliable operation of the BES;”	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The Technical Rationale has been modified to more appropriately address the language in R2.2.8 and R2.2.9.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	

ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) in response to this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
PacifiCorp requests that the term “critical natural gas infrastructure” be defined. Additionally, PacifiCorp would request that the definition, at a minimum, state “critical natural gas infrastructure” is natural gas infrastructure that if rendered unavailable would adversely impact generator output and would affect the reliable operation of the Bulk Electric System. The definition of BES Cyber Asset (included below) can be looked to for language similar to what PacifiCorp is requesting. **BES Cyber Asset** A Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one or more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the reliable operation of the Bulk Electric System. Redundancy of affected Facilities, systems, and equipment shall not be considered when determining adverse impact. Each BES Cyber Asset is included in one or more BES Cyber Systems.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making “critical natural gas infrastructure load” a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
AEP believes the revisions provide clarity.	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Yes, CenterPoint Energy Houston Electric, LLC (CEHE) agrees that the proposed EOP-011-4 Requirement R2 language provides sufficient clarity in regards to limiting critical natural gas infrastructure participation in demand response.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon supports EEI's comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kinte Whitehead - Exelon - 3	

Answer	Yes
Document Name	
Comment	
Exelon supports EEI comments.	
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 that the proposed EOP-011-4 Requirement R2 language provides sufficient clarity in regards to limiting critical natural gas infrastructure participation in demand response.	
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
Southern Company agrees with EEI comments that the language in proposed EOP-011-4, Requirement R2, provides sufficient clarity in regards to limiting critical natural gas infrastructure participation in demand response systems. However, Southern Company would point out a potential gap in the standard concerning TO/DP exclusion of Critical Natural Gas Infrastructure loads in their Demand Response Programs. Language for the use of and provision for excluding Critical Natural Gas Infrastructure loads as demand response to mitigate Energy Emergencies within the Balancing Authority Area is only present in the R2 requirements for BA. R1 requirements for TOP and R7 requirements for TO/DP only require provisions for the identification and prioritization of Critical Natural Gas Infrastructure loads, not the exclusion from Demand Response Programs. As written, the standard gives the BA no authority to require that TOs or DPs develop their Demand Response programs in this manner and the BA Operating Plans(s) can only accommodate what is provided by the TOP, TO, and DP. To close this gap Southern Company would suggest that parallel requirements to R2.2.8 be placed upon the TOP, TO, and DP to exclude any identified designated critical natural gas infrastructure loads in their Demand Response Program offered for use in the BA Operating Plan(s) to mitigate Energy Emergencies during periods when it would adversely impact the reliable operation of the BES. The Commission should clarify that critical natural gas infrastructure can participate in Demand Response Programs such as real-time pricing which do not restrict the natural gas facilities from operating during energy emergencies. **Recommendation 1i states: 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' (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.	
Likes 0	
Dislikes 1	Platte River Power Authority, 1, Archie Marissa
Response	
Thank you for the comment. The SDT feels it is appropriate to limit this to the Balancing Authorities Operating Plan(s) as per Key Recommendation 1h.	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	
BHP is not a BA.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
BHP is not a BA.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	Yes
Document Name	
Comment	
BHP is not a BA.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
Answer	Yes
Document Name	
Comment	
BHP is not a BA.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment.	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Comments: *The SDT may want to consider defining the term "Critical Natural Gas Infrastructure Load" while recognizing that some Responsible Entities may already have an approved definition in place for their jurisdiction (see proposed language below):* *Critical Natural Gas Infrastructure Load - Shall have the meaning established by the Responsible Entity's approved governing documents or by the applicable regulatory authorities, or, if no applicable definition exists, is defined as any natural gas infrastructure load, if de-energized, could adversely impact BES reliability".*	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making "critical natural gas infrastructure load" a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	

PNM is in agreement that there is sufficient clarity regarding EOP-011-4 R2 and is in agreemetn with EEI's comments.	
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 Constellation Segements 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, 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 the comments of the Edison Electric Institue (EEI) to question #1,	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI agrees that the language in proposed EOP-011-4, Requirement R2, provides sufficient clarity in regards to limiting critical natural gas infrastructure participation in demand response systems.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	

Constellation has no additional comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Dave Krueger - SERC Reliability Corporation - 10	
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.	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Joshua London - Eversource Energy - 1, Group Name Eversource	
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, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
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.	

Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
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	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Marc Sedor - Seminole Electric Cooperative, Inc. - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
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.	
Tracy MacNicoll - Utility Services, Inc. - 4	
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.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Ken Habgood - Seminole Electric Cooperative, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
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 appreciates and supports the standard drafting team's (SDT) efforts in address the Joint Inquiry report for Winter Storm Uri. Texas RE is concerned, however, that Balancing Authorities (BAs), the entities responsible for developing Operating Plans in EOP-011-4 R2 may lack sufficient information to properly design those plans. As an initial matter, Texas RE notes that there is no provision for the BA receiving information regarding critical natural gas infrastructure loads. Texas RE recommends an explicit requirement for the BA to receive the critical natural gas infrastructure load information. Texas RE is also concerned the BAs may not receive information on the criticality of natural gas loads in multiple TOP Areas. If the natural gas infrastructure is in TOP Area 1 but affects units in TOP Area 2, it is unclear how TOP Area 2 would recognize the impact.

Moreover, while Texas RE understands the need for flexibility, Texas RE is also concerned the phrase "when it would adversely impact the reliable operation of the BES" does not fully meet the recommendation objective to "prohibit use" of critical natural gas infrastructure loads for demand response. As noted in the February 2021 Cold Weather Outages in Texas and the South Central United States Joint Inquiry Report ("Joint Inquiry"), BA operating plans may include natural gas infrastructure loads in demand response programs. In contrast, however, designated critical natural gas infrastructure loads which, "if de-energized, would adversely affect BES natural gas-fired generation" should be prohibited from participating in demand response programs. (Joint Inquiry, at 207). The proposed EOP-011-4 R2.2.2.8 language appears to permit critical natural gas infrastructure to participate in demand response programs if it would not adversely impact reliability. However, as the Joint Inquiry defines "critical natural gas infrastructure loads" as "natural gas infrastructure loads which, if de-energized, could adversely affect the provision of natural gas to BES-fired natural gas-fired generating units, thereby adversely affecting BES reliability," the inclusion of critical natural gas infrastructure should, by definition, adversely impact BES reliability. Instead of effectively creating a hollow provision and potential confusion, Texas RE recommends either removing this phrase "when in would adversely impact . . . BES" and/or clarify that non-critical natural gas infrastructure loads may be properly included in BA-developed demand response programs.

Texas RE recommends the requirement apply to any manual or automatic load shed programs. The term "Interruptible Load" references the inactive function LSE. The other terms, curtailable Load and demand response, are not defined.

Likes 0	
Dislikes 0	

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Response	
Thank you for your comment. The SDT discussed and declined to create a separate provision that would require Transmission Operators to provide a listing of critical natural gas infrastructure loads to the Balancing Authority. If necessary, this could be obtained by the Balancing Authority though their Data Specifications. The SDT discussed whether the exclusion of critical natural gas infrastructure loads as Interruptible Load, curtailable Load, and demand response should be limited to certain situations or be a complete prohibition. The SDT determined that a complete prohibition is not necessary at all times given that the natural gas system does not have the same limitations and criticality during all seasons and weather conditions. The SDT has limited the exclusion of these loads from Interruptible Load, curtailable Load, and demand response only to periods of extreme cold weather. Entities should note that the proposed Standard represents a minimum requirement which can be exceeded by individual entities if deemed appropriate. EOP-011-4 requirements that address manual load shedding or automatic load shedding are primarily in R1 and R8, not R2.2.8.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	
Document Name	

Comment	
No comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	
Document Name	
Comment	
N/A to Hydro One	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

See the unofficial comment form for additional information: https://www.nerc.com/pa/Stand/Project202107ExtremeColdWeatherDL/2021-07_Cold_Weather_Phase%202_Unofficial_Comment_Form_02282023.docx

2. The standard drafting team (SDT) made changes to the applicability section based on the recommendation above (additional clarity included in the technical rationale). Do you believe these are the correct Functional Entities to include? If not, please provide details and any other Functional Entities be added with justification.

Scott McGough - Georgia System Operations Corporation - 3	
Answer	No
Document Name	
Comment	
The NERC Reliabilty Standard for Undervoltage Load Shedding, PRC-010-2 references “UVLS entities” as an applicable entity. GSOC suggests considering UVLS entities be a Functional entity that would apply under “automatic Load shedding” for R7.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. PRC-010-2 defines UVLS entities as “Distribution Providers and Transmission Owners responsible for the ownership, operation or control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator.” Distribution Providers and Transmission Owners have been included in the Applicability section of EOP-011-4 so it is not necessary to also include the term “UVLS entities.”	
Ken Habgood - Seminole Electric Cooperative, Inc. - 4	
Answer	No
Document Name	

Comment	
Should not include the additional functional entities as proposed in 4.1.4, 4.1.5 and 4.1.6. This is adding extra layers of coordination and processes that will be complex and difficult due to multiple DPs trying to coordinate in multiple TOs area .. This would be burdensome on the TOP as well.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT disagrees. In many cases, Transmission Operators are dependent on Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners to implement portions of Requirement R1.2.5. The SDT determined that is necessary to expand the Applicability of EOP-011-4 to these Functional Entities in order to address all entities responsible for performing operator-controlled manual Load shedding or automatic Load shedding per Key Recommendation 1i. To the extent additional coordination is required, this is an appropriate burden to ensure operator-controlled manual Load shedding or automatic Load shedding are performed in a manner that support the reliable operation of the BES.	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
Should not include the additional functional entities as proposed in 4.1.4, 4.1.5 and 4.1.6. This is adding extra layers of coordination and processes that will be complex and difficult due to multiple DPs trying to coordinate in multiple TOs area .. This would be burdensome on the TOP as well.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT disagrees. In many cases, Transmission Operators are dependent on Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners to implement portions of Requirement R1.2.5. The SDT determined that is necessary to expand the Applicability of EOP-011-4 to these Functional Entities in order to address all entities responsible for performing operator-controlled manual Load shedding or automatic Load shedding per Key Recommendation 1i. To the extent additional coordination is required, this is an appropriate burden to ensure operator-controlled manual Load shedding or automatic Load shedding are performed in a manner that support the reliable operation of the BES.

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	

We don’t believe that the proposed changes to the applicability section sufficiently address recommendation 1i. The recommendation references the roles of the Planning Coordinator and Transmission Planner in regard to automatic load shedding (e.g., underfrequency load shedding, undervoltage load shedding), but those entities have not been addressed. While the entities added (DP, UFLS-Only DP, TO) have a role in implementing automatic load shedding programs developed by the PC or TP, we believe the drafting team should consider changes to the PRC-006 (Automatic Underfrequency Load Shedding) and PRC-010 (Undervoltage Load Shedding) standards to more fully address recommendation 1i.

We question the addition of “or automatic” in R1, Part 1.2.5. We suggest the following restructuring for 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 for identifying any other entities (DP, TO) that help execute manual Load shedding during an Emergency;

1.2.5.3. Provisions for the periodic identification and prioritization of designated critical loads, including critical natural gas infrastructure loads;

1.2.5.4. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that serve designated critical loads, including critical natural gas infrastructure loads; 1.2.5.5. Provisions for periodic coordination with the appropriate UFLS Entities and UVLS Entities to obtain information on their circuits that are utilized for automatic underfrequency load shed (UFLS) or automatic undervoltage load shed (UVLS); and 1.2.5.6. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for automatic underfrequency load shed (UFLS) or automatic undervoltage load shed (UVLS).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT discussed the inclusion of the Planning Coordinator and Transmission Planner roles in Key Recommendation 1i and determined that it was not necessary to include them in EOP-011-4. The SDT also determined that it was not necessary to make changes to PRC-006 or PRC-010. The reasoning for this is that the Planning Coordinator and Transmission Planner responsibilities in PRC-006 and PRC-010 are primarily around the development UFLS programs and UVLS programs. The implementation of those programs is handled by UFLS entities and UVLS entities which by definition includes Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners. EOP-011-4 does not address the development of UFLS Programs and UVLS Programs. Changes were made to R1.2.5, R2.2.9 and R8.1 to more consistently address operator-controlled manual Load shedding and automatic Load shedding.	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	No
Document Name	
Comment	
SRP supports TPWR comments.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Marc Sedor - Seminole Electric Cooperative, Inc. - 3	
Answer	No
Document Name	
Comment	
Should not include the additional functional entities as proposed in 4.1.4, 4.1.5 and 4.1.6. This is adding extra layers of coordination and processes that will be complex and difficult due to multiple DPs trying to coordinate in multiple TOs area .. This would be burdensome on the TOP as well.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT disagrees. In many cases, Transmission Operators are dependent on Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners to implement portions of Requirement R1.2.5. The SDT determined that is necessary to expand the Applicability of EOP-011-4 to these Functional Entities in order to address all entities responsible for performing operator-controlled manual Load shedding or automatic Load shedding per Key Recommendation 1i. To the extent additional coordination is required, this is an appropriate burden to ensure operator-controlled manual Load shedding or automatic Load shedding are performed in a manner that support the reliable operation of the BES.	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	No

Document Name	
Comment	
Tacoma Power requests additional clarity on the applicability section. For EOP-011-4 Requirements 1.2.5.5 and 1.2.5.6, does the SDT intend for TOPs to account for all distribution providers in their Operating Plans (even non-BES providers), or is it limited to registered Distribution Providers only? Additionally, is the TOP responsible for identifying critical natural gas infrastructure loads that are located on non-registered distribution provider networks? If this Standard is requiring TOPs to account for non-registered distribution providers, then there may be difficulty collecting this information, since these providers aren't subject to NERC jurisdiction.	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	
Thank you for your comment. The Applicability section and TOP obligations for identifying and notifying in Requirement R7 is limited to entities registered with NERC as a Distribution Provider, UFLS-Only Distribution Provider, or Transmission Owner.	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	No
Document Name	
Comment	
Should not include the additional functional entities as proposed in 4.1.4, 4.1.5 and 4.1.6. This is adding extra layers of coordination and processes that will be complex and difficult due to multiple DPs trying to coordinate in multiple TOs area .. This would be burdensome on the TOP as well.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The SDT disagrees. In many cases, Transmission Operators are dependent on Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners to implement portions of Requirement R1.2.5. The SDT determined that is necessary to expand the Applicability of EOP-011-4 to these Functional Entities in order to address all entities responsible for performing operator-controlled manual Load shedding or automatic Load shedding per Key Recommendation 1i. To the extent additional coordination is required, this is an appropriate burden to ensure operator-controlled manual Load shedding or automatic Load shedding are performed in a manner that support the reliable operation of the BES.	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Regardless of DP, TO or UFLS-Only DP applicability, BPA believes those entities do not have the legal authority to require natural gas companies to identify and disclose information pertaining to their critical natural gas facilities (locations, etc.). Natural gas entities are not NERC Registered entities. BPA seeks clarity on how this information could be obtained if a natural gas entity refuses to provide its information.	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	
Thank you for your comment. Additional content has been added to the Technical Rationale to address this topic. The identification and prioritization of critical natural gas loads requires coordination with natural gas facility owners and operators. The SDT recognizes that entities are dependent upon the cooperation of natural gas facility owners and operators to complete this task. However, it is outside the scope of the SDT to develop methods to compel natural gas owners and operators to cooperate and provide specific information to various entities.	
Thomas Foltz - AEP - 5	
Answer	No

Document Name	
Comment	
While AEP does not object to the three entities which have been added as Functional Entities in 4.1.4 through 4.1.6, we believe natural gas owners and operators would need to be added as well. Please see our response to Question 4 regarding their omission.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Natural gas owners and operators are not NERC functional entities and it is outside the scope of the SDT to address this topic. The identification and prioritization of critical natural gas loads requires coordination with natural gas facility owners and operators. The SDT recognizes that entities are dependent upon the cooperation of natural gas facility owners and operators to complete this task. However, it is outside the scope of the SDT to develop methods to compel natural gas owners and operators to cooperate and provide specific information to various entities.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) in response to this question. Additionally, ERCOT would like to highlight that assigning real-time operational tasks to TOs would require modifications to COM, IRO, and TOP Reliability Standards to ensure these entities have the communications infrastructure and compliance responsibilities necessary to reliably receive and execute real-time operating instructions. ERCOT continues to encourage the use of proper registration, Coordinated Functional Registration agreements, or Regional Standards to address scenarios in which one functional entity might be better suited to perform tasks typically carried out by a different functional entity. ERCOT discourages the creation of ambiguous obligations for a functional entity, such as a TO, to perform tasks typically reserved for a different functional entity, such as a TOP or a DP.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT agrees with your comment and has made changes in R7 and R8 to more appropriately characterize the roles of Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners as "assisting with the mitigation of operating Emergencies." In alignment with this change, the term "Operating Plan" in R8 has been changed to "Load shedding plan."	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	
The SRC[1] thanks the SDT for adopting its recommendation made during Project 2021-07 Phase 1 (Draft #1). SRC agrees with the proposed additions to the applicability section, as these functional entities (i.e., Distribution Provider, UFLS-only Distribution Provider and Transmission Owners) have important roles to play in protecting critical natural gas infrastructure loads from load shed. That said, the SRC is concerned with the use of the proposed language, "Operating Plan," in the Applicability section and in Requirement R7, as it may be construed to assign UFLS-Only Distribution Providers and Transmission Owners real-time operational tasks that they are not equipped to handle. Therefore, SRC recommends the language "to mitigate operating Emergencies" in applicability sections 4.1.5 and 4.1.6 be revised to read "to assist with mitigating operating Emergencies," and that the language in R7 be modified as indicated below. Other clarifications to Requirement R7 are also proposed in the SRC's response to Question 9. **R7.** Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner identified in a Transmission Operator's Operating Plan(s) to *assist with* mitigat*ing* operating Emergencies in its Transmission Operator Area shall, *in consultation with the Transmission Operator, develop, maintain, implement, and provide to the Transmission Operator an Operator-controlled manual, or automatic Load shedding program, that accounts for each of the following, as applicable:* [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]	

[1] For purposes of these comments, the IRC SRC includes the following entities: CAISO (with the exception of our response to question 5), ERCOT (with the exception of our responses to questions 3, 5 and 8), IESO, ISO-NE, MISO, NYISO, PJM and SPP.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT agrees with your comment and has made changes in R7 and R8 to more appropriately characterize the roles of Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners as "assisting with the mitigation of operating Emergencies." In alignment with this change, the term "Operating Plan" in R8 has been changed to "Load shedding plan."	
Tracy MacNicoll - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Recommend specifically identifying that the Operating Plans that make a TO/DP/DP-UFLS applicable are those referenced in R1. Curently written, this could be interpereted as any TO/DP/DP-UFLS that is part of a TOP Operating Plan to mitigate operating Emergencies is applicable to EOP-011-4. See applicability section of PRC-023 as an example.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the approach of identifying and notifying Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners to make this clearer in R7 and R8.	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	

Comment	
This seems to be the correct entities to include in the applicability section The SDT should consider adding automatic to EOP-011 R7.1.2. As in R1.2.5.2, the sub-requirements only call for the minimization of overlap between MANUAL load shed circuits and designated critical loads. Adding automatic to R7.1.2 would emphasize the minimization of overlap for both manual and automatic load shed circuits, while not prohibiting the overlap where it may be necessary as stated in the technical rationale. Although the intent is there, the standard doesn't explicitly address that potential overlap. Recommend adding automatic to R7.1.2 The proposed R1.2.5.5 is specific to "critical gas infrastructure load". The SDT should consider that this be rewritten to be more generic to encompass all "designated critical loads" and not just for gas infrastructure? Does this make sense to specifically call it out in a separate requirement. The SDT should consider whether or not to include a new term in the NERC Glossary of "Designated Critical Load" which would define what the minimum standard critical loads are, including, but not limited to critical gas infrastructure, critical fuel delivery infrastructure, off-site nuclear feeds, public safety, public health, etc. A recommendation for language is provided in ISO-NE's response to Question 4.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Changes were made to R1.2.5, R2.2.9, and R8.1 to more consistently address operator-controlled manual Load shedding and automatic Load shedding. The SDT discussed and chose to maintain the separate provisions related to the identification and prioritization of critical natural gas infrastructure in 1.2.5.5 and 8.1.5.	

The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making “critical natural gas infrastructure load” a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.

Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
In support of MRO NSRF comments.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment, please see response to MRO NSRF.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI agrees that TOs, DPs and UFLS-Only DPs are the correct Functional Entities.	
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 Constellation Segements 5 and 6	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment.	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	
PNM is in agreement that with the three additions to the functional entities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
There is a concern with the use of the proposed language, “Operating Plan,” in Requirement R7 as it may denote real-time operational tasks to UFLS-Only Distribution Providers and Transmission Owners that they are not equipped to handle. IESO recommends that “Operating Plan” be replaced with “Load Shedding Procedures”.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The SDT agrees with your comment and has made changes in R7 and R8 to more appropriately characterize the roles of Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners as "assisting with the mitigation of operating Emergencies." In alignment with this change, the term "Operating Plan" in R8 has been changed to "Load shedding plan."	
Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
Answer	Yes
Document Name	
Comment	
BHP is not a BA.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	Yes
Document Name	
Comment	
BHP is not a BA.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.
Micah Runner - Black Hills Corporation - 1

Answer	Yes
Document Name	
Comment	
BHP is not a BA.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	
BHP is not a BA.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Lindsey Mannion - ReliabilityFirst - 10	

Answer	Yes
Document Name	
Comment	
TO, DP, and DP-UFLS appear to be the correct Functional Entities, but RF recommends considering a requirement for the TOP to notify identified TO, DP, or DP-UFLS Functional Entities. This could be accomplished by revising R1 Part 1.2.5.6 to state "Provisions for the identification and notification of…" or by adding a separate requirement analogous to EOP-005-3 R2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT agrees this is an issue and has added a new R7 and modified R8 to include the concept of identification and notification. Please see the Technical Rationale for additional explanation of these changes.	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
Some clarification may be beneficial in regards to whether this is the expectation for natural gas transmission and distribution facilities, or does this expectation also include natural gas production facilities (wells, processing plants, etc).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making "critical natural gas infrastructure load" a defined term, providing flexibility for individual entities to	

apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	

Southern Company believes that the language as written is overly broad as to the applicability of DPs. Therefore, Southern Company would suggest language changes in the Applicability section 4.1.4 to include only DPs with identified Critical Natural Gas Infrastructure loads as Applicable Functional Entities:

"4.1.4 Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area **as serving one or more Critical Natural Gas Infrastructure loads** "

Southern Company would also add the following language to clarify R7 to specify that the operating plans now required by the TOs and DPs are to achieve the goal of implementing portions of the TOPs requirements in R1.2.5 as stated in the EOP-011-4 Technical Rationale:

"Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner identified in a Transmission Operator's Operating Plan(s) **as implementing portions of its Requirements in R1.2.5** to mitigate operating Emergencies in its Transmission Operator Area shall develop, maintain and implement one or more Operating Plan(s). The Operating Plan(s) shall be provided to the Transmission Operator. The Operating Plan(s) shall include the following, as applicable:"

Alternately, R7 could be narrowed such that the DP does not need to develop and Operating Plan so long as the DP communicates to the TOP how the load is served and that no Critical Natural Gas Infrastructure loads are part of any load shed or Demand Response programs. Suggested modifications to R7 are as follows:

"Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner identified in a Transmission Operator's Operating Plan(s) **which serves one or more Critical Natural Gas Infrastructure loads shall communicate to the Transmission Operator how the load(s) is served and verify that the load(s) is not included in the Distribution Provider's manual or automatic load shed programs and that the load(s) is not in a Demand Response Program which would restrict operation during an Energy Emergency.**"

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT disagrees that the Applicability is overly broad and should in fact be applicable beyond just the handling of critical natural gas infrastructure loads. In many cases, Transmission Operators are dependent on Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners to implement portions of Requirement R1.2.5. The SDT determined that is necessary to expand the Applicability of EOP-011-4 to these Functional Entities in order to address all entities responsible for performing operator-controlled manual Load shedding or automatic Load shedding per Key Recommendation 1i. To the extent additional coordination is required, this is an appropriate burden to ensure operator-controlled manual Load shedding or automatic Load shedding are performed in a manner that support the reliable operation of the BES.	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Southern Indiana Gas & Electric Company (SIGE) agrees that the TOs, DPs and UFLS-Only DPs are the correct Functional Entities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	

Comment	
Exelon supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon supports EEI's comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Yes, CEHE agrees that the TOs, DPs, and UFLS-Only DPs are the correct Functional Entities.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
ATC agrees with the changes made by the SDT to the applicable entities as these are the entities that have the information the TOP or BA needs to develop appropriate plans. In addition, these are typically the entities with the direct relationships with the end-use customer natural gas infrastructure loads. It is also important to note that successfully complying with the standard requires cooperation from these end-use customers, who have no regulatory obligation to provide this information.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Lori Frisk - Allete - Minnesota Power, Inc. - 1	
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.	
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	
Thank you for your support.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
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	
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.	
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.	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
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; Jeremy Harris, 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.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Steven Rueckert - Western Electricity Coordinating Council - 10	
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, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD	

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.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Jou Yang - 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.	
Joshua London - Eversource Energy - 1, Group Name Eversource	
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.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
Answer	

Document Name	
Comment	
PJM supports the IRC SRC comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE agrees with the changes to the applicability section of EOP-011-4. Texas RE recommends that TP/PC also be included so planners will be made aware of critical natural gas infrastructure loads during planning analyses and understand which loads to drop in order to plan effectively (and not exacerbate an operational issue).

Likes 0	
Dislikes 0	

Response
Thank you for your comment. The SDT discussed the inclusion of the Planning Coordinator and Transmission Planner roles in Key Recommendation 1i and determined that it was not necessary to include them in EOP-011-4. The SDT also determined that it was not necessary to make changes to PRC-006 or PRC-010. The reasoning for this is that the Planning Coordinator and Transmission Planner responsibilities in PRC-006 and PRC-010 are primarily around the development UFLS programs and UVLS programs. The implementation of those programs is handled by UFLS entities and UVLS entities which by definition includes Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners. EOP-011-4 does not address the development of UFLS Programs and UVLS Programs.

3. Is the implementation timeframe for EOP-011-4 Requirement R7 reasonable given that it is applicable to Functional Entities who were not previously included in Applicability for EOP-011-3?

Dave Krueger - SERC Reliability Corporation - 10	
Answer	No
Document Name	
Comment	
On behalf of the SERC Generator Working Group (GWG) We believe the intent is that those loads have been identified within 18 months is reasonable. However, if those critical loads need to be removed, that may not be possible, if, for example, a new feeder must be built. Request clarity that the intent is the former, not latter.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	No

Document Name	
Comment	
ATC does not agree that the implementation timeframe for EOP-011-4 Requirement 7 is reasonable. TOPs that are not vertically integrated utilities, like ATC, will need to rely on a number of Distribution Providers to provide information related to prioritization of designated critical natural gas infrastructure. As such, 18 months is not enough time to gather all of the information, modify load shed plans, and train system operators on the new plans. An implementation timeframe of 24 to 36 months would be more realistic.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

Eighteen months would not be sufficient for the new Functional Entities (4.1.4 through 4.1.6) to become compliant with their EOP-011 obligations. Additional time will be needed to develop accurate lists of critical gas infrastructure and install Distribution SCADA network equipment to allow load shed to take to place as per R7. AEP instead recommends an implementation period of 36 months. To ensure the success of any implementation period used, AEP believes it would be beneficial if the RTOs provided natural gas providers a registration system that Functional Entities could use to comply with R7.

Likes 0	
Dislikes 0	

Response
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	

Comment
FE supports EEI Comments which state: EEI could support 18 months to identify critical natural gas infrastructure, however, 18 months is insufficient for TOs, DPs and UFLS Only DPs to either move those loads to other feeders or in many cases to entirely exclude those feeders from their load shedding programs and find

other suitable offsetting loads in their place. Often this work requires both engineering and field crew support to fully accomplish. The effort will likely require 36 months to fully implement. For this reason, we suggest a phased approach that provides 18 months to identify the critical natural gas infrastructure and 18 additional months to make system and field changes.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA disagrees with 18 months as a feasible timeframe to implement EOP-011-4. BPA believes these revisions would require identification of all critical natural gas facilities across BPA's very large transmission network footfrint, which spans the entire Pacific Northwest. BPA believes this could potentially require removal and/or installation of new UFLS relays at all substation locations surrounding that natural gas critiacal load. BPA believes the amount of work required to achieve this, including design and construction activities, could take up to 5+ years. BPA recommends a longer, phased in approach, similar to PRC-005 (PSMP) or PRC-002 (Equipment Monitoring).	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	No
Document Name	
Comment	
Request 36 months	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements.	

The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.

Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
No,CEHE could support the 18 month implementation timeframe; however, CEHE also supports the comments as submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	

Comment	
Exelon supports EEI's comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kinte Whitehead - Exelon – 3	
Answer	No
Document Name	
Comment	
Exelon supports EEI comments.	
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	No
Document Name	
Comment	
As drafted, Southern Company agrees with EEI comments that 18 months is insufficient for DPs to document and implement a plan to identify, designate, and prioritize critical natural gas infrastructure loads. If the standard was narrowed as suggested in our comments for	

Question 2, for DPs to verify the exclusion of gas infrastructure loads from their manual and automatic load shed programs, Southern Company believes 18 months may be sufficient time.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
This will be a very difficult implementation time frame for the Distribution Provider to meet. Suggest at least a 48month implementation.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12	

additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	No
Document Name	
Comment	
RF recommends the implementation plan specify the timeframe allotted for a TO, DP, or DP-UFLS newly identified in a TOP Operating Plan to develop its own Operating Plan following notification by the TOP.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
MRO NSRF is supportive of 18 months; MRO NSRF does not want to see the implementation period go beyond 18 months to ensure all impacted entities have updated load shed plans in place in time for the 2025-2026 Winter Season. Additionally, MRO NSRF refers the Standard Drafting team to Recommendation 28 of *The February 2021 Cold Weather Outages in Texas and the South Central United States* report. The MRO NSRF encourages the standard drafting team to consider how the content of this recommendation can be taken into account. Recommendation 28 states that various entities "should jointly conduct a study to establish guidelines to assist natural gas infrastructure entities in identifying critical natural gas infrastructure loads…" Recommendation 28 also states that "This Recommendation is necessary to support Key Recommendation 1i, regarding the protection of critical natural gas infrastructure loads."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	

AEPC has signed on to ACES comments below:

There is not a separate implementation phase for a newly identified DP, DP-UPFL, and/or TO. As an example, if the standard goes into effect 1/1/2025 and the TOP now identifies a DP in its Operational Plan on 1/1/2025 (per proposed Requirement R1.2.5.6), the current language and Implementation Plan seems to indicate that the DP must immediately have a plan implemented on the same day. Thus, we recommend a phased-in compliance approach for Requirement R7.

Furthermore, there is no provision in Requirement R7 for how long a newly identified DP, DP-UFLS, or TO has to develop their Operating Plan(s) in the future. In other words, if at some point in the future the TOP revises their Operating Plan(s) to now include a previously unidentified DP, the verbiage in R7 seems to indicate that the DP would be required to develop an Operating Plan on the same day. We recommend modifying the text of Requirement R7 as follows:

"R7. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner identified in a Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area shall develop, maintain, and implement one or more Operating Plan(s) within six (6) calendar months of being notified by the Transmission Operator. The Operating Plan(s) shall be provided to the Transmission Operator. The Operating Plan(s) shall include the following, as applicable:"

Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements.

The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	No
Document Name	
Comment	
PNM supports EEI's suggested phased approach that provides 18 months to identify the critical natural gas infrastructure and 18 additional months to make system and field changes.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No

Document Name	
Comment	
APS agrees with EEI and supports a phased approach that provides 18 months to identify the critical natural gas infrastructure and 18 additional months to make system and field changes. The 18-month time frame is sufficient to identify natural gas infrastructure. However, it is insufficient for TOs, DPs, and UFLS Only DPs to either move those loads to other feeders or to entirely exclude those feeders from their load shedding programs and find other suitable offsetting loads in their place. This work often requires both engineering and field crew support to fully accomplish and will likely require 36 months to fully implement.	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, 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 the comments of the Edison Electric Institue (EEI) to question #3,	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI could support 18 months to identify critical natural gas infrastructure, however, 18 months is insufficient for TOs, DPs and UFLS Only DPs to either move those loads to other feeders or in many cases to entirely exclude those feeders from their load shedding programs and find other suitable offsetting loads in their place. Often this work requires both engineering and field crew support to fully accomplish. The effort will likely require 36 months to fully implement. For this reason, we suggest a phased approach that provides 18 months to identify the critical natural gas infrastructure and 18 additional months to make system and field changes.	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	

Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
In support of MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	No
Document Name	
Comment	

A phased in implementation time would be more reasonable, 25-50-75-100% on an annual basis starting after 12 months as larger Transmission Entities need a longer implementation period. Under R7 7.1.4 it is not clear what is meant by this sub-requirement and what the impact to implementation may be. It is not clear if this is implying some type of dynamic selection of load based on system conditions or something else so clarity on the intent of this would be helpful.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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. Please refer to the Technical Rationale for EOP-011-3 for additional explanation on the background of 7.1.4 (which is now 8.1.4). This is the same requirement as was included in EOP-011-3 R1.2.5.4.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group does not agree that the implementation timeframe for EOP-011-4 R7 is reasonable. The 18-month implementation timeframe is insufficient to identify all critical natural gas infrastructure and to modify all impacted operator-controlled or manual load shed	

plans. The 18 months would be sufficient for identification, and an additional 18 months would be necessary for development of new and/or the modification of existing load shed plans to ensure that they are adequately avoiding critical natural gas infrastructure while also meeting the reliability needs of the load shed process. It is also important to remember that this process is contingent on cooperation from natural gas customers, who have no regulatory obligation to provide this information. WEC Energy Group also holds that since natural gas customers must self-identify their critical natural gas infrastructure, the language in the standard should take this into account.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
Marc Sedor - Seminole Electric Cooperative, Inc. - 3	
Answer	No
Document Name	
Comment	
Request 36 months	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Given our concerns with Draft 1, it's difficult to comment on the reasonableness of an 18 month implementation timeframe. Our sense is that a longer implementation period (perhaps 24 to 30 months) would be more reasonable for some entities given the expanded entity applicability and need to develop and implement a process for identifying "critical natural gas infrastructure loads".	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements.	

The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.

Lori Frisk - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	

Tracy MacNicoll - Utility Services, Inc. - 4	
Answer	No
Document Name	
Comment	

18 months for the identification of applicable circuits is appropriate, however the implementation of adding those circuits to a load shedding program requires an additional 12-18 months (especially for R7.1.5 critical natural gas infrastructure loads)	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
Request 36 months	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.

Ken Habgood - Seminole Electric Cooperative, Inc. - 4	
Answer	No
Document Name	
Comment	
Request 36 months	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	No
Document Name	
Comment	

There is not a separate implementation phase for a newly identified DP, DP-UPFL, and/or TO. As an example, if the standard goes into effect 1/1/2025 and the TOP now identifies a DP in its Operational Plan on 1/1/2025 (per proposed Requirement R1.2.5.6), the current language and Implementation Plan seems to indicate that the DP must immediately have a plan implemented on the same day. Thus, we recommend a phased-in compliance approach for Requirement R7.

Furthermore, there is no provision in Requirement R7 for how long a newly identified DP, DP-UFLS, or TO has to develop their Operating Plan(s) in the future. In other words, if at some point in the future the TOP revises their Operating Plan(s) to now include a previously unidentified DP, the verbiage in R7 seems to indicate that the DP would be required to develop an Operating Plan on the same day. We recommend modifying the text of Requirement R7 as follows:
"R7. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner identified in a Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area shall develop, maintain, and implement one or more Operating Plan(s) within six (6) calendar months of being notified by the Transmission Operator. The Operating Plan(s) shall be provided to the Transmission Operator. The Operating Plan(s) shall include the following, as applicable:"

Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements.

The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT recommends a 24-month implementation timeframe to allow for the coordination, budget revisions, staffing changes, and systems upgrades that may be necessary to accomplish the new tasks.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	

Comment	
PacifiCorp is supportive of 18 months; PacifiCorp does not want to see the implementation period go beyond 18 months to ensure all impacted entities have updated load shed plans in place in time for the 2025-2026 Winter Season. Additionally, PacifiCorp refers the Standard Drafting team to Recommendation 28 of *The February 2021 Cold Weather Outages in Texas and the South Central United States* report. PacifiCorp encourages the standard drafting team to consider how the content of this recommendation can be taken into account. Recommendation 28 states that various entities "should jointly conduct a study to establish guidelines to assist natural gas infrastructure entities in identifying critical natural gas infrastructure loads…" Recommendation 28 also states that "This Recommendation is necessary to support Key Recommendation 1i, regarding the protection of critical natural gas infrastructure loads."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
Scott McGough - Georgia System Operations Corporation - 3	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Southern Indiana Gas & Electric Company (SIGE) agrees that the 18 month implementation timeframe is reasonable.	
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 Constellation Segements 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. Alison Mackellar on behalf of Constellation Segments 5 and 6	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
An 18 month implementation timeframe may be appropriate assuming the NERC Standard is approved through FERC on the same general timetable as the Phase 1 Standards, FERC approval approx. Feb 2024, with effective date of October 1, 2025 which would be prior to the 2025 winter period. However, the SDT should consider that based on the current status of the SDT through Phase 2 with this version of EOP-011 already at the first ballot, a 12 month timeframe might be appropriate so that if FERC were to approve the Standard in 2023, there would be the possibility of the effective date being prior to the 2024 winter period, or at least near the start of the 2024 winter period. If Phase 2 Standards revisions were to be adopted before October 1, 2023, the effective date would aling with the expected Effective date of the Phase 1 EOP-011 and EOP-012 which could eliminate a potential risk of compliance with multiple versions of the same Standard. ISO-NE does not support any implementation timeframe that goes beyond the start of the 2025-2026 Winter.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12	

additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	
The SRC[1] supports an implementation timeframe of 18 months to ensure Requirement R7 is effective in time for the 2025-2026 winter season [1] For purposes of these comments, the IRC SRC includes the following entities: CAISO (with the exception of our response to question 5), ERCOT (with the exception of our responses to questions 3, 5 and 8), IESO, ISO-NE, MISO, NYISO, PJM and SPP.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the	

first day of the first calendar quarter that is six 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.	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
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.	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
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.	
Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Joshua London - Eversource Energy - 1, Group Name Eversource	
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, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD	
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.	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
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	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
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	
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.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	
Document Name	
Comment	
WECC has no comment on the implementation timeline, and leaves it to the entities that have to implement the requirements to provide feedback.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	

Answer	
Document Name	
Comment	
PJM supports the IRC SRC comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	

4. Do the changes in EOP-011 provide sufficient clarity and flexibility in regards to the treatment of critical natural gas infrastructure in operator-controlled manual Load shedding and automatic load shedding?

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	No
Document Name	
Comment	
EOP-011-4, R2.2.8 states “Provisions for excluding critical natural gas infrastructure loads as Interruptible Load, curtailable Load, and demand response during periods when it would adversely impact the reliable operation of the BES”. So if it is “critical,” which is not a defined term, it must be excluded from any manual /automatic load shed. This seems to remove flexibility. The flexibility will only show up if it is not classified as “critical” which defeats the purpose of this revision.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making “critical natural gas infrastructure load” a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.	
Scott McGough - Georgia System Operations Corporation - 3	
Answer	No
Document Name	
Comment	

R1: GSOC agrees with the SDT's recommendation to protect critical natural gas infrastructure loads from automatic Load shedding. However, GSOC has concerns introducing automatic Load shedding requirements within EOP-011-4 under requirements R1.2.5 thereby indicating that it would be applicable to the TOP when the TOP is not responsible for automatic Load shedding schemes. Automatic Load shedding design requirements and corresponding applicable entities are addressed in their respective NERC Reliability Standards PRC-006-5 and PRC-010-2 which includes PC, TP, TO, DP, UVLS entities, and UFLS-Only DP. Alternatively, rather than introducing any automatic Load shedding requirements within EOP-011-4, R1.2.5, GSOC recommends revisions to PRC-006 and PRC-010, accordingly, to introduce new design requirements for "identification and prioritization of designtated critical natural gas infrastructure loads". In doing so, the appropriate subject matter experts responsible for these schemes and requirements would become more aware of this issue and address this concern accordingly. As long as R7 still contains requirements for addressing automatic Load shedding by the responsible entities, the TOP can still identify the appropriate entities required to mitigate operating Emergencies in its Transmission Operator Area under R1.2.5.6 without introducing automatic Load shedding within R1.2.5. R7: The Extreme Cold Weather Preparedness Technical Rationale and Justification for EOP-011-4 document indicates "automatic Load shedding" was introduced to align with sub-requirement "*Provisions for the identification and prioritization of designated critical natural gas infrastructure loads*" to be applicable to automatic Load shedding. For clarity, GSOC recommends separating "Operator-controlled manual Load shedding" from "automatic Load shedding" requirements such that R7.1 only addresses "Operator-controlled manual Load shedding". In addition, requirements 7.1.1 through 7.1.5 and a new R7.2 would only address "automatic Load shedding" (thereby requiring the removal "or automatic" from 7.1. The new R7.2 could read as: "*R7.2 Automatic Load shedding during an Emergency that accounts for provisions for the identification and prioritization of designated critical natural gas infrastructure loads.*"

Likes 0	
Dislikes 0	

Response
Thank you for your comment. The SDT discussed the option of making modifications to PRC-006 and PRC-010 and determined that it was not necessary and would be most appropriate to keep these load shed requirements in one location. Each of the sub-requirements under 1.2.5 intentionally utilizes the term "provisions." This term, which has been carried forward from EOP-011-2 and EOP-011-3, 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.

To ensure that all Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners are aware of any new responsibilities the SDT has added a new R7 and modified R8 to include the concept of identification and notification. Please see the Technical Rationale for additional explanation of these changes.	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
PacifiCorp acknowledges that the proposed language offers sufficient flexibility; however, it lacks clarity. As highlighted in our response to Question #1, we request that the term "critical natural gas infrastructure" be defined.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making "critical natural gas infrastructure load" a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) in response to this question.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	No
Document Name	
Comment	
Requirement R1.2.5.6 requires the Transmission Operator to include "provisions for the identification of Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners required to mitigate operating Emergencies in its Transmission Operator Area" and Requirement R7 requires the affected entities to develop, maintain, and implement an Operating Plan; however, there is no requirement for the TOP to notify the affected entities. How then will the entities identified in the TOP's Operating Plan(s) know that Requirement R7 is now applicable to them? Therefore, we recommend including a requirement for the TOP to notify the affected entities. We propose adding Requirement 1.2.5.7 utilizing the following text. "R1.2.5.7. The TOP shall notify the entities identified pursuant to the application of 1.2.5.6 within 30 days of the latest approved revision date or by the effective date of the Operating Plan; whichever is later." Lastly, we recommend that the identification of designated critical natural gas infrastructure loads should be performed at a single operating level, specifically by the TOP. Thus, we recommend the removal of Requirement R7.1.5.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT agrees this is an issue and has added a new R7 and modified R8 to include the concept of identification and notification. Please see the Technical Rationale for additional explanation of these changes.	

The SDT disagrees that the identification and designation of critical natural gas infrastructure loads should be performed at a single level. This is because Transmission Operators are not necessarily aware of the characteristics or topology of individual loads served by Distribution Providers, UFLS-Only Distribution Providers, or Transmission Owners. It would clearly be beneficial for these entities to collaborate with their Transmission Operator in these activities, but this is not included as a requirement.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
As described in SRC's response to Question 1, the SRC believes the proposed language provides flexibility, but not clarity.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the response to Question 1.	
Lori Frisk - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
We don't believe the Draft 1 standard provides sufficient clarity in regards to the treatment of critical natural gas infrastructure with respect to operator-controlled manual Load shedding and automatic load shedding. See responses to Questions 1-2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the response to Questions 1 and 2.	
Kimberly Bentley - Kimberly Bentley On Behalf of: Sean Erickson, Western Area Power Administration, 1, 6; - Kimberly Bentley	
Answer	No
Document Name	
Comment	
WAPA acknowledges that the proposed language offers sufficient flexibility; however, it lacks clarity. As highlighted in our response to Question #1, we request that the term "critical natural gas infrastructure" be defined.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making "critical natural gas infrastructure load" a defined term, providing flexibility for individual entities to	

apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	No
Document Name	
Comment	
SRP supports TPWR comments. In addtion, on Question 1, it feels like there is a word missing in the 1h recommendation. Also, what is that is being prohibited in the BA’s operating plan? Lastly, how is “critical natural gas infrastructure” defined and what does “demand response of critical natural gas infrstructure load” mean? Or how is “demand response” interpreted here?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The intent is to prohibit the inclusion of critical natural gas infrastructure loads in various demand response programs. Critical natural gas infrastructure loads that are essential to the reliable operation of the BES should not voluntarily participate in programs that may require them to ramp down or disconnect during extreme cold weather which is when they are needed the most.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	No
Document Name	
Comment	
IID recommends that the SDT develop a definition or guidance for what is considered critical natural gas infrastructure loads in either the Technical Rationale or other Implementation Guidance specific to EOP-011. Furthermore, IID recommends registration of natural gas infrastructure owners and operators.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making "critical natural gas infrastructure load" a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	No
Document Name	
Comment	
The SDT should consider that the current and proposed language of EOP-011 does not require an entity to minimize the overlap between critical gas infrastructure loads or a designated critical load and automatic load shed circuits. Although the intent is there with the addition of "automatic" in R1.2.5, the standard doesn't explicitly address the potential overlap of critical loads on automatic load shed circuits as it does for manual load shed circuits. Recommend adding automatic to R1.2.5.2. to close that loop. Recommended change: 1.2.5.2. Provisions to minimize the overlap of circuits that are designated for manual and **automatic** load shed and circuits that serve designated critical loads, **including designated critical gas infrastructure loads** The proposed R1.2.5.5 is specific to "critical gas infrastructure load". The SDT should consider that this be be removed is the above proposal is used or be rewritten to be more generic to encompass all "designated critical loads" and not just for gas infrastructure? Does it make sense to specifically call out one specific critical load and not others in a separate requirement.	

The SDT should consider whether or not to include a new term(s) in the NERC Glossary of “Designated Critical Load” and/or “Critical Natural Gas Infrastructure” which would define what the minimum standard critical loads are, including, but not limited to critical gas infrastructure, critical fuel delivery infrastructure, off-site nuclear station service, public safety, public health, etc	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Changes were made to R1.2.5, R2.2.9 and R8.1 to more consistently address operator-controlled manual Load shedding and automatic Load shedding. The SDT discussed and chose to maintain the separate provisions related to the identification and prioritization of critical natural gas infrastructure in 1.2.5.5 and 8.1.5. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making “critical natural gas infrastructure load” a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.	
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	
The proposed changes in EOP-011 do not provide sufficient clarity. Tacoma Power understands that the SDT does not want to limit or prescribe a single identification method to entities. However, not providing any examples in the Technical Rationale results in lack of clarity, and leaves the definition for the critical natural gas infrastructure loads to each entity. The application of this definition will be inconsistent between entities and auditors. For example, some entities may miss identifying a critical load simply because the entity has a different	

threshold or definition of what is considered "critical." Tacoma Power recommends that the SDT develop a definition or guidance for what is considered critical natural gas infrastructure loads in either the Technical Rationale or other Implementation Guidance specific to EOP-011.

Tacoma Power recognizes that the Reliability Guideline, "Natural Gas and Electrical Operational Coordination Considerations," includes guidance on identification of critical natural gas system components and dual-fuel supplier components that could assist with R1.2.5.5. However, Tacoma Power is concerned about the application of this guideline in the absence of a clear definition of what is considered a critical natural gas infrastructure load. Below is a summary of how application of this guideline and lack of a definition can result in confusion or inconsistency.

The Requirement R1.2.5.5 is not clear if critical natural gas infrastructure is focused solely on electric generation load, or if as specified in Chapter 2 of the Reliability Guideline, that non-electric generation load is also considered a "critical" natural gas load. For example, would a natural gas meter at a hospital be considered "critical"? Or is the scope of R1.2.5.5 limited only to major or bulk transmission of natural gas and pipelines that supply natural gas power plants?

Additionally, R1.2.5.5 and the Reliability Guideline is not clear on the responsibilities of a BA or TOP that does not have natural gas generation in their footprint or service territory. For example, if a TOP has a substation that powers a natural gas pipeline which eventually serves a natural gas power plant physically located in the TOP footprint, but the plant is not connected to the TOP's/TO's system nor is the plant within their BA's BAA. This situation exists within Tacoma Power's footprint and as written, the compliance obligations for meeting R1.2.5.5 are not clear.

Lastly, the Reliability Guideline proposes that electric transmission and distribution owners reach out to regulatory entities, natural gas companies and organizations, and secondary fuel suppliers. Reaching out to this many organizations and agencies, as well as receiving their responses, may be unattainable in the proposed implementation timeline and will be difficult to maintain the coordination. As capured by the MRO NSRF comments, these organizations are not subject to NERC Standards and as a result, may not respond or prioritize coordination with TOPs. Tacoma Power recommends utilizing a note similar to CIP-013 R2 to address this concern. This note should specify compliance with R1.2.5.5 does not include the natural gas companies' or fuel suppliers' performance and adherence to the TOP requests.

Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	

Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making “critical natural gas infrastructure load” a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint. The identification and prioritization of critical natural gas loads requires coordination with natural gas facility owners and operators. The SDT recognizes that entities are dependent upon the cooperation of natural gas facility owners and operators to complete this task. However, it is outside the scope of the SDT to develop methods to compel natural gas owners and operators to cooperate and provide specific information to various entities.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group acknowledges that the proposed language offers sufficient flexibility; however, it lacks clarity. As highlighted in our response to Question #1, we request that the term "critical natural gas infrastructure load" be defined.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making “critical natural gas infrastructure load” a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.	
Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	

Comment	
In support of MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, 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 the comments of the Edison Electric Institue (EEI) to question #4,	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	

APS believes that clarification is needed because responsible entities do not have the visibility to identify such loads, so they are reliant on natural gas facilities owners, however, natural gas facility owners have no regulatory obligation to self-identify their facilities as critical. To address this concern, APS suggests modifications to Requirement 1, subpart 1.2.5.5 and Requirement R7, subpart 7.1.5 as follows:

Requirement 1, subpart 1.2.5.5:

Provisions for the identification and prioritization of designated critical natural gas infrastructure loads**, as identified by the responsible natural gas infrastructure owner/operator**; and

Requirement R7, subpart 7.1.5:

Provisions for the identification and prioritization of designated critical natural gas infrastructure loads**, as identified by the responsible natural gas infrastructure owner/operator**.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The identification and prioritization of critical natural gas loads requires coordination with natural gas facility owners and operators. The SDT recognizes that entities are dependent upon the cooperation of natural gas facility owners and operators to complete this task. However, it is outside the scope of the SDT to develop methods to compel natural gas owners and operators to cooperate and provide specific information to various entities.

Steven Rueckert - Western Electricity Coordinating Council - 10

Answer	No
Document Name	

Comment

Please refer back to WECC's comments on question 1. WECC believes the is enough flexibility, but not enough clarity.

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the response to Question 1.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD	
Answer	No
Document Name	
Comment	
The changes in EOP-011 do not provide sufficient clarity because the term “critical natural gas infrastructure” is not defined. The SDT should create this definition so that it is clear to entities how to identify these types of loads.	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making “critical natural gas infrastructure load” a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	

AEPC has signed on to ACES comments below: Requirement R1.2.5.6 requires the Transmission Operator to include "provisions for the identification of Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners required to mitigate operating Emergencies in its Transmission Operator Area" and Requirement R7 requires the affected entities to develop, maintain, and implement an Operating Plan; however, there is no requirement for the TOP to notify the affected entities. How then will the entities identified in the TOP's Operating Plan(s) know that Requirement R7 is now applicable to them? Therefore, we recommend including a requirement for the TOP to notify the affected entities. We propose adding Requirement 1.2.5.7 utilizing the following text. "R1.2.5.7. The TOP shall notify the entities identified pursuant to the application of 1.2.5.6 within 30 days of the latest approved revision date or by the effective date of the Operating Plan; whichever is later. Lastly, we recommend that the identification of designated critical natural gas infrastructure loads should be performed at a single operating level, specifically by the TOP. Thus, we recommend the removal of Requirement R7.1.5.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT agrees this is an issue and has added a new R7 and modified R8 to include the concept of identification and notification. Please see the Technical Rationale for additional explanation of these changes. The SDT disagrees that the identification and designation of critical natural gas infrastructure loads should be performed at a single level. This is because Transmission Operators are not necessarily aware of the characteristics or topology of individual loads served by Distribution Providers, UFLS-Only Distribution Providers, or Transmission Owners. It would clearly be beneficial for these entities to collaborate with their Transmission Operator in these activities, but this is not included as a requirement.	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	

Comment	
MRO NSRF acknowledges that the proposed language offers sufficient flexibility; however, it lacks clarity. As highlighted in our response to Question #1, we request that the term "critical natural gas infrastructure load" be defined.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making "critical natural gas infrastructure load" a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	No
Document Name	
Comment	
Reference comment on question 1. Additionally, while EOP-011 does address the overlap between circuits designated for operator-controlled manual or automatic Load shedding and those used for UFLS/UVLS, RF recommends requirements to prioritize certain circuits for the implementation of UFLS and/or UVLS fall under PRC-006 and PRC-010. It is not clear in the current draft of EOP-011 that the "provisions for the identification and prioritization of designated critical natural gas infrastructure loads" also apply to UFLS and UVLS programs.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT discussed the option of making modifications to PRC-006 and PRC-010 and determined that it was not necessary and would be most appropriate to keep these load shed requirements in one location. Each of the sub-requirements under 1.2.5	

intentionally utilizes the term "provisions." This term, which has been carried forward from EOP-011-2 and EOP-011-3, 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. To ensure that all Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners are aware of any new responsibilities the SDT has added a new R7 and modified R8 to include the concept of identification and notification. Please see the Technical Rationale for additional explanation of these changes. Additionally, changes were made to R1.2.5, R2.2.9, and R8.1 to more consistently address operator-controlled manual Load shedding and automatic Load shedding.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Again, the changes do not identify how or who will be responsible for determining and identifying the critical natural gas infrastructure.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Additional content has been added to the Technical Rationale to address this topic.	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

Please see BPA's response to Q1 and Q3 above.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
Coordination between the Electric industry and the Gas Industry in terms of communication and operational obligations must be sufficient to fully apply the intent of EOP-011-4. Until clear guidance of communication and the coordination can be provided – either through standard modification or assigned entity responsibility – FirstEnergy cannot support the proposed treatment of critical natural gas infrastructure in manual Load shedding and automatic load shedding.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	No
Document Name	

Comment	
The changes do not provide sufficient clarity of what constitutes critical natural gas infrastructure. ATC requests that the term "critical natural gas infrastructure" be defined. Additionally, ATC requests that the definition, at a minimum, state "critical natural gas infrastructure" is natural gas infrastructure that if rendered unavailable would adversely impact the reliable operation of the Bulk Electric System. *With the addition of "automatic" to R1.2.5, the standard unintentionally conflicts with the new NERC paradigm that recognizes the role of the Planning Coordinator (PC) in the design and implementation of UFLS under PRC-006 and the PC and the Transmission Planning in the design and implantation of UVLS under PRC-010. Years ago, the load shedding requirements for the operating horizon listed both manual and automatic load shedding. However, automatic load shedding was removed due to recognition that the TOP and/or the BA do not design or implement automatic load shedding schemes. With the reintroduction of the term "automatic", this standard will now require the TOP and/or BA to be directly involved in the design and deployment of automatic load shedding schemes developed by these other entities. If the intention of the SDT is to capture automated schemes developed with a TOP or BA EMS to aid the manual load shedding process, additional language is needed to ensure the appropriate scope is understood by all parties either auditing this standard or seeking to be compliant under this standard.*	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making "critical natural gas infrastructure load" a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint. The SDT discussed the option of making modifications to PRC-006 and PRC-010 and determined that it was not necessary and would be most appropriate to keep these load shed requirements in one location. Each of the sub-requirements under 1.2.5 intentionally utilizes the term "provisions." This term, which has been carried forward from EOP-011-2 and EOP-011-3, 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.	
Alison MacKellar - Constellation - 5	

Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	Yes
Document Name	
Comment	
We would like to see a requirement for the RC to identify the overlap requirements for MLS and UFLS.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Requirement R3 requires the Reliability Coordinator to review Operating Plan(s) submitted by a Transmission Operator or Balancing Authority.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes

Document Name	
Comment	
EEI agrees that the proposed changes to EOP-011 provide sufficient clarity and flexibility in regard to the treatment of critical natural gas infrastructure in operator-controlled manual Load shedding and automatic load shedding.	
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 Constellation Segements 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	

Answer	Yes
Document Name	
Comment	
PNM agrees that there is sufficient clarity and flexibility for critical natural gas loads in regards to load shedding.	
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	
Southern Company would suggest language changes that would require coordination between natural gas facility owners and the responsible functional entities to identify Critical Natural Gas Infrastructure loads. Southern Company would modify requirement R7, subpart 7.1.5 to the following: "7.1.5 Provisions for the identification and prioritization of designated critical natural gas infrastructure loads, as identified by the responsible natural gas infrastructure owner/operator in coordination with the applicable Functional Entity. **TOP-002-5 (Questions 5-6)** **Recommendation 1g of the Report states: 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)**

As explained by the Report on the 2021 event, Key Recommendation 1g was intended to "take the next logical step [after TOP-003-5 and EOP-011-2 changes take effect in April 2023] and eliminate doubt about which entity is responsible to provide information or act on information," preventing BAs and RCs from being surprised during extreme cold weather events (See Report at pp 189-190). The SDT would like feedback on the first bulleted subpart of Key Recommendation 1g, which, in essence, recommends a requirement that the GOs/GOPs provide the BA with the generating units MWs, including MWh the GO/GOP reasonably believes that it can rely upon during the local forecasted cold weather.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Additional content has been added to the Technical Rationale to address this topic. The identification and prioritization of critical natural gas loads requires coordination with natural gas facility owners and operators. The SDT recognizes that entities are dependent upon the cooperation of natural gas facility owners and operators to complete this task. However, it is outside the scope of the SDT to develop methods to compel natural gas owners and operators to cooperate and provide specific information to various entities.

Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF

Answer	Yes
Document Name	
Comment	
Southern Indiana Gas & Electric Company (SIGE) agrees that the proposed language in R1.2.5.5 and R7.1.5 provides sufficient clarity and flexibility in regards to the treatment of critical natural gas infrastructure in operator-controlled manual Load shedding and automatic load shedding.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Daniel Gacek - Exelon - 1	
Answer	Yes

Document Name	
Comment	
Exelon supports EEI's comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Yes, CEHE agrees that the proposed changes to EOP-011 provide sufficient clarity and flexibility in regard to the treatment of critical natural gas infrastructure in operator-controlled manual Load shedding and automatic load shedding.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	

AEP agrees that clarity and flexibility have been added to EOP-011, however we still believe registration of natural gas infrastructure owner and operators themselves, with the RTOs in an official capacity, would add more clarity and improve overall system reliability associated with natural gas service to generating facilities. Because the proposed revisions do not include natural gas owners and operators as new Functional Entities, AEP has chosen to vote Negative on EOP-011-4.

The word "critical", as used in lower case to qualify both loads and natural gas infrastructure loads, is subjective and subject to interpretation. This will likely result in an inconsistent application of the term across entities. AEP suggests that clarity be provided as to how to properly identify loads, including natural gas infrastructure loads, as "critical."

Similar to our response to Question #3, we believe it would beneficial to have a criteria of critical levels similar to that used by Transmission Planning to illustrate the different risk levels. Potential examples might include 1) generation on-site backup, 2) critical to generation supply for loss of one site 3) becomes critical if electrical supply were lost at two sites in area (indicates a combination), and 4) critical to generation supply for loss of three sites and so forth. The criteria used could also capture risk to one RTO area as opposed to affecting multiple RTO regions via the interstate pipeline system. We believe it would be beneficial for NERC to work directly with FERC and gas suppliers to develop this set of criteria to assist in properly identifying risk.

AEP believes clarity is needed regarding scenarios when the Distribution Provider and the Transmission Operator are not within the same company. For those situations, it is unclear how self-identification would occur and what their obligations might be.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Additional content has been added to the Technical Rationale to address this topic. The identification and prioritization of critical natural gas loads requires coordination with natural gas facility owners and operators. The SDT recognizes that entities are dependent upon the cooperation of natural gas facility owners and operators to complete this task. However, it is outside the scope of the SDT to develop methods to compel natural gas owners and operators to cooperate and provide specific information to various entities.

The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making "critical natural gas infrastructure load" a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint. The potential criteria of critical levels in your comment represents a reasonable approach that entity may choose to take in crafting their prioritization approach in 1.2.5.5 or 8.1.5. To ensure that all Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners are aware of any new responsibilities the SDT has added a new R7 and modified R8 to include the concept of identification and notification. Please see the Technical Rationale for additional explanation of these changes.

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
Answer	Yes
Document Name	
Comment	

Yes. The changes in EOP-011 and the supporting technical rationale provide sufficient clarify and flexibility.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Ken Habgood - Seminole Electric Cooperative, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

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.	
Tracy MacNicoll - Utility Services, Inc. - 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.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Marc Sedor - Seminole Electric Cooperative, Inc. - 3	
Answer	Yes
Document Name	
Comment	
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	
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.	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
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.	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
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.	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	
Document Name	
Comment	

No comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
Answer	
Document Name	
Comment	
PJM supports the IRC SRC comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE recommends the requirement apply to any manual or automatic load shed programs. The term “Interruptible Load” references the inactive LSE function. The other terms, curtailable Load and demand response, are not defined.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the response to Question 1.	

See the unofficial comment form for additional information: https://www.nerc.com/pa/Stand/Project202107ExtremeColdWeatherDL/2021-07_Cold_Weather_Phase%202_Unofficial_Comment_Form_02282023.docx

5. Please comment on whether information pertaining to the generating unit's MWs, including MWhs the GO/GOP reasonably believes that the BA can rely upon during local forecasted cold weather, would be useful to your operations during local forecasted cold weather. Alternatively, is there a better way for the BA to develop assumptions related to cold weather needs to address this specific metric rather than asking for this information from the GO/GOPs? Please provide comments and revisions to the draft language.

Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
No, CEHE supports the comments as submitted by Edison Electric Institute and agrees the GO/GOP would be the best source for the reliable projections.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI.	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	

Exelon supports EEI's comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI.	
Kinte Whitehead - Exelon - 3	
Answer	No
Document Name	
Comment	
Exelon supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI.	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	No
Document Name	
Comment	
Southern Indiana Gas & Electric Company (SIGE) supports Edison Electric Institute’s comment and agrees the GO/GOP would be the best source for the most reliable projections.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Southern Company agrees with EEI comments that The GO/GOP would be the source for the most reliable projections. Southern Company would add that providing the MWhs is not helpful. The anticipated schedule for the 5-day period would be more useful, along with additional MWhs available above the projected schedule, only if availability limitations exist.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI. The SDT appreciates the input on the need to adjust the standard as needed.	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
BHP as TOP, amount of MWh is not useful for BHP as a TOP. More interested in if a unit is or is not available which we would have through new cold weather standards with TOP-003-5.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comments to assist the SDT on drafting the standard.	
Micah Runner - Black Hills Corporation - 1	
Answer	No
Document Name	
Comment	
BHP as TOP, amount of MWh is not useful for BHP as a TOP. More interested in if a unit is or is not available which we would have through new cold weather standards with TOP-003-5.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments to assist the SDT on drafting the standard.	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	No
Document Name	
Comment	
BHP as TOP, amount of MWh is not useful for BHP as a TOP. More interested in if a unit is or is not available which we would have through new cold weather standards with TOP-003-5.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comments to assist the SDT on drafting the standard.	
Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
Answer	No
Document Name	
Comment	
BHP as TOP, amount of MWh is not useful for BHP as a TOP. More interested in if a unit is or is not available which we would have through new cold weather standards with TOP-003-5.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments to assist the SDT on drafting the standard.	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	No
Document Name	
Comment	
The requested generator data is only as good as the availability of the natural gas supply. More needs to be done to ensure supply meets and or exceeds demand and or increase generation of other available resources to make the industry and generation reliable. In addition, BAs, particularly in organized markets, need greater certainty from the GOs as to the need for their resources during projected periods of extreme cold weather. In this regard, market operators need to be held accountable for a greater level of precision in load forecasting so that gas supply can be procured in advance more thoughtfully and not as a result of wildly inaccurate estimates. Where is the	

added accountability on the market operators for improving its processes? A significant amount of the 'emergency' in December 2022 could have been averted by better load forecasting and generation scheduling practices at the ISO/RTO level.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Market operation recommendations are outside of the scope of the SAR. Please see the FERC recommendation report for recommendations related to market operations.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	
APS believes that information pertaining to the generating unit's MWs the GO/GOP reasonably believes that the BA can rely upon during local forecasted cold weather would be useful to our operations during local forecasted cold weather. APS does not believe that information pertaining to the generating unit's MWhs the GO/GOP reasonably believes that the BA can rely upon during local forecasted cold weather would be useful to our operations during local forecasted cold weather. APS agrees that the GO/GOP would be the source for the most reliable projections.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment and the SDT did not adjust the standard to add MWhs.	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, 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	
The GO/GOP would be the source for the most reliable projections.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments to assist the SDT on drafting the standard.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
The GO/GOP would be the source for the most reliable projections.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments to assist the SDT on drafting the standard.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	

Ameren perfers not to make assumptions on the performance of generators during cold weather events. We believe that MISO may be better suited to provide this information.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments to assist the SDT on drafting the standard.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	No
Document Name	
Comment	
Capability of generating units is necessary for BAs to develop Operating Plans, regardless of weather conditions. It is the responsibility of the GO/GOP to understand and communicate this information to the BA. The GO/GOP would be the source for the most reliable projections	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments to assist the SDT on drafting the standard.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	

This information is already required to be provided with the update to TOP-003-5.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments to assist the SDT on drafting the standard.	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
Capability of generating units is necessary for BAs to develop Operating Plans, regardless of weather conditions. It is the sole responsibility of the GO/GOP to understand and communicate this information to the BA.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments to assist the SDT on drafting the standard.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
The proposed approach is unlikely to result in useful information. While owners and operators of some simpler facilities with hard cutoff protection, such as wind turbines, may be able to forecast cold weather performance with some degree of certainty, more complex facilities,	

such as thermal generation facilities, have many, many variables that impact cold weather performance and make it difficult for owners and operators to accurately forecast cold weather performance.

Older units may have had several retrofits that make a design limit highly inaccurate. A thorough, recently conducted engineering analysis can provide more accuracy than original design limits; however, even these types of analyses will lose accuracy over time as generating units suffer degradation and are retrofitted. Even recent historical performance will become less dependable over time and is inherently limited to temperatures actually observed. Historical performance data also may not capture the impact of maintenance or upgrades undertaken to address previous performance failures.

In addition to the limitations of performance limit calculations, there are also inherent inaccuracies in the temperature forecasts used to attempt to determine the limits that may apply during an upcoming event, as these forecasts may be based on information from weather stations many miles away from a given generating facility. Fuel supply and inventory information also depend on natural gas suppliers providing timely and accurate notifications to GOs and GOPs. RCs and BAs ultimately depend on information that other entities provide to them and will continue to encounter scenarios where unit performance does not conform to provided limits and where units suddenly identify fuel constraints as an event unfolds because their fuel provider did not provide sufficient advance notice of fuel supply constraints.

Given these inherent inaccuracies and uncertainties in availability forecasts, a forecast from a GO or GOP that a unit is going to be fully or partially unavailable would only be useful to a BA if the unavailability is certain; forecasts based on potential risks or potential unavailability are not typically useful to BAs. Generating units preemptively coming offline because of anticipated cold weather is counterproductive unless there is a need to protect equipment. All of this taken together means that information pertaining to a generating unit's MWs, including MWhs, the GO/GOP reasonably believes that the BA can rely upon during local forecasted cold weather would not be useful to the operations of ERCOT during local forecasted cold weather.

A more effective approach would be to require GO/GOPs to provide BAs with data about specific constraints that might limit the capabilities of their units, such as known fuel and emissions constraints, and allow each BA the leeway to develop its own approach and assumptions related to cold weather needs based on its past experiences and the unique characteristics of its Balancing Authority Area.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. While the team discussed inclusion of the recommend constraints, they did not adjust the drafted standard to include them. The SDT believes it has accomplished the intent of your suggested approach with proposed R8. To the extent that the BA needs additional information from the GO/GOP to implement its Operating Process, that is covered under the data specification in TOP-003.	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	No
Document Name	
Comment	
It does not seem practical for plants to guess at what they expect they can do during cold weather. They already have to plan to fully perform during expected cold weather based on past history. Why would anyone expect, or rely on, anything other than 100% performance. That is what we design the system to (Ten Year Site plans, long term forecasts, etc.). The standard appears to only penalize an entity if they have another Winter Storm Uri, which we of course do not want it to happen again. It seems unnecessary to double the size of all our generators and transmission lines so we can operate to the unforeseen failure of so many things all at once. We are making progress, but this standard has many ways to meet an entities needs and very few ways to succeed short of another Uri and not having any issues.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The intent of the SAR and requirements is not to create penalties based on storm status. The intent is the useful flow of relevant information so that the BA can manage its footprint during a cold weather event and there is no suggestion or requirement to implement the investments in generator output or transmission capability. Proposed R8 is structured to promote data exchange between the GO and BA to allow the BA to create processes to aid in the management of cold weather periods.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes

Document Name	
Comment	
MISO is Entergy's Balancing Authority.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	

N/A	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Capability of generating units is necessary for BAs to develop Operating Plans, regardless of weather conditions. It is the sole responsibility of the GO/GOP to understand and communicate this information to the BA.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments to assist the SDT on drafting the standard.	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
The expected generation is important for performing an accurate Operational Planning Analysis, OPA. BA's determine generation resource commitment based on generation limitation derates and outages in the outage management system, per TOP-003 and IRO-010. Due to the	

recent additions in TOP-003 and IRO-010 to specifically identify cold weather limitations of generators this is already integrated into OPAs and real-time assessments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments to assist the SDT on drafting the standard.	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
SDT may want to consider that it may be useful to areas where wholesale electricity markets are not operating, to propose a requirement to have the GO/GOP to provide its BA with a reasonable forecast pertaining to its generating unit(s)' forecasted MW/MWh output during local forecasted cold weather so the BA can use this information when developing its five-day hourly forecast for their BA footprint.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments to assist the SDT on drafting the standard. The SDT did not require this due to majority of respondents commenting on there was no need for MWh provided to the BA.	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	

PNM's assessment is that MW forcasting from generators should come from the GO/GOP. PNM supports EEI comments that the GO/GOP would be the source for the most reliable projections.	
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 Constellation Segements 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	

Comment	
In support of MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to NSRF comments.	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	

The BA already has the tools and the authority necessary to plan for generating unit MWH. There is no need for another process, except to define “critical natural gas infrastructure load” and add it to the plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments to assist the SDT on drafting the standard.	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
We believe this data would be beneficial and should be supplied by the GO/GOP to the BA.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments to assist the SDT on drafting the standard.	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
No Additional Comments	

Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Marc Sedor - Seminole Electric Cooperative, Inc. - 3	
Answer	Yes
Document Name	
Comment	
Capability of generating units is necessary for BAs to develop Operating Plans, regardless of weather conditions. It is the sole responsibility of the GO/GOP to understand and communicate this information to the BA.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments to assist the SDT on drafting the standard.	
Kimberly Bentley - Kimberly Bentley On Behalf of: Sean Erickson, Western Area Power Administration, 1, 6; - Kimberly Bentley	
Answer	Yes
Document Name	
Comment	
WAPA believes it would be useful to BA operations to have the GO/GOP, in accordance with the BA's documented methodology, provide a reasonable five-day hourly forecast of MW or MWh output for each generating unit during local forecasted cold weather so the BA can incorporate this information into the five-day hourly forecast for their BA footprint.	

WAPA believes what is critical to making this work is a framework similar to that for load forecasting. GOs/GOPs should not be penalized for failure to predict their energy output with complete accuracy. There should be some recognition that new factors can emerge or existing factors (including the weather forecast) change in real-time, thereby altering the energy output forecast. WAPA recommends the GO/GOPs provide their BA with a reasonable forecast to work with.

WAPA supports a framework that would ask GO/GOPs to provide their forecasted energy output information to the BA as:

1. GO/GOPs are in the best position to provide an educated forecast for their units' performance. Not ony does the GO/GOP have superior past performance data (over that of the BA) to perform this analysis, they also have superior knowledge of how their unit will likely perform under projected conditions

2. BAs receiving a more accurate output forecast would be in an improved position to increase the accuracy of their dispatch and unit commitment. Without this information, the BA must employ manual methods (e.g. phone calls) to gather this information anecdotally.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT agrees that GOs should not be penalized for providing a reasonable forecast and have structured the requirements to not require such. The SDT did not require this due to majority of respondents commenting on there was no need for MWh provided to the BA.

Devon Tremont - Taunton Municipal Lighting Plant - 1

Answer	Yes
Document Name	

Comment

Response to the question regarding MW/MWh data being useful to operations: This question will receive varied responses depending on the functional registrations of the respondent, but as a GO/GOP/TO/DP, this information would be useful to us as we will use this information as an indication of potential Emergency situations, assuming that we will be receiving notice prior to cold weather event rather than just prior to the season. As a GO/GOP in ISO-NE territory, we would consider self-scheduling some or all of our thermal resource's capability to mitigate

the impact of a potential pay-for-performance (ISO-NE market construct that is triggered when reserve deficient) event. As a DP, this will allow us to better prepare for manual load shedding, such as calling in additional staff to prepare for rotation and restoration of outages	
Likes 0	
Dislikes 0	
Response	
The SDT did not require this due to majority of respondents commenting on there was no need for MWh provided to the BA.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	

The SRC[1] believes it would be useful for GO/GOPs to provide their BAs with a reasonable forecast of their generating unit(s)' MW/MWh output during local forecasted cold weather so the BA can use this information when developing its five-day hourly forecast for its BA footprint.

In the absence of a generator output forecast, the Balancing Authority might attempt to create its own forecast using the information it has available, such as historical generator performance; however, this would only represent a BA's best guess, which would still be less informed and less accurate than a forecast created by a GO/GOP for its own unit(s).

The SRC proposes that the GO/GOP would provide the BA with an hourly forecast of their expected energy output for the following reasons:

1. **GO/GOPs are in the best position to prepare an educated forecast for their generating units' output.** The GO/GOP will have more detailed past performance data than the BA will have, along with superior knowledge of how their unit will likely perform under expected weather conditions. The GO/GOP will also have more intimate knowledge of their fuel supply and inventory, start-up concerns, environmental limitations, and other factors listed in Part 8.2.

2. **A BA that receives a more accurate output forecast will be in an improved position to increase the accuracy and strategy of its unit commitment and dispatch.** With the information from the GO/GOP described above, the BA will be in an improved position to determine when to deploy the generating units in its footprint. In addition, it will minimize the burden on the BA to employ manual methods, such as phone calls, to gather this information anecdotally. In order for this approach to function properly, it is critical that this requirement be established under a framework like that used for load forecasting. Specifically, GO/GOPs should not be penalized for failure to predict their energy output with complete accuracy. There should be some recognition that new factors will emerge and existing factors, such as the weather forecast, will change in real-time, thereby causing the actual energy output realized to diverge from the forecasted output [1] For purposes of these comments, the IRC SRC includes the following entities: CAISO (with the exception of our response to question 5), ERCOT (with the exception of our responses to questions 3, 5 and 8), IESO, ISO-NE, MISO, NYISO, PJM and SPP.

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT did not require this due to majority of respondents commenting on there was no need for MWh provided to the BA. The SDT believes it has crafted standards that allow the BA to receive such information from the GOs and other information as well to utilize in its Operating Process to manage cold weather periods. The SDT agrees GO' should not be penalized for failure to achieve complete accuracy and has not included such a requirement in the proposal.	
Ken Habgood - Seminole Electric Cooperative, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Capability of generating units is necessary for BAs to develop Operating Plans, regardless of weather conditions. It is the sole responsibility of the GO/GOP to understand and communicate this information to the BA.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your 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	
Thank you for your response.	
Teresa Krabe - Lower Colorado River Authority - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
Answer	
Document Name	
Comment	

Abstain	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
NA	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI.	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	
Document Name	
Comment	
No comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
Answer	
Document Name	
Comment	
PJM supports the IRC SRC comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to IRC SCR.	

Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	
Document Name	
Comment	
N/A to Hydro One	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	
Document Name	

Comment	
PacifiCorp holds that through existing processes, BAs possess the needed means to collect all information necessary to make determinations about generation availability during local forcasted cold weather. Currently, PacifiCorp sees a reliability gap between what Generator Owners (GOs) /Generator Operators (GOPs) offer into the market and the amount of energy (MWh) that shows up in real-time. PacifiCorp's Risk Assessment Team analyzes this gap and attempts to close it using the information we have available; e.g. historical generator performance, to develop a "best guess" forecast for generator output. At best, our guess is uncertain. Rather than requiring the BA to put on the hat of a generator and attempt to make an educated guess on their behalf, what we would like to see is something akin to what is done with load forecasting. PacifiCorp supports a framework that would ask GO/GOPs to provide their forecasted energy output information to the BA for the following reasons: 1. GO/GOPs are in the best position to provide an educated forecast for their units' performance. Not ony does the GO/GOP have superior past performance data (over that of the BA) to perform this analysis, they also have superior knowledge of how their unit will likely perform under projected conditions; e.g. if a GO/GOP has been told by their natural gas supplier that there is a 50% chance that their natural gas supply will be curtailed, the GO/GOP could incorporate this information into their energy output forecast. 2. BAs receiving a more accurate output forecast would be in an improved position to increase the accuracy of their dispatch and unit commitment. Without this information, the BA must employ manual methods (e.g. phone calls) to gather this information anecdotally. What is critical to making this work is a framework similar to that for load forecasting. GOs/GOPs should not be penalized for failure to predict their energy output with complete accuracy. There should be some recognition that new factors can emerge or existing factors change in real-time, thereby altering the energy output forecast. PacifiCorp recommends the GO/GOPs provide their BA with a reasonable forecast to work with.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The SDT did not require this due to majority of respondents commenting on there was no need for MWh provided to the BA. The SDT believes it has crafted standards that allow the BA to receive such information from the GOs and other information as well to utilize in its Operating Process to manage cold weather periods. The SDT agrees GO' should not be penalized for failure to achieve complete accuracy and has not included such a requirement in the proposal.	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	Q5-6.PNG
Comment	
The MRO NSRF believes it would be useful to BA operations to have the GO/GOP, in accordance with the BA's documented methodology, provide a reasonable five-day hourly forecast of MW or MWh output for each generating unit during local forecasted cold weather so the BA can incorporate this information into the five-day hourly forecast for their BA footprint. The MRO NSRF believes what is critical to making this work is a framework similar to that for load forecasting. GOs/GOPs should not be penalized for failure to predict their energy output with complete accuracy. There should be some recognition that new factors can emerge or existing factors (including the weather forecast) change in real-time, thereby altering the energy output forecast. The MRO NSRF recommends the GO/GOPs provide their BA with a reasonable forecast to work with. Currently, MRO NSRF sees a reliability gap between what Generator Owners (GOs) /Generator Operators (GOPs) offer into the market and the amount of energy (MWh) that shows up in real-time. In part this is due to the fact that generators do not know in advance how many hours they will be dispatched to run, thereby making it difficult for them to reflect when they expect to "run out of fuel" in their forecast.	

A MRO NSRF member's Risk Assessment Team analyzes this gap and attempts to close it using the information we have available; e.g. historical generator performance, to develop a "best guess" forecast for generator output. That said, our "best guess" is still uncertain. Rather than requiring the BA to put on the hat of a generator and attempt to make an educated guess on their behalf, what we would like to see is something akin to what is done with load forecasting. The MRO NSRF supports a framework that would ask GO/GOPs to provide their forecasted energy output information to the BA for the following reasons: 1. GO/GOPs are in the best position to provide an educated forecast for their units' performance. Not only does the GO/GOP have superior past performance data (over that of the BA) to perform this analysis, they also have superior knowledge of how their unit will likely perform under projected weather conditions; e.g. if a GO/GOP has been told by their natural gas supplier that there is a 50% chance that their natural gas supply will be curtailed, the GO/GOP could incorporate this information into their energy output forecast. 2. BAs receiving a more accurate output forecast would be in an improved position to increase the accuracy of their dispatch and unit commitment. With the information from the GO/GOP described above, the BA will be in an improved position to determine when to deploy the generating units in their footprint. In addition, it will reduce the need for the BA to employ manual methods (e.g. phone calls) to gather this information anecdotally.	
Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	
Response	
Thank you for your comment. The SDT did not require this due to majority of respondents commenting on there was no need for MWh provided to the BA. The SDT believes it has crafted standards that allow the BA to receive such information from the GOs and other information as well to utilize in its Operating Process to manage cold weather periods. The SDT agrees GO' should not be penalized for failure to achieve complete accuracy and has not included such a requirement in the proposal.	

6. Recommendation 1g, bullets 2 and 3 of the Report suggests that each Balancing Authority should be required to use the data provided by the Generator Owner/Generator Operator to determine total generating capacity that can be relied upon during "local forecasted cold weather," and utilize such information 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." The SDT proposes a new Requirement R8 in TOP-002 that requires a Balancing Authority to create an extreme cold weather Operating Process within its Operating Plan to formalize the Balancing Authority's analysis functions and Real-time monitoring of its Balancing Authority Area during extreme cold weather. Do you agree the language in proposed Requirement R8 of TOP-002 addresses the intent of and is the appropriate manner in which to satisfy Recommendation 1g? Please provide the reasoning or justification for your position in the comments.

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	No
Document Name	
Comment	
We are of the opinion that the analysis is not needed. If we come up negative, we already have a Capacity Emergency Procedure. It does not have to be a stand alone "Cold Weather" Capacity Emergency Plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	

ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) in response to this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to SRC.	
Ken Habgood - Seminole Electric Cooperative, Inc. - 4	
Answer	No
Document Name	
Comment	
Per TOP-003 R4., BAs are already required to develop Operating Plans for the next-day that address expected generation resource commitment and dispatch, which require knowledge of generating units' capabilities, regardless of the weather conditions. The proposed R8 is redundant and unnecessary, as what it requires is already addressed in TOP-003-5 and TOP-002-4. Further, R8.3 is now requiring development of an Operating Plan, although it doesn't explicitly state it but it includes the same elements required in R4 with the addition of a weather forecast, for a five-day period, but only during an extreme cold weather period.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has reviewed your comment and decided, based on the scope of the SAR and FERC's recommendations, that a specific requirement for an operating process is appropriate in this case.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	

Comment	
Requirement R8 as written only partially addresses the intent of Recommendation 1g While Requirement R8 addresses a *portion* of the intent of Recommendation 1g (bullets 2 and 3), the SRC believes it is insufficient to achieve the overall intent of Recommendation 1g without a corresponding requirement for GO/GOPs to provide BAs with their output forecasts (bullet 1). Without a corresponding requirement for the GO/GOP to provide its BA with an expected output forecast for its unit(s), there may be a reliability gap in terms of what the BA can generate to comply with Parts 8.2 and 8.3 as described in the SRC's response to Question #5. The GO/GOP is in a superior position to provide the information listed in Part 8.2. Therefore, for the BA to develop a methodology that considers these operating limitations, there must be an equal and opposite requirement for the GO/GOP to provide this information to the BA. The time horizon for the GO/GOP requirement must mirror the proposed BA requirement for Part 8.3; i.e. an *hourly* generator output forecast for *five days* into the future. **There is a mismatch in time horizons for the Operating Process (R8) and Operating Plan (R4)** The SRC supports the proposal of a flexible, methodology-based approach to identifying an extreme cold weather period; however, the SRC believes the proposed language in Requirement R8 conflicts with the language in Requirement R4. Under the proposed language, R8 and R4 both reference the Operating Plan; however, R4 contemplates the Operating Plan as applying to next-day operations only, while R8, Part 8.3 specifically requires a "five-day hourly forecast." To rectify this mismatch, the SRC proposes the following modification: **R8.** Each Balancing Authority shall have an extreme cold weather Operating Process, *to inform* its Operating Plan developed in Requirement R4, addressing preparations for and operations during extreme cold weather periods. The extreme cold weather Operating Process shall include: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT reviewed your comment as part of the discussions and determined, based on a number of industry comments, to delete the link with the Operating Plan and have the Operating Process be a stand-alone requirement that is supplemental. The SDT believes the BA is equipped with the necessary ability under data specification requirements to receive the data from the GOs and has built flexibility into the requirement to allow the BA to manage its footprints under its own developed methodologies, rather than dictating with specificity.	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
Per TOP-003 R4., BAs are already required to develop Operating Plans for the next-day that address expected generation resource commitment and dispatch, which require knowledge of generating units' capabilities, regardless of the weather conditions. The proposed R8 is redundant and unnecessary, as what it requires is already addressed in TOP-003-5 and TOP-002-4. Further, R8.3 is now requiring development of an Operating Plan, although it doesn't explicitly state it but it includes the same elements required in R4 with the addition of a weather forecast, for a five-day period, but only during an extreme cold weather period.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has reviewed your comment and decided, based on the scope of the SAR and FERC's recommendations, that a specific requirement for an operating process is appropriate in this case.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	

There are redundancies between this language and TOP-003-5 and EOP-011-2. This language also adds additional data requirements not included in TOP-003-5. TOP-003-5 does not include data related to generation start failure. TOP-002-5, R8 part 8.2.3 (Start-up issues) is not included in TOP-003-5.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT discussed this and chose not to include that information in TOP-002 R8. The SDT believes that TOP-003 gives the BA the ability to ask for any information they deem necessary.	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	No
Document Name	
Comment	
SRP supports TPWR comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to TPWR.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	

Most of the requirements in R8, such as reserve margin, fall under the responsibility of our BA which is MISO.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Marc Sedor - Seminole Electric Cooperative, Inc. - 3	
Answer	No
Document Name	
Comment	
Per TOP-003 R4., BAs are already required to develop Operating Plans for the next-day that address expected generation resource commitment and dispatch, which require knowledge of generating units' capabilities, regardless of the weather conditions. The proposed R8 is redundant and unnecessary, as what it requires is already addressed in TOP-003-5 and TOP-002-4. Further, R8.3 is now requiring development of an Operating Plan, although it doesn't explicitly state it but it includes the same elements required in R4 with the addition of a weather forecast, for a five-day period, but only during an extreme cold weather period.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has reviewed your comment and decided, based on the scope of the SAR and FERC's recommendations, that a specific requirement for an operating process is appropriate in this case.	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	No
Document Name	

Comment	
Including a requirement for a BA to have a methodology to identify an Extreme Cold Weather period in their area seems to be a good fit for the recommendation. Proposed Requirement 8.3.1 states, "expected generation resource commitment and dispatch" with regards to a five-day hourly forecast. Generation resource commitments are typically done as a function of the markets and are done in the day-ahead time horizon. While some baseload generation is capable of being projected, many other intermittent and self-scheduled peaking facilities are much more difficult to accurately project, especially beyond a couple days. The SDT should consider changing requirement 8.3.1 to "Anticipated available resources" as resource commitment and dispatch are typically viewed as operating day or day-ahead activities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT discussed and determined that R8.3 is intended to be a longer time horizon rather just day-ahead. Additionally, the SDT determined that the words "expected" and "anticipated" are interpreted similarly and opted to retain the term "expected." While the SDT understands that markets optimize the costs, the BA has a reliability function to ensure generation and loads balance.	
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	

For TOP-002-5 Requirement 8.3, Tacoma Power is unsure whether this Requirement is for the BAA or for each generating unit. Tacoma Power recommends modifying the Requirement 8.3 to specify whether it's applied to BAA or each generating unit. For example, "A methodology to determine a five-day hourly forecast **within each Balancing Authority Area** during the identified extreme cold weather periods that includes..."	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	
Thank you for your comment. The SDT clarified "BAA" in the main body of R8 so that it applies to 8.1 through 8.3.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	
APS agrees that much on the language in R8. However, a key element in Recommendation 1g bullets 2 is missing, which is that each "Balancing Authority should be required to use the data provided by the Generator Owner/Generator Operator." We recommend the following edits to R8 in bold: Each Balancing Authority shall have an extreme cold weather Operating Process, as part of its Operating Plan, developed in Requirement R4, **that in combination with its own evaluation, utilizing resource capability and fuel availability data provided by the responsible GO/GOP**, **addresses** preparations for and operations during extreme cold weather periods. The extreme cold weather Operating Process shall include: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The SDT determined that other standard requirements regarding plans and processes (See R4) do not have that level of detail, and rather, require the BA to have a plan or processes in place, the proposed requirements follow the same paradigm.	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	No
Document Name	
Comment	
IWECC believes the proposed language is relatively clear and auditable but there is some question about when this cold weather operating process should be implemented and appear in the daily operating plan. An auditor may expect to see it addressed in a daily plan during December but probably would not expect it to appear in the plan for July. But there is a possibility that unless it was addressed in the process, some auditors would expect to see a forecast and determination of cold weather considerations included in every operating plan. The requirements for when, or what triggers, the process should be included in the subrequirements for R8 to reduce the chance of an unreasonable audit approach	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT agrees and has modified language of R8 and removed the tie to R4.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD	
Answer	No
Document Name	
Comment	

SMUD agrees with the comment provided by Tacoma Power. It is unclear whether TOP-002-5 Requirement 8.3 applies to the BA Area or to each generating unit.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to Tacoma Power.	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	No
Document Name	
Comment	
Operational Planning Analyses are conducted using temperature forecasts and expected generation resource commitment and dispatch. The process during cold weather would be no different than any other OPA. Generation limitations are identified as outages or derates in the outage management system, per TOP-003 and IRO-010.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	No
Document Name	
Comment	

As currently proposed, R8 states that each Balancing Authority's "extreme cold weather Operating Process" is to be "part of its Operating Plan developed in Requirement R4." However, R4 requires Operating Plan(s) for "the next day," implying that these Operating Plans may vary from day to day throughout the year. RF recommends R8 be revised to state that the "extreme cold weather Operating Process" is "to support the development of the Operating Plan(s) pursuant to R4." An Operating Plan developed for a day in July is unlikely to need to include an extreme cold weather Operating Process, but Operating Plans for days that may fall during extreme cold weather periods should be developed in accordance with the Operating Process, which must be available for use when needed.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT agrees and has modified language of R8 and removed the tie to R4.	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	No
Document Name	
Comment	
Per TOP-003 R4., BAs are already required to develop Operating Plans for the next-day that address expected generation resource commitment and dispatch, which require knowledge of generating units' capabilities, regardless of the weather conditions. The proposed R8 is redundant and unnecessary, as what it requires is already addressed in TOP-003-5 and TOP-002-4. Further, R8.3 is now requiring development of an Operating Plan, although it doesn't explicitly state it but it includes the same elements required in R4 with the addition of a weather forecast, for a five-day period, but only during an extreme cold weather period.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT has reviewed your comment and decided, based on the scope of the SAR and FERC's recommendations, that a specific requirement for an operating process is appropriate in this case.	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	

Without requiring the GO/GOP to provide an expected output forecast for its unit(s) as described in our response to Question #5, PacifiCorp sees a real reliability gap in terms of what the BA will be able to generate to satisfy Parts 8.2 and 8.3 (below). The GO/GOP is in a far superior position to provide the information listed in Parts 8.2.1 - 8.2.5 to that of the BA. Therefore, for the BA to develop a methodology that considers those operating limitations, there must be an equal and opposite requirement on the GO/GOP to provide these limitations to the BA. The time horizon for the GO/GOP requirement must mirror the proposed BA requirement for Part 8.3; i.e. an hourly generator output forecast for five days into the future.

8.2 A methodology that determines an appropriate reserve margin during the extreme cold weather period considering the generating unit(s) operating limitations in previous extreme cold weather periods including:

8.2.1 Capability and availability;

8.2.2 Fuel supply and inventory concerns;

8.2.3 Start-up issues;

8.2.4 Fuel switching capabilities; and

8.2.5 Environmental constraints

8.3 A methodology to determine a five-day hourly forecast during the identified extreme cold weather periods that includes: 8.3.1 Expected generation resource commitment and dispatch. 8.3.2 Interchange scheduling; 8.3.3 Demand patterns; 8.3.4 Capacity and energy reserve requirements, including deliverability capability; and 8.3.5 Weather forecast	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT determined that the BA is empowered under the current data specification requirements to request and receive all necessary information needed from the GO/GOP.	
Kimberly Bentley - Kimberly Bentley On Behalf of: Sean Erickson, Western Area Power Administration, 1, 6; - Kimberly Bentley	
Answer	Yes
Document Name	
Comment	
However, without requiring the GO/GOP to provide an expected output forecast for its unit(s) as described in response to Question #5, there is a real reliability gap in terms of what the BA will be able to generate to satisfy Parts 8.2 and 8.3 (below). The GO/GOP is in a far superior position to provide the information listed in Parts 8.2.1 - 8.2.5 to that of the BA. Therefore, for the BA to develop a methodology that considers those operating limitations, there must be an equal and opposite requirement on the GO/GOP to provide these limitations to the BA. The time horizon for the GO/GOP requirement must mirror the proposed BA requirement for Part 8.3.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. The SDT determined that the BA is empowered under the current data specification requirements to request and receive all necessary information needed from the GO/GOP.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
The BA already has the authority under the standards to require the GO/GOP to report any fuel supply and inventory concerns. In addition, R3 of EOP-012 requires a cold weather preparedness plan which includes "generating unit(s) operating limitation in cold weather to include:...Fuel supply and inventory concerns".	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
In support of MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to MRO NSRF.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI agrees the language in Requirement R8 appropriately addresses the intent of Recommendation 1g bullets 2 and 3.	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco on behalf of Constellation Segements 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	
PNM is in agreement with that language in R8.	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	Yes
Document Name	
Comment	
Additional resources should be utilized to offset the demand for natural gas if that industry cannot meet demand. The 'all the eggs in one basket' approach is problematic and suggests a more thoughtful resource balance is necessary to mitigate these effects.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The requirements will provide the BA with information necessary to consider its resource adequacy needs and react accordingly.	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
The MRO NSRF believes that while the proposed language for Requirement R8 of TOP-002 is appropriate to address the intent of Recommendation 1g relative to the BA's role (bullets 2 and 3) , it is insufficient to achieve the overall intent of Recommendation 1g without a corresponding requirement for GO/GOPs to provide the information described under bullet 1. Without requiring the GO/GOP to provide an expected output forecast for its unit(s) as described in our response to Question #5, MRO NSRF sees a real reliability gap in terms of what the BA will be able to generate to satisfy Parts 8.2 and 8.3 (below). The GO/GOP is in a far superior	

position to provide the information listed in Parts 8.2.1 - 8.2.5 to that of the BA. Therefore, for the BA to develop a methodology that considers those operating limitations, there must be an equal and opposite requirement on the GO/GOP to provide these limitations to the BA. The time horizon for the GO/GOP requirement must mirror the proposed BA requirement for Part 8.3; i.e. an hourly generator output forecast for five days into the future.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT determined that the BA is empowered under the current data specification requirements to request and receive all necessary information needed.	
Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
Answer	Yes
Document Name	
Comment	
BHP is not a BA.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	Yes
Document Name	
Comment	

BHP is not a BA.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
BHP is not a BA.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	
BHP is not a BA,	
Likes 0	

Dislikes 0	
Response	
Thank you for your 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 comments that the language in Requirement R8 appropriately addresses the intent of Recommendation 1g bullets 2 and 3.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon supports EEI comments.	
Likes 0	
Dislikes 0	
Response	

Thank you for your support. Please see response to EEI.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon supports EEI's comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your support. Please see response to EEI.	
Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Yes.	
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	
N/A	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
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.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	

Answer	Yes
Document Name	
Comment	
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	
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.	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, 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.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	

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.	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	
Document Name	
Comment	
N/A to Hydro One	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	

Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
Answer	
Document Name	
Comment	
PJM supports the IRC SRC comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to IRC SRC comments.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	

Comment	
Texas RE noticed the use of the term "extreme cold weather period," which is not defined in the NERC Glossary. EOP-012-1 introduced the term "Extreme Cold Weather Temperature," and it is unclear how or whether these two terms work together. Specifically, would an "extreme cold weather period" only include time periods in which Extreme Cold Weather Temperatures (i.e., 0.2 percentile temperatures) would be reached, conditions which approach, but do not reach those extremes but could have reliability impacts, operating conditions before and after such periods, and, if so, for how long? The SDT may wish to clarify these relationships. It is unclear what the expectation is for BAs that cover a large geographic area that is subject to significant differences in weather. Would the Operating Process only apply to the part of the area that is subject to the extreme cold weather? Texas RE notes that reserve margin is generally not considered in sub-areas of a Balancing Authority Area. Texas RE recommends defining the term "reserve margin" in Requirement Part 8.2. Texas RE understands that the intent of the recommendation 1g was to provide clear delineation of responsibilities and estimates of generation availability so that BAs and Reliability Coordinators (RCs) can perform real-time monitoring and managing of generating resources as part of its capacity and energy operating plans. If the SDT retains the concept of a "reserve margin" to perform this function, Texas RE believes it is appropriate to better clarify that relationship. Texas RE inquires whether the expectation is to create the five-day hourly forecast that goes beyond the "extreme cold weather period' per Requirement part 8.2. For example, the cold weather period defined by the BA is 24 hours of consecutive freezing weather across the entire Balancing Authority Area but is only forecasted for 2 days. Texas RE understands the current language to indicate there would need to be a five-day forecast the day ahead of the forecasted temperature (per the Operating Plan), the first day of the forecasted temperature Operating Plan and then the Operating Plan developed on second day of forecasted extreme cold weather would include the five-day forecast. Is this the SDT's intent?	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. The SDT decided to not define reserve margin as this term is used in other standards. The SDT has also clarified the intent by adding the concept of BAA to the main requirement and language of R8.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
NA	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
To simplify the requirement and maintain consistency with the intent of the rest of TOP-002, BPA recommends removing the "five-day hourly forecast" requirement of R8.3. BPA suggests the intent of Recommendation 1g would be satisfied by modifying R8.3 to state: **"A methodology to include the extreme cold weather reserve margin determined in R8.2 when creating the Balancing Authority Operating Plan for the next-day addressed by R4."**	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.

Dislikes 0	
Response	
Thank you for your comment. Due to similar concerns expressed by much of industry, the SDT deleted the tie to R4 and has made R8 supplemental rather than a requirement for the Operating Plan.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	
Document Name	
Comment	
MISO is Entergy's Balancing Authority.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
Answer	
Document Name	
Comment	
Abstain	
Likes 0	
Dislikes 0	
Response	

Thank you for your response.

7. The SDT proposes that the modifications in EOP-011-4, EOP-012-2, and TOP-002-5 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.

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
See our response to Q3. Until we gain full understanding of the assigned obligations related to identifying and implementing these recommendations and the TOP and BAs response toward these modifications, FirstEnergy cannot determine the cost effectiveness of these proposals.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Please see the response to Q3.	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	No
Document Name	
Comment	
The coordination efforts between multiple DPs in multiple TOs area and the staffing needed to create plans, process, implement and manage is burdensome and costly to the TOPs, DPs and TOs.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	No
Document Name	
Comment	
The addition of R8 in TOP-002-05 is redundant. The OPA process does not change based on the weather. Requirement R4 requires an Operating Plan, whether that plan is to mitigate impacts in a cold weather scenario or extreme summer temperatures is irrelevant.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT believes the new R8 Operating Process is not redundant to the R4 Operating Plan.	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
BHP will not 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	
BHP will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	No
Document Name	
Comment	
BHP will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
Answer	No
Document Name	
Comment	
BHP will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
AEPC has signed on to ACES comments below: We believe that the identification of critical natural gas infrastructure loads should be performed at a single operating level. To require the TO, DP, DP-UFLS, TOP, and BA to all perform the same identification function(s) seems redundant and inefficient. Please see our comments for questions 3, and 4 above for additional details.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. Please see responses to Q3 and 4.	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	No
Document Name	
Comment	
Their needs to be a documented plan for generating facilities to recoup the cost for modifications and upgrades of freeze protection measures and additional layers of freeze protection measures.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. It is outside the SDT and NERC's purview to address cost recovery mechanisms.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
Until these recommendations are implemented WEC Energy Group is unable to make a determination as to the cost effectiveness of the modifications.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

Marc Sedor - Seminole Electric Cooperative, Inc. - 3	
Answer	No
Document Name	
Comment	
The coordination efforts between multiple DPs in multiple TOs area and the staffing needed to create plans, process, implement and manage is burdensome and costly to the TOPs, DPs and TOs.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Depending on the number of identified items that require physical changes and engineering updates, these standard changes may require multiple projects on the distribution system. These projects will involve equipment that may have supply chain challenges that will add time and expense to the process.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The implementation plan for EOP-011 has been extended to address some timeframe concerns.	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	

Answer	No
Document Name	
Comment	
The coordination efforts between multiple DPs in multiple TOs area and the staffing needed to create plans, process, implement and manage is burdensome and costly to the TOPs, DPs and TOs.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
The SRC is concerned that TOP-002-5 as written is not the most cost-effective approach since it lacks a corresponding requirement for the GO/GOP to provide the BA with their MW/MWh output forecast. Historically, SRC members (as registered BAs) have incurred additional costs when implementing BA requirements when there is not a corresponding requirement for other Responsible Entities (e.g., GOs and GOPs), to provide the BA with the information needed for the BA to perform its compliance obligation(s). This increases the overall cost of compliance, as the BA must develop and employ alternative processes to obtain the data needed (e.g., modifications to a FERC tariff, revisions to membership agreements, engagement in regional rulemaking processes, etc.). In addition to the cost of delays, there may also be costs associated with the BA receiving lower quality data than if the obligation to provide data had been enshrined in a Reliability Standard or other regulatory rule.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. The SDT did not include a requirement for the GO/GOP or the BA to request the MW/MWh information. Additionally, the SDT believes that other information required under R8 is available through a data specification.	
Ken Habgood - Seminole Electric Cooperative, Inc. - 4	
Answer	No
Document Name	
Comment	
The coordination efforts between multiple DPs in multiple TOs area and the staffing needed to create plans, process, implement and manage is burdensome and costly to the TOPs, DPs and TOs.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	No
Document Name	
Comment	
We believe that the identification of critical natural gas infrastructure loads should be performed at a single operating level. To require the TO, DP, DP-UFLS, TOP, and BA to all perform the same identification function(s) seems redundant and inefficient. Please see our comments for questions 3, and 4 above for additional details.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to Q3 and Q4.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) in response to this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	No
Document Name	
Comment	
On the surface this may seem as a low cost option; however, if you delve deeper into the reason for the need for the standards, we would have to overbuild the BES for extreme events like Uri. This does not appear as cost effective. While Electricity is a critical commodity, there is a time when we will have to shed firm load. It will be during an extreme event. No one wants to, but we cannot build, economically, the infrastructure to keep this from happening.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. The SDT does not believe that EOP-011 and TOP-002 do not have requirements that would be considered “overbuild”. The proposed requirement in TOP-002 is designed to provide more notice for the potential need to curtail firm load and then EOP-011 requirements are designed to improve or minimize the amount of firm load needed to be curtailed during severe events.	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Question should be updated to remove EOP-012	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
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 Constellation Segements 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
In support of MRO NSRF comments.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment.	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	Yes
Document Name	
Comment	
We would like to see a longer implementation period with a phased in approach, 25% per 12 month period starting after 12 months to ensure a more cost effective implementation.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to Q8 regarding implementation timeframes.	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	Yes
Document Name	
Comment	
In New England, we do not anticipate severe cost increases in complying with the proposed standard revisions as our plants are built with cold weather in mind. We believe that the BA will incur the greatest cost implications in complying with R8.3 as an hourly forecast can be very involved for large systems.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
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	
LaTroy Brumfield - American Transmission Company, LLC - 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	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District,	

3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD	
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	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, 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	
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	
Teresa Krabe - Lower Colorado River Authority - 5	
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	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	

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	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	
Document Name	
Comment	
CEHE Abstains from Question 7.	
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 does not think this answer will be known until everything is fully implemented.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	
Document Name	
Comment	

No comment.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
Answer	
Document Name	
Comment	
PJM supports the IRC SRC comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	
Document Name	
Comment	
No comments	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment.	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	
Document Name	
Comment	
No Comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

8. Do you agree with the implementation plan proposed by the SDT? 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.

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT recommends a 24-month implementation timeframe to account for the coordination, budget revisions, staffing changes, and systems upgrades necessary to accomplish the new tasks. New forecasts and tools often require multiple projects to acquire the necessary input data and to process and display that data to users. This often requires extensive testing as well.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has extended the proposed implementation timeframe on TOP-002-5 from 12 months to 18 months to address industry concerns.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	No
Document Name	
Comment	
There is not a separate implementation phase for a newly identified DP, DP-UPFL, and/or TO. As an example, if the standard goes into effect 1/1/2025 and the TOP now identifies a DP in its Operational Plan on 1/1/2025 (per proposed Requirement R1.2.5.6), the current language and	

Implementation Plan seems to indicate that the DP must immediately have a plan implemented on the same day. Thus, we recommend a phased-in compliance approach for Requirement R7. Per our recommendation for modifying R7 in response to Question 3, we recommend a phased-in implementation plan for this standard. It is our recommendation that the phased-in compliance date be no earlier than six (6) calendar months after the effective date of R1.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
Ken Habgood - Seminole Electric Cooperative, Inc. - 4	
Answer	No
Document Name	
Comment	
For EOP-011, propose 36 months. The coordination and agreements between multiple DPs and multiple DP's in multiple TOs areas, could possibly take a significant amount of time. For TOP-002, propose 18 months to remain consistent with other revisions.	
Likes 0	
Dislikes 0	

Response	
Thanks for your comment. The SDT has extended the proposed implementation timeframe on TOP-002-5 from 12 months to 18 months to address industry concerns. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
The SRC[1] supports an 18-month implementation timeframe for EOP-011. In addition, the SRC supports an 18-month implementation timeframe for TOP-002. (This would extend the proposed 12-month timeframe to 18 months (assuming the SDT adopts the SRC's recommendation for the GO/GOP to provide the MW/MWh output forecast as described in the SRC's response to Questions 5 and 6). This would align the implementation timeframe for all Phase 2 requirements to 18 months, ensuring all requirements would be in place prior to the Winter 2025-2026 season [1] For purposes of these comments, the IRC SRC includes the following entities: CAISO (with the exception of our response to question 5), ERCOT (with the exception of our responses to questions 3, 5 and 8), IESO, ISO-NE, MISO, NYISO, PJM and SPP.	
Likes 0	

Dislikes 0	
Response	

Thanks for your comment. The SDT has extended the proposed implementation timeframe on TOP-002-5 from 12 months to 18 months to address industry concerns. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements.

The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.

Kristine Ward - Seminole Electric Cooperative, Inc. - 1

Answer	No
Document Name	
Comment	

For EOP-011, propose 36 months. The coordination and agreements between multiple DPs and multiple DP's in multiple TOs areas, could possibly take a significant amount of time. For TOP-002, propose 18 months to remain consistent with other revisions.

Likes 0	
Dislikes 0	
Response	

Thanks for your comment. The SDT has extended the proposed implementation timeframe on TOP-002-5 from 12 months to 18 months to address industry concerns. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and

R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements.

The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

Depending on the number of identified items that require physical changes and engineering updates, this may not be possible in an 18 month period. The SDT should consider a phased approach to this implementation plan.

Likes 0	
Dislikes 0	

Response

Thanks for your comment. The SDT has extended the proposed implementation timeframe on TOP-002-5 from 12 months to 18 months to address industry concerns. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements.

The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.

Kimberly Bentley - Kimberly Bentley On Behalf of: Sean Erickson, Western Area Power Administration, 1, 6; - Kimberly Bentley	
Answer	No
Document Name	
Comment	
Recommend aligning the implementation plans for EOP-011-4 and TOP-002-5 to 18 months.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has extended the proposed implementation timeframe on TOP-002-5 from 12 months to 18 months to address industry concerns. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	No
Document Name	
Comment	
IID recommends an 18-month implementation plan.	

Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has extended the proposed implementation timeframe on TOP-002-5 from 12 months to 18 months to address industry concerns. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren recommends extending the implementation plan for TOP-002-5 be extended to 18 months.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has extended the proposed implementation timeframe on TOP-002-5 from 12 months to 18 months to address industry concerns.	
Marc Sedor - Seminole Electric Cooperative, Inc. - 3	

Answer	No
Document Name	
Comment	
For EOP-011, propose 36 months. The coordination and agreements between multiple DPs and multiple DP's in multiple TOs areas, could possibly take a significant amount of time. For TOP-002, propose 18 months to remain consistent with other revisions.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	

We would propose for EOP-011-4 that R7 has a later implementation date than R1 to afford those entities identified by their TOPs sufficient time to prepare and comply.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	
Tacoma Power supports MRO NSRF comments on the implementation timeframe.	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	

Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group proposes that the implementation timeframe for TOP-002-5 be extended from 12 months to 18 months	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has extended the proposed implementation timeframe on TOP-002-5 from 12 months to 18 months to address industry concerns.	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	No
Document Name	
Comment	

A phased in implementation approach, 25% per 12 month period, starting after 12 months.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
In support of MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and	

R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements.

The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.

Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	

As stated in response to question #3, APS supports a phased approach for EOP-011-4 Requirement R7 that provides 18 months to identify the critical natural gas infrastructure and 18 additional months to make system and field changes. The 18-month time frame is sufficient to identify natural gas infrastructure. However, it is insufficient for TOs, DPs, and UFLS Only DPs to either move those loads to other feeders or to entirely exclude those feeders from their load shedding programs and find other suitable offsetting loads in their place. This work often requires both engineering and field crew support to fully accomplish and will likely require 36 months to fully implement.

Likes 0	
Dislikes 0	

Response

Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements.

The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the

first day of the first calendar quarter that is six 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.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
AEPC has signed on to ACES comments below: There is not a separate implementation phase for a newly identified DP, DP-UPFL, and/or TO. As an example, if the standard goes into effect 1/1/2025 and the TOP now identifies a DP in its Operational Plan on 1/1/2025 (per proposed Requirement R1.2.5.6), the current language and Implementation Plan seems to indicate that the DP must immediately have a plan implemented on the same day. Thus, we recommend a phased-in compliance approach for Requirement R7. Per our recommendation for modifying R7 in response to Question 3, we recommend a phased-in implementation plan for this standard. It is our recommendation that the phased-in compliance date be no earlier than six (6) calendar months after the effective date of R1.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the	

first day of the first calendar quarter that is six 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.

Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Tri-State suggests a 48month implementation plan.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	

Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	No
Document Name	
Comment	

For EOP-011, propose 36 months. The coordination and agreements between multiple DPs and multiple DP's in multiple TOs areas, could possibly take a significant amount of time. For TOP-002, propose 18 months to remain consistent with other revisions.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
Implementation timeframe should be extended to at least 24 months to allow sufficient time to collect and incorporate the data. An implementation period of 36 months will allow for sufficient time to train all system operators on the updated plans.	
Likes 0	
Dislikes 0	
Response	

Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
As stated in our response to Question #3, eighteen months would not be sufficient for these new Functional Entities to become compliant with their EOP-011 obligations. AEP instead recommends an implementation period of 36 months for EOP-011.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the	

first day of the first calendar quarter that is six 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.

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	No
Document Name	

Comment

See our response to Q3. Until we gain full understanding of the assigned obligations related to identifying and implementing these recommendations and the TOP and BAs response toward these modifications, FirstEnergy cannot support the implementation plan for TOP-002-5.

Likes 0	
Dislikes 0	

Response

Thanks for your comment. The SDT has extended the proposed implementation timeframe on TOP-002-5 from 12 months to 18 months to address industry concerns.

Dave Krueger - SERC Reliability Corporation - 10

Answer	No
Document Name	

Comment

On behalf of the SERC GWG

See above for R7. There is no timeframe issued for newly identified Distribution Providers, UFLS-Only DPs, or Transmission Owners to implement/respond to the TOP plan.

Likes 0	

Dislikes 0	
Response	

Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements.

The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements.

The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the

first day of the first calendar quarter that is six 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.	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Add language to align implementation plan timeframes to 18 months.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	

An 18 month implementation timeframe may be appropriate assuming the NERC Standard is approved through FERC on the same general timetable as the Phase 1 Standards, FERC approval approx. Feb 2024, with effective date of October 1, 2025 which would be prior to the 2025 winter period. However, the SDT should consider that based on the current status of the SDT through Phase 2 with this version of EOP-011 already at the first ballot, a 12 month timeframe might be appropriate so that if FERC were to approve the Standard in 2023, there would be the possibility of the effective date being prior to the 2024 winter period, or at least near the start of the 2024 winter period. If Phase 2 Standards revisions were to be adopted before October 1, 2023, the effective date would aling with the expected Effective date of the Phase 1 EOP-011 and EOP-012 which could eliminate a potential risk of compliance with multiple versions of the same Standard. ISO-NE does not support any implementation timeframe that goes beyond the start of the 2025-2026 Winter.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	

Comment	
Constellation has no additional comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the proposed 12 month implementation plan for TOP-002-5.	
Likes 0	
Dislikes 0	

Response	
Thanks for your comment. The SDT has extended the proposed implementation timeframe on TOP-002-5 from 12 months to 18 months to address industry concerns.	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco on behalf of Constellation Segements 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	

Answer	Yes
Document Name	
Comment	
PNM is in support of a 12 month implementation timeframe for TOP-002-5.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has extended the proposed implementation timeframe on TOP-002-5 from 12 months to 18 months to address industry concerns.	
Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
Answer	Yes
Document Name	
Comment	
Date on SDT timeline states NERC Board of Trustees adoption is October 2022, shouldn't that be 2023?	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. You are correct on the timing change.	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	Yes

Document Name	
Comment	
Date on SDT timeline states NERC Board of Trustees adoption is October 2022, shouldn't that be 2023?	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. You are correct on the timing change.	
Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
Date on SDT timeline states NERC Board of Trustees adoption is October 2022, shouldn't that be 2023?	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. You are correct on the timing change.	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	

Date on SDT timeline states NERC Board of Trustees adoption is October 2022, shouldn't that be 2023?	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. You are correct on the timing change.	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
12 months for TOP-003 and 18 months for EOP-011 seem reasonable. Please refer to comments on question 3.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
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 EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Yes, CEHE supports the proposed 12 month implementation plan for the TOP-002-5.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The SDT has extended the proposed implementation timeframe on TOP-002-5 from 12 months to 18 months to address industry concerns.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon supports EEI's comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI.	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI.	

Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Southern Indiana Gas & Electric Company (SIGE) supports the proposed 12 month implementation plan for the TOP-002-5.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has extended the proposed implementation timeframe on TOP-002-5 from 12 months to 18 months to address industry concerns	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA agrees with the Implementation Plan for TOP-002-5 but disagrees with the Implementation Plan for EOP-011-4. Please also see BPA's response to question 3.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and	

R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	

Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements.

The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.

Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, 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	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements.	

The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements.	

The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements.	

The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	
Document Name	
Comment	

No comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.	
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
Answer	
Document Name	
Comment	
PJM supports the IRC SRC comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8,	

R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six 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.

Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	
Document Name	
Comment	
WECC leaves comment on the implementation plan to those entities that have to implement the standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI.	

9. Is there any part of the proposed requirements, as currently drafted, that is unclear? If so, how would you make it clearer?	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
While the proposed requirements we feel are clear, until we gain full understanding of the assigned obligations related to identifying and implementing these recommendations and the TOP and BAs response toward these modifications, FirstEnergy cannot support these modifications.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.	
Kinte Whitehead - Exelon - 3	
Answer	No
Document Name	
Comment	
Exelon supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI.	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon supports EEI's comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI.	
Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No

Document Name	
Comment	
No.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	No
Document Name	
Comment	
PNM believes that changes are described sufficiently.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	

Constellation has no additional comments. Kimberly Turco on behalf of Constellation Segements 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, 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 the comments of the Edison Electric Institue (EEI) to question #9,	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	

Comment	
EEI agrees that the proposed changes to EOP-011 and TOP-002-5 are sufficiently clear.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	
Constellation has no additional comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your response.	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Micah Runner - Black Hills Corporation - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your response.	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Marc Sedor - Seminole Electric Cooperative, Inc. - 3	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your response.	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Ken Habgood - Seminole Electric Cooperative, Inc. - 4	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
On behalf of the SERC GWG For R7: The requirement states “The Operating Plan(s) shall be provided to the Transmission Operator.” Should this be “as requested by the Transmission Operator”? Does the TOP really want to be flooded with every DP’s full operating plan?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has clarified the wording to “shall provide the associated Load shedding plan” to limit data flow to the TOP.	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	

Comment	
As metioned in the response to question 4, the standard does not define what is meant by "critical natural gas infrastructure". ATC requests that the term "critical natural gas infrastructure" be defined.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making "critical natural gas infrastructure load" a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company would clarify language in EOP-011-4 R1.2.5 that currently could be confusing regarding operator controlled MLS and automatic UFLS/UVLS as follows: "Operator-controlled **Manual Load Shed and/or Automatic Load Shed** during an Emergency that accounts for each of the following:" Southern Company would also suggest language modifications to TOP-002-5 R8 to reduce confusion in the BA having a process and having next day plans as follows: "Each Balancing Authority shall have an extreme cold weather Operating Process, **which it uses in developing** its **next day** Operating Plan **consistent with** Requirement R4, addressing preparations for and operations during extreme cold weather periods."	

Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Regarding the comment on EOP-011, changes were made to R1.2.5, R2.2.9, and R8.1 to more consistently address operator-controlled manual Load shedding and automatic Load shedding. Regarding the comment on TOP-002, the SDT reviewed your comment as part of the discussions and determined, based on a number of industry comments, to delete the link with the Operating Plan and have the Operating Process be a stand-alone requirement that is supplemental.	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Please refer to comments on questions 1 and 4.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see responses to Q1 and 4.	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	

More clarification is needed on the phrase “minimize the overlap” in EOP-011 Requirements 7.1.2 and 7.1.3.. How will an entity determine if it has minimized the overlap enough to satisfy an auditor and meet the expectation of the requirement?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT believes the wording is sufficient to meet most situations and does not want to be overly prescriptive in limiting how an entity meets the requirements. Additionally, the team did not modify the language “minimize the overlap” during this draft. Please see the Technical Rationale for additional information.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
See previous comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	Yes
Document Name	
Comment	

See earlier comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD	
Answer	Yes
Document Name	
Comment	
The term “critical natural gas infrastructure” needs to be defined with a formal definition.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making “critical natural gas infrastructure load” a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes

Document Name	
Comment	
Please see the response to question 1. WECC believes that more clarity to EOP--11-4 on identification of "critical" natural gas ficility load is possible.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making “critical natural gas infrastructure load” a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
APS believes that clarification is needed in EOP-011-4 because responsible entities do not have the visibility to identify such loads, so they are reliant on natural gas facilities owners, however, natural gas facility owners have no regulatory obligation to self-identify their facilities as critical. To address this concern, APS suggests modifications to Requirement 1, subpart 1.2.5.5 and Requirement R7, subpart 7.1.5 as follows: Requirement 1, subpart 1.2.5.5: Provisions for the identification and prioritization of designated critical natural gas infrastructure loads**, as identified by the responsible natural gas infrastructure owner/operator**; and Requirement R7, subpart 7.1.5:	

Provisions for the identification and prioritization of designated critical natural gas infrastructure loads**, as identified by the responsible natural gas infrastructure owner/operator**.	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	
Thank you for your comment. The identification and prioritization of critical natural gas loads requires coordination with natural gas facility owners and operators. The SDT recognizes that entities are dependent upon the cooperation of natural gas facility owners and operators to complete this task. However, it is outside the scope of the SDT to develop methods to compel natural gas owners and operators to cooperate and provide specific information to various entities.	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	Yes
Document Name	
Comment	
We would like more clarification on what is a "Designated Critical Load". Many standards have overlapping definitions so a clear definition of what this means would support a consistent application.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making "critical natural gas infrastructure load" a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	

Answer	Yes
Document Name	
Comment	
Please refer to the comments in response to Question #10.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to Q10.	
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	
See previous comments submitted on TOP-002 Requirement 8.3 and definition of critical natural gas infrastructure in EOP-011 R1.2.5.5.	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	
Thank you for your comments. Please see previous responses from the SDT.	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes

Document Name	
Comment	

The SDT should consider that the current and proposed language of EOP-011 R1 does not prevent an entity from having critical gas infrastructure loads or a designated critical load from being included in its automatic load shed circuits. Although the intent is there, the standard doesn't explicitly address that potential overlap. Recommend adding automatic to R1.2.5.2

The proposed R1.2.5.5 is specific to "critical gas infrastructure load". The SDT should consider that this be rewritten to be more generic to encompass all "designated critical loads" and not just for gas infrastructure? Does this make sense to specifically call it out in a separate requirement.

The SDT should consider whether or not to include a new term in the NERC Glossary of "Designated Critical Load" which would define what the standard critical loads are, including, but not limited to critical gas infrastructure, critical fuel delivery infrastructure, off-site nuclear feeds, public safety, public health, etc.

These specifics could be called out in the sub requirement as well.

Suggested R1.2.5 Language for additions of "automatic" to 1.2.5.2 and the specific critical loads to 1.2.5.5.

Option 1:

1.2.5. {C}Operator-controlled manual load shedding or automatic 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 and automatic 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.; 1.2.5.5. Provisions for the identification and prioritization of designated critical loads, including; 1.2.5.5.1. Natural gas infrastructure, 1.2.5.5.2. Other fuel supply infrastructure, 1.2.5.5.3. Public safety and public health infrastructure 1.2.5.6. {C}Provisions for the identification of Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners required to mitigate operating Emergencies in its Transmission Operator Area. Option 2 for R1.2.5.5 with "Designated Critical Load" glossary term: 1.2.5.5 Provisions for the identification and prioritization of designated critical loads The SDT should consider the above recommendations be incorporated into R7 for the DP and UFLS-Only DP Requirement as well since the same comments apply.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making "critical natural gas infrastructure load" a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint. The team has added "automatic" to Part 1.2.5.2.	

Thank you for your suggestions on "Designated Critical Load" and the proposed standard requirement changes. The SDT has determined this is out of scope of this teams SAR and chose to maintain the separate provisions related to the identification and prioritization of critical natural gas infrastructure in 1.2.5.5 and 8.1.5.

Kimberly Bentley - Kimberly Bentley On Behalf of: Sean Erickson, Western Area Power Administration, 1, 6; - Kimberly Bentley	
Answer	Yes
Document Name	
Comment	
Define "critical natural gas infrastructure" as be used in the requirement	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making "critical natural gas infrastructure load" a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
See previous question responses.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comments. Please see response to previous questions.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	

In order to streamline R1, the SRC recommends that Part 1.2.5.5 be consolidated with Part 1.2.5.2 as follows:

1.2.5.2 Provisions to *identify and* minimize the overlap of circuits that are designated for manual *or automatic* Load shed and circuits that serve designated critical loads*, including known critical natural gas infrastructure loads*;

EOP-011, Requirement R7

The SRC is concerned with the use of the proposed language "Operating Plan," in Requirement R7, as it may be read to assign UFLS-Only Distribution Providers and Transmission Owners real-time operational tasks that they are not equipped to handle. Therefore, the SRC recommends R7 be modified as indicated below:

R7. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner identified in a Transmission Operator's Operating Plan(s) to *assist with* mitigat*ing* operating Emergencies in its Transmission Operator Area shall, *in consultation with the Transmission Operator, develop, maintain, and implement, and provide to the Transmission Operator an Operator-controlled manual, or automatic Load shedding program, that accounts for each of the following,* as applicable:[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]

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

7.2. Provisions to *identify and* minimize the overlap of circuits that are designated for manual *or automatic* Load shed and circuits that serve designated critical loads, *including known critical natural gas infrastructure loads*;

7.3. 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* 7.4. 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	
Thank you for your comments. Please refer to the SDT’s response to your previous comments.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
See our previous comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	

ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) in response to this question. Additionally, ERCOT refers the SDT to its response to question 2 to highlight the need to clarify the obligations of TOs and other applicable entities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Please refer to the SDT response to question 2.	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your comments.	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Please see response to EEI.	

Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
Answer	
Document Name	
Comment	
PJM supports the IRC SRC comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Please see response to IRC SRC.	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	

10. Provide any additional comments for the SDT to consider, including the provided technical rationale document, if desired.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	
ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) in response to this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Please see response to IRC SRC.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	
Document Name	
Comment	
We believe the proposed modifications are a good first attempt at meeting the identified key recommendations; however, we also believe that there are a few key areas that need additional review and clarification. Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	
Document Name	
Comment	
If the SDT does not accept the SRC's recommendation to define the term "*critical natural gas infrastructure load,*" as discussed in the SRC's response to Question 1, the SRC requests the SDT include guidance on implementing this concept in the technical rationale for the Standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making "critical natural gas infrastructure load" a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	
Document Name	
Comment	
Please consider updating TOP-002-5 Section C. Compliance with the most recent NERC wording used for Section C. Compliance.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT has updated this wording in the posted draft.	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
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 comment.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	

Document Name	
Comment	
In Technical Rationale for EOP-011-4, the word “load” is both capitalized and not capitalized throughout the document. IID recommends the SDT check the capitalization of “load” and ensure it’s consistent throughout the document	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has reviewed the technical rationale and fixed the inconsistent capitalizations.	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	
Document Name	
Comment	
No Additional Comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
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	
In the Technical Rationale for EOP-011-4, the word "load" is both capitalized and not capitalized throughout the document. Tacoma Power recommends the SDT check the capitalization of "load" and ensure it's consistent throughout the document.	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	
Thank you for your comment. The SDT has reviewed the technical rationale and fixed the inconsistent capitalizations.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	
Document Name	
Comment	
• There appears to be a correlation between EOP-011-4 R1 and EOP-001-4 R7, however there does not appear to be a similar correlation referencing obligations for others for EIP-011-4 R2. • EOP-011-4 R2 is redundant with TOP-002-5 R8. Suggest language modifications to TOP-002-5 R8 to reduce confusion in the BA having a process and having next day plans. • In EOP-011-4 R7.1, DP is being obligated to respond to implementing a TOP's timeframe for which it may not be capable. It is the TOP which should be obligated to be capable of meeting the TOP's timeframe.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 1. The SDT put the correlation between R1 and R7 because the TOPs have the direct relationship and communication with the DPs and TOs that they communicate with from a load shed standpoint.	

2. The SDT does not agree that EOP-011 R2 and TOP-002 are redundant. The SDT believes that the process required in TOP-002 R8 is a distinct new process that is intended to address a specific scenario whereas the emergency operating plan is intended to mitigate capacity emergencies during multiple types of scenarios. EOP-011 is a plan to address an emergency that is occurring in real-time. TOP-002 is addressing a look ahead process to avoid needing to implement the EOP Plan in real-time.

The SDT does not agree with this statement. The DP does have the obligation of having provisions for manual load shedding capability of being implemented in a timeframe adequate for mitigating the emergency.

Alison MacKellar - Constellation - 5	
Answer	
Document Name	
Comment	
Constellation has no additional comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	
Document Name	
Comment	
Gas is important for generation but generation is also important. Non-BES connected distributed generation should also be identified that would provide support to the BES.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The scope of the SDT is limited to responding to the FERC recommendations per the SAR.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
Please consider updating TOP-002-5 Section C. Compliance with the most recent NERC wording used for the compliance section.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has updated this wording in the posted draft.	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments.
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis
Answer
Document Name
Comment
PJM supports the IRC SRC comments.
Likes 0
Dislikes 0
Response
Thank you for your comments. Please see response to IRC SRC.
Kimberly Turco - Constellation - 6
Answer
Document Name
Comment
Constellation has no additional comments. Kimberly Turco on behalf of Constellation Segements 5 and 6
Likes 0
Dislikes 0
Response

Thank you for your comments.	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	
Document Name	
Comment	
No additional comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Romel Aquino - Edison International - Southern California Edison Company - 3	
Answer	
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Please see response to EEI.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	

Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Please see response to EEI.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	
AEPC signed on to ACES comments: We believe the proposed modifications are a good first attempt at meeting the identified key recommendations; however, we also believe that there are a few key areas that need additional review and clarification. Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Joshua London - Eversource Energy - 1, Group Name Eversource	

Answer	
Document Name	
Comment	
EOP-011 R1.2.5.5 should be removed and the requirement "Provisions for the identification and prioritization of designated critical natural gas infrastructure loads" be a DP only responsibility(R7.1.5.). TOP’s do not know what natural gas customers they serve and where ‘critical natural gas infrstructure’ loads are found on the distribution system, and sharing of customer information from DP to TOP may not always be allowed.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT believes that the TOP should have provisions while understanding that the DP may have the relationship with the natural gas supplier. The DP would have to share their load shedding plan, not detailed customer information.	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	
Document Name	
Comment	
ReliabilityFirst appreciates the Standard Drafting Team’s diligent work on this project.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Daniel Gacek - Exelon - 1	

Answer	
Document Name	
Comment	
Exelon supports EEI's comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI.	
Kinte Whitehead - Exelon - 3	
Answer	
Document Name	
Comment	
Exelon supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI.	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	
Document Name	
Comment	

ATC does not believe that critical natural gas infrasture loads require its own sub-requirement for R1.2.5, since it is a subset of "designated critical loads."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT believes that specifically calling out critical natural gas loads is needed to meet the FERC recommendations.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	

None.

Likes 0	
Dislikes 0	

Response
Thank you for your response.

REMINDER
Standards Announcement
Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2

Initial Ballots and Non-binding Polls Open through April 13, 2023

Now Available

Initial ballots and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels are open through **8 p.m. Eastern, Thursday, April 13, 2023** for the following:

- EOP-011-4 – Emergency Operations
- TOP-002-5 – Operations Planning
- Implementation Plan

This posting does not include EOP-012-2. The drafting team is holding this standard back to make revisions based on FERC Order Approving Extreme Cold Weather Reliability Standards EOP-011-3 and EOP-012-1 and Directing Modification of Reliability Standard EOP-012-1, N. Am. Elec. Reliability Corp., 182 FERC ¶ 61,094 (Feb. 16, 2023). An initial posting for EOP-012-2 will occur at a future date.

Reminder Regarding Corporate RBB Memberships
Under the NERC Rules of Procedure, each entity and its affiliates is collectively permitted one voting membership per Registered Ballot Body Segment. Each entity that undergoes a change in corporate structure (such as a merger or acquisition) that results in the entity or affiliated entities having more than the one permitted representative in a particular Segment must withdraw the duplicate membership(s) prior to joining new ballot pools or voting on anything as part of an existing ballot pool. Contact ballotadmin@nerc.net to assist with the removal of any duplicate registrations.

Balloting
Members of the ballot pools associated with this project can log in and submit their votes by accessing the Standards Balloting and Commenting System (SBS) here.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*

- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps
The ballot results will be announced and posted on the project page. The drafting team will review all responses received during the comment period and determine the next steps of the project.

For 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

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

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

Formal Comment Period Open through April 13, 2023
Ballot Pools Forming through March 29, 2023

Now Available

A formal comment period is open through **8 p.m. Eastern, Thursday, April 13, 2023** for the following:

- EOP-011-4 – Emergency Operations
- TOP-002-5 – Operations Planning
- Implementation Plan

This posting does not include EOP-012-2. The drafting team is holding this standard back to make revisions based on FERC Order Approving Extreme Cold Weather Reliability Standards EOP-011-3 and EOP-012-1 and Directing Modification of Reliability Standard EOP-012-1, N. Am. Elec. Reliability Corp., 182 FERC ¶ 61,094 (Feb. 16, 2023). An initial posting for EOP-012-2 will occur at a future date.

Commenting

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

Reminder Regarding Corporate RBB Memberships

Under the NERC Rules of Procedure, each entity and its affiliates is collectively permitted one voting membership per Registered Ballot Body Segment. Each entity that undergoes a change in corporate structure (such as a merger or acquisition) that results in the entity or affiliated entities having more than the one permitted representative in a particular Segment must withdraw the duplicate membership(s) prior to joining new ballot pools or voting on anything as part of an existing ballot pool. Contact ballotadmin@nerc.net to assist with the removal of any duplicate registrations.

Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Wednesday, March 29, 2023.** 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 **April 4-13, 2023**.

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.

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BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/272)
Ballot Name: 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 EOP-011-4 IN 1 ST
Voting Start Date: 4/4/2023 12:01:00 AM
Voting End Date: 4/13/2023 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 251
Total Ballot Pool: 283
Quorum: 88.69
Quorum Established Date: 4/13/2023 1:20:46 PM
Weighted Segment Value: 45.64

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	77	1	25	0.424	34	0.576	0	8	10
Segment: 2	8	0.8	2	0.2	6	0.6	0	0	0
Segment: 3	63	1	26	0.491	27	0.509	0	5	5
Segment: 4	14	1	3	0.273	8	0.727	0	0	3
Segment: 5	69	1	28	0.528	25	0.472	0	9	7
Segment: 6	44	1	18	0.514	17	0.486	0	4	5
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	7	0.4	4	0.4	0	0	0	2	1
Totals:	283	6.2	106	2.83	117	3.37	0	28	32

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	Allete - Minnesota Power, Inc.	Lori Frisk		Negative	Comments Submitted
1	APS - Arizona Public Service Co.	Daniela Atanasovski		None	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Negative	Comments Submitted
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Black Hills Corporation	Micah Runner		Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Third-Party Comments
1	City Utilities of Springfield, Missouri	Michael Bowman		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Third-Party Comments
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Affirmative	N/A
1	Duke Energy	Katherine Street		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Alan Kloster	Affirmative	N/A
1	Eversource Energy	Joshua London		Negative	Comments Submitted
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Abstain	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte		None	N/A
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	Joseph McClung		Negative	Third-Party Comments
1	KAMO Electric Cooperative	Micah Breedlove		None	N/A
1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Affirmative	N/A
1	Los Angeles Department of Water and Power	Pjoy Chua		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		Abstain	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Nikki Carson-Marquis	Negative	Third-Party Comments
1	Muscatine Power and Water	Andrew Kurriger		Negative	Third-Party Comments
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	New York Power Authority	Salvatore Spagnolo		Negative	Third-Party Comments
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	Third-Party Comments
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
1	Oncor Electric Delivery	Byron Booker	Gul Khan	Affirmative	N/A
1	Orlando Utilities Commission	Aaron Staley		Abstain	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Abstain	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
1	Platte River Power Authority	Marissa Archie		Negative	Third-Party Comments
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Negative	Comments Submitted
1	Puget Sound Energy, Inc.	Anna Lavik		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	Comments Submitted
1	Salt River Project	Sarah Blankenship	Israel Perez	Negative	Comments Submitted
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	SaskPower	Wayne Guttormson		None	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Negative	Comments Submitted
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Negative	Third-Party Comments
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Negative	Comments Submitted
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Negative	Comments Submitted
1	Taunton Municipal Lighting Plant	Devon Tremont		Affirmative	N/A
1	Tennessee Valley Authority	David Plumb		Negative	Third-Party Comments
1	Tri-State G and T Association, Inc.	Donna Wood		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	Western Area Power Administration	Sean Erickson	Kimberly Bentley	Negative	Comments Submitted
1	Xcel Energy, Inc.	Eric Barry		None	N/A
2	California ISO	Darcy O'Connell		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
2	Independent Electricity System Operator	Harishkumar Subramani Vijay Kumar		Affirmative	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.	Thomas Foster	Elizabeth Davis	Negative	Third-Party Comments
2	Southwest Power Pool, Inc. (RTO)	Matthew Harward		Affirmative	N/A
3	AEP	Kent Feliks		Negative	Comments Submitted
3	Ameren - Ameren Services	David Jendras Sr		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Black Hills Corporation	Josh Combs	Rachel Schuldt	Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Negative	Comments Submitted
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Schroeder		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		None	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	Eversource Energy	Vicki O'Leary		Negative	Comments Submitted
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Florida Municipal Power Agency	Navid Nowakhtar	LaKenya Vannorman	None	N/A
3	Georgia System Operations Corporation	Scott McGough		Negative	Comments Submitted
3	Great River Energy	Michael Brytowski	Joseph Knight	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		Negative	Third-Party Comments
3	KAMO Electric Cooperative	Tony Gott		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		Abstain	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		Negative	Third-Party Comments
3	New York Power Authority	David Rivera		Negative	Third-Party Comments
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Third-Party Comments
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	Third-Party Comments
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney		None	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Omaha Public Power District	David Heins		Negative	Third-Party Comments
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Abstain	N/A
3	Platte River Power Authority	Richard Kiess		Negative	Comments Submitted
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Negative	Comments Submitted
3	Salt River Project	Mathew Weber	Israel Perez	Negative	Comments Submitted
3	Santee Cooper	Vicky Budreau		Abstain	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		Negative	Comments Submitted
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Negative	Third-Party Comments
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Tennessee Valley Authority	Ian Grant		Negative	Third-Party Comments
3	Tri-State G and T Association, Inc.	Ryan Walter		Negative	Comments Submitted
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
3	Xcel Energy, Inc.	Nicholas Friebel		Negative	Third-Party Comments
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Third-Party Comments
4	Austin Energy	Tony 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		Negative	Comments Submitted
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Third-Party Comments
4	Northern California Power Agency	Marty Hostler		None	N/A
4	Oklahoma Municipal Power Authority	Michael Watt		None	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Negative	Third-Party Comments
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Comments Submitted
4	Seminole Electric Cooperative, Inc.	Ken Habgood		Negative	Comments Submitted
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Utility Services, Inc.	Tracy MacNicoll		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Negative	Comments Submitted
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	AES - AES Corporation	Ruchi Shah		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier	Carly Miller	Affirmative	N/A
5	Bonneville Power Administration	Christopher Siewert		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		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	Jeffrey Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Helen Wang		Affirmative	N/A
5	Constellation	Alison MacKellar		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Third-Party Comments
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	Enel Green Power	Natalie Johnson		Abstain	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Robert Loy		Negative	Comments Submitted
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Affirmative	N/A
5	Hydro-Qu?bec Production	Carl Pineault		Abstain	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Negative	Comments Submitted
5	JEA	John Babik		Negative	Third-Party Comments
5	Lincoln Electric System	Brittany Millard		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	Manitoba Hydro	Kristy-Lee Young		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Muscatine Power and Water	Neal Nelson		Negative	Third-Party Comments
5	National Grid USA	Robin Berry		Affirmative	N/A
5	NB Power Corporation	David Melanson		Affirmative	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	Richard Vendetti		None	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Third-Party Comments
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Third-Party Comments
5	Northern California Power Agency	Jeremy Lawson		Abstain	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Third-Party Comments
5	Oglethorpe Power Corporation	Donna Johnson		Negative	Third-Party Comments
5	Omaha Public Power District	Mahmood Safi		Negative	Third-Party Comments
5	Ontario Power Generation Inc.	Constantin Chitescu		Abstain	N/A
5	Orlando Utilities Commission	Dania Colon		None	N/A
5	Pattern Operators LP	George E Brown		Negative	Third-Party Comments
5	Platte River Power Authority	Jon Osell		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
5	PSEG Nuclear LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Negative	Comments Submitted
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	Comments Submitted
5	Salt River Project	Jennifer Bennett	Israel Perez	Negative	Comments Submitted
5	Santee Cooper	Marty Watson		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Negative	Comments Submitted
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Jim Howell, Jr.		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	Tennessee Valley Authority	Nehtisha Rollis		Negative	Third-Party Comments
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Negative	Comments Submitted
5	U.S. Bureau of Reclamation	Wendy Kalidass		None	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		None	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	AEP	Justin Kuehne		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		None	N/A
6	Austin Energy	Imane Mrini		Affirmative	N/A
6	Black Hills Corporation	Claudine Bates		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		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
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
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Jennifer Flandermeyer	Alan Kloster	Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted
6	Great River Energy	Donna Stephenson		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
6	Manitoba Hydro	Kelly Bertholet		Abstain	N/A
6	Muscatine Power and Water	Nicholas Burns		Negative	Third-Party Comments
6	New York Power Authority	Shelly Dineen		Negative	Third-Party Comments
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Abstain	N/A
6	NiSource - Northern Indiana Public Service Co.	Joseph OBrien		Negative	Third-Party Comments
6	Northern California Power Agency	Dennis Sismaet		None	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Third-Party Comments
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments
6	Platte River Power Authority	Sabrina Martz		Negative	Comments Submitted
6	Portland General Electric Co.	Stefanie Burke		None	N/A
6	Powerex Corporation	Raj Hundal		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Anne Kronshage		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	M LeRoy Patterson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	Comments Submitted
6	Salt River Project	Timothy Singh	Israel Perez	Negative	Comments Submitted
6	Santee Cooper	Glenda Horne		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		Negative	Third-Party Comments
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Negative	Comments Submitted
6	Tennessee Valley Authority	Armando Rodriguez		Negative	Third-Party Comments
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
6	Western Area Power Administration	Chrystal Dean		None	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	Wesley Yeomans		None	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Lindsey Mannion		Abstain	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Previous 1 Next

Showing 1 to 283 of 283 entries

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/272)
Ballot Name: 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 TOP-002-5 IN 1 ST
Voting Start Date: 4/4/2023 12:01:00 AM
Voting End Date: 4/13/2023 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 250
Total Ballot Pool: 282
Quorum: 88.65
Quorum Established Date: 4/13/2023 1:28:38 PM
Weighted Segment Value: 44.59

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	76	1	25	0.455	30	0.545	0	12	9
Segment: 2	8	0.8	1	0.1	7	0.7	0	0	0
Segment: 3	63	1	25	0.5	25	0.5	0	7	6
Segment: 4	14	1	3	0.3	7	0.7	0	2	2
Segment: 5	69	1	26	0.51	25	0.49	0	10	8
Segment: 6	44	1	17	0.5	17	0.5	0	5	5
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	7	0.4	4	0.4	0	0	0	2	1
Totals:	282	6.2	101	2.764	111	3.436	0	38	32

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	Allete - Minnesota Power, Inc.	Lori Frisk		Abstain	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		None	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Negative	Comments Submitted
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Black Hills Corporation	Micah Runner		Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Third-Party Comments
1	City Utilities of Springfield, Missouri	Michael Bowman		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Third-Party Comments
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Affirmative	N/A
1	Duke Energy	Katherine Street		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Alan Kloster	Affirmative	N/A
1	Eversource Energy	Joshua London		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Abstain	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte		None	N/A
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	Joseph McClung		Negative	Third-Party Comments
1	KAMO Electric Cooperative	Micah Breedlove		None	N/A
1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Affirmative	N/A
1	Los Angeles Department of Water and Power	Pjoy Chua		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		Abstain	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Nikki Carson-Marquis	Negative	Third-Party Comments
1	Muscatine Power and Water	Andrew Kurriger		Negative	Third-Party Comments
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	New York Power Authority	Salvatore Spagnolo		Negative	Third-Party Comments
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	Third-Party Comments
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
1	Oncor Electric Delivery	Byron Booker	Gul Khan	Abstain	N/A
1	Orlando Utilities Commission	Aaron Staley		Abstain	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Abstain	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
1	Platte River Power Authority	Marissa Archie		Negative	Third-Party Comments
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Negative	Comments Submitted
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Negative	Comments Submitted
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Salt River Project	Sarah Blankenship	Israel Perez	Negative	Comments Submitted
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	SaskPower	Wayne Guttormson		None	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Negative	Comments Submitted
1	Sempra - San Diego Gas and Electric	Mohamed 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	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Negative	Comments Submitted
1	Taunton Municipal Lighting Plant	Devon Tremont		Affirmative	N/A
1	Tennessee Valley Authority	David Plumb		Negative	Third-Party Comments
1	Tri-State G and T Association, Inc.	Donna Wood		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	Western Area Power Administration	Sean Erickson	Kimberly Bentley	Negative	Comments Submitted
1	Xcel Energy, Inc.	Eric Barry		None	N/A
2	California ISO	Darcy O'Connell		Negative	Third-Party Comments
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	Independent Electricity System Operator	Harishkumar Subramani Vijay Kumar		Affirmative	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.	Thomas Foster	Elizabeth Davis	Negative	Third-Party Comments
2	Southwest Power Pool, Inc. (RTO)	Matthew Harward		Negative	Third-Party Comments
3	AEP	Kent Feliks		Abstain	N/A
3	Ameren - Ameren Services	David Jendras Sr		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs	Rachel Schuldt	Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Schroeder		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		None	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Alan Kloster	Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Florida Municipal Power Agency	Navid Nowakhtar	LaKenya Vannorman	None	N/A
3	Georgia System Operations Corporation	Scott McGough		None	N/A
3	Great River Energy	Michael Brytowski	Joseph Knight	Negative	Third-Party Comments
3	Imperial Irrigation District	Glen Allegranza	Denise Sanchez	Negative	Comments Submitted
3	JEA	Marilyn Williams		Negative	Third-Party Comments
3	KAMO Electric Cooperative	Tony Gott		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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		Abstain	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		Negative	Third-Party Comments
3	New York Power Authority	David Rivera		Negative	Third-Party Comments
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Third-Party Comments
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	Third-Party Comments
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney		None	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
3	Omaha Public Power District	David Heins		Negative	Third-Party Comments
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Platte River Power Authority	Richard Kiess		Negative	Comments Submitted
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Negative	Comments Submitted
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Negative	Comments Submitted
3	Salt River Project	Mathew Weber	Israel Perez	Negative	Comments Submitted
3	Santee Cooper	Vicky Budreau		Abstain	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		Negative	Comments Submitted
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		Negative	Third-Party Comments
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Negative	Third-Party Comments
3	Tri-State G and T Association, Inc.	Ryan Walter		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
3	Xcel Energy, Inc.	Nicholas Friebel		Negative	Third-Party Comments
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Third-Party Comments
4	Austin Energy	Tony 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	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Third-Party Comments
4	Northern California Power Agency	Marty Hostler		Abstain	N/A
4	Oklahoma Municipal Power Authority	Michael Watt		None	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Negative	Third-Party Comments
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Comments Submitted
4	Seminole Electric Cooperative, Inc.	Ken Habgood		Negative	Comments Submitted
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Negative	Comments Submitted
4	Utility Services, Inc.	Tracy MacNicoll		Abstain	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Negative	Comments Submitted
5	AEP	Thomas Foltz		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	AES - AES Corporation	Ruchi Shah		None	N/A
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		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier	Carly Miller	Affirmative	N/A
5	Bonneville Power Administration	Christopher Siewert		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		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	Jeffrey Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Helen Wang		Affirmative	N/A
5	Constellation	Alison MacKellar		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Third-Party Comments
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	DTE Energy - Detroit Edison Company	Adrian Raducea		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Enel Green Power	Natalie Johnson		Abstain	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Affirmative	N/A
5	Hydro-Qu?bec Production	Carl Pineault		Abstain	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Negative	Comments Submitted
5	JEA	John Babik		Negative	Third-Party Comments
5	Lincoln Electric System	Brittany Millard		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	Manitoba Hydro	Kristy-Lee Young		Abstain	N/A
5	Muscatine Power and Water	Neal Nelson		Negative	Third-Party Comments
5	National Grid USA	Robin Berry		Affirmative	N/A
5	NB Power Corporation	David Melanson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Richard Vendetti		None	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Third-Party Comments
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Third-Party Comments
5	Northern California Power Agency	Jeremy Lawson		Abstain	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Third-Party Comments
5	Oglethorpe Power Corporation	Donna Johnson		Negative	Third-Party Comments
5	Omaha Public Power District	Mahmood Safi		Negative	Third-Party Comments
5	Ontario Power Generation Inc.	Constantin Chitescu		Abstain	N/A
5	Orlando Utilities Commission	Dania Colon		None	N/A
5	Pattern Operators LP	George E Brown		Negative	Third-Party Comments
5	Platte River Power Authority	Jon Osell		Negative	Comments Submitted
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
5	PSEG Nuclear LLC	Tim Kucey		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Negative	Comments Submitted
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	Comments Submitted
5	Salt River Project	Jennifer Bennett	Israel Perez	Negative	Comments Submitted
5	Santee Cooper	Marty Watson		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Negative	Comments Submitted
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Abstain	N/A
5	Southern Company - Southern Company Generation	Jim Howell, Jr.		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	Tennessee Valley Authority	Nehtisha Rollis		Negative	Third-Party Comments
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Negative	Comments Submitted
5	U.S. Bureau of Reclamation	Wendy Kalidass		None	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		None	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Negative	Third-Party Comments
6	AEP	Justin Kuehne		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		None	N/A
6	Austin Energy	Imane Mrini		Affirmative	N/A
6	Black Hills Corporation	Claudine Bates		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	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		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	John Sturgeon		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Negative	Comments Submitted
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	Great River Energy	Donna Stephenson		Negative	Third-Party Comments
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Manitoba Hydro	Kelly Bertholet		Abstain	N/A
6	Muscatine Power and Water	Nicholas Burns		Negative	Third-Party Comments
6	New York Power Authority	Shelly Dineen		Negative	Third-Party Comments
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Abstain	N/A
6	NiSource - Northern Indiana Public Service Co.	Joseph OBrien		Negative	Third-Party Comments
6	Northern California Power Agency	Dennis Sismaet		None	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Third-Party Comments
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments
6	Platte River Power Authority	Sabrina Martz		Negative	Comments Submitted
6	Portland General Electric Co.	Stefanie Burke		None	N/A
6	Powerex Corporation	Raj Hundal		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Anne Kronshage		Negative	Comments Submitted
6	Public Utility District No. 2 of Grant County, Washington	M LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	Comments Submitted
6	Salt River Project	Timothy Singh	Israel Perez	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Santee Cooper	Glenda Horne		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		Negative	Third-Party Comments
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Negative	Comments Submitted
6	Tennessee Valley Authority	Armando Rodriguez		Negative	Third-Party Comments
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
6	Western Area Power Administration	Chrystal Dean		None	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	Wesley Yeomans		None	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Lindsey Mannion		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 282 of 282 entries

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/272)
Ballot Name: 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 Implementation Plan IN 1 OT
Voting Start Date: 4/4/2023 12:01:00 AM
Voting End Date: 4/13/2023 8:00:00 PM
Ballot Type: OT
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 249
Total Ballot Pool: 281
Quorum: 88.61
Quorum Established Date: 4/13/2023 1:56:07 PM
Weighted Segment Value: 44.62

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	76	1	26	0.448	32	0.552	0	9	9
Segment: 2	7	0.6	2	0.2	4	0.4	0	1	0
Segment: 3	63	1	25	0.481	27	0.519	0	5	6
Segment: 4	14	1	2	0.182	9	0.818	0	0	3
Segment: 5	69	1	27	0.509	26	0.491	0	9	7
Segment: 6	44	1	16	0.457	19	0.543	0	4	5
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	7	0.4	4	0.4	0	0	0	2	1
Totals:	281	6	102	2.677	117	3.323	0	30	32

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	Allete - Minnesota Power, Inc.	Lori Frisk		Negative	Comments Submitted
1	APS - Arizona Public Service Co.	Daniela Atanasovski		None	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Negative	Comments Submitted
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Black Hills Corporation	Micah Runner		Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Third-Party Comments
1	City Utilities of Springfield, Missouri	Michael Bowman		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Third-Party Comments
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Affirmative	N/A
1	Duke Energy	Katherine Street		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Alan Kloster	Affirmative	N/A
1	Eversource Energy	Joshua London		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Abstain	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte		None	N/A
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	Joseph McClung		Negative	Third-Party Comments
1	KAMO Electric Cooperative	Micah Breedlove		None	N/A
1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	Pjoy Chua		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		Abstain	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Nikki Carson-Marquis	Negative	Third-Party Comments
1	Muscatine Power and Water	Andrew Kurriger		Negative	Third-Party Comments
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	New York Power Authority	Salvatore Spagnolo		Negative	Third-Party Comments
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		Negative	Third-Party Comments
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
1	Oncor Electric Delivery	Byron Booker	Gul Khan	Affirmative	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	Abstain	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
1	Platte River Power Authority	Marissa Archie		Negative	Third-Party Comments
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Negative	Comments Submitted
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Salt River Project	Sarah Blankenship	Israel Perez	Negative	Comments Submitted
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	SaskPower	Wayne Guttormson		None	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Negative	Comments Submitted
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Negative	Third-Party Comments
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Negative	Comments Submitted
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Taunton Municipal Lighting Plant	Devon Tremont		Affirmative	N/A
1	Tennessee Valley Authority	David Plumb		Negative	Third-Party Comments
1	Tri-State G and T Association, Inc.	Donna Wood		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	Western Area Power Administration	Sean Erickson	Kimberly Bentley	Negative	Comments Submitted
1	Xcel Energy, Inc.	Eric Barry		None	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
2	Independent Electricity System Operator	Harishkumar Subramani Vijay Kumar		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	ISO New England, Inc.	John Pearson	Keith Jonassen	Abstain	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Negative	Comments Submitted
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Negative	Third-Party Comments
2	Southwest Power Pool, Inc. (RTO)	Matthew Harward		Negative	Third-Party Comments
3	AEP	Kent Feliks		Negative	Comments Submitted
3	Ameren - Ameren Services	David Jendras Sr		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs	Rachel Schuldt	Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Negative	Comments Submitted
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Schroeder		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		None	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Alan Kloster	Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Florida Municipal Power Agency	Navid Nowakhtar	LaKenya Vannorman	None	N/A
3	Georgia System Operations Corporation	Scott McGough		None	N/A
3	Great River Energy	Michael Brytowski	Joseph Knight	Negative	Third-Party Comments
3	Imperial Irrigation District	Glen Allegranza	Denise Sanchez	Negative	Comments Submitted
3	JEA	Marilyn Williams		Negative	Third-Party Comments
3	KAMO Electric Cooperative	Tony Gott		None	N/A
3	Lincoln Electric System	Sam Christensen		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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		Abstain	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		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	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	Third-Party Comments
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney		None	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
3	Omaha Public Power District	David Heins		Negative	Third-Party Comments
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Abstain	N/A
3	Platte River Power Authority	Richard Kiess		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Negative	Comments Submitted
3	Salt River Project	Mathew Weber	Israel Perez	Negative	Comments Submitted
3	Santee Cooper	Vicky Budreau		Abstain	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		Negative	Comments Submitted
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Negative	Third-Party Comments
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Negative	Third-Party Comments
3	Tri-State G and T Association, Inc.	Ryan Walter		Negative	Comments Submitted
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Xcel Energy, Inc.	Nicholas Friebel		Negative	Third-Party Comments
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Third-Party Comments
4	Austin Energy	Tony 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		Negative	Comments Submitted
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Third-Party Comments
4	Northern California Power Agency	Marty Hostler		None	N/A
4	Oklahoma Municipal Power Authority	Michael Watt		None	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Negative	Third-Party Comments
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Comments Submitted
4	Seminole Electric Cooperative, Inc.	Ken Habgood		Negative	Comments Submitted
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Negative	Comments Submitted
4	Utility Services, Inc.	Tracy MacNicoll		Negative	Comments Submitted
4	WEC Energy Group, Inc.	Matthew Beilfuss		Negative	Comments Submitted
5	AEP	Thomas Foltz		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	AES - AES Corporation	Ruchi Shah		Abstain	N/A
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		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier	Carly Miller	Affirmative	N/A
5	Bonneville Power Administration	Christopher Siewert		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		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	Jeffrey Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Helen Wang		Affirmative	N/A
5	Constellation	Alison MacKellar		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Third-Party Comments
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	DTE Energy - Detroit Edison Company	Adrian Raducea		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Enel Green Power	Natalie Johnson		Abstain	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Robert Loy		Negative	Comments Submitted
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Affirmative	N/A
5	Hydro-Qu?bec Production	Carl Pineault		Abstain	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Negative	Comments Submitted
5	JEA	John Babik		Negative	Third-Party Comments
5	Lincoln Electric System	Brittany Millard		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	Manitoba Hydro	Kristy-Lee Young		Abstain	N/A
5	Muscatine Power and Water	Neal Nelson		Negative	Third-Party Comments
5	National Grid USA	Robin Berry		Affirmative	N/A
5	NB Power Corporation	David Melanson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Richard Vendetti		None	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Third-Party Comments
5	Northern California Power Agency	Jeremy Lawson		Abstain	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Third-Party Comments
5	Oglethorpe Power Corporation	Donna Johnson		Negative	Third-Party Comments
5	Omaha Public Power District	Mahmood Safi		Negative	Third-Party Comments
5	Ontario Power Generation Inc.	Constantin Chitescu		Abstain	N/A
5	Orlando Utilities Commission	Dania Colon		None	N/A
5	Pattern Operators LP	George E Brown		Negative	Third-Party Comments
5	Platte River Power Authority	Jon Osell		Negative	Comments Submitted
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
5	PSEG Nuclear LLC	Tim Kucey		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Negative	Comments Submitted
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	Comments Submitted
5	Salt River Project	Jennifer Bennett	Israel Perez	Negative	Comments Submitted
5	Santee Cooper	Marty Watson		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Negative	Comments Submitted
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Jim Howell, Jr.		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	Tennessee Valley Authority	Nehtisha Rollis		Negative	Third-Party Comments
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Negative	Comments Submitted
5	U.S. Bureau of Reclamation	Wendy Kalidass		None	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		None	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Negative	Third-Party Comments
6	AEP	Justin Kuehne		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		None	N/A
6	Austin Energy	Imane Mrini		Affirmative	N/A
6	Black Hills Corporation	Claudine Bates		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		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
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
6	Edison International - Southern California Edison Company	Kenya Streeter		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Jennifer Flandermeyer	Alan Kloster	Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted
6	Great River Energy	Donna Stephenson		Negative	Third-Party Comments
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Manitoba Hydro	Kelly Bertholet		Abstain	N/A
6	Muscatine Power and Water	Nicholas Burns		Negative	Third-Party Comments
6	New York Power Authority	Shelly Dineen		Negative	Third-Party Comments
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Abstain	N/A
6	NiSource - Northern Indiana Public Service Co.	Joseph OBrien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		None	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Third-Party Comments
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments
6	Platte River Power Authority	Sabrina Martz		Negative	Comments Submitted
6	Portland General Electric Co.	Stefanie Burke		None	N/A
6	Powerex Corporation	Raj Hundal		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia		Negative	Third-Party Comments
6	Public Utility District No. 1 of Chelan County	Anne Kronshage		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	M LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	Comments Submitted
6	Salt River Project	Timothy Singh	Israel Perez	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Santee Cooper	Glenda Horne		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		Negative	Third-Party Comments
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Negative	Comments Submitted
6	Tennessee Valley Authority	Armando Rodriguez		Negative	Third-Party Comments
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
6	Western Area Power Administration	Chrystal Dean		None	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	Wesley Yeomans		None	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Lindsey Mannion		Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A

Previous 1 Next

Showing 1 to 281 of 281 entries

BALLOT RESULTS

Ballot Name: 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 EOP-011-4 | Non-binding Poll IN 1 NB
Voting Start Date: 4/4/2023 12:01:00 AM
Voting End Date: 4/13/2023 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 240
Total Ballot Pool: 273
Quorum: 87.91
Quorum Established Date: 4/13/2023 2:07:57 PM
Weighted Segment Value: 47.06

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	74	1	22	0.423	30	0.577	12	10
Segment: 2	7	0.4	2	0.2	2	0.2	3	0
Segment: 3	61	1	22	0.489	23	0.511	10	6
Segment: 4	14	1	3	0.273	8	0.727	1	2
Segment: 5	67	1	23	0.523	21	0.477	16	7
Segment: 6	42	1	13	0.464	15	0.536	8	6
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	7	0.3	3	0.3	0	0	3	1
Totals:	273	5.7	88	2.672	99	3.028	53	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	Allete - Minnesota Power, Inc.	Lori Frisk		Negative	Comments Submitted
1	APS - Arizona Public Service Co.	Daniela Atanasovski		None	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	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		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Bonneville Power Administration	Kamala Rogers-Holliday		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Comments Submitted
1	City Utilities of Springfield, Missouri	Michael Bowman		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Affirmative	N/A
1	Duke Energy	Katherine Street		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Alan Kloster	Affirmative	N/A
1	Eversource Energy	Joshua London		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis		Negative	Comments Submitted
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Comments Submitted
1	Great River Energy	Gordon Pietsch		Negative	Comments Submitted
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Abstain	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte		None	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Joseph McClung		Negative	Comments Submitted
1	KAMO Electric Cooperative	Micah Breedlove		None	N/A
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	Pjoy Chua		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	Negative	Comments Submitted
1	Muscatine Power and Water	Andrew Kurriger		Negative	Comments Submitted
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	Omaha Public Power District	Doug Peterchuck		Negative	Comments Submitted
1	Oncor Electric Delivery	Byron Booker	Gul Khan	Affirmative	N/A
1	Orlando Utilities Commission	Aaron Staley		Abstain	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Abstain	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
1	Platte River Power Authority	Marissa Archie		Negative	Comments Submitted
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		None	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Negative	Comments Submitted
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	Comments Submitted
1	Salt River Project	Sarah Blankenship	Israel Perez	Negative	Comments Submitted
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	SaskPower	Wayne Guttormson		None	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Negative	Comments Submitted
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Negative	Comments Submitted
1	Taunton Municipal Lighting Plant	Devon Tremont		Affirmative	N/A
1	Tennessee Valley Authority	David Plumb		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Donna Wood		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	Western Area Power Administration	Sean Erickson	Kimberly Bentley	Negative	Comments Submitted
1	Xcel Energy, Inc.	Eric Barry		None	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
2	Independent Electricity System Operator	Harishkumar Subramani Vijay Kumar		Affirmative	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		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Abstain	N/A
2	Southwest Power Pool, Inc. (RTO)	Matthew Harward		Affirmative	N/A
3	AEP	Kent Feliks		Abstain	N/A
3	Ameren - Ameren Services	David Jendras Sr		Abstain	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs	Rachel Schuldt	Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Negative	Comments Submitted
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Schroeder		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	DTE Energy - Detroit Edison Company	Marvin Johnson		None	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	Eversource Energy	Vicki O'Leary		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Florida Municipal Power Agency	Navid Nowakhtar	LaKenya Vannorman	None	N/A
3	Georgia System Operations Corporation	Scott McGough		Negative	Comments Submitted
3	Great River Energy	Michael Brytowski	Joseph Knight	Negative	Comments Submitted
3	Imperial Irrigation District	Glen Allegranza	Denise Sanchez	Negative	Comments Submitted
3	JEA	Marilyn Williams		Negative	Comments Submitted
3	KAMO Electric Cooperative	Tony Gott		None	N/A
3	Lincoln Electric System	Sam Christensen		Abstain	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	Muscatine Power and Water	Seth Shoemaker		Negative	Comments Submitted
3	National Grid USA	Brian Shanahan		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Nebraska Public Power District	Tony Eddleman		Negative	Comments Submitted
3	New York Power Authority	David Rivera		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	Comments Submitted
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney		None	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
3	Omaha Public Power District	David Heins		Negative	Comments Submitted
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Abstain	N/A
3	Platte River Power Authority	Richard Kiess		Negative	Comments Submitted
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	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	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Salt River Project	Mathew Weber	Israel Perez	Negative	Comments Submitted
3	Santee Cooper	Vicky Budreau		Abstain	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		Negative	Comments Submitted
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		Negative	Comments Submitted
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Comments Submitted
4	Austin Energy	Tony 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		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Comments Submitted
4	Northern California Power Agency	Marty Hostler		Affirmative	N/A
4	Oklahoma Municipal Power Authority	Michael Watt		None	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Negative	Comments Submitted
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Comments Submitted
4	Seminole Electric Cooperative, Inc.	Ken Habgood		Negative	Comments Submitted
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Negative	Comments Submitted
4	Utility Services, Inc.	Tracy MacNicoll		Abstain	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Negative	Comments Submitted
5	AEP	Thomas Foltz		Abstain	N/A
5	AES - AES Corporation	Ruchi Shah		Affirmative	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		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	Black Hills Corporation	Sheila Suurmeier	Carly Miller	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Bonneville Power Administration	Christopher Siewert		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		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	Jeffrey Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Helen Wang		Affirmative	N/A
5	Constellation	Alison MacKellar		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	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	Enel Green Power	Natalie Johnson		Abstain	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Robert Loy		Negative	Comments Submitted
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Hydro-Qu?bec Production	Carl Pineault		Abstain	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Negative	Comments Submitted
5	JEA	John Babik		Negative	Comments Submitted
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Negative	Comments Submitted
5	National Grid USA	Robin Berry		Affirmative	N/A
5	NB Power Corporation	David Melanson		Affirmative	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	Richard Vendetti		None	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Comments Submitted
5	Northern California Power Agency	Jeremy Lawson		Abstain	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Comments Submitted
5	Oglethorpe Power Corporation	Donna Johnson		Negative	Comments Submitted
5	Omaha Public Power District	Mahmood Safi		Negative	Comments Submitted
5	Ontario Power Generation Inc.	Constantin Chitescu		Abstain	N/A
5	Orlando Utilities Commission	Dania Colon		None	N/A
5	Pattern Operators LP	George E Brown		Negative	Comments Submitted
5	Platte River Power Authority	Jon Osell		Negative	Comments Submitted
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
5	PSEG Nuclear LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Negative	Comments Submitted
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	Comments Submitted
5	Salt River Project	Jennifer Bennett	Israel Perez	Negative	Comments Submitted
5	Santee Cooper	Marty Watson		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Negative	Comments Submitted
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Jim Howell, Jr.		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	Negative	Comments Submitted
5	Tennessee Valley Authority	Nehtisha Rollis		Abstain	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Negative	Comments Submitted
5	U.S. Bureau of Reclamation	Wendy Kalidass		None	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		None	N/A
6	AEP	Justin 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	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		None	N/A
6	Austin Energy	Imane Mrini		Affirmative	N/A
6	Black Hills Corporation	Claudine Bates		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Negative	Comments Submitted
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		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Jennifer Flandermeyer	Alan Kloster	Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted
6	Great River Energy	Donna Stephenson		Negative	Comments Submitted
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
6	Muscatine Power and Water	Nicholas Burns		Negative	Comments Submitted
6	New York Power Authority	Shelly Dineen		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Abstain	N/A
6	NiSource - Northern Indiana Public Service Co.	Joseph OBrien		Negative	Comments Submitted
6	Northern California Power Agency	Dennis Sismaet		None	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Comments Submitted
6	Omaha Public Power District	Shonda McCain		Negative	Comments Submitted
6	Platte River Power Authority	Sabrina Martz		Negative	Comments Submitted
6	Portland General Electric Co.	Stefanie Burke		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Powerex Corporation	Raj Hundal		Abstain	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Anne Kronshage		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	M LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	Comments Submitted
6	Salt River Project	Timothy Singh	Israel Perez	Negative	Comments Submitted
6	Santee Cooper	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.	Kati Barr		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Negative	Comments Submitted
6	Tennessee Valley Authority	Armando Rodriguez		None	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
6	Western Area Power Administration	Chrystal Dean		None	N/A
7	Oxy - Occidental Chemical	Venona Greaff		None	N/A
10	Midwest Reliability Organization	William Steiner		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	New York State Reliability Council	Wesley Yeomans		None	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Lindsey Mannion		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 273 of 273 entries

BALLOT RESULTS

Ballot Name: 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 TOP-002-5 | Non-binding Poll IN 1 NB
Voting Start Date: 4/4/2023 12:01:00 AM
Voting End Date: 4/13/2023 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 236
Total Ballot Pool: 271
Quorum: 87.08
Quorum Established Date: 4/13/2023 2:10:22 PM
Weighted Segment Value: 47.49

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	74	1	21	0.429	28	0.571	15	10
Segment: 2	7	0.4	2	0.2	2	0.2	3	0
Segment: 3	60	1	21	0.488	22	0.512	10	7
Segment: 4	14	1	3	0.3	7	0.7	1	3
Segment: 5	66	1	22	0.524	20	0.476	17	7
Segment: 6	42	1	13	0.464	15	0.536	8	6
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	7	0.3	3	0.3	0	0	3	1
Totals:	271	5.7	85	2.705	94	2.995	57	35

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	Allete - Minnesota Power, Inc.	Lori Frisk		Abstain	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		None	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	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		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Comments Submitted
1	City Utilities of Springfield, Missouri	Michael Bowman		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Affirmative	N/A
1	Duke Energy	Katherine Street		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Alan Kloster	Affirmative	N/A
1	Eversource Energy	Joshua London		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Negative	Comments Submitted
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Comments Submitted
1	Great River Energy	Gordon Pietsch		Negative	Comments Submitted
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Abstain	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte		None	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Joseph McClung		Negative	Comments Submitted
1	KAMO Electric Cooperative	Micah Breedlove		None	N/A
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	Pjoy Chua		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	Negative	Comments Submitted
1	Muscatine Power and Water	Andrew Kurriger		Negative	Comments Submitted
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	Omaha Public Power District	Doug Peterchuck		Negative	Comments Submitted
1	Oncor Electric Delivery	Byron Booker	Gul Khan	Abstain	N/A
1	Orlando Utilities Commission	Aaron Staley		Abstain	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Abstain	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
1	Platte River Power Authority	Marissa Archie		Negative	Comments Submitted
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		None	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Negative	Comments Submitted
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Negative	Comments Submitted
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	Comments Submitted
1	Salt River Project	Sarah Blankenship	Israel Perez	Negative	Comments Submitted
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	SaskPower	Wayne Guttormson		None	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Sempra - San Diego Gas and Electric	Mohamed 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
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Negative	Comments Submitted
1	Taunton Municipal Lighting Plant	Devon Tremont		Affirmative	N/A
1	Tennessee Valley Authority	David Plumb		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Donna Wood		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	Western Area Power Administration	Sean Erickson	Kimberly Bentley	Negative	Comments Submitted
1	Xcel Energy, Inc.	Eric Barry		None	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
2	Independent Electricity System Operator	Harishkumar Subramani Vijay Kumar		Affirmative	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		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Abstain	N/A
2	Southwest Power Pool, Inc. (RTO)	Matthew Harward		Affirmative	N/A
3	AEP	Kent Feliks		Abstain	N/A
3	Ameren - Ameren Services	David Jendras Sr		None	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs	Rachel Schuldt	Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Schroeder		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Alan Kloster	Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Florida Municipal Power Agency	Navid Nowakhtar	LaKenya Vannorman	None	N/A
3	Georgia System Operations Corporation	Scott McGough		None	N/A
3	Great River Energy	Michael Brytowski	Joseph Knight	Negative	Comments Submitted
3	Imperial Irrigation District	Glen Allegranza	Denise Sanchez	Negative	Comments Submitted
3	JEA	Marilyn Williams		Negative	Comments Submitted
3	KAMO Electric Cooperative	Tony Gott		None	N/A
3	Lincoln Electric System	Sam Christensen		Abstain	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	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		Negative	Comments Submitted

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		Negative	Comments Submitted
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	Comments Submitted
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney		None	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
3	Omaha Public Power District	David Heins		Negative	Comments Submitted
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Abstain	N/A
3	Platte River Power Authority	Richard Kiess		Negative	Comments Submitted
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Negative	Comments Submitted
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Negative	Comments Submitted
3	Salt River Project	Mathew Weber	Israel Perez	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Santee Cooper	Vicky Budreau		Abstain	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		Negative	Comments Submitted
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		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		Negative	Comments Submitted
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Comments Submitted
4	Austin Energy	Tony 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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Comments Submitted
4	Northern California Power Agency	Marty Hostler		None	N/A
4	Oklahoma Municipal Power Authority	Michael Watt		None	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Negative	Comments Submitted
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Comments Submitted
4	Seminole Electric Cooperative, Inc.	Ken Habgood		Negative	Comments Submitted
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Negative	Comments Submitted
4	Utility Services, Inc.	Tracy MacNicoll		Abstain	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		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		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	Black Hills Corporation	Sheila Suurmeier	Carly Miller	Affirmative	N/A
5	Bonneville Power Administration	Christopher Siewert		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		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	Jeffrey Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Helen Wang		Affirmative	N/A
5	Constellation	Alison MacKellar		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	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	Enel Green Power	Natalie Johnson		Abstain	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Abstain	N/A
5	Hydro-Qu?bec Production	Carl Pineault		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Hydro-Quebec (HQ)	Junji Yamaguchi		None	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Negative	Comments Submitted
5	JEA	John Babik		Negative	Comments Submitted
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Negative	Comments Submitted
5	National Grid USA	Robin Berry		Affirmative	N/A
5	NB Power Corporation	David Melanson		Affirmative	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	Richard Vendetti		None	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Comments Submitted
5	Northern California Power Agency	Jeremy Lawson		Abstain	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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		Abstain	N/A
5	Orlando Utilities Commission	Dania Colon		None	N/A
5	Pattern Operators LP	George E Brown		Negative	Comments Submitted
5	Platte River Power Authority	Jon Osell		Negative	Comments Submitted
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
5	PSEG Nuclear LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Negative	Comments Submitted
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	Comments Submitted
5	Salt River Project	Jennifer Bennett	Israel Perez	Negative	Comments Submitted
5	Santee Cooper	Marty Watson		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Negative	Comments Submitted
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Abstain	N/A
5	Southern Company - Southern Company Generation	Jim Howell, Jr.		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	Negative	Comments Submitted
5	Tennessee Valley Authority	Nehtisha Rollis		Abstain	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Negative	Comments Submitted
5	U.S. Bureau of Reclamation	Wendy Kalidass		None	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		None	N/A
6	AEP	Justin 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	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		None	N/A
6	Austin Energy	Imane Mrini		Affirmative	N/A
6	Black Hills Corporation	Claudine Bates		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	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
6	Edison International - Southern California Edison Company	Kenya Streeter		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Great River Energy	Donna Stephenson		Negative	Comments Submitted
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
6	Muscatine Power and Water	Nicholas Burns		Negative	Comments Submitted
6	New York Power Authority	Shelly Dineen		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Abstain	N/A
6	NiSource - Northern Indiana Public Service Co.	Joseph OBrien		Negative	Comments Submitted
6	Northern California Power Agency	Dennis Sismaet		None	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Comments Submitted
6	Omaha Public Power District	Shonda McCain		Negative	Comments Submitted
6	Platte River Power Authority	Sabrina Martz		Negative	Comments Submitted
6	Portland General Electric Co.	Stefanie Burke		None	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Anne Kronshage		Negative	Comments Submitted
6	Public Utility District No. 2 of Grant County, Washington	M LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	Comments Submitted
6	Salt River Project	Timothy Singh	Israel Perez	Negative	Comments Submitted
6	Santee Cooper	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.	Kati Barr		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Negative	Comments Submitted
6	Tennessee Valley Authority	Armando Rodriguez		None	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
6	Western Area Power Administration	Chrystal Dean		None	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	Wesley Yeomans		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Lindsey Mannion		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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Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination

Action

- Approve the following waiver of provisions of the Standard Processes Manual (SPM) for Project 2021-07:
  - Additional formal comment and ballot period (s) reduced from 45 days to as little as 25 days, with ballot conducted during the last 10 days of the comment period. (Sections 4.9 and 4.12)
  - Final ballot reduced from 10 days to five calendar days. (Section 4.9)

Background

As stated in the SAR, the primary purpose of this project is intended to address reliability related findings from FERC, NERC, and Regional Entity Joint Staff Inquiry into the February 2021 Cold Weather Grid Operations (joint inquiry). From February 8 - 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 - 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 that jeopardized bulk-power system reliability.

At its November 2021 meeting, the NERC Board of Trustees (Board) approved the following resolution regarding Project 2021-07:

> **FURTHER RESOLVED**, that the Board hereby directs that the development of new or revised Reliability Standards to address the recommendations of the joint inquiry team for cold weather operations, preparedness, and coordination to 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;
> - 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.

Work under Project 2021-07 has since proceeded in two phases, consistent with the Board's resolution. The first phase of work completed in the fall of 2022 and resulted in Reliability Standards EOP-011-3 and EOP-012-1. The second phase of work, which is underway, is developing Reliability Standards EOP-011-4 and TOP-002-5.

On February 16, 2023, shortly before the first ballot on the phase two standards, FERC issued an order approving Reliability Standards EOP-011-3 and EOP-012-2 while directing five areas for additional revisions. FERC directed NERC to submit a revised EOP-012 standard by February 2024.[1]

In summary, there are two sets of deadlines governing Project 2017-07: the Board's September 30, 2023 deadline for the completion of EOP-011-4 and TOP-002-5, and FERC's February 2024 deadline for completion of EOP-012-2.

NERC Standard Processes Manual Section 16.0 Waiver provides as follows:

> The Standards Committee may waive any of the provisions contained in this manual for good cause shown, but limited to the following circumstances:
>
> - In response to a national emergency declared by the United States or Canadian government that involves the reliability of the Bulk Electric System or cyber attack on the Bulk Electric System;
> - Where necessary to meet regulatory deadlines;
> - Where necessary to meet deadlines imposed by the NERC Board of Trustees; or
> - Where the Standards Committee determines that a modification to a proposed Reliability Standard or its Requirement(s), a modification to a defined term, a modification to an Interpretation, or a modification to a Variance has already been vetted by the industry through the standards development process or is so insubstantial that developing the modification through the processes contained in this manual will add significant time delay.

Summary

Due to the issuance of FERC's February 16, 2023 Order directing further revisions to EOP-012 by February 2024, the Project 2021-07 drafting team was delayed in the planned development timeline for the standards addressing the phase 2 recommendations of the February 2021 joint inquiry report. The Project 2021-07 SDT leadership and NERC staff request that the SC consider a waiver of certain provisions of the SPM regarding the length of comment periods and ballots in order to meet the September 30, 2023 development deadline for EOP-011-4 and TOP-002-5 set by the Board.

The Project 2021-07 SDT leadership and NERC staff also request that the SC consider a waiver of these same provisions for EOP-012-2, in the event shortened comment and ballot periods are needed to develop a consensus standard by the February 2024 FERC deadline.

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[1] *Order Approving Extreme Cold Weather Reliability Standards EOP-011-3 and EOP-012-2 and Directing Modification of Reliability Standard EOP-012-1,* 182 FERC ¶ 61,094 (Feb. 16, 2023), available here.

The requesters ask to shorten the additional formal comment and ballot period(s) for Project 2021-07 from 45 days to as few as 25 days, with a ballot and non-binding poll during the last 10 days of the 25 day period. In addition, the requesters ask to shorten the final ballot from 10 days to five days.

Minutes
Standards Committee Meeting

A. Casuscelli, chair, called to order the meeting of the Standards Committee (SC) on August 23, 2023, at 1:02 p.m. Eastern. A. Oswald called roll and determined the meeting had a quorum. The SC member attendance and proxy sheets are attached as Attachment 1.

NERC Antitrust Compliance Guidelines and Public Announcement
The SC secretary called attention to the NERC Antitrust Compliance Guidelines and the public meeting notice and directed questions to NERC's General Counsel, Sonia C. Rocha.

Introduction and Chair's Remarks
A. Casuscelli welcomed the SC, guests, and proxies to the meeting.

Review August 23, 2023 Agenda (agenda item 1)
The SC approved the August 23, 2023 meeting agenda.

Consent Agenda (agenda item 2)
The SC approved the July 19, 2023 SC Meeting Minutes. The SC was informed about Project 2023-04 Modifications to CIP-003 SC Action without a Meeting.

Projects Under Development (agenda item 3)
C. Yeung reviewed the Project Tracking Spreadsheet. L. Harkness reviewed the Project Posting Schedule.

Project Management Posting Coordination (agenda item 4)
M. Brytowski provided an overview of the Project Management Oversight Subcommittee (PMOS) posting coordination. C. Yeung provided insight into how liaisons could work with developers and drafting team (DT) leadership to coordinate schedules. S. Kim shared that Standard Development is looking to host a webinar that details the prioritization of projects and the risk registry update. Discussion will continue to the next SC meeting.

Legal Update and Upcoming Standards Filings (agenda item 9)
L. Perotti provided an update.

Errata to Reliability Standard TOP-003-6 (agenda item 6)
L. Harkness provided an overview of the errata changes. V. O'Leary motioned to accept the errata changes to TOP-003-6 to remove the word "using" from Requirement R5 and correct the grammar of the word "methods" in Requirement R2 Part 2.5.5.

The SC approved the motion with no objections or abstentions.

Project 2023-03 Internal Network Security Monitoring (agenda item 5)
J. Calderon provided an overview of the project background and standard authorization request (SAR). S. Rueckert made a motion to accept the revised Project 2023-03 Internal Network Security Monitoring Standard Authorization Request (SAR), authorize drafting of Reliability Standard(s) identified in the SAR, and approve a waiver of provisions of the Standard Processes Manual for Project 2023-03 Internal Network Security Monitoring (INSM) due to regulatory deadlines, as follows:

- Initial formal comment and ballot period reduced from 45 days to as few as 30 calendar days, with ballot pools formed in the first 20 days and initial ballot and non-binding poll of Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) conducted during the last five days of the comment period (Sections 4.9, 4.10);
- Additional formal comment and ballot period(s) reduced from 45 days to as few as 20 calendar days, with ballot(s) and non-binding poll(s) conducted during the last five days of the comment period (Sections 4.9, 4.10).
- Final ballot reduced from 10 days to as few as five calendar days (Section 4.13)

The SC approved the motion with no objections or abstentions.

Project 2021-08 Modifications to FAC-008 (agenda item 7)
J. Calderon provided an overview of the project background. V. O'Leary asked if the additional requirement nine aligned with the SAR's scope. B. Wu shared that requirement nine complements requirement 6, which requirement 9 focuses on maintaining data to keep requirement six enforceable. V. O'Leary made a motion to authorize initial posting of the proposed Reliability Standard FAC-008-6 and the associated Implementation Plan for a 45-day formal comment period, with ballot pools formed in the first 30 days and parallel initial ballots and non-binding polls on the VRFs and VSLs, conducted during the last 10 days of the comment period.

The SC approved the motion with no objections or abstentions.

Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination (agenda item 8)
L. Harkness provided an overview of the project's background. S. Rueckert inquired when the SDT would have to respond to comments from the last formal comment period. A. Oswald mentioned that the SDT would have enough time to respond to comments. S. Rueckert made a motion to approve the following waiver of provisions of the Standard Processes Manual (SPM) for Project 2021-07:

- Additional formal comment and ballot period (s) reduced from 45 days to as little as 20 days, with the ballot conducted during the last 10 days of the comment period. (Sections 4.9 and 4.12)
- Final ballot reduced from 10 days to five calendar days. (Section 4.9)

The SC approved the motion with no abstentions. William Chambliss, Kent Feliks, and Terri Pyle opposed.

R. Blohm asked about the classifications of NERC membership sectors and, specifically, inquired about the ”associate” category and how it is defined. L. Perotti explained how the NERC membership sectors differ from the registered body segments and provided a brief overview.

Adjournment
The meeting adjourned at 2:29 p.m. Eastern.

Standards Committee
2023 Segment Representatives

Segment and Terms	Representative	Organization	Proxy	Present (Member or Proxy)
Chair 2022-23	Amy Casuscelli* Manager, Reliability Assurance & Risk Management	Xcel Energy		X
Vice Chair 2022-23	Todd Bennett* Managing Director, Reliability Compliance & Audit Services	Associated Electric Cooperative, Inc.		X
Segment 1-2022-23	Michael Jones Manager, Reliability Standards & Policy	National Grid		X
Segment 1-2021-22	Troy Brumfield* Regulatory Compliance Manager	American Transmission Company		X
Segment 2-2022-23	Jamie Johnson Infrastructure Compliance Manager	California ISO		N
Segment 2-2021-22	Charles Yeung Executive Director Interregional Affairs	Southwest Power Pool		X
Segment 3-2022-23	Kent Feliks Manager NERC Reliability Assurance – Strategic Initiatives	American Electric Power Company, Inc.		X
Segment 3-2021-22	Vicki O' Leary Director – Reliability, Compliance, and Implementation	Eversource Energy		X
Segment 4-2022-23	Marty Hostler Reliability Compliance Manager	Northern California Power Agency		X
Segment 4-2021-22	Patti Metro Senior Grid Operations & Reliability Director	National Rural Electric Cooperative Associate	Alice Wright	X
Segment 5-2022-23	Terri Pyle Utility Operational Compliance and NERC Compliance Office	Oklahoma Gas and Electric		X
Segment 5-2021-22	Jim Howell Markets Compliance Manager	Southern Company Generation		X

Segment and Terms	Representative	Organization	Proxy	Present (Member or Proxy)
Segment 6-2022-23	Sarah Snow* Manager of Reliability Compliance	Cooperative Energy		X
Segment 6-2021-22	Justin Welty Senior Manager, NERC Reliability Standards	NextEra Energy		X
Segment 7-2022-23	Kristine Martz Industry Specialist, Power & Utilities	Amazon Web Services		X
Segment 7-2021-22	Venona Greaff* Senior Energy Analyst	Occidental Chemical Corporation		X
Segment 8-2022-23	Robert Blohm[1] Managing Director	Keen Resources Ltd.		X
Segment 8-2021-22	Philip Winston Retired (Southern Company)	Independent		X
Segment 9-2022-23	Sarosh Muncherji[1] Cyber Security Specialist	British Columbia Utilities Commission		X
Segment 9-2021-22	William Chambliss General Counsel	Virginia State Corporation Commission		X
Segment 10-2022-23	Tony Purgar Senior Manager, Operational Analysis & Awareness	ReliabilityFirst		X
Segment 10-2021-22	Steven Rueckert Director of Standards	WECC		X

[1] Serving as Canadian Representative
*Denotes SC Executive Committee Member

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 second draft of the proposed standard for a formal 20-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
45-day formal comment period with ballot –Phase 2	2/28/23 – 4/13/23

Anticipated Actions	Date
20-day comment period and additional ballot – Phase 2	August – September 2023
10-day final ballot	September 2023
NERC Board of Trustees (Board) adoption	October 2023

A. Introduction

1. **Title:** **Emergency Operations**

2. **Number:** **EOP-011-4**

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

   4.1.4 Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

   4.1.5 UFLS-Only Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

   4.1.6 Transmission Owner identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

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 or automatic 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 or automatic Load shed and circuits that serve designated critical loads which are essential to the reliability of the BES;

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);

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;

1.2.5.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES; and

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 excluding critical natural gas infrastructure loads which are essential to the reliability of the BES as Interruptible Load, curtailable Load, and demand response during extreme cold weather periods within each Balancing Authority Area;

2.2.9. Provisions for Transmission Operators to implement operator-controlled manual Load shedding or automatic Load shedding in accordance with Requirement R1 Part 1.2.5; and

2.2.10. Provisions to determine reliability impacts of:

2.2.10.1. Cold weather conditions; and

2.2.10.2. 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.

R7. Each Transmission Operator shall annually identify and notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through operator-controlled manual Load shedding or automatic Load shedding. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Long-term Planning]*

M7. Each Transmission Operator will have documentation, such as dated emails or other correspondences that it identified and notified Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners annually in accordance with Requirement R7.

R8. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area shall develop, maintain, and implement a Load shedding plan, within 30 months of being notified by the Transmission Operator. The Load shedding plan shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

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

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

8.1.2. Provisions to minimize the overlap of circuits that are designated for manual or automatic Load shed and circuits that serve designated critical loads which are essential to the reliability of the BES;

8.1.3. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS;

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

8.1.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES.

8.2. Provisions to provide the Load shedding plan to the Transmission Operator for review.

M8. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area will have a dated Load shedding plan(s) developed in accordance with Requirement R8 and evidence that the Load shedding plan(s) was provided to its Transmission Operator; evidence such as a review or revision history to indicate that the Load shedding 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 Load shedding plan(s) was implemented for times when an Emergency has occurred, in accordance with 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 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.
- 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.
- The Reliability Coordinator shall maintain evidence of compliance since the last audit for Requirements R3, R5, and R6.
- The Transmission Operator shall maintain evidence of compliance since the last audit for Requirement R7.
- The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner 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 R8 and.

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	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	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 #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
		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	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 #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
			Operator within 30 calendar days.	
R4	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	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 #	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	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	N/A	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding or automatic Load shedding, but notified one or more of those entities more than 1 but fewer than 30 days late.	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding or automatic Load shedding, but notified one or more of those entities 30 days or more, but fewer than 60 days late.	The Transmission Operator did not identify or notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding or automatic Load shedding. OR The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding or automatic Load shedding, but notified one or more of those entities 60 days or more late.

R8	N/A	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to maintain it in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to provide it to its Transmission Operator in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner failed to develop a Load shedding plan(s) in accordance with Requirement R8. OR The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to implement it in accordance with Requirement R8.

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	October 26, 2022	Adopted by Board of Trustees	Revised under Project 2021-07
3	February 16, 2023	FERC approved EOP-011-3. *N. Am. Elec. Reliability Corp.*, 182 FERC 61,094	
4	TBD		Revised under Project 2021-07

Attachment 1-EOP-011-4
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 second draft of the proposed standard for a formal 20-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
45-day formal comment period with ballot –Phase 2	2/28/23 – 4/13/23

Anticipated Actions	Date
20-day comment period and additional ballot – Phase 2	August – September 2023
10-day final ballot	September 2023
NERC Board of Trustees (Board) adoption	October 2023

A. Introduction

1. **Title:** **Emergency Operations**
2. **Number:** **EOP-011-4**
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

   4.1.4 Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

   4.1.5 UFLS-Only Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

   4.1.6 Transmission Owner identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area
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 or automatic 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 or automatic Load shed and circuits that serve designated critical loads which are essential to the reliability of the BES;

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);

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;

1.2.5.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES; and

~~**1.2.5.6.** Provisions for the identification of Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners required to mitigate operating Emergencies in its Transmission Operator Area.~~

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 excluding critical natural gas infrastructure loads which are essential to the reliability of the BES as Interruptible Load, curtailable Load, and demand response during extreme cold weather periods ~~when it would adversely impact the reliable operation of the BES;~~within each Balancing Authority Area;

2.2.9. Provisions for Transmission Operators to implement operator-controlled manual Load ~~shed~~shedding or automatic Load shedding in accordance with Requirement R1 Part 1.2.5; and

2.2.10. Provisions to determine reliability impacts of:

2.2.10.1. Cold weather conditions; and

2.2.10.2. 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.

R7. Each Transmission Operator shall annually identify and notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through operator-controlled manual Load shedding or automatic Load shedding. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Long-term Planning]*

M7. Each Transmission Operator will have documentation, such as dated emails or other correspondences that it identified and notified Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners annually in accordance with Requirement R7.

R8. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner ~~identified in~~notified by a Transmission ~~Operator's Operating Plan(s) to mitigate~~Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area shall develop, maintain, and implement ~~one or more Operating Plan(s).~~a Load shedding plan, within 30 months of being notified by the Transmission Operator. The ~~Operating Plan(s) shall be provided to the Transmission Operator. The Operating Plan(s)~~Load shedding plan shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

~~7.1.~~8.1. Operator-controlled manual Load shedding or automatic Load shedding during an Emergency that accounts for each of the following:

~~7.1.1.~~8.1.1. Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;

~~7.1.2.~~8.1.2. Provisions to minimize the overlap of circuits that are designated for manual or automatic Load shed and circuits that serve designated critical loads which are essential to the reliability of the BES;

~~7.1.3.~~8.1.3. 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~~)~~;

~~7.1.4.~~8.1.4. Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions; and

~~7.1.5.~~8.1.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES.

8.2. Provisions to provide the Load shedding plan to the Transmission Operator for review.

M8. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner ~~identified in~~notified by a Transmission ~~Operator's Operating Plan(s) to mitigate~~Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area will have a dated ~~Operating Plan~~ Load shedding plan(s) developed in accordance with Requirement ~~R7~~R8 and evidence that the ~~Operating~~

~~Plan~~Load shedding plan(s) was provided to its Transmission Operator; evidence such as a review or revision history to indicate that the ~~Operating Plan~~Load shedding 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~~Load shedding plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement ~~R7~~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 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~~.
- The Transmission Operator shall maintain evidence of compliance since the last audit for Requirement R7.
- The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner 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 ~~R7~~R8 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	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	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 #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		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	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 #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			Operator within 30 calendar days.	
R4	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	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 #	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	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	N/A	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding or automatic Load shedding, but notified one or more of those entities more than 1 but fewer than 30 days late.	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding or automatic Load shedding, but notified one or more of those entities 30 days or more, but fewer than 60 days late.	The Transmission Operator did not identify or notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding or automatic Load shedding. OR The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding or automatic Load shedding, but notified one or more of those entities 60 days or more late.

~~R7~~R8	N/A	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed ~~an Operating Plan~~a Load shedding plan(s~~)~~), but failed to maintain it in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed ~~an Operating Plan~~a Load shedding plan(s~~)~~), but failed to provide it to its Transmission Operator in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner failed to develop ~~an Operating Plan(s).~~a Load shedding plan(s) in accordance with Requirement R8. OR The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed ~~an Operating Plan~~a Load shedding plan(s~~)~~), but failed to implement it in accordance with Requirement R8.

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~~October 26, 2022	Adopted by Board of Trustees	Revised under Project 2021-07
3	February 16, 2023	FERC approved EOP-011-3. *N. Am. Elec. Reliability Corp.*, 182 FERC 61,094	
4	TBD		Revised under Project 2021-07

Attachment 1-EOP-011-4
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 second draft of the proposed standard for a formal 25-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
45-day formal comment period with ballot –Phase 2	2/28/23 – 4/13/23

Anticipated Actions	Date
25-day comment period and additional ballot – Phase 2	August – September 2023
10-day final ballot	September 2023
NERC Board of Trustees (Board) adoption	October 2023

A. Introduction

1. **Title:** **Emergency Operations**

2. **Number:** **EOP-011-~~3~~4**

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

   4.1.4 Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

   4.1.5 UFLS-Only Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

   4.1.6 Transmission Owner identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

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 or automatic 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 or automatic Load shed and circuits that serve designated critical loads which are essential to the reliability of the BES;

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);

~~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~~.~~;

1.2.5.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES; and

1.2.6. Provisions to determine reliability impacts of:

1.2.6.1. ~~cold~~Cold weather conditions; and

1.2.6.2. ~~extreme~~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~~Capability and availability;

2.2.3.2. ~~fuel~~Fuel supply and inventory concerns;

2.2.3.3. ~~fuel~~Fuel switching capabilities; and

2.2.3.4. ~~environmental~~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 excluding critical natural gas infrastructure loads which are essential to the reliability of the BES as Interruptible Load, curtailable Load, and demand response during extreme cold weather periods within each Balancing Authority Area;

~~2.2.8.~~2.2.9. Provisions for Transmission Operators to implement operator-controlled manual Load ~~shed~~shedding or automatic Load shedding in accordance with Requirement R1 Part 1.2.5; and

~~2.2.9.~~2.2.10. Provisions to determine reliability impacts of:

~~2.2.9.1.~~2.2.10.1. ~~cold~~Cold weather conditions; and

~~2.2.9.2.~~2.2.10.2. ~~extreme~~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.

R7. Each Transmission Operator shall annually identify and notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through operator-controlled manual Load shedding or automatic Load shedding. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Long-term Planning]*

M7. Each Transmission Operator will have documentation, such as dated emails or other correspondences that it identified and notified Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners annually in accordance with Requirement R7.

R8. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area shall develop, maintain, and implement a Load shedding plan, within 30 months of being notified by the Transmission Operator. The Load shedding plan shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

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

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

8.1.2. Provisions to minimize the overlap of circuits that are designated for manual or automatic Load shed and circuits that serve designated critical loads which are essential to the reliability of the BES;

8.1.3. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS;

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

8.1.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES.

8.2. Provisions to provide the Load shedding plan to the Transmission Operator for review.

M8. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area will have a dated Load shedding plan(s) developed in accordance with Requirement R8 and evidence that the Load shedding plan(s) was provided to its Transmission Operator; evidence such as a review or revision history to indicate that the Load shedding 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 Load shedding plan(s) was implemented for times when an Emergency has occurred, in accordance with 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 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~~.
- The Transmission Operator shall maintain evidence of compliance since the last audit for Requirement R7.
- The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner 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 R8 and.

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	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	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 #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		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	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 #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			Operator within 30 calendar days.	
R4	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	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 #	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	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	N/A	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding or automatic Load shedding, but notified one or more of those entities more than 1 but fewer than 30 days late.	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding or automatic Load shedding, but notified one or more of those entities 30 days or more, but fewer than 60 days late.	The Transmission Operator did not identify or notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding or automatic Load shedding. OR The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding or automatic Load shedding, but notified one or more of those entities 60 days or more late.

R8	N/A	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to maintain it in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to provide it to its Transmission Operator in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner failed to develop a Load shedding plan(s) in accordance with Requirement R8. OR The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to implement it in accordance with Requirement R8.

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
~~2~~3	October ~~28,~~26, 2022	Adopted by Board of Trustees~~FERC Approved EOP-011-3 Docket Number RD23-1-000~~	Revised under Project 2021-07
3	February 16,~~2022~~ 2023	FERC approved EOP-011-3. *N. Am. Elec. Reliability Corp.*, 182 FERC 61,094~~Adopted by Board of Trustees~~	~~Revised under Project 2021-07~~
~~3~~4	TBD	~~Effective Date~~	Revised under Project 2021-07

Attachment 1-EOP-011-~~3~~4 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 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 20-day comment and 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
45-day formal comment period with ballot –Phase 2	2/28/23 – 4/13/23

Anticipated Actions	Date
20-day formal comment period with additional ballot – Phase 2	August - September 2023
10-day final ballot	September 2023
Board adoption	October 2023

A. Introduction

1. **Title: Operations Planning**
2. **Number: TOP-002-5**
3. **Purpose:** To ensure that Transmission Operators and Balancing Authorities have plans for operating within specified limits.
4. **Applicability:**
   - **4.1.** Transmission Operator
   - **4.2.** Balancing Authority
5. **Effective Date:**

   See Implementation Plan.
6. **Background:**

   See Project 2021-07 project page.

B. Requirements and Measures

R1. Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Each Transmission Operator shall have evidence of a completed Operational Planning Analysis. Such evidence could include but is not limited to dated power flow study results.

R2. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Transmission Operator shall have evidence that it has an Operating Plan to address potential System Operating Limits (SOLs) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1. Such evidence could include but it is not limited to plans for precluding operating in excess of each SOL that was identified as a result of the Operational Planning Analysis.

R3. Each Transmission Operator shall notify entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Transmission Operator shall have evidence that it notified entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in the plan(s). Such evidence could include but is not limited to dated operator logs, or email records.

R4. Each Balancing Authority shall have an Operating Plan(s) for the next day that addresses: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1 Expected generation resource commitment and dispatch;

4.2 Interchange scheduling;

4.3 Demand patterns; and

4.4 Capacity and energy reserve requirements, including deliverability capability.

M4. Each Balancing Authority shall have evidence that it has developed a plan to operate within the criteria identified. Such evidence could include but is not limited to dated operator logs or email records.

R5. Each Balancing Authority shall notify entities identified in the Operating Plan(s) cited in Requirement R4 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Each Balancing Authority shall have evidence that it notified entities identified in the plan(s) cited in Requirement R4 as to their role in the plan(s). Such evidence could include but is not limited to dated operator logs or email records.

R6. Each Transmission Operator shall provide its Operating Plan(s) for next day operations identified in Requirement R2 to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M6. Each Transmission Operator shall have evidence that it provided its Operating Plan(s) for next day operations identified in Requirement R2 to its Reliability Coordinator. Such evidence could include but is not limited to dated operator logs or email records.

R7. Each Balancing Authority shall provide its Operating Plan(s) for next day operations identified in Requirement R4 to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M7. Each Balancing Authority shall have evidence that it provided its Operating Plan(s) for next day operations identified in Requirement R4 to its Reliability Coordinator. Such evidence could include but is not limited to dated operator logs or email records.

R8. Each Balancing Authority shall have an extreme cold weather Operating Process for its Balancing Authority Area, addressing preparations for and operations during extreme cold weather periods. The extreme cold weather Operating Process shall include, but is not limited to: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

8.1 A methodology for identifying an extreme cold weather period within each Balancing Authority Area;

8.2 A methodology to determine an adequate reserve margin during the extreme cold weather period considering the generating unit(s) operating limitations in previous extreme cold weather periods that includes, but is not limited to:

8.2.1 Capability and availability;

8.2.2 Fuel supply and inventory concerns;

8.2.3 Start-up issues;

8.2.4 Fuel switching capabilities; and

8.2.5 Environmental constraints.

8.3 A methodology to determine a five-day hourly forecast during the identified extreme cold weather periods that includes, but is not limited to:

8.3.1 Expected generation resource commitment and dispatch;

8.3.2 Interchange scheduling;

8.3.3 Demand patterns;

8.3.4 Capacity and energy reserve requirements, including deliverability capability; and

8.3.5 Weather forecast.

M8. Each Balancing Authority shall have evidence that it has developed an extreme cold weather Operating Process in accordance with Requirement R8.

C. Compliance

1. Compliance Monitoring Process

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

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

Each Transmission Operator and Balancing Authority shall keep data or evidence to show compliance for each applicable Requirement for a rolling 90-calendar days period for analyses, the most recent 90-calendar days for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Operator or Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

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

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

Table of Compliance Elements

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1	N/A	N/A	N/A	The Transmission Operator did not have an Operational Planning Analysis allowing it to assess whether its planned operations for the next day within its Transmission Operator Area exceeded any of its System Operating Limits (SOLs).
R2	N/A	N/A	N/A	The Transmission Operator did not have an Operating Plan to address potential System Operating Limit (SOL) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1.
R3	The Transmission Operator did not notify one impacted entity or 5% or less of the entities, whichever is greater identified in the	The Transmission Operator did not notify two entities or more than 5% and less than or equal to 10% of the impacted entities, whichever is greater, identified in the	The Transmission Operator did not notify three impacted entities or more than 10% and less than or equal to 15% of the entities, whichever is greater, identified in the	The Transmission Operator did not notify four or more entities or more than 15% of the impacted NERC identified in the Operating Plan(s) as to their role in the plan(s).

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Operating Plan(s) as to their role in the plan(s).	Operating Plan(s) as to their role in the plan(s).	Operating Plan(s) as to their role in the plan(s).	
R4	The Balancing Authority has an Operating Plan, but it does not address one of the criteria in Requirement R4.	The Balancing Authority has an Operating Plan, but it does not address two of the criteria in Requirement R4.	The Balancing Authority has an Operating Plan, but it does not address three of the criteria in Requirement R4.	The Balancing Authority did not have an Operating Plan.
R5	The Balancing Authority did not notify one impacted entity or 5% or less of the entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Balancing Authority did not notify two entities or more than 5% and less than or equal to 10% of the impacted entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Balancing Authority did not notify three impacted entities or more than 10% and less than or equal to 15% of the entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Balancing Authority did not notify four or more entities or more than 15% of the impacted entities identified in the Operating Plan(s) as to their role in the plan(s).
R6	N/A	N/A	N/A	The Transmission Operator did not provide its Operating Plan(s) for next day operations as identified in Requirement R2 to its Reliability Coordinator.
R7	N/A	N/A	N/A	The Balancing Authority did not provide its Operating Plan(s) for next day operations as

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				identified in Requirement R4 to its Reliability Coordinator.
R8	N/A	The Balancing Authority had an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods, but it did not address one of the Requirements or sub-Requirements of R8 Parts 8.1 through 8.3.	The Balancing Authority had an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods, but it did not address two of the Requirements or sub-Requirements of R8 Parts 8.1 through 8.3.	The Balancing Authority did not have an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Extreme Cold Weather Preparedness Technical Rationale and Justification for TOP-002-5

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	August 2, 2006	Adopted by Board of Trustees	Revised
2	November 1, 2006	Adopted by Board of Trustees	Revised
2	June 14, 2007	Fixed typo in R11., (subject to …)	Errata
2a	February 10, 2009	Added Appendix 1 – Interpretation of R11 approved by BOT on February 10, 2009	Interpretation
2a	December 2, 2009	Interpretation of R11 approved by FERC on December 2, 2009	Same Interpretation
2b	November 4, 2010	Added Appendix 2 – Interpretation of R10 adopted by the Board of Trustees	
2b	October 20, 2011	FERC Order issued approving the Interpretation of R10 (FERC’s Order became effective on October 20, 2011)	
2.1b	March 8, 2012	Errata adopted by Standards Committee; (Removed unnecessary language from the Effective Date section. Deleted retired sub-requirements from Requirement R14)	Errata

Version	Date	Action	Change Tracking
2.1b	April 11, 2012	Additional errata adopted by Standards Committee; (Deleted language from retired sub-requirement from Measure M7)	Errata
2.1b	September 13, 2012	FERC approved	Errata
3	May 6, 2012	Revisions under Project 2007-03	Revised
3	May 9, 2012	Adopted by Board of Trustees	Revised
4	April 2014	Revisions under Project 2014-03	Revised
4	November 13, 2014	Adopted by NERC Board of Trustees	Revisions under Project 2014-03
4	November 19, 2015	FERC approved TOP-002-4. Docket No. RM15-16-000. Order No. 817.	
5	TBD	Revisions under Project 2021-07	Revised

Standard Development Timeline

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Description of Current Draft

This is the second draft of the proposed standard for a formal 20-day comment and ballot period.

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A. Introduction

1. **Title: Operations Planning**
2. **Number: TOP-002-5**
3. **Purpose:** To ensure that Transmission Operators and Balancing Authorities have plans for operating within specified limits.
4. **Applicability:**
   4.1. Transmission Operator
   4.2. Balancing Authority
5. **Effective Date:**
   See Implementation Plan.
6. **Background:**
   See Project 2021-07 project page.

B. Requirements and Measures

R1. Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Each Transmission Operator shall have evidence of a completed Operational Planning Analysis. Such evidence could include, but is not limited to dated power flow study results.

R2. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Transmission Operator shall have evidence that it has an Operating Plan to address potential System Operating Limits (SOLs) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1. Such evidence could include, but it is not limited to plans for precluding operating in excess of each SOL that was identified as a result of the Operational Planning Analysis.

R3. Each Transmission Operator shall notify entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Transmission Operator shall have evidence that it notified entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in the plan(s). Such

evidence could include, but is not limited to dated operator logs, or ~~e-mail~~email records.

R4. Each Balancing Authority shall have an Operating Plan(s) for the next day that addresses: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1 Expected generation resource commitment and dispatch;

4.2 Interchange scheduling;

4.3 Demand patterns; and

4.4 Capacity and energy reserve requirements, including deliverability capability.

M4. Each Balancing Authority shall have evidence that it has developed a plan to operate within the criteria identified. Such evidence could include, but is not limited to dated operator logs or email records.

R5. Each Balancing Authority shall notify entities identified in the Operating Plan(s) cited in Requirement R4 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Each Balancing Authority shall have evidence that it notified entities identified in the plan(s) cited in Requirement R4 as to their role in the plan(s). Such evidence could include, but is not limited to dated operator logs or email records.

R6. Each Transmission Operator shall provide its Operating Plan(s) for next day operations identified in Requirement R2 to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M6. Each Transmission Operator shall have evidence that it provided its Operating Plan(s) for next day operations identified in Requirement R2 to its Reliability Coordinator. Such evidence could include, but is not limited to dated operator logs or email records.

R7. Each Balancing Authority shall provide its Operating Plan(s) for next day operations identified in Requirement R4 to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M7. Each Balancing Authority shall have evidence that it provided its Operating Plan(s) for next day operations identified in Requirement R4 to its Reliability Coordinator. Such evidence could include, but is not limited to dated operator logs or email records.

R8. Each Balancing Authority shall have an extreme cold weather Operating Process~~, as part of its Operating Plan developed in Requirement R4~~ for its Balancing Authority Area, addressing preparations for and operations during extreme cold weather periods. The extreme cold weather Operating Process shall include, but is not limited to: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

8.1 A methodology for identifying an extreme cold weather period within each Balancing Authority Area;

8.2 A methodology ~~that determines~~to determine an ~~appropriate~~adequate reserve margin during the extreme cold weather period considering the generating unit(s) operating limitations in previous extreme cold weather periods ~~including:~~that includes, but is not limited to:

8.2.1 Capability and availability;

8.2.2 Fuel supply and inventory concerns;

8.2.3 Start-up issues;

8.2.4 Fuel switching capabilities; and

8.2.5 Environmental constraints.

8.3 A methodology to determine a five-day hourly forecast during the identified extreme cold weather periods that includes, but is not limited to:

8.3.1 Expected generation resource commitment and dispatch;

8.3.2 Interchange scheduling;

8.3.3 Demand patterns;

8.3.4 Capacity and energy reserve requirements, including deliverability capability; and

8.3.5 Weather forecast.

M8. Each Balancing Authority shall have evidence that it has developed an extreme cold weather Operating Process in accordance with Requirement R8.

C. Compliance

1. Compliance Monitoring Process

~~1.1.~~ Compliance Enforcement Authority

~~1.2.~~1.1. ~~As defined in the NERC Rules of Procedure,~~: "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 NERC~~mandatory and enforceable Reliability Standards in their respective jurisdictions.

~~1.3. Compliance Monitoring and Assessment Processes~~

~~As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" 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.~~

~~1.4.~~ ~~Data~~Evidence Retention

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

Each Transmission Operator and Balancing Authority shall keep data or evidence to show compliance for each applicable Requirement for a rolling 90-calendar days period for analyses, the most recent 90-calendar days for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Operator or Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

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

~~1.5. Additional Compliance Information~~

~~None.~~

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

Table of Compliance Elements

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Transmission Operator did not have an Operational Planning Analysis allowing it to assess whether its planned operations for the next day within its Transmission Operator Area exceeded any of its System Operating Limits (SOLs).
R2	N/A	N/A	N/A	The Transmission Operator did not have an Operating Plan to address potential System Operating Limit (SOL) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1.
~~For the Requirement R3 and R5 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.~~				

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R3	The Transmission Operator did not notify one impacted entity or 5% or less of the entities, whichever is greater identified in the Operating Plan(s) as to their role in the plan(s).	The Transmission Operator did not notify two entities or more than 5% and less than or equal to 10% of the impacted entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Transmission Operator did not notify three impacted entities or more than 10% and less than or equal to 15% of the entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Transmission Operator did not notify four or more entities or more than 15% of the impacted NERC identified in the Operating Plan(s) as to their role in the plan(s).
R4	The Balancing Authority has an Operating Plan, but it does not address one of the criteria in Requirement R4.	The Balancing Authority has an Operating Plan, but it does not address two of the criteria in Requirement R4.	The Balancing Authority has an Operating Plan, but it does not address three of the criteria in Requirement R4.	The Balancing Authority did not have an Operating Plan.
R5	The Balancing Authority did not notify one impacted entity or 5% or less of the entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Balancing Authority did not notify two entities or more than 5% and less than or equal to 10% of the impacted entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Balancing Authority did not notify three impacted entities or more than 10% and less than or equal to 15% of the entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Balancing Authority did not notify four or more entities or more than 15% of the impacted entities identified in the Operating Plan(s) as to their role in the plan(s).

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R6	N/A	N/A	N/A	The Transmission Operator did not provide its Operating Plan(s) for next day operations as identified in Requirement R2 to its Reliability Coordinator.
R7	N/A	N/A	N/A	The Balancing Authority did not provide its Operating Plan(s) for next day operations as identified in Requirement R4 to its Reliability Coordinator.
R8	N/A	The Balancing Authority had an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods, but it did not address one of the ~~parts~~Requirements or sub-Requirements of ~~Requirement~~ R8 Parts 8.1 through 8.3.	The Balancing Authority had an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods, but it did not address two of the ~~parts~~Requirements or sub-Requirements of ~~Requirement~~ R8 Parts 8.1 through 8.3.	The Balancing Authority did not have ~~a~~an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

~~Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.~~

Extreme Cold Weather Preparedness Technical Rationale and Justification for TOP-002-5

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	August 2, 2006	Adopted by Board of Trustees	Revised
2	November 1, 2006	Adopted by Board of Trustees	Revised
2	June 14, 2007	Fixed typo in R11., (subject to …)	Errata
2a	February 10, 2009	Added Appendix 1 – Interpretation of R11 approved by BOT on February 10, 2009	Interpretation
2a	December 2, 2009	Interpretation of R11 approved by FERC on December 2, 2009	Same Interpretation
2b	November 4, 2010	Added Appendix 2 – Interpretation of R10 adopted by the Board of Trustees	
2b	October 20, 2011	FERC Order issued approving the Interpretation of R10 (FERC's Order became effective on October 20, 2011)	
2.1b	March 8, 2012	Errata adopted by Standards Committee; (Removed unnecessary language from the Effective Date section. Deleted retired sub-requirements from Requirement R14)	Errata
2.1b	April 11, 2012	Additional errata adopted by Standards Committee; (Deleted language from retired sub-requirement from Measure M7)	Errata
2.1b	September 13, 2012	FERC approved	Errata
3	May 6, 2012	Revisions under Project 2007-03	Revised
3	May 9, 2012	Adopted by Board of Trustees	Revised

4	April 2014	Revisions under Project 2014-03	Revised
4	November 13, 2014	Adopted by NERC Board of Trustees	Revisions under Project 2014-03
4	November 19, 2015	FERC approved TOP-002-4. Docket No. RM15-16-000. Order No. 817.	
5	TBD	Revisions under Project 2021-07	Revised

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 25-day comment and 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
45-day formal comment period with ballot –Phase 2	2/28/23 – 4/13/23

Anticipated Actions	Date
25-day formal comment period with additional ballot – Phase 2	August - September 2023
10-day final ballot	September 2023
Board adoption	October 2023

A. Introduction

1. **Title: Operations Planning**
2. **Number: TOP-002-~~4~~5**
3. **Purpose:** To ensure that Transmission Operators and Balancing Authorities have plans for operating within specified limits.
4. **Applicability:**
   4.1. Transmission Operator
   4.2. Balancing Authority
5. **Effective Date:**
   See Implementation Plan.
6. **Background:**
   ~~See Project 2014-03 project page.~~
   See Project 2021-07 project page.

B. Requirements and Measures

R1. Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). -*[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Each Transmission Operator shall have evidence of a completed Operational Planning Analysis. -Such evidence could include but is not limited to dated power flow study results.

R2. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. -*[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Transmission Operator shall have evidence that it has an Operating Plan to address potential System Operating Limits (SOLs) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1. -Such evidence could include but it is not limited to plans for precluding operating in excess of each SOL that was identified as a result of the Operational Planning Analysis.

R3. Each Transmission Operator shall notify entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). -*[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Transmission Operator shall have evidence that it notified entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in the plan(s). -Such evidence could include but is not limited to dated operator logs, or ~~e-mail~~email records.

R4. Each Balancing Authority shall have an Operating Plan(s) for the next~~-~~ day that addresses: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1 Expected generation resource commitment and dispatch;

4.2 Interchange scheduling;

4.3 Demand patterns~~-~~; and

4.4 Capacity and energy reserve requirements, including deliverability capability.

M4. Each Balancing Authority shall have evidence that it has developed a plan to operate within the criteria identified. Such evidence could include but is not limited to dated operator logs or ~~e-mail~~email records.

R5. Each Balancing Authority shall notify entities identified in the Operating Plan(s) cited in Requirement R4 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Each Balancing Authority shall have evidence that it notified entities identified in the plan(s) cited in Requirement R4 as to their role in the plan(s). Such evidence could include but is not limited to dated operator logs or ~~e-mail~~email records.

R6. Each Transmission Operator shall provide its Operating Plan(s) for next~~-~~ day operations identified in Requirement R2 to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M6. Each Transmission Operator shall have evidence that it provided its Operating Plan(s) for next~~-~~ day operations identified in Requirement R2 to its Reliability Coordinator. Such evidence could include but is not limited to dated operator logs or ~~e-mail~~email records.

R7. Each Balancing Authority shall provide its Operating Plan(s) for next~~-~~ day operations identified in Requirement R4 to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M7. Each Balancing Authority shall have evidence that it provided its Operating Plan(s) for next~~-~~ day operations identified in Requirement R4 to its Reliability Coordinator. Such evidence could include but is not limited to dated operator logs or ~~e-mail~~email records.

R8. Each Balancing Authority shall have an extreme cold weather Operating Process for its Balancing Authority Area, addressing preparations for and operations during extreme cold weather periods. The extreme cold weather Operating Process shall include, but is not limited to: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

8.1 A methodology for identifying an extreme cold weather period within each Balancing Authority Area;

8.2 A methodology to determine an adequate reserve margin during the extreme cold weather period considering the generating unit(s) operating limitations in previous extreme cold weather periods that includes, but is not limited to:

8.2.1 Capability and availability;

8.2.2 Fuel supply and inventory concerns;

8.2.3 Start-up issues;

8.2.4 Fuel switching capabilities; and

8.2.5 Environmental constraints.

8.3 A methodology to determine a five-day hourly forecast during the identified extreme cold weather periods that includes, but is not limited to:

8.3.1 Expected generation resource commitment and dispatch;

8.3.2 Interchange scheduling;

8.3.3 Demand patterns;

8.3.4 Capacity and energy reserve requirements, including deliverability capability; and

8.3.5 Weather forecast.

M8. Each Balancing Authority shall have evidence that it has developed an extreme cold weather Operating Process in accordance with Requirement R8.

C. Compliance

1. Compliance Monitoring Process

~~1.1.~~ Compliance Enforcement Authority

~~1.2.~~1.1. ~~As defined in the NERC Rules of Procedure,~~: "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 NERC~~mandatory and enforceable Reliability Standards in their respective jurisdictions.

~~1.3. Compliance Monitoring and Assessment Processes~~

~~As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" 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.~~

~~1.4.~~ ~~Data~~Evidence Retention

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

Each Transmission Operator and Balancing Authority shall keep data or evidence to show compliance for each applicable Requirement for a rolling 90-calendar days period for analyses, the most recent 90-calendar days for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Operator or Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

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

~~1.5. Additional Compliance Information~~

~~None.~~

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

Table of Compliance Elements

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Transmission Operator did not have an Operational Planning Analysis allowing it to assess whether its planned operations for the next day within its Transmission Operator Area exceeded any of its System Operating Limits (SOLs).
R2	N/A	N/A	N/A	The Transmission Operator did not have an Operating Plan to address potential System Operating Limit (SOL) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1.
R3	The Transmission Operator did not notify one impacted entity or 5% or less of the entities, whichever is greater identified in the	The Transmission Operator did not notify two entities or more than 5% and less than or equal to 10% of the impacted entities, whichever is greater, identified in the	The Transmission Operator did not notify three impacted entities or more than 10% and less than or equal to 15% of the entities, whichever is greater, identified in the	The Transmission Operator did not notify four or more entities or more than 15% of the impacted NERC identified in the Operating Plan(s) as to their role in the plan(s).

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Operating Plan(s) as to their role in the plan(s).	Operating Plan(s) as to their role in the plan(s).	Operating Plan(s) as to their role in the plan(s).	
R4	The Balancing Authority has an Operating Plan, but it does not address one of the criteria in Requirement R4.	The Balancing Authority has an Operating Plan, but it does not address two of the criteria in Requirement R4.	The Balancing Authority has an Operating Plan, but it does not address three of the criteria in Requirement R4.	The Balancing Authority did not have an Operating Plan.
R5	The Balancing Authority did not notify one impacted entity or 5% or less of the entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Balancing Authority did not notify two entities or more than 5% and less than or equal to 10% of the impacted entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Balancing Authority did not notify three impacted entities or more than 10% and less than or equal to 15% of the entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Balancing Authority did not notify four or more entities or more than 15% of the impacted entities identified in the Operating Plan(s) as to their role in the plan(s).
R6	N/A	N/A	N/A	The Transmission Operator did not provide its Operating Plan(s) for next day operations as identified in Requirement R2 to its Reliability Coordinator.
R7	N/A	N/A	N/A	The Balancing Authority did not provide its Operating Plan(s) for next day operations as

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				identified in Requirement R4 to its Reliability Coordinator.
R8	N/A	The Balancing Authority had an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods, but it did not address one of the Requirements or sub-Requirements of R8 Parts 8.1 through 8.3.	The Balancing Authority had an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods, but it did not address two of the Requirements or sub-Requirements of R8 Parts 8.1 through 8.3.	The Balancing Authority did not have an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

~~Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.~~

Extreme Cold Weather Preparedness Technical Rationale and Justification for TOP-002-5

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	August 2, 2006	Adopted by Board of Trustees	Revised
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4	November 19, 2015	FERC approved TOP-002-4. Docket No. RM15-16-000. ~~-~~Order No. 817.	
5	TBD	Revisions under Project 2021-07	Revised

~~Guidelines and Technical Basis~~

~~Rationale:~~

~~During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.~~

~~Rationale for Definitions:~~

~~Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.~~

~~Rationale for R1:~~

~~Terms deleted in Requirement R1 as they are now contained in the revised definition of Operational Planning Analysis~~

~~Rationale for R2:~~

~~The change to Requirement R2 is in response to NOPR paragraph 42 and in concert with proposed changes made to proposed TOP-001-4~~

~~Rationale for R3:~~

~~Changes in response to IERP recommendation~~

~~Rationale for R4 and R5:~~

~~These Requirements were added to address IERP recommendations~~

~~Rationale for R6 and R7:~~

~~Added in response to SW Outage Report recommendation 1~~

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Implementation Plan

Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 – Reliability Standards EOP-011-4 and TOP-002-5

Applicable Standard(s)

- EOP-011-4 Emergency Operations
- TOP-002-5 Operations Planning

Requested Retirement(s)

- EOP-011-3
- TOP-002-4

Prerequisite Standard(s)

- None

Proposed Definition(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 (the "Joint Inquiry 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 outaged megawatts (MW) of load after the August 2003 Northeast blackout and the August 1996 West Coast

[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 Joint Inquiry Report").

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). At the time the Event occurred, the Event was the fourth in the previous 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 Joint Inquiry Report for new or enhanced NERC Reliability Standards. Phase 1 of this project developed Reliability Standards EOP-011-3 and EOP-012-1. This implementation plan addresses Reliability Standards EOP-011-4 and TOP-002-5, which were developed to address the Phase 2 recommendations.

Proposed Reliability Standard EOP-011-4 is a revised Reliability Standard that builds upon changes first made in Reliability Standard EOP-011-3 to address Recommendation 1j of the Joint Inquiry Report regarding minimizing the overlap of manual Load shed and automatic Load shed programs such as underfrequency Load shed (UFLS) and undervoltage Load shed (UVLS). Proposed EOP-011-4 includes new requirements for excluding critical natural gas loads from load shed programs during periods where their participation could adversely impact the BES and for relevant entities to develop Operating Plan(s) addressing load shed considerations in response to Recommendations 1h and 1i of the Joint Inquiry Report.

Proposed Reliability Standard TOP-002-5 is a revised Reliability Standard that would require the Balancing Authority to specifically address extreme cold weather in its Operating Plans, including developing a methodology to determine the number of resources that can reasonably be expected to be available during extreme cold weather conditions. These revisions were developed to address Key Recommendation 1g of the Joint Inquiry Report.

General Considerations

This implementation plan reflects consideration that entities will need time to develop and implement new Requirements as follows:

For proposed Reliability Standard EOP-011-4, this plan reflects consideration of the interaction that will be required between applicable entities and natural gas entities, as well as the fact that several

entities (Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner) will have obligations under this standard for the first time under proposed Requirement R8.

For proposed TOP-002-5, this implementation plan reflects consideration of the time needed to develop and implement a new extreme cold weather Operating Process under proposed Requirement R8.

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.

Reliability Standard EOP-011-4

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 six (6) 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 six (6) 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-011-4 – Requirement R1 Part 1.2.5

Entities shall not be required to comply with the new and revised provisions in Requirement R1 Part 1.2.5 until 30 months after the effective date of Reliability Standard EOP-011-4.

Compliance Date for EOP-011-4 – Requirement R2 Part 2.2.8 and Part 2.2.9

Entities shall not be required to comply with the new and revised provisions in Requirement R2 Part 2.2.8 and Part 2.2.9 until 30 months after the effective date of Reliability Standard EOP-011-4.

Compliance Date for EOP-011-4 – Requirement R8

Entities shall not be required to comply with Requirement R8 until the later of: (1) 30 months following notification by a Transmission Operator per EOP-011-4 Requirement R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area; or (2) 30 months after the effective date of Reliability Standard EOP-011-4.

Reliability Standard TOP-002-5

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.

Retirement Date

Reliability Standards EOP-011-3 and TOP-002-4
Reliability Standards EOP-011-3 and TOP-002-4 shall be retired immediately prior to the effective date of Reliability Standards EOP-011-4 and TOP-002-5 in the particular jurisdiction in which the revised standards are becoming effective.

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Implementation Plan

Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 – Reliability Standards EOP-011-4 and TOP-002-5

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Requested Retirement(s)

- EOP-011-3
- TOP-002-4

Prerequisite Standard(s)

- None

Proposed Definition(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 (the "Joint Inquiry 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 outaged megawatts (MW) of load after the August 2003 Northeast blackout and the August 1996 West Coast

[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 Joint Inquiry Report").

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Extreme cold weather has repeatedly challenged the reliable operation of the bulk-power system (BPS). ~~The~~At the time the Event occurred, the Event was the fourth in the ~~past~~previous 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 Joint Inquiry Report for new or enhanced NERC Reliability Standards. Phase 1 of this project developed Reliability Standards EOP-011-3 and EOP-012-1. This implementation plan addresses Reliability Standards EOP-011-4 and TOP-002-5, which were developed to address the Phase 2 recommendations.

Proposed Reliability Standard EOP-011-4 is a revised Reliability Standard that builds upon changes first made in Reliability Standard EOP-011-3 to address Recommendation 1j of the Joint Inquiry Report regarding minimizing the overlap of manual Load shed and automatic Load shed programs such as underfrequency Load shed (UFLS) and undervoltage Load shed (UVLS). Proposed EOP-011-4 includes new requirements for excluding critical natural gas loads from load shed programs during periods where their participation could adversely impact the BES and for relevant entities to develop Operating Plan(s) addressing load shed considerations in response to Recommendations 1h and ~~1l~~1i of the Joint Inquiry Report.

Proposed Reliability Standard TOP-002-5 is a revised Reliability Standard that would require the Balancing Authority to specifically address extreme cold weather in its Operating Plans, including developing a methodology to determine the number of resources that can reasonably be expected to be available during extreme cold weather conditions. These revisions were developed to address Key Recommendation 1g of the Joint Inquiry Report.

General Considerations

This implementation plan reflects consideration that entities will need time to develop~~, implement, and maintain enhanced cold weather plans and freeze protection measures,~~ and implement new Requirements as follows:

For proposed Reliability Standard EOP-011-4, this plan reflects consideration of the interaction that will be required between applicable entities and natural gas entities, as well as the fact that several

entities (Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner) will have obligations under this standard for the first time under proposed Requirement ~~R7~~R8.

For proposed TOP-002-5, this implementation plan reflects consideration of the time needed to develop and implement a new extreme cold weather Operating Process under proposed Requirement R8.

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.

Reliability Standard EOP-011-4

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 six (6) 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 six (6) 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-011-4 – Requirement R1 Part 1.2.5

Entities shall not be required to comply with the new and revised provisions in Requirement R1 Part 1.2.5 until 30 months after the effective date of Reliability Standard EOP-011-4.

Compliance Date for EOP-011-4 – Requirement R2 Part 2.2.8 and Part 2.2.9

Entities shall not be required to comply with the new and revised provisions in Requirement R2 Part 2.2.8 and Part 2.2.9 until 30 months after the effective date of Reliability Standard EOP-011-4.

Compliance Date for EOP-011-4 – Requirement R8

Entities shall not be required to comply with Requirement R8 until the later of: (1) 30 months following notification by a Transmission Operator per EOP-011-4 Requirement R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area; or (2) 30 months after the effective date of Reliability Standard EOP-011-4.

Reliability Standard TOP-002-5

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.

~~**Reliability Standard TOP-002-5**~~

~~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 12 months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.~~

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

Retirement Date

Reliability Standards EOP-011-3 and TOP-002-4

Reliability Standards EOP-011-3 and TOP-002-4 shall be retired immediately prior to the effective date of Reliability Standards EOP-011-4 and TOP-002-5 in the particular jurisdiction in which the revised standards are becoming effective.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Comment Form

Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2

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 | Phase 2** by **8 p.m. Eastern, Tuesday, September 12, 2023.**

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

Background Information

Extreme cold weather and precipitation affected the south central United States February 8-20, 2021. Many 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 Event was most severe February 15-18, 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

EOP-011-4 (Questions 1-3)

1. Do you agree with the new R7 for identification and notification?

   ☐ Yes
   ☐ No

   Comments:

2. Is the 30-month time frame in R8 adequate time for the physical changes that may be required to comply with these requirements?

   ☐ Yes
   ☐ No

   Comments:

3. The SDT has elected to add clarifying language in the applicable requirements in lieu of making "critical natural gas infrastructure load" a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities and their relative impact on the BES. Do you agree with this approach?

   ☐ Yes
   ☐ No

   Comments:

TOP-002-5 (Question 4)

4. The SDT modified the proposed Requirement R8 to remove the link between the required Operating Process and the Operating Plan required under Requirement R4. Do you agree with this modification?

   ☐ Yes
   ☐ No

   Comments:

General (Questions 5-7)

5. The SDT proposes that the modifications in EOP-011-4 and TOP-002-5 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:

6. Do you agree with the implementation plan proposed by the SDT? 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:

7. Provide any additional comments for the SDT to consider, including the provided technical rationale document, if desired.

   Comments:

Violation Risk Factor and Violation Severity Level Justifications

Project 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-011-4

VRF Justification for EOP-011-4, Requirement R1

The VRF did not change from the previous EOP-011-3 Reliability Standard.

VSL Justification for EOP-011-4, Requirement R1

The VSL did not change from the previous EOP-011-3 Reliability Standard.

VRF Justification for EOP-011-4, Requirement R2

The VRF did not change from the previous EOP-011-3 Reliability Standard.

VSL Justification for EOP-011-4, Requirement R2

The VSL did not change from the previous EOP-011-3 Reliability Standard.

VRF Justification for EOP-011-4, Requirement R3

The VRF did not change from the previous EOP-011-3 Reliability Standard.

VSL Justification for EOP-011-4, Requirement R3

The VSL did not change from the previous EOP-011-3 Reliability Standard.

VRF Justification for EOP-011-4, Requirement R4

The VRF did not change from the previous EOP-011-3 Reliability Standard.

VSL Justification for EOP-011-4, Requirement R4

The VSL did not change from the previous EOP-011-3 Reliability Standard.

VRF Justification for EOP-011-4, Requirement R5

The VRF did not change from the previous EOP-011-3 Reliability Standard.

VSL Justification for EOP-011-4, Requirement R5

The VSL did not change from the previous EOP-011-3 Reliability Standard.

VRF Justification for EOP-011-4, Requirement R6
The VRF did not change from the previous EOP-011-3 Reliability Standard.

VSL Justification for EOP-011-4, Requirement R6
The VSL did not change from the previous EOP-011-3 Reliability Standard.

VRF Justifications for EOP-011-4, Requirement R7	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to the fact that identifying and notifying entities that are required to assist with the mitigation of operating Emergencies through operator-controlled manual Load shedding or automatic Load shedding 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. Therefore, it is in line with the definition of a Lower 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	The assignment of Lower VRF is consistent with the VRF assignments for other requirements in the proposed 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 Lower VRF requirement per the criteria filed with FERC as part of the ERO’s Sanctions Guidelines.
FERC VRF G5 Discussion	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective.

VRF Justifications for EOP-011-4, Requirement R7	
Proposed VRF	**Lower**
Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	Therefore, the VRF reflects the risk of the whole requirement.

VSLs for EOP-011-4, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
N/A	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding or automatic Load shedding, but notified one or more of those entities more than 1 but fewer than 30 days late.	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding or automatic Load shedding, but notified one or more of those entities 30 days or more, but fewer than 60 days late.	The Transmission Operator did not identify or notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding or automatic Load shedding. OR The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding or automatic Load shedding, but notified one or more of those entities 60 days or more late.

VSL Justifications for EOP-011-4, 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 <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-011-4, Requirement R8	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate due to the fact that a lack of a Load shedding plan 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. Therefore, it is in line with the definition of a High 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	The assignment of High VRF is consistent with the VRF assignments for other requirements in the proposed 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 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-011-4, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
N/A	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to maintain it in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to provide it to its Transmission Operator in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner failed to develop a Load shedding plan(s) in accordance with Requirement R8. OR The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to implement it in accordance with Requirement R8.

TOP-002-5

VRF Justification for TOP-002-5, Requirement R1
The VRF did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VSL Justification for TOP-002-5, Requirement R1
The VSL did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VRF Justification for TOP-002-5, Requirement R2
The VRF did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VSL Justification for TOP-002-5, Requirement R2

The VSL did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VRF Justification for TOP-002-5, Requirement R3
The VRF did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VSL Justification for TOP-002-5, Requirement R3
The VSL did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VRF Justification for TOP-002-5, Requirement R4
The VRF did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VSL Justification for TOP-002-5, Requirement R4
The VSL did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VRF Justification for TOP-002-5, Requirement R5
The VRF did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VSL Justification for TOP-002-5, Requirement R5
The VSL did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VRF Justification for TOP-002-5, Requirement R6
The VRF did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VSL Justification for TOP-002-5, Requirement R6
The VSL did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VRF Justification for TOP-002-5, Requirement R7
The VRF did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VSL Justification for TOP-002-5, Requirement R7
The VSL did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VRF Justifications for TOP-002-5, Requirement R8	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that not having an Operating Process to identify cold weather and calculate appropriate demand and reserves while accounting for generating unit operation limitations 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	The assignment of Medium VRF is consistent with the VRF assignments for other requirements in the proposed 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 TOP-002-5, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
N/A	The Balancing Authority had an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods, but it did not address one of the Requirements or sub-Requirements of R8 Parts 8.1 through 8.3.	The Balancing Authority had an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods, but it did not address two of the Requirements or sub-Requirements of R8 Parts 8.1 through 8.3.	The Balancing Authority did not have an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods.

VSL Justifications for TOP-002-5, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed 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-011-4

August 2023

RELIABILITY | RESILIENCE | SECURITY

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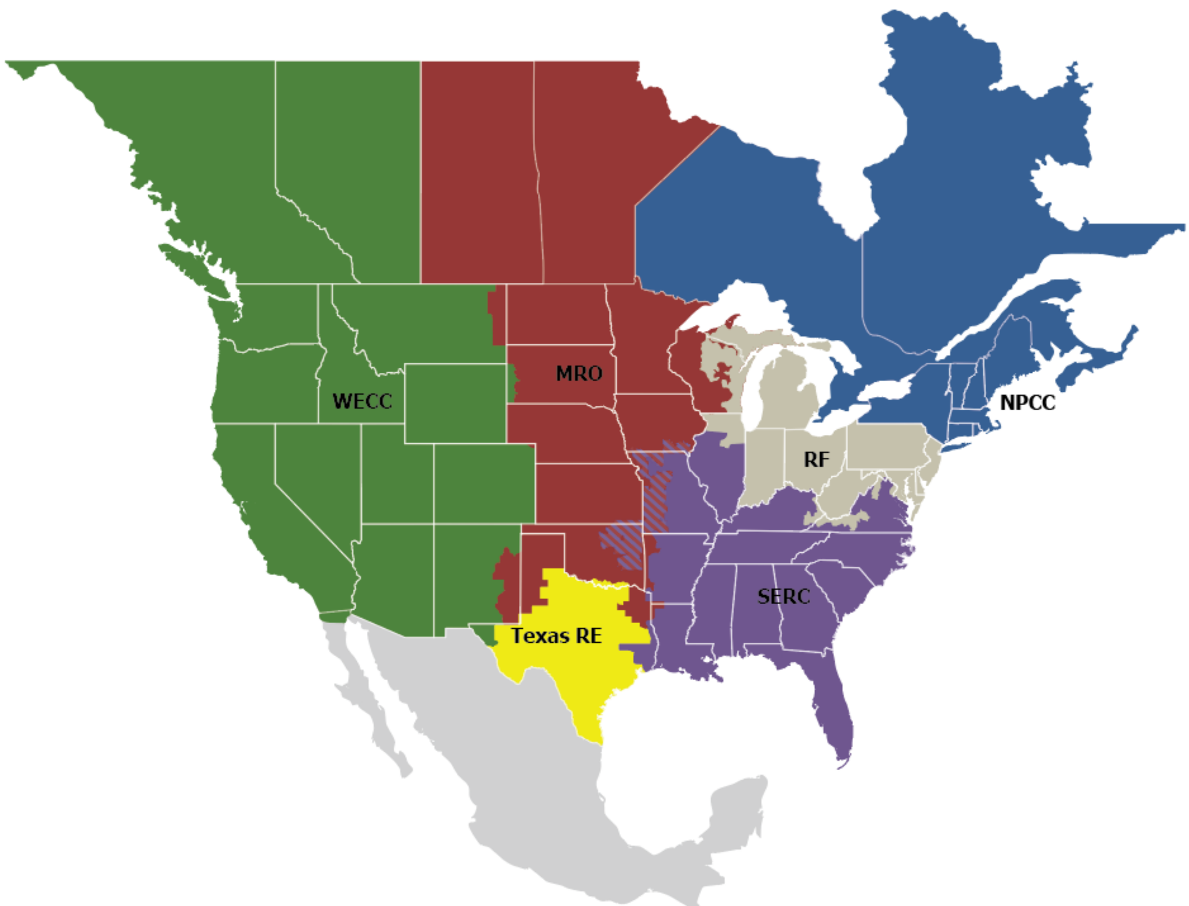
Table of Contents

Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of 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 proposed Reliability Standard EOP-011-4. 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-011-4 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 10 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 was completed by September 30, 2022, and submitted 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, R7, and R8

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. *Operator-controlled manual Load shedding and automatic 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 or automatic Load shed and circuits that serve designated critical loads which are essential to the reliability of the BES;*

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);*

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;*

1.2.5.5. *Provisions for the identification and prioritization of designated critical natural gas loads which are essential to the reliability of the BES; and*

1.2.6. *Provisions to determine reliability impacts of:*

1.2.6.1. *Cold weather conditions; and*

1.2.6.2. *Extreme weather conditions.*

R7. *Each Transmission Operator shall annually identify and notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding or automatic Load shedding.*

R8. *Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area, shall develop, maintain, and implement a Load shedding plan, within 30 months of being notified by the Transmission Operator. The Load shedding plan shall include the following, as applicable:*

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

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

8.1.2. *Provisions to minimize the overlap of circuits that are designated for manual or automatic Load shed and circuits that serve designated critical loads which are essential to the reliability of the BES;*

8.1.3. *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);*

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

8.1.5. *Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES.*

8.2. *Provisions to provide the Load shedding plan to the Transmission Operator for review.*

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)*

Applicability, Requirement R7 and R8

Expansion of Applicability

In many cases, Transmission Operators are dependent on Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners to implement portions of Requirement R1.2.5. The Project 2021-07 standard drafting team (SDT) determined that it is necessary to expand the Applicability of EOP-011-4 to these Functional Entities in order to address all entities responsible for performing operator-controlled manual Load shedding or automatic Load shedding per Key Recommendation 1i. Planning Coordinators and Transmission Planners were purposely excluded from applicability even though they are mentioned in Key Recommendation 1i because they are not responsible for performing operator-controlled manual Load shedding or automatic Load shedding.

EOP-011-4 Requirement R7 is a new requirement that was added to require that Transmission Operators annually identify and notify any Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners that are required to assist with mitigation of operating Emergencies in their Transmission Operator Area. The Transmission Operator has the overarching responsibility to mitigate operating Emergencies. If a Transmission Operator relies on other functional entities in accomplishing various aspects of manual or automatic Load shedding, they must be identified and notified per R7. Those identified and notified entities are subject to Requirement R8. The initial performance of R7 is required upon the effective date of EOP-011-4, which is on the first day of the first calendar quarter that is six 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. This approach to Requirement R7 ensures that newly applicable entities who will be subject to Requirement R8 are identified and notified in a timely manner thus minimizing any delay in implementing Requirement R8. Requirement R7 includes an annual provision to ensure that any additional entities, or changes to existing entities, required to assist with the mitigation of Operating emergencies are appropriately identified and notified on an ongoing basis.

EOP-011-4 Requirement R8 is a new requirement that is specific to Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners identified by the Transmission Operator in Requirement R7. It includes the relevant portions of Requirement R1.2.5 that address operator-controlled manual Load shedding or automatic Load shedding. The SDT found it appropriate to place these requirements specifically on Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners because many times they are the entities performing operator-controlled manual Load shedding or automatic Load shedding and have the capability of ensuring that these requirements are appropriately implemented for the Loads they represent. Entities that are subject to R8 have 30 months after being notified by a Transmission Operator in R7 to become compliant with these requirements.

Requirement R1, Part 1.2.5 and Requirement R8, Part 8.1

EOP-011-4 Requirement R1.2.5.5 was added to require Transmission Operators to include provisions to identify and prioritize critical natural gas infrastructure Loads which are essential to the reliability of the BES in their Operating Plan(s). EOP-011-4 Requirement R8.1.5 mirrors this requirement and is applicable to Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners. In addition to the following content, entities are encouraged to review guidance from *Reliability Guideline: Gas and Electrical Operational Coordination Considerations* in developing their approach to identify and prioritize critical natural gas infrastructure loads.

Manual and Automatic

EOP-011-4 Requirement 1.2.5 was modified to include "automatic Load shedding" in addition to "operator-controlled manual Load shedding." The result of this modification is that Requirement R1.2.5.5, which requires the identification and prioritization of critical natural gas Loads which are essential to the reliability of the BES, is also applicable to automatic Load shedding. It is important to identify and prioritize critical natural gas Loads not just for the purposes of manual Load shed but also in consideration of automatic Load shedding schemes. This modification does not prohibit the inclusion of critical natural gas Loads in automatic Load shedding, but it does require the prioritization of critical natural gas Loads which are essential to the reliability of the BES. This change was also incorporated into the new EOP-011-4 Requirement R8.1.

Critical Natural Gas Infrastructure Loads

The SDT has elected to add clarifying language in the applicable requirements and expand content in this Technical Rationale document in lieu of making "critical natural gas infrastructure Load" a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may necessarily have been overly broad; and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.

A reasonable application of this term should be informed by the entity's approved governing documents and guidance established by applicable regulatory authorities. A practical example of guidance that provides reasonable direction and flexibility has been developed by the Public Utility Commission of Texas in response to Winter Storm Uri (*Guidance Document for Power Delivery and Restoration During Energy Emergencies*). It is essential for entities to recognize that being overly broad in the application of this term may negatively impact reliability. If everything is critical, then nothing is truly critical.

The various regions covered by NERC requirements will have large variances in natural gas infrastructure that might be considered essential to the reliability of the BES. For example, Texas considers a single forced stoppage of natural gas transportation capacity a "major" event only if it disrupts greater than 200 MMcf per day. The entire state of Vermont used less than 70 times that amount of gas over the course of the entire year in 2021 and would therefore likely consider any infrastructure that moves a small fraction of the Texas quantity of gas "critical." Some locations would consider large gas collection sites (wellheads) as critical while others simply have no gas collection systems. Gas compression stations may be critical in some locations while others, potentially located near large underground high-pressure storage sites, may not be considered as critical. Entities should develop critical load classifications and criteria for prioritizing critical loads for BES reliability based on the unique features of its system.

Identification of Critical Natural Gas Infrastructure Loads

Critical natural gas Loads must be identified so that they can then be prioritized from an operator-controlled manual Load shedding and automatic Load shedding perspective. The identification and prioritization of critical natural gas loads requires coordination with natural gas facility owners and operators. This can be accomplished in a number of ways and the SDT did not prescribe specific methods in the drafting of EOP-011-4. Methods may include:

- Distribution of criteria to natural gas infrastructure entities soliciting information to identify critical facilities that would likely adversely affect BES reliability if de-energized;
- Reliance on self-identification of critical gas infrastructure driven by local jurisdictional requirements;
- Use of historical information and coordination with resources and gas suppliers from existing Operating Plans.

The SDT recognizes that entities are dependent upon the cooperation of natural gas facility owners and operators to complete this task. However, it is outside the scope of the SDT to develop methods to compel natural gas owners and operators to cooperate and provide specific information to various entities.

It is also recognized that BES registered entities are not expected to become experts in natural gas infrastructure, nor are natural gas entities expected to become experts in electrical generation. Those natural gas Loads determined to be critical to the reliability of the BES may also change gradually over time as changes occur in the BES and natural gas supply system, requiring regular review of prioritization schemes. The goal of pre-event planning and emergency response is to promote sufficient knowledge so that discussions of natural gas facility criticality can be conducted prior to and during extreme cold weather events. This allows Reliability Coordinators, Balancing Authorities, Regional Entities, Transmission Operators, Transmission Owners, and Distribution Providers to adjust Load shedding schemes as necessary to maximize availability of natural gas resources and to minimize impacts on the BES.

Prioritization of Critical Natural Gas Infrastructure Loads

The SDT recognizes that it is not reasonable to set a broad expectation of "protecting" critical natural gas Loads as initially recommended in the Joint Inquiry Report. Instead, it is more appropriate for entities to consider how critical natural gas infrastructure Loads are prioritized under various conditions. 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. Continued communication between electricity and natural gas providers is crucial to maintain situational awareness to avoid unintended consequences of Load shedding of critical natural gas infrastructure Loads. Prioritization should take into account the relative criticality of various loads within the natural gas supply chain and their potential impact to BES reliability. For example, critical natural gas Loads such as compression facilities that directly impact gas pipelines serving gas-fired generators should be prioritized above gas production facilities.

Most entities will find it appropriate to completely exclude a subset of the most critical natural gas infrastructure Loads that directly impact BES generators from manual and automatic Load shed. It is recommended to prioritize other critical natural gas Loads so that they are only shed if necessary, based on the Load shed magnitude.

An example method of prioritizing critical natural gas Loads may include:

- Identifying critical natural gas infrastructure Loads with the highest level of criticality and potential impact to BES reliability such that they can be completely excluded from operator-controlled manual Load shed and automatic Load shed programs;
- Prioritizing other critical natural gas infrastructure Loads not included in automatic Load shed programs such that they are only shed if necessary, based on the Load shed magnitude; and
- Prioritizing other critical natural gas infrastructure Loads included in automatic Load shed programs such that they are allocated to the lower frequency, or longer time-delay, steps in a UFLS program to ensure that they are less likely to be interrupted.

Requirement R2

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 excluding critical natural gas infrastructure loads which are essential to the reliability of the BES as Interruptible Load, curtailable Load, and demand response during extreme cold weather periods within each Balancing Authority Area;*

2.2.9. *Provisions for Transmission Operators to implement operator-controlled manual Load shedding or automatic Load shedding in accordance with Requirement R1 Part 1.2.5; and*

2.2.10. *Provisions to determine reliability impacts of:*

2.2.10.1. *cold weather conditions; and*

2.2.10.2. *extreme weather conditions.*

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.

Requirement R2, Part 2.2.8

EOP-011-4 Requirement 2.2.8 was added to address Key Recommendation 1h by prohibiting the use of certain critical natural gas infrastructure loads for demand response. This prohibition does not apply to all natural gas infrastructure loads. Instead, the Balancing Authority is only required to exclude those critical natural gas infrastructure loads which are essential to the reliability of the BES. Additionally, it is recognized that a complete prohibition is not necessary at all times given that the natural gas system does not have the same limitations and criticality during all seasons and weather conditions. For this reason, the SDT has limited the exclusion of these loads from Interruptible Load, curtailable Load, and demand response only to periods of extreme cold weather.

Requirement R2, Part 2.2.9

Key Recommendation 1i requires the Balancing Authorities to include in their Operating Plan(s) for their Balancing Authority Areas provisions for operator-controlled manual Load shedding that identifies and protects critical natural gas infrastructure loads in their respective areas. Further, the recommendation also includes provisions within these operating plans to require manual and automatic Load shed entities within their respective footprints to protect identified critical natural gas infrastructure loads from manual and automatic Load shedding.

The current provision, Requirement R2 Part 2.2.9, which references Transmission Operator responsibilities under R1 Part 1.2.5, satisfies the requirements of Key Recommendation 1i with respect to the Balancing Authority. Requirement R1 Part 1.2.5 requires that Transmission Operators have provisions to identify and prioritize critical natural gas infrastructure loads which are essential to the reliability of the BES from a manual Load shedding and automatic Load shedding perspective. The Balancing Authority relies on the Transmission Operator when it directs Load shedding. In addition, as described above, Requirement R8 extends these requirements to the applicable Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners who are identified in a Transmission Operator's Operating Plan to assist with the mitigation of Operating emergencies. Therefore, the objectives of the recommendation that Load shedding entities identify and protect critical natural gas infrastructure loads are satisfied.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Extreme Cold Weather Preparedness

Technical Rationale and Justification for EOP-011-4

~~February~~August 2023

RELIABILITY | RESILIENCE | SECURITY

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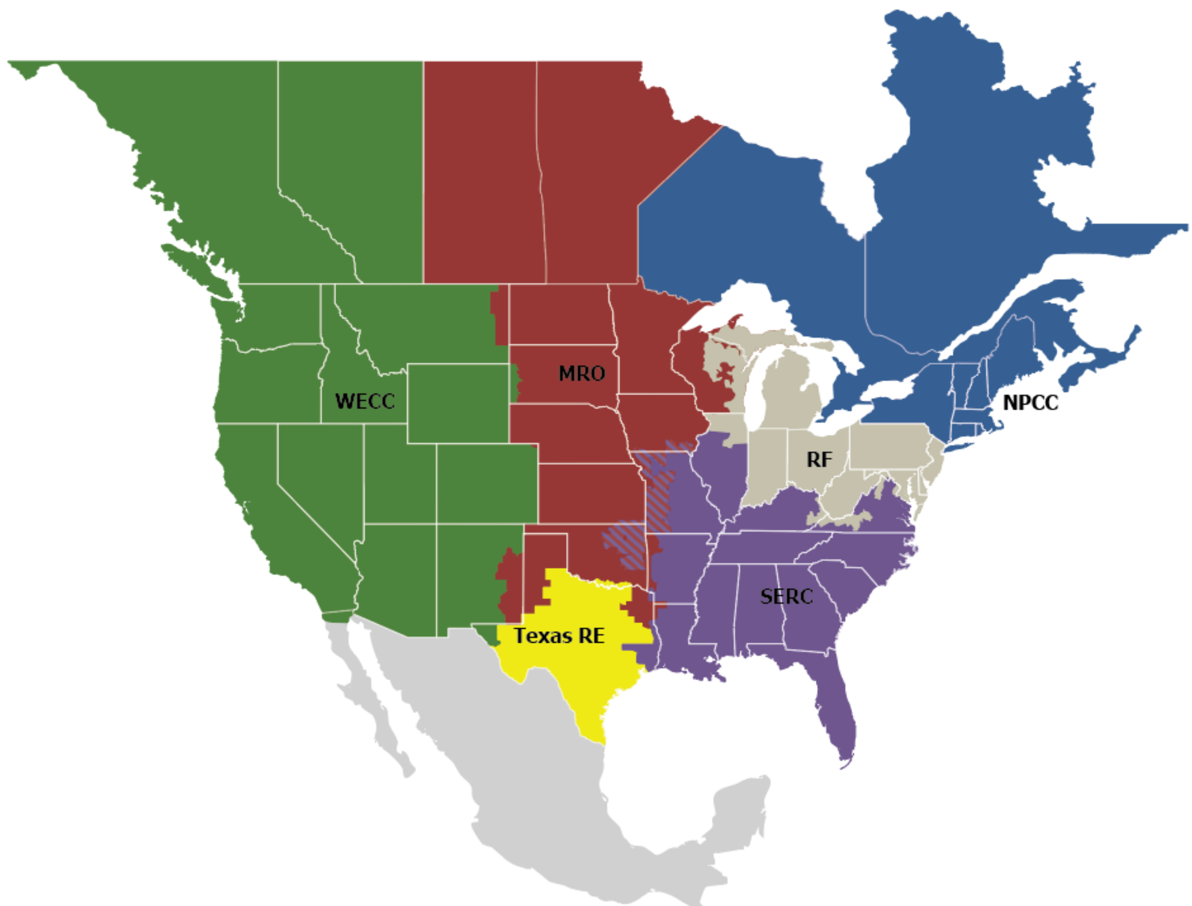
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of 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~~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~~Standard EOP-011-4. 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-011-4 ~~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~~northeast blackout and the August 1996 ~~West Coast~~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~~10 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 was completed by September 30, 2022, and submitted 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.

~~Applicability~~

*~~**4.1.** Functional Entities:~~*

*~~**4.1.1** Balancing Authority~~*

*~~**4.1.2** Reliability Coordinator~~*

*~~**4.1.3** Transmission Operator~~*

*~~**4.1.4** Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area~~*

*~~**4.1.5** UFLS-Only Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area~~*

*~~**4.1.6** Transmission Owner identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area~~*

Requirement R1, R7, and ~~R7~~R8

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 ~~or~~Load shedding and automatic 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 or automatic Load shed and circuits that serve designated critical loads which are essential to the reliability of the BES;*

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);*

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;*

1.2.5.5. *Provisions for the identification and prioritization of designated critical natural gas ~~infrastructure loads~~loads which are essential to the reliability of the BES; and*

~~***1.2.5.6.*** *Provisions for the identification of Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners required to mitigate operating Emergencies in its Transmission Operator Area.*~~

1.2.6. *Provisions to determine reliability impacts of:*

1.2.6.1. *Cold weather conditions; and*

1.2.6.2. *Extreme weather conditions.*

~~***R7***~~**R7.** *Each Transmission Operator shall annually identify and notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding or automatic Load shedding.*

R8*.* *Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner ~~identified in~~notified by a Transmission ~~Operator's Operating Plan(s)~~Operator per R7 to ~~mitigate~~assist with the mitigation of operating Emergencies in its Transmission Operator Area, shall develop, maintain, and implement ~~one or more Operating Plan(s).~~ a Load shedding plan, within 30 months of being notified by the Transmission Operator. The ~~Operating Plan(s) shall be provided to the Transmission Operator. The Operating Plan(s)~~Load shedding plan shall include the following, as applicable: ~~[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]~~*

~~***7.1.***~~***8.1.*** *Operator-controlled manual ~~or~~Load shedding and automatic Load shedding during an Emergency that accounts for each of the following:*

~~***7.1.1.***~~***8.1.1.*** *Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;*

~~***7.1.2.***~~***8.1.2.*** *Provisions to minimize the overlap of circuits that are designated for manual or automatic Load shed and circuits that serve designated critical loads which are essential to the reliability of the BES;*

~~***7.1.3.***~~***8.1.3.*** *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);*

~~***7.1.4.***~~***8.1.4.*** *Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions; and*

~~***7.1.5.***~~***8.1.5.*** *Provisions for the identification and prioritization of designated critical natural gas infrastructure loads~~.~~ which are essential to the reliability of the BES.*

8.2. *Provisions to provide the Load shedding plan to the Transmission Operator for review.*

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~~Authorities' and Transmission ~~Operators~~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~~Authorities', Transmission ~~Operators~~Operators', Planning ~~Coordinators~~Coordinators', and Transmission ~~Planners~~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)*

Applicability, Requirement ~~R1.2.5.6~~R7 and ~~Requirement R7~~R8

Expansion of Applicability

In many cases, Transmission Operators ~~(TOP)~~ are dependent on Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners to implement portions of Requirement R1.2.5. The Project 2021-07 standard drafting team (SDT) determined that it is necessary to expand the Applicability of EOP-011-4 to these Functional Entities in order to address all entities responsible for performing operator-controlled manual Load shedding or automatic ~~load~~Load shedding per Key Recommendation 1i. Planning Coordinators and Transmission Planners were purposely excluded from applicability even though they are mentioned in Key Recommendation 1i because they are not responsible for performing operator-controlled manual Load shedding or automatic Load shedding.

EOP-011-4 Requirement ~~R1.2.5.6~~R7 is a new requirement that was added to require that Transmission Operators annually identify and notify any Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners that are required to ~~mitigate~~assist with mitigation of operating Emergencies in their Transmission Operator Area. The Transmission Operator has the overarching responsibility to mitigate operating Emergencies. If a Transmission Operator relies on other ~~Functional Entities to accomplish~~functional entities in accomplishing various aspects of manual or automatic Load shedding, they must be identified ~~in~~and notified per R7. Those identified and notified entities are subject to Requirement R8. The initial performance of R7 is required upon the ~~TOP's~~effective date of EOP-011-4, which is on the first day of the first calendar quarter that is six 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. This approach to Requirement R7 ensures that newly applicable entities who will be subject to Requirement R8 are identified and notified in a timely manner thus minimizing any delay in implementing Requirement R8. Requirement R7 includes an annual provision to ensure that any additional entities, or changes to existing entities, required to assist with the mitigation of Operating ~~Plan(s).~~emergencies are appropriately identified and notified on an ongoing basis.

EOP-011-4 Requirement ~~R7~~R8 is a new requirement that is specific to Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners identified by the Transmission Operator in Requirement ~~R1.2.5.6.~~ R7. It includes the relevant portions ~~EOP-011-4~~of Requirement R1.2.5 that address operator-controlled manual Load shedding or automatic ~~load~~Load shedding. The SDT found it appropriate to place these requirements specifically on Distribution

Providers, UFLS-Only Distribution Providers, and Transmission Owners because many times they are the entities performing operator-controlled manual Load shedding or automatic Load shedding and have the capability of ensuring that these requirements are appropriately implemented for the Loads they represent. Entities that are subject to R8 have 30 months after being notified by a Transmission Operator in R7 to become compliant with these requirements.

Requirement R1, Part 1.2.5 and Requirement ~~R7~~R8, Part ~~7~~8.1

~~*Identify and Prioritize Critical Natural Gas Loads*~~

EOP-011-4 Requirement R1.2.5.5 was added to require Transmission Operators to include provisions to identify and prioritize critical natural gas ~~loads~~infrastructure Loads which are essential to the reliability of the BES in their Operating Plan(s). EOP-011-4 Requirement ~~R7~~R8.1.5 mirrors this requirement and is applicable to Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners. In addition to the following content, entities are encouraged to review guidance from ~~Reliability Guideline: Gas and Electrical Operational Coordination Considerations (add hyperlink).~~*Reliability Guideline: Gas and Electrical Operational Coordination Considerations* in developing their approach to identify and prioritize critical natural gas infrastructure loads.

Manual ~~AND~~and Automatic

EOP-011-4 Requirement 1.2.5 was modified to include "automatic Load shedding" in addition to "operator-controlled manual Load shedding." The result of this modification is that Requirement R1.2.5.5, which requires the identification and prioritization of critical natural gas Loads which are essential to the reliability of the BES, is also applicable to automatic Load shedding. It is important to identify and prioritize critical natural gas Loads not just for the purposes of manual Load shed but also in consideration of automatic Load shedding schemes. This modification does not prohibit the inclusion of critical natural gas Loads in automatic Load shedding, but it does require the prioritization of critical natural gas Loads which are essential to the reliability of the BES. This change was also incorporated into the new EOP-011-4 Requirement ~~R7~~R8.1.

Critical Natural Gas Infrastructure Loads

The SDT has elected to add clarifying language in the applicable requirements and expand content in this Technical Rationale document in lieu of making "critical natural gas infrastructure Load" a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may necessarily have been overly broad; and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.

A reasonable application of this term should be informed by the entity's approved governing documents and guidance established by applicable regulatory authorities. A practical example of guidance that provides reasonable direction and flexibility has been developed by the Public Utility Commission of Texas in response to Winter Storm Uri (*Guidance Document for Power Delivery and Restoration During Energy Emergencies*). It is essential for entities to recognize that being overly broad in the application of this term may negatively impact reliability. If everything is critical, then nothing is truly critical.

The various regions covered by NERC requirements will have large variances in natural gas infrastructure that might be considered essential to the reliability of the BES. For example, Texas considers a single forced stoppage of natural gas transportation capacity a "major" event only if it disrupts greater than 200 MMcf per day. The entire state of Vermont used less than 70 times that amount of gas over the course of the entire year in 2021 and would therefore likely consider any infrastructure that moves a small fraction of the Texas quantity of gas "critical." Some locations would consider large gas collection sites (wellheads) as critical while others simply have no gas collection systems. Gas compression stations may be critical in some locations while others, potentially located near large underground high-pressure storage sites, may not be considered as critical. Entities should develop critical load classifications and criteria for prioritizing critical loads for BES reliability based on the unique features of its system.

Identification of Critical Natural Gas Infrastructure Loads

Critical natural gas ~~loads~~Loads must be identified so that they can then be prioritized from an operator-controlled manual Load shedding and automatic Load shedding perspective. The identification and prioritization of critical natural gas loads requires coordination with natural gas facility owners and operators. This can be accomplished in ~~several~~a number of ways and the SDT did not prescribe specific methods in the drafting of EOP-011-4. Methods may include:

- Distribution of criteria to natural gas infrastructure entities soliciting information to identify critical facilities that would likely adversely affect BES reliability if de-energized;
- Reliance on self-identification of critical gas infrastructure driven by local jurisdictional requirements;
- Use of historical ~~info~~information and coordination with resources and gas suppliers from existing Operating Plans.

The SDT recognizes that entities are dependent upon the cooperation of natural gas facility owners and operators to complete this task. However, it is outside the scope of the SDT to develop methods to compel natural gas owners and operators to cooperate and provide specific information to various entities.

It is also recognized that BES registered entities are not expected to become experts in natural gas infrastructure, nor are natural gas entities expected to become experts in electrical generation. Those natural gas Loads determined to be critical to the reliability of the BES may also change gradually over time as changes occur in the BES and natural gas supply system, requiring regular review of prioritization schemes. The goal of pre-event planning and emergency response is to promote sufficient knowledge so that discussions of natural gas facility criticality can be conducted prior to and during extreme cold weather events. This allows Reliability Coordinators, Balancing Authorities, Regional Entities, Transmission Operators, Transmission Owners, and Distribution Providers to adjust Load shedding schemes as necessary to maximize availability of natural gas resources and to minimize impacts on the BES.

Prioritization of Critical Natural Gas Infrastructure Loads

The SDT recognizes that it is not reasonable to set a broad expectation of "protecting" critical natural gas Loads as initially recommended in the Joint Inquiry Report. Instead, it is more appropriate for entities to consider how critical natural gas infrastructure ~~loads~~Loads are prioritized under various conditions. It is important to recognize that criticality designations must be considered in the context of the situation. Critical ~~loads~~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.~~ Loads. Transmission Operators should consider establishing priorities for different types of critical ~~loads~~Loads. The critical Load designation, priority, and conditions during the event will influence which critical ~~loads~~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~~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. Continued communication between electricity and natural gas providers is crucial to maintain situational awareness to avoid unintended consequences of Load shedding of critical natural gas infrastructure Loads. Prioritization should ~~consider~~take into account the relative criticality of various loads within the natural gas supply chain ~~as compared to~~and their potential impact to BES reliability. For example, critical natural gas ~~loads~~Loads such as compression facilities that directly impact gas pipelines serving gas-fired generators should be prioritized above gas production facilities.

Most entities will find it appropriate to completely exclude a subset of the most critical natural gas infrastructure Loads that directly impact BES generators from manual and automatic Load shed. It is recommended to prioritize other critical natural gas Loads so that they are only shed if necessary, based on the Load shed magnitude.

An example method of prioritizing critical natural gas ~~loads~~Loads may include:

- Identifying critical natural gas infrastructure Loads with the highest level of criticality and potential impact to BES reliability such that they can be completely excluded from operator-controlled manual Load shed and automatic Load shed programs;
- Prioritizing other critical natural gas infrastructure Loads not included in automatic Load shed programs such that they are only shed if necessary, based on the Load shed magnitude; and
- Prioritizing other critical natural gas infrastructure Loads included in automatic Load shed programs such that they are allocated to the lower frequency, or longer time-delay, steps in a UFLS program to ensure that they are less likely to be interrupted.

Requirement R2

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 excluding critical natural gas infrastructure loads which are essential to the reliability of the BES as Interruptible Load, curtailable Load, and demand response during extreme cold weather periods ~~when it would adversely impact the reliable operation of the BES~~within each Balancing Authority Area;*

2.2.9. *Provisions for Transmission Operators to implement operator-controlled manual Load ~~shed~~shedding or automatic Load shedding in accordance with Requirement R1 Part 1.2.5; and*

2.2.10. *Provisions to determine reliability impacts of:*

2.2.10.1. *~~Cold~~cold weather conditions; and*

2.2.10.2. *~~Extreme~~extreme weather conditions.*

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.*

Requirement R2, Part 2.2.8

EOP-011-4 Requirement 2.2.8 was added to ~~require Balancing Authorities to include provisions to identify and prioritize~~address Key Recommendation 1h by prohibiting the use of certain critical natural gas infrastructure loads ~~in their Operating Plan(s), similar to EOP-011-4 Requirements R1.2.5 and R7.1.5 applicable to Transmission Operators, Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners. The Technical Rationale verbiage above regarding the identification and prioritization of~~ for demand response. This prohibition does not apply to all natural gas infrastructure loads. Instead, the Balancing Authority is only required to exclude those critical natural gas ~~Loads applicable~~infrastructure loads which are essential to ~~Requirements R1.2.5 and R7.1.5 is also applicable to Requirement R2.2.8.~~

~~It is important to stress that in~~ the ~~verbiage above applicable to R1.2.5 and R7.1.5, and~~reliability of the ~~Key Recommendation 1h and Recommendation 28 from the Joint Inquiry Report~~BES. Additionally, it is recognized that ~~"critical" is situational, i.e. depending on the local conditions, and may change during the course of~~ a ~~severe weather event. That is, during an event, any element of natural gas processing and delivery may become "critical". Continued communication between electricity and~~ complete prohibition is not necessary at all times given the natural gas ~~providers is crucial to maintain situational awareness to avoid unintended consequences of load shedding of critical natural gas loads.~~

~~It is also recognized that BES registered entities are not expected to become experts in natural gas infrastructure, nor are natural gas entities expected to become experts in electrical generation. Those natural gas loads determined to be critical may also change more gradually over time as changes occur in the BES and natural gas supply~~ system~~,~~ ~~requiring regular review of prioritization schemes. The goal of pre-event planning and emergency response is to promote sufficient knowledge so that discussions of natural gas facility~~ does not have the same limitations and criticality ~~can be conducted prior to and during severe~~during all seasons and weather conditions. For this reason, the SDT has limited the exclusion of these loads from Interruptible Load, curtailable Load, and demand response only to periods of extreme cold weather ~~to allow Reliability Coordinators, Balancing Authorities, Regional Entities, Transmission Operators, Transmission Owners, and Distribution Providers to adjust load shedding schemes as necessary to maximize availability of natural gas resources and minimize impact on the BES~~.

Requirement R2, Part 2.2.9

Key Recommendation 1i requires the Balancing Authorities to include in their Operating Plan(s) for their Balancing Authority Areas provisions for operator-controlled manual ~~load~~Load shedding that identifies and protects critical natural gas infrastructure loads in their respective areas. Further, the recommendation also includes provisions within these operating plans to require manual and automatic ~~load~~Load shed entities within their respective footprints to protect identified critical natural gas infrastructure loads from manual and automatic ~~load~~Load shedding.

The current provision~~-~~, Requirement R2 Part 2.2.9, which references Transmission Operator responsibilities under R1 Part 1.2.5~~.~~, satisfies the requirements of Key Recommendation 1i with respect to the Balancing Authority. Requirement R1 Part 1.2.5 ~~identifies and protects~~requires that Transmission Operators have provisions to identify and prioritize critical natural gas infrastructure loads ~~from manual and automatic load shedding within the Transmission Operator's Operating Plan(s),~~ which ~~the~~ are essential to the reliability of the BES from a manual Load shedding and automatic Load shedding perspective. The Balancing Authority relies on the Transmission Operator when it directs ~~load~~ Load shedding~~ provisions (*See* Requirement R2 Part 2.2.9).~~. In addition, as described above, Requirement ~~R7~~ R8 extends these requirements to the applicable ~~to the~~ Distribution ~~Provider~~Providers, UFLS-Only Distribution ~~Provider~~Providers, and Transmission ~~Owner, identifies and protects critical natural gas infrastructure loads from manual and automatic load shedding, and are essential~~ Owners who are identified in ~~the implementation of~~ a Transmission Operator's Operating Plan to assist with the mitigation of Operating ~~Plan(s).~~emergencies. Therefore, the objectives of the recommendation that ~~load~~ Load shedding entities identify and protect critical natural gas infrastructure loads are satisfied~~ within the Transmission Operator's Operating Plan(s).~~.

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Extreme Cold Weather Preparedness

Technical Rationale and Justification for TOP-002-5

August 2023

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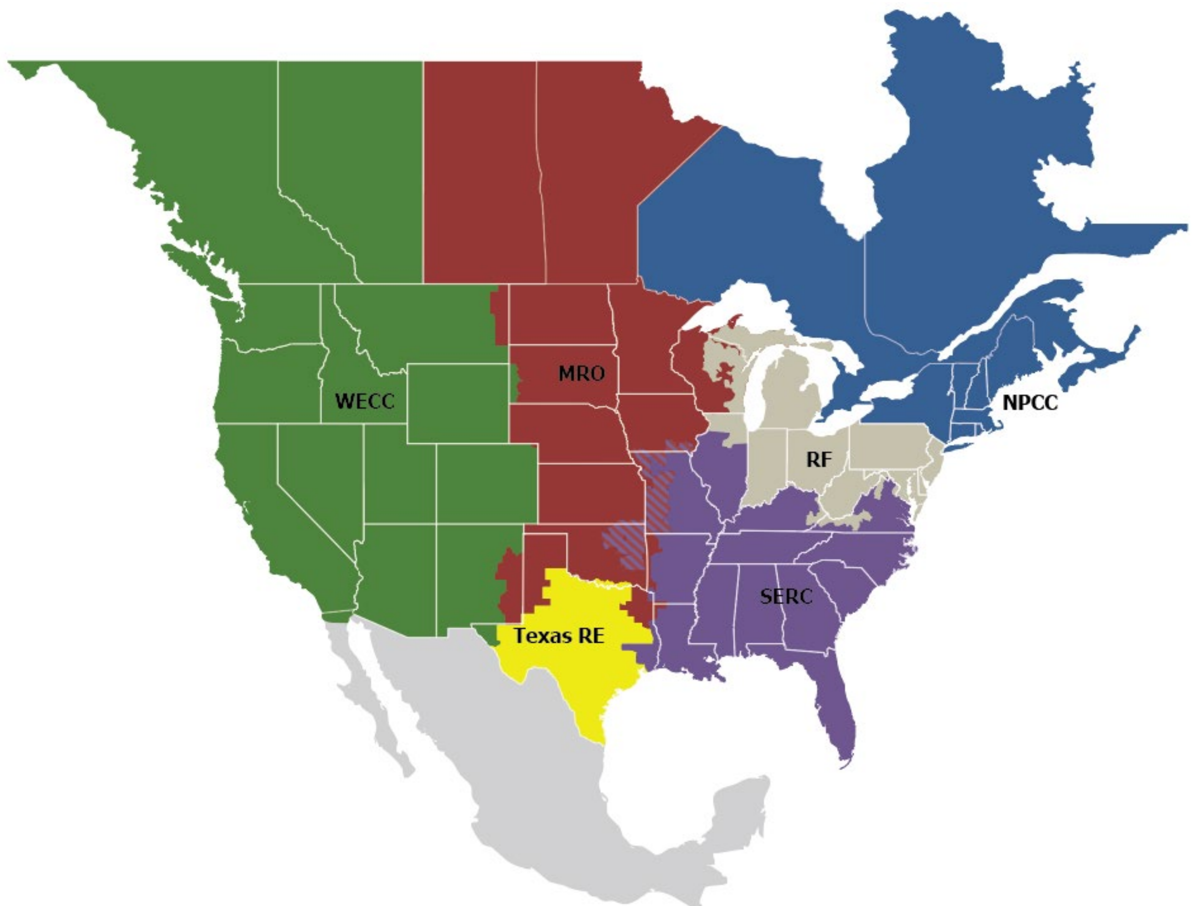
Preface

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 TOP-002-5. 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 TOP-002-5 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.

TOP-002-5

Requirement R8

R8. *Each Balancing Authority shall have an extreme cold weather Operating Process for its Balancing Authority Area, addressing preparations for and operations during extreme cold weather periods. The extreme cold weather Operating Process shall include, but is not limited to:*

8.1 A methodology for identifying an extreme cold weather period within each Balancing Authority Area;

8.2 A methodology to determine an adequate reserve margin during the extreme cold weather period considering the generating unit(s) operating limitations in previous extreme cold weather periods that includes, but is not limited to:

8.2.1 Capability and availability;

8.2.2Fuel supply and inventory concerns

8.2.3 Start-up issues;

8.2.4 Fuel switching capabilities; and

8.2.5 Environmental constraints.

8.3 A methodology to determine a five-day hourly forecast during the identified extreme cold weather periods that includes, but is not limited to:

8.3.1 Expected generation resource commitment and dispatch;

8.3.2 Interchange scheduling;

8.3.3 Demand patterns;

8.3.4 Capacity and energy reserve requirements, including deliverability capability; and

8.3.5 Weather forecast.

<u>Key Recommendation 1g:</u> 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.

General Considerations

There have been several past events during extreme cold weather where load and resource balancing issues have occurred, due to both unexpected generator trips and higher loads than forecasted. A proactive Operating Process required prior to the onset of extreme cold weather events would formalize the Balancing Authority's extreme cold weather preparations for those periods, including forecasting load needs and adequate reserve requirements. Initial drafts to incorporate the Operating Process tied the process to the Operating Plan described in Requirement R4. To remove any ambiguity whether a cold weather Operating Process must be developed for all Operating Plans during all seasons, the standard drafting team (SDT) structured Requirement R8 to be stand-alone. Therefore, the Operating Process contained in Requirement R8 will address preparations and operations for extreme cold weather periods and is not required for other seasonal conditions. The Operating Process is specific to extreme cold weather operations to formalize the process to review and respond to oncoming conditions that may affect generation availability and capability, forecasted load, and determining whether additional capability/reserves should be ready to serve loads during extreme cold weather.

The Project 2021-07 SDT does not believe that prescriptive processes must be used for every Balancing Authority to develop their methodology. This is based in part on the differences in the size of Balancing Authorities (for reference, in 2020, 14 Balancing Authorities had peak loads of less than 200 MWs, while two had peak loads of more than 100,000 MWs[1]). The differences between Balancing Authority footprints, loads, and market structures or lack thereof, make a single consistent methodology inappropriate. Requirement R8, Parts R8.2 and R8.3 contain criteria, including data requirements, the Balancing Authority will use as part of its methodologies. Due to the criteria being the minimum required, the SDT team has included "but not limited to" language to allow the Balancing Authority that flexibility in needed information and process that is vital to ensure the methodologies can effectively accomplish the reliability need, and reflect the intent of the standard to require inclusion of the various listed items but not exclude other items that the Balancing Authority may consider valuable and germane to include in its methodologies.

The SDT developed the proposed requirement to ensure that the Balancing Authorities address the increased uncertainty related to these extreme weather events in a manner appropriate and adequate for their Balancing Authority Area. Each Balancing Authority can develop a methodology consistent with the Requirement they feel provides the best solutions to sustain an adequate level of reliability during an upcoming extreme cold weather event.

[1]Source: OY 2022 BAL-003 Frequency Bias Settings 01 Jun 2022
https://www.nerc.com/comm/OC/RS%20Landing%20Page%20DL/Frequency%20Response%20Standard%20Resources/OY_2022_Frequency_Bias_Annual_Calculations_REVISION_4.26.22.pdf

Technical Rationale from TOP-002-4

This section contains a "cut and paste" of the Technical Rationale components of the former Guidelines and Technical Basis (GTB) as-is from TOP-002-4 standard to preserve any historical references.

Rationale for Definitions:
Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Rationale for R1:
Terms deleted in Requirement R1 as they are now contained in the revised definition of Operational Planning Analysis

Rationale for R2:
The change to Requirement R2 is in response to NOPR paragraph 42 and in concert with proposed changes made to proposed TOP-001-4

Rationale for R3:
Changes in response to IERP recommendation

Rationale for R4 and R5:
These Requirements were added to address IERP recommendations

Rationale for R6 and R7:
Added in response to SW Outage Report recommendation 1

This section contains a "cut and paste" of the "Associated Documents" section as is in TOP-002-4 Standard to preserve any historical references:
Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario, but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow, but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA.

When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of “the Operating Plan document” for compliance purposes.

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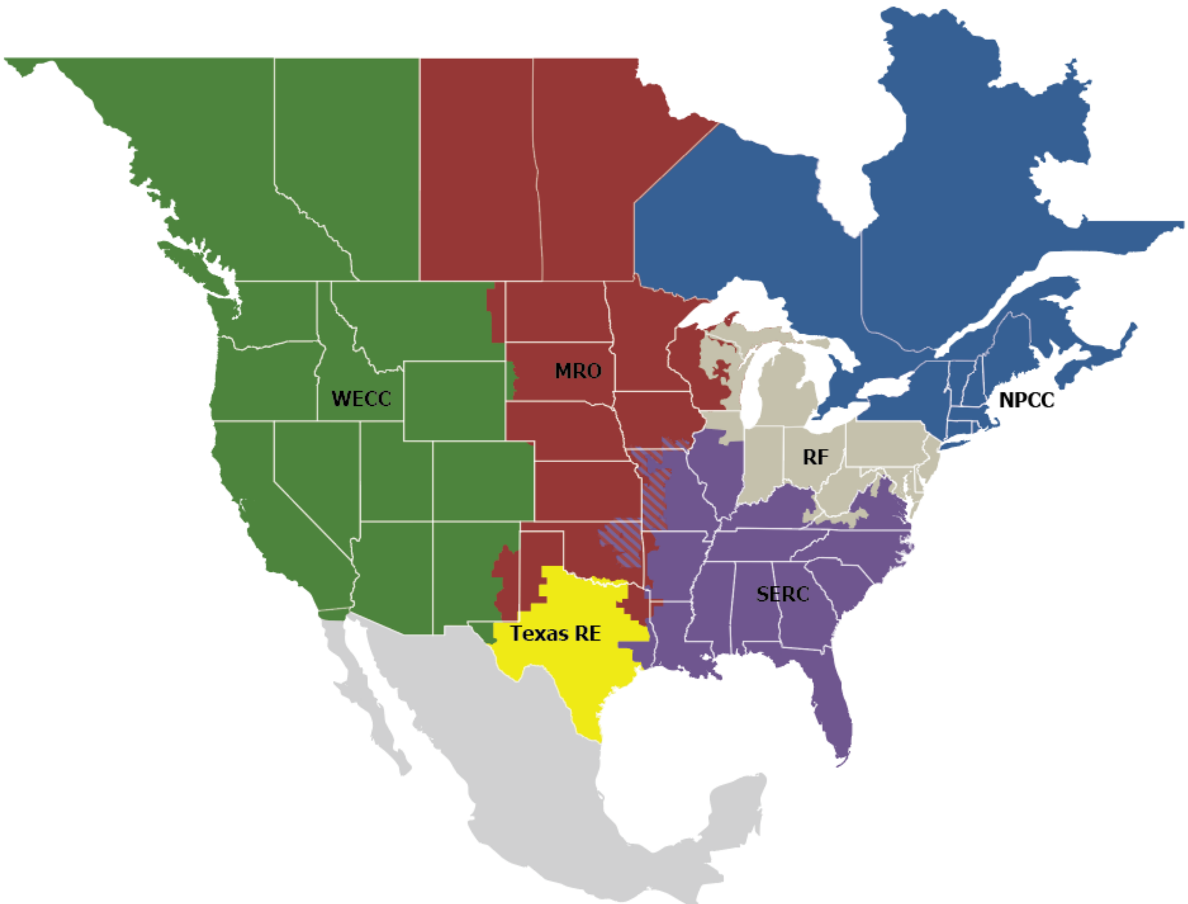

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- New and revised Reliability Standards to be submitted for regulatory approval before Winter 2023/2024: development completed by September 30, 2023, for the Board's consideration in October 2023 to address Key Recommendations 1a, 1b, 1c, 1g, 1h, and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

TOP-002-5

Requirement R8

R8. *Each Balancing Authority shall have an extreme cold weather Operating Process~~, as part of~~ for its ~~Operating Plan developed in Requirement R4~~Balancing Authority Area, addressing preparations for and operations during extreme cold weather periods. The extreme cold weather Operating Process shall include~~: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]~~, but is not limited to:*

8.1 A methodology for identifying an extreme cold weather period within each Balancing Authority Area;

8.2 A methodology ~~that determines~~to determine an ~~appropriate~~adequate reserve margin during the extreme cold weather period considering the generating unit(s) operating limitations in previous extreme cold weather periods ~~including~~that includes, but is not limited to:

8.2.1 Capability and availability;

8.2.~~2 Fuel~~2 Fuel supply and inventory concerns;

8.2.3 Start-up issues;

8.2.4 Fuel switching capabilities; and

8.2.5 Environmental constraints.

8.3 A methodology to determine a five-day hourly forecast during the identified extreme cold weather periods that includes, but is not limited to:

8.3.1 Expected generation resource commitment and dispatch;

8.3.2 Interchange scheduling;

8.3.3 Demand patterns;

8.3.4 Capacity and energy reserve requirements, including deliverability capability; and

8.3.5 Weather forecast.

Key Recommendation 1g: 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

"~~manage~~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.

General Considerations

~~In reviewing TOP-003, the SDT determined that the current standards provide Transmission Operators and Balancing Authorities with sufficient flexibility to request whatever data is needed from the Generator Owners to fulfill their operational and planning responsibilities. As such, the SDT focused their edits on TOP-002 to ensure the Balancing Authority had an appropriate extreme cold weather Operating Process in place to ensure reliability during these extreme events.~~

There have been several past events during extreme cold weather where ~~Load~~load and resource balancing issues have occurred, due to both unexpected generator trips and higher ~~Loads~~loads than forecasted. A proactive Operating Process required prior to the onset of extreme cold weather events would formalize the Balancing Authority's extreme cold weather preparations ~~within their Operating Plan for those periods, including forecasting Load needs and reserve requirements.~~for those periods, including forecasting load needs and adequate reserve requirements. Initial drafts to incorporate the Operating Process tied the process to the Operating Plan described in Requirement R4. To remove any ambiguity whether a cold weather Operating Process must be developed for all Operating Plans during all seasons, the standard drafting team (SDT) structured Requirement R8 to be stand-alone. Therefore, the Operating Process contained in Requirement R8 will address preparations and operations for extreme cold weather periods and is not required for other seasonal conditions. The Operating Process is specific to extreme cold weather operations to formalize the process to review and respond to oncoming conditions that may affect generation availability and capability, forecasted ~~Load~~load, and determining whether additional capability/reserves should be ready to serve ~~Loads~~loads during extreme cold weather.

The Project 2021-07 SDT does not believe that prescriptive processes must be used for every Balancing Authority to develop their methodology. This is based in part on the differences in the size of Balancing Authorities (for reference, in 2020, 14 Balancing Authorities had peak ~~Loads~~loads of less than 200 MWs, while two had peak ~~Loads~~loads of more than 100,000 MWs[1]). The differences between Balancing Authority footprints, ~~Loads~~loads, and market structures or lack thereof, make a single consistent methodology inappropriate. Requirement R8, Parts R8.2 and R8.3 contain criteria, including data requirements, the Balancing Authority will use as part of its methodologies. Due to the criteria being the minimum required, the SDT team has included "but not limited to" language to allow the Balancing Authority that flexibility in needed information and process that is vital to ensure the methodologies can effectively accomplish the reliability need, and reflect the intent of the standard to require inclusion of the various listed items but not exclude other items that the Balancing Authority may consider valuable and germane to include in its methodologies.

The SDT developed the proposed requirement to ensure that the Balancing Authorities address the increased uncertainty related to these extreme weather events in a manner appropriate and adequate for their Balancing Authority Area. Each Balancing Authority can develop a methodology consistent with the Requirement they feel provides the best solutions to sustain an adequate level of reliability during an upcoming extreme cold weather event.

[1]Source: OY 2022 BAL-003 Frequency Bias Settings 01 Jun 2022
https://www.nerc.com/comm/OC/RS%20Landing%20Page%20DL/Frequency%20Response%20Standard%20Resources/OY_2022_Frequency_Bias_Annual_Calculations_REVISION_4.26.22.pdf

Technical Rationale ~~through~~from TOP-002-4

This section contains a "cut and paste" of the Technical Rationale components of the former Guidelines and Technical Basis (GTB) as-is from TOP-002-4 standard to preserve any historical references.

Rationale for Definitions:
Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Rationale for R1:
Terms deleted in Requirement R1 as they are now contained in the revised definition of Operational Planning Analysis

Rationale for R2:
The change to Requirement R2 is in response to NOPR paragraph 42 and in concert with proposed changes made to proposed TOP-001-4

Rationale for R3:
Changes in response to ~~Independent Experts Review Project (~~IERP~~)~~ recommendation

Rationale for R4 and R5:
These Requirements were added to address IERP recommendations

Rationale for R6 and R7:
Added in response to SW Outage Report recommendation 1

This section contains a "cut and paste" of the "Associated Documents" section as is in TOP-002-4 Standard to preserve any historical references:
Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario, but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow, but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does

not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.

Standards Announcement

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

Formal Comment Period Open through September 12, 2023

Now Available

A 20-day formal comment period for **Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination – Phase II** is open through **8 p.m. Eastern, Tuesday, September 12, 2023** for the following standards and implementation plan:

- EOP-011-4 – Emergency Operations
- TOP-002-5 – Operations Planning
- Implementation Plan

The standard drafting team's considerations of the responses received from the previous comment period are reflected in this draft of the standard.

Reminder Regarding Corporate RBB Memberships

Under the NERC Rules of Procedure, each entity and its affiliates is collectively permitted one voting membership per Registered Ballot Body Segment. Each entity that undergoes a change in corporate structure (such as a merger or acquisition) that results in the entity or affiliated entities having more than the one permitted representative in a particular Segment must withdraw the duplicate membership(s) prior to joining new ballot pools or voting on anything as part of an existing ballot pool. Contact ballotadmin@nerc.net to assist with the removal of any duplicate registrations.

Commenting

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

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

Next Steps
Additional ballots for the standard(s) and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **September 1 – 12, 2023.**

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

For more information or assistance, contact Manager of Standards Development, Alison Oswald (via email) or at 404-275-9410. 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

Comment Report

Project Name:	2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination - Phase 2 | Draft 2 - EOP-011-4 and TOP-002-5
Comment Period Start Date:	8/24/2023
Comment Period End Date:	9/12/2023
Associated Ballots:	2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 EOP-011-4 | Non-binding Poll AB 2 NB 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 EOP-011-4 AB 2 ST 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 Implementation Plan AB 2 OT 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 TOP-002-5 | Non-binding Poll AB 2 NB 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 TOP-002-5 AB 2 ST

There were 62 sets of responses, including comments from approximately 152 different people from approximately 106 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

EOP-011-4 (Questions 1-3)

1. Do you agree with the new R7 for identification and notification?

2. Is the 30-month time frame in R8 adequate time for the physical changes that may be required to comply with these requirements?

3. The SDT has elected to add clarifying language in the applicable requirements in lieu of making "critical natural gas infrastructure load" a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities and their relative impact on the BES. Do you agree with this approach?

TOP-002-5 (Question 4)

4. The SDT modified the proposed Requirement R8 to remove the link between the required Operating Process and the Operating Plan required under Requirement R4. Do you agree with this modification?

General (Questions 5-7)

5. The SDT proposes that the modifications in EOP-011-4 and TOP-002-5 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.

6. Do you agree with the implementation plan proposed by the SDT? 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.

7. Provide any additional comments for the SDT to consider, including the provided technical rationale document, if desired.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
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
Jennie Wike	Jennie Wike		WECC	Tacoma Power	Jennie Wike	Tacoma Public Utilities	1,3,4,5,6	WECC
					John Merrell	Tacoma Public Utilities (Tacoma, WA)	1	WECC
					John Nierenberg	Tacoma Public Utilities (Tacoma, WA)	3	WECC
					Hien Ho	Tacoma Public Utilities (Tacoma, WA)	4	WECC
					Terry Gifford	Tacoma Public Utilities (Tacoma, WA)	6	WECC
					Ozan Ferrin	Tacoma Public Utilities (Tacoma, WA)	5	WECC
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,RF,SERC,Texas RE,WECC	ACES Collaborators	Bob Soloman	Hoosier Energy Electric Cooperative	1	RF
					Scott Brame	North Carolina Electric Membership Corporation	1,3,4,5	SERC
					Jason Procuniar	Buckeye Power, Inc.	4	RF
					Bill Pezalla	Old Dominion Electric Cooperative	3,4	SERC
					Nikki Carson-Marquis	Minnkota Power Cooperative, Inc.	1	MRO

					Nikki Carson-Marquis	Minnkota Power Cooperative, Inc.	1	MRO
					Jordan Mcclellan	Southern Illinois Power Cooperative	1	SERC
Eversource Energy	Joshua London	1		Eversource	Joshua London	Eversource Energy	1	NPCC
					Vicki O'Leary	Eversource Energy	3	NPCC
MRO	Jou Yang	1,2,3,4,5,6	MRO	MRO NSRF	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Chris Bills	City of Independence, Power and Light Department	5	MRO
					Fred Meyer	Algonquin Power Co.	3	MRO
					Christopher Bills	City of Independence Power & Light	3,5	MRO
					Larry Heckert	Alliant Energy Corporation Services, Inc.	4	MRO
					Marc Gomez	Southwestern Power Administration	1	MRO
					Matthew Harward	Southwest Power Pool, Inc. (RTO)	2	MRO
					Bryan Sherrow	Board of Public Utilities	1	MRO
					Terry Harbour	Berkshire Hathaway Energy - MidAmerican Energy Co.	1	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Jamison Cawley	Nebraska Public Power District	1,3,5	MRO

					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Shonda McCain	Omaha Public Power District	6	MRO
					George E Brown	Pattern Operators LP	5	MRO
					George Brown	Acciona Energy USA	5	MRO
					Jaimin Patel	Saskatchewan Power Cooperation	1	MRO
					Kimberly Bentley	Western Area Power Administration	1,6	MRO
					Jay Sethi	Manitoba Hydro	1,3,5,6	MRO
					Michael Ayotte	ITC Holdings	1	MRO
Entergy	Julie Hall	6		Entergy	Oliver Burke	Entergy - Entergy Services, Inc.	1	SERC
					Jamie Prater	Entergy	5	SERC
Electric Reliability Council of Texas, Inc.	Kennedy Meier	2		ISO/RTO Council Standards Review Committee (SRC)	Bobbi Welch	Midcontinent ISO, Inc.	2	NA - Not Applicable
					Darcy O'Connell	California ISO	2	WECC
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Harishkumar Subramani Vijay Kumar	Independent Electricity System Operator	2	NPCC
					John Pearson	ISO New England, Inc.	2	NPCC
					Kennedy Meier	Electric Reliability Council of Texas, Inc.	2	Texas RE
					Matthew Harward	Southwest Power Pool, Inc. (RTO)	2	NA - Not Applicable

					Thomas Foster	PJM Interconnection, L.L.C.	2	RF
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	RF
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Jim Howell, Jr.	Southern Company - Southern Company Generation	5	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Alain Mukama	Hydro One Networks, Inc.	1	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1	NPCC

				Michele Tondalo	United Illuminating Co.	1	NPCC
				Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
				Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
				Randy Buswell	Vermont Electric Power Company	1	NPCC
				James Grant	NYISO	2	NPCC
				John Pearson	ISO New England, Inc.	2	NPCC
				Harishkumar Subramani Vijay Kumar	Independent Electricity System Operator	2	NPCC
				Randy MacDonald	New Brunswick Power Corporation	2	NPCC
				Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
				David Burke	Orange and Rockland	3	NPCC
				Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
				Salvatore Spagnolo	New York Power Authority	1	NPCC
				Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
				David Kwan	Ontario Power Generation	4	NPCC
				Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
				Glen Smith	Entergy Services	4	NPCC
				Sean Cavote	PSEG	4	NPCC
				Jason Chandler	Con Edison	5	NPCC

					Tracy MacNicoll	Utility Services	5	NPCC
					Shivaz Chopra	New York Power Authority	6	NPCC
					Vijay Puran	New York State Department of Public Service	6	NPCC
					ALAN ADAMSON	New York State Reliability Council	10	NPCC
					David Kiguel	Independent	7	NPCC
					Joel Charlebois	AESI	7	NPCC
					Joshua London	Eversource Energy	1	NPCC
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
Stephen Whaite	Stephen Whaite			ReliabilityFirst Ballot Body Member and Proxies	Lindsey Mannion	ReliabilityFirst	10	RF
					Stephen Whaite	ReliabilityFirst	10	RF
Tim Kelley	Tim Kelley		WECC	SMUD and BANC	Nicole Looney	Sacramento Municipal Utility District	3	WECC
					Charles Norton	Sacramento Municipal Utility District	6	WECC
					Wei Shao	Sacramento Municipal Utility District	1	WECC
					Foung Mua	Sacramento Municipal Utility District	4	WECC
					Nicole Goi	Sacramento Municipal Utility District	5	WECC

					Kevin Smith	Balancing Authority of Northern California	1	WECC

EOP-011-4 (Questions 1-3)

1. Do you agree with the new R7 for identification and notification?

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
MRO NSRF disagrees with R7. As it is currently written, the elements outlined in R7 should be incorporated as a subcomponent of R1. For a Transmission Operator to successfully develop, maintain, and implement an Operating Plan, as mandated by R1, the Transmission Operator must also and initially (and as necessary or required moving forward) notify relevant entities, which is the action specified in R7.	
Likes 3	OGE Energy - Oklahoma Gas and Electric Co., 3, Hargrove Donald; OGE Energy - Oklahoma Gas and Electric Co., 1, Pyle Terri; JEA, 1, McClung Joseph
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
Without fully knowing what expectations will result from our TOP (PJM), FirstEnergy cannot support this new requirement.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren is unsure how we are supposed to know what registered Distribution Providers are in our Transmission Operator Area. We suggest some sort of automatic notification when a new Distribution Provider becomes registered within our Transmission Operator Area, or an easily accessible list of Distribution Providers.	

Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
1. NCPA supports others opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Tri-State somewhat agrees with R7 but would like clarity on the following: }If an entity has unplanned or unusual circumstances that may not fall under “operating emergency” situations where they ask for manual load shed to occur when it normally wouldn’t will they still be required to notify the Distribution Providers/Transmission Owners under R7?	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 4	
Answer	No
Document Name	
Comment	
NO, NCPA supports various other opposing comments that have been submitted.	
Likes 0	

Dislikes 0	
Response	
Michael Whitney - Northern California Power Agency - 3	
Answer	No
Document Name	
Comment	
NCPA supports comments others' opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	
Lenise Kimes - City and County of San Francisco - 1 - WECC	
Answer	No
Document Name	
Comment	
The notification should be required to be given initially and upon changes, and reviewed at least annually.	
Likes 0	
Dislikes 0	
Response	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jeremy Lawson - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
WEC Energy Group supports the new R7 language for identification and notification.	
Likes 0	
Dislikes 0	
Response	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	Yes
Document Name	

Comment	
The current wording reads like it is missing what the entities are being notified of as the purpose reads to be part of the entity classification not that they are being notified that they are required to assist with mitigation.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
PNM and TNMP supports the new identification and notification language in R7.	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
AZPS agrees with the new R7 for identification and notification.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	

EEI supports the new R7 language for identification and notification.	
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 with the SRC that the term “automatic Load shedding” be replaced with “undervoltage Load shedding or underfrequency Load shedding” throughout EOP-011-4. Thus eliminating normal SPS/RAS operations from the EOP-011 requirements	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
The drafting team should consider whether the addition of sub-requirements could enhance clarity and provide more flexibility for this TOP task. For example, following the initial performance of R7 the TOP might annually review the list of entities previously identified and only notify any newly identified entities that their assistance is needed. For entities that have previously been notified, the need for their continued assistance could be communicated annually and the status of their implementation readiness requested. A provision could also be added to allow the TOP to extend the 30-month initial implementation for an entity subject to R8 when justifiable conditions warrant.	
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 agrees with the new R7 for identification and notification.	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC)	
Answer	Yes
Document Name	
Comment	
The ISO/RTO Council (IRC) Standards Review Committee (SRC) (consisting, for purposes of these comments, of CAISO, ERCOT, IESO, ISO-NE, PJM, MISO, and SPP) agrees with the new requirement R7, but recommends that the term “automatic Load shedding” be replaced with “undervoltage Load shedding or underfrequency Load shedding” throughout EOP-011-4. The term “automatic Load shedding” encompasses more than just UVLS or UFLS Load shedding. Specifically, it may be interpreted to include other frameworks that may involve automatic load Shedding, such as Remedial Action Schemes (which are addressed by PRC-012-2), that are not necessarily used to assist with the mitigation of operating Emergencies and are therefore outside the scope of EOP-011-4.	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rebecca Zahler - Public Utility District No. 1 of Chelan County - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 1,3,5,6	
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	

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mia Wilson - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 1, 6, 5; Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Whaite - Stephen Whaite On Behalf of: Lindsey Mannion, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Tracy MacNicoll - Utility Services, Inc. - 4	
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	
Martin Sidor - NRG - NRG Energy, Inc. - 5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Matt Lewis - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
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	

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

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt

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	

Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2

Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	
Document Name	
Comment	
Does not apply to Reclamation.	
Likes 0	
Dislikes 0	
Response	

Mike Gabriel - Greybeard Compliance Services, LLC - 5	
Answer	

Document Name	
Comment	
We support the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE appreciates and supports the standard drafting team's (SDT) efforts in address the Joint Inquiry report for Winter Storm Uri. Texas RE recommends there be a requirement for the DP, DPUF, and TO to acknowledge receipt of the notification that they are required to assist with mitigation of operating Emergencies. Additionally, Texas RE is concerned with the 30-month implementation of a Load shed plan in Requirement R8. Texas RE requests the SDT's justification for a 30-month implementation of developing a load shed plan. Furthermore, Requirement R7 does not provide specific detail what is required assist with the mitigation of operating Emergencies so it is unclear why a 30-month implementation is necessary.	
Likes 0	
Dislikes 0	
Response	

2. Is the 30-month time frame in R8 adequate time for the physical changes that may be required to comply with these requirements?

Lenise Kimes - City and County of San Francisco - 1 - WECC	
Answer	No
Document Name	
Comment	
Thirty months is too long to make the plan. Possibly there could be a separate timetable applied. 6-12 months to establish and communicate the emergency plan to the TOP and the efforts needed to be able to implement it. This allows the TOP time comment and coordinate for any concerns ahead of time. Something like an additional 18 months if new equipment, etc. is needed to be able to implement/support the plan.	
Likes 0	
Dislikes 0	
Response	

Michael Whitney - Northern California Power Agency - 3	
Answer	No
Document Name	
Comment	
NCPA supports comments others' opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	

Marty Hostler - Northern California Power Agency - 4	
Answer	No
Document Name	
Comment	
NO, NCPA supports various other opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	

Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
1. NCPA supports others opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	No
Document Name	
Comment	
For EOP-011, Seminole proposes a 36-month implementation time frame. The coordination and agreements between multiple DPs and multiple DPs in multiple TOs' areas could possibly take a significant amount of time. For TOP-002, Seminole proposes an 18 month implementation time frame to remain consistent with other revisions.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren would like more clarification around the phrase "physical changes." Due to the long lead times in today's environment, it is hard to make a 30-month commitment if there are changes that require a longer time to implement.	
Likes 0	
Dislikes 0	
Response	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
Without fully knowing what expectations will result from our TOP (PJM), FirstEnergy cannot support this time frame	
Likes 0	
Dislikes 0	
Response	

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA believes 30 months is too short of a timeframe to address physical infrastructure changes. Without knowing the scope of how many “critical natural gas infrastructure loads” there are throughout the entire Pacific Northwest and how many UFLS relays would need to be relocated, designed and installed, BPA cannot commit to a 30 month implementation. BPA reiterates its comments from the previous comment period and recommends a longer, phased in approach, similar to PRC-005 (PSMP) or PRC-002 (Equipment Monitoring). This would include a timeframe to identify loads and an additional timeframe to design, schedule, and install any required elements.	
Likes 0	
Dislikes 0	
Response	

Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	No
Document Name	
Comment	
Reclamation does not agree. Addressing existing equipment upgrades as well as Implementation of new equipment are time and cost burden actions that can vary based on funding, equipment availability, manpower, industry limitations and other unforeseen items.	
Likes 0	
Dislikes 0	
Response	

Jeremy Lawson - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC)	
Answer	Yes
Document Name	
Comment	
As detailed in its response to question 6, below, the SRC believes that entities that already assist with Load shed should only need a 30-month timeframe for part 8.1.5 and should have a shorter timeframe for the remaining parts of R8. Additionally, the SRC believes that the implementation plan adequately addresses the implementation timeframe for R8 for both new and existing entities, and that including the 30-month timeframe in R8 is therefore redundant. Consequently, the SRC recommends that references to the 30-month timeframe be removed from R8 in the interests of clarity and efficiency.	
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 believes that 30 months is adequate for those DPs, UFLS-Only DPs, and TOs that are identified in R7.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
The proposed R7 would require TOPs to "annually identify and notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through operator-controlled manual Load shedding or automatic Load shedding". The Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are the recipients of such TOP notifications would then have 30-months to "develop, maintain, and implement a Load shedding plan" that must have the capability of being "operator-controlled" (as reflected in R8, Part 8.1). We interpret the term "operator-controlled" to mean controllable by a NERC defined System Operator (in this case, the TOP). If the TOP has an annual obligation to "identify and notify", but the recipient(s) of such notifications have 30-months to develop and implement an associated Load shedding plan (the "maintain" part would not kick in until after the initial Load-shedding plan is developed and implemented), a TOP could conceivably issue three annual notifications under R7 before a recipient completes its initial performance of R8. The drafting team should consider whether the 30-month interval for an initial performance of R8 is sufficiently covered within the implementation plan and can be removed from the requirement language.	
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 supports the 30-month time frame for physical changes.	
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 30-month time frame for DPs, UFLS-Only DPs, and TOs to make changes in conformance with Requirement R7 notifications.	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
AZPS supports the 30-month time frame in R8 for physical changes that may be required to comply.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
PNM and TNMP supports the proposed 30-month time frame for DPs, UFLS-Only DPs, and TOs to make changes in conformance with Requirement R7 notifications.	
Likes 0	
Dislikes 0	

Response	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	Yes
Document Name	
Comment	
It is not clear what the intent of requirement 2.2.8 is and whether this requires exclusion of natural gas infrastructure loads only during extreme cold weather periods? If this is a requirement, a 30 month implementation of such a system requirement may be more technically challenging and take a longer period of time to implement.	
Likes 0	
Dislikes 0	

Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
While a 30 month time frame seems reasonable, AEP requests that it be revised to instead state 30 *calendar* months.	
Likes 0	
Dislikes 0	

Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
WEC Energy Group supports the proposed 30-month time frame for DPs, UFLS-Only DPs, and TOs to make changes in conformance with Requirement R7 notifications.	
Likes 0	
Dislikes 0	

Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
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	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
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 Collaborators	

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	
Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
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	
Matt Lewis - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tracy MacNicoll - Utility Services, Inc. - 4	
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	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 1, 6, 5; Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mia Wilson - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO

Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rebecca Zahler - Public Utility District No. 1 of Chelan County - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
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	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 2	OGE Energy - Oklahoma Gas and Electric Co., 3, Hargrove Donald; OGE Energy - Oklahoma Gas and Electric Co., 1, Pyle Terri
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1,6	

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	

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	
Comment	
Texas RE agrees that 30 months is adequate for physical changes that may be required to comply with Requirement R7. Texas RE is concerned, however, with the 30-month time frame for non-physical changes. The concern is that the TOP would not be able to mitigate an Operating Emergency seen in the next year if it has to wait 30 months for the DP, DP UFLS, or TO's Load shed plan if there are no physical changes needed and there is simply an update to the plan itself. Texas RE recommends that if there are no physical changes needed, the timeline should be shorter.	
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 does not take a position on this issue.	
Likes 0	
Dislikes 0	
Response	
Mike Gabriel - Greybeard Compliance Services, LLC - 5	
Answer	
Document Name	
Comment	
We support the NAGF comments.	
Likes 0	
Dislikes 0	
Response	

3. The SDT has elected to add clarifying language in the applicable requirements in lieu of making "critical natural gas infrastructure load" a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities and their relative impact on the BES. Do you agree with this approach?	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
MRO NSRF appreciates the SDT's effort to strike a balanced approach concerning the term "critical natural gas infrastructure load." However, MRO NSRF maintains that if the standard incorporates this term, it must be well-defined to facilitate the effective identification and prioritization by Transmission Operators. Although the specific operational equipment qualifying as "critical natural gas infrastructure load" may vary across or even within regions, the fundamental characteristics of what constitutes a "critical natural gas infrastructure load" and the reliability risks that they may pose to the Bulk Electric System (BES) remain constant. Additionally, MRO NSRF is concerned about the practicality of implementing a requirement that explicitly relies on the coordination with natural gas facility owners and operators for successful implementation. The Technical Rational notes that achieving this coordination relies on the voluntary cooperation of these natural gas entities. At the same time, it acknowledges that the SDT (nor NERC) has the authority to enforce such cooperation. MRO NSRF finds it problematic to mandate, through an enforceable reliability standard, an action that entities cannot guarantee the completion of due to factors beyond their control.	
Likes 3	OGE Energy - Oklahoma Gas and Electric Co., 3, Hargrove Donald; OGE Energy - Oklahoma Gas and Electric Co., 1, Pyle Terri; JEA, 1, McClung Joseph
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
Although there may be varying definitions that exist across the NERC footprint for "critical natural gas infrastructure load," NERC should nonetheless pursue a standardized definition to provide a minimum threshold as to what "critical natural gas infrastructure load" is. (Note: This would also allow for more restrictive regional or local definitions where desired.)	
Likes 0	
Dislikes 0	
Response	

Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	No
Document Name	
Comment	
By specifically identifying natural gas infrastructure loads, other critical industries are excluded. Reclamation recommends removing requirement R8.1.5.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA believes the obligation of Responsible Entities to comply with EOP-011's requirements should not depend on the extent to which natural gas providers are willing to voluntarily work with Responsible Entities to identify critical natural gas infrastructure loads. The SDT noted it does not have the scope to develop methods to compel natural gas facility owners and operators to cooperate and provide specific information; the same is true of the Responsible Entities. With Transmission Entities having no legal or regulatory means to "require" natural gas facility owners to self- identify critical natural loads, BPA believes this sets industry up for failure when attempting to meet these revised requirements. This might need to go to a FERC level to require natural gas facility owners to self-identify critical natural loads to Transmission Entities. BPA cannot assure its compliance if it's based upon voluntary actions that natural gas companies might not be willing to complete. BPA understands that the information needed would be highly confidential, and represents a very high national security risk. Critical natural gas facility information will likely be closely guarded and not readily shared.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

AEP is unsure exactly what “clarifying language” is that Question 3 is referencing. If it is in regards to the addition of “critical loads which are essential to the reliability of the BES”, AEP disagrees with their proposed inclusion. Please see our response to Question 7 where our concerns are expressed in more detail.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FirstEnergy believes this still does not address our concern toward clarity of what will be deemed critical and who will determine that designation.	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	
Tacoma Power appreciates the efforts of the SDT to balance the approach to identifying critical natural gas infrastructure and not limiting entities in their identification methods. However, if the Standard incorporates this term, it must be well-defined to facilitate the effective identification and prioritization by Transmission Operators. Tacoma Power concurs that specific operational equipment qualifying as "critical natural gas infrastructure load" may vary across or even within regions. This variation is why it’s important that the fundamental characteristics of what constitutes a “critical natural gas infrastructure load” and the reliability risks that they may pose to the Bulk Electric System (BES) remain constant. Tacoma Power is concerned without these characteristics defined, each entity or auditor will have a different definition of what is considered “critical.”	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	

Answer	No
Document Name	
Comment	

Ameren understands the flexibility to identify critical natural gas loads, but would like guidelines as to what is considered critical. Ameren would also like a definition of extreme cold weather in the standard or in the glossary of terms.

Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	

1. NCPA supports others opposing comments that have been submitted.

Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	

Tri-State supports the MRO NSRF comments for this question:

"MRO NSRF appreciates the SDT's effort to strike a balanced approach concerning the term "critical natural gas infrastructure load." However, MRO NSRF maintains that if the standard incorporates this term, it must be well-defined to facilitate the effective identification and prioritization by Transmission Operators. Although the specific operational equipment qualifying as "critical natural gas infrastructure load" may vary across or even within regions, the fundamental characteristics of what constitutes a “critical natural gas infrastructure load” and the reliability risks that they may pose to the Bulk Electric System (BES) remain constant.”

“Additionally, MRO NSRF is concerned about the practicality of implementing a requirement that explicitly relies on the coordination with natural gas facility owners and operators for successful implementation. The Technical Rational notes that achieving this coordination relies on the voluntary cooperation of these natural gas entities. At the same time, it acknowledges that the SDT (nor NERC) has the authority to enforce such cooperation. MRO NSRF finds it problematic to mandate, through an enforceable reliability standard, an action that entities cannot guarantee the completion of due to factors beyond their control.”

Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 4	
Answer	No
Document Name	
Comment	
NO, NCPA supports various other opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	
Michael Whitney - Northern California Power Agency - 3	
Answer	No
Document Name	
Comment	
NCPA supports comments others' opposing comments that have been submitted.	
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 is of the opinion that the SDT should add additional clarifying language to ensure that the Applicable Entity makes the final determination of these loads prior to a final ballot.	
Likes 0	
Dislikes 0	

Response	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeremy Lawson - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes

Document Name	
Comment	
WEC Energy Group supports the SDT's approach and agrees that the added language is superior to defining "critical natural gas infrastructure load". WEC Energy Group also agrees that the SDT should not try to define this term since the equipment subject to being considered critical could change over time. In addition, allowing the BA, TOP and DP to work with the customer is more likely to provide better end results than a definition created by this SDT.	
Likes 0	
Dislikes 0	
Response	
Rebecca Zahler - Public Utility District No. 1 of Chelan County - 5	
Answer	Yes
Document Name	
Comment	
This was clarified for 1.2.5.5., but was not clarified in 1.2.5.2. It is recommended similar clarification also be applied to 1.2.5.2 regarding the critical natural gas infrastructure.	
Likes 0	
Dislikes 0	
Response	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	Yes
Document Name	
Comment	
No omments	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes

Document Name	
Comment	
PNM and TNMP agrees the including language in the standard to support the term “critical natural gas infrastructure load” vice creating a new definition; however, we support EEI’s comment regarding the addition of “as defined by the responsible entity” to the standard.	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
AZPS agrees with the clarifying language.	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
The NAGF agrees that the SDT should not try to define this term since the equipment subject to being considered critical could change over time. In addition, allowing the BA, TOP and DP to work with the customer is more likely to provide better end results than a definition created by this SDT.	
Likes 1	OGE Energy - Oklahoma Gas and Electric Co., 1, Pyle Terri
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 5,6	
Answer	Yes
Document Name	

Comment	
We agree as long as this approach is remembered down the road.	
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 and agrees that the added language is superior to defining "critical natural gas infrastructure load", however, to ensure further clarity and to align with the technical rational, we ask the SDT to consider the following edits to those instances where this phrase is used (see our proposed edits in bold face below). critical natural gas infrastructure loads which are essential to the reliability of the BES **as defined by the responsible TO/DP**	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
The drafting team should consider whether all the entities subject to the proposed R8 will have the information needed to identify and prioritize "designated critical natural gas infrastructure loads which are essential to the reliability of the BES" (R8, Part 8.1.5). The proposed standard essentially assigns this task to five different entities (TOP in R1, Part 1.2.5.5; BA in R2, Part 2.2.8; and DP/UFLS-Only DP/TO in R8, Part 8.1.5) with no indication of coordination or shared understanding.	
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 agrees that the added language is superior to defining "critical natural gas infrastructure load".

Likes 0	
Dislikes 0	
Response	

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC

Answer	Yes
Document Name	
Comment	

SMUD and BANC support the comments submitted by the EEI.

Likes 0	
Dislikes 0	
Response	

Julie Hall - Entergy - 6, Group Name Entergy

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ben Hammer - Western Area Power Administration - 1,6

Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 1,3,5,6	
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	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Mia Wilson - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 1, 6, 5; Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Stephen Whaite - Stephen Whaite On Behalf of: Lindsey Mannion, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tracy MacNicoll - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Matt Lewis - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
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	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
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	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
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	
Likes 0	
Dislikes 0	
Response	

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lenise Kimes - City and County of San Francisco - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC)	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Gabriel - Greybeard Compliance Services, LLC - 5	
Answer	
Document Name	
Comment	

We support the NAGF comments.

Likes 0	
Dislikes 0	

Response

TOP-002-5 (Question 4)

4. The SDT modified the proposed Requirement R8 to remove the link between the required Operating Process and the Operating Plan required under Requirement R4. Do you agree with this modification?

Michael Whitney - Northern California Power Agency - 3	
Answer	No
Document Name	
Comment	
NCPA supports comments others' opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	

Marty Hostler - Northern California Power Agency - 4	
Answer	No
Document Name	
Comment	
NO, NCPA supports various other opposing comments that have been submitted.	
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	
8.2 is awkward, and it is not clear if the load shedding plan should be submitted to the TOP for review and approval; or, if there must be provisions in the plan to submit the plan to the TOP for review. This will be a problem during enforcement, where an entity may submit their plan for approval by the TOP, for review, but fails to have a process for submitting the plan, in the plan.	

Implementation of the plan would reasonably be expected when there is a system emergency that requires load shedding; however, R8 could be read as 30 days to implement when notified by the TOP. This may sound like a petty issue; however, these issues always crop up and the wording should be improved. Regarding M8, and evidence suggested for developing, maintaining and implementing a Load Plan: There is nothing required to show the plan was approved by the TOP; or, if the TOP did not approve, the process requiring the resolution of the issues and subsequent resubmission and approval.	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
1. NCPA supports others opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
TOP-002 provides requirements for the Operational Planning Analysis, which is performed on a daily basis. The detailed requirements for the Extreme Cold Weather plan enumerated in R8 will be performed only when specific criteria are met. BPA believes the details of the cold weather plan belongs in another standard, probably EOP-011.	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	

Comment	
Part 8.3: MISO remains concerned that the term "forecast" is typically used to denote weather forecasts only and would not typically encompass the items under Part 8.3 which is more akin to an Operating Plan described under requirement R4. We agree the Operating Plan should be adequate to meet the timeframe for the identified extreme cold weather period; however, requiring a **five-day forecast** for every "identified extreme cold weather period" may not be necessary. To provide flexibility, MISO suggests the language provided below: **8.3** A methodology to determine an adequate Operating Plan during the identified (or forecasted) extreme cold weather periods… As detailed in prior SRC comments submitted regarding draft 1 of TOP-002-5, MISO continues to be concerned that the approach taken in TOP-002-5 is not the most cost-effective approach due to the lack of corresponding requirements on the GO/GOP to provide the BA with information needed by the BA to fulfill its obligations. Historically, when this has happened, the BA has incurred additional costs and delays in obtaining the information needed as the BA must develop and employ alternative processes (e.g., modifications to FERC tariffs, revisions to membership agreements, engagement in regional rulemaking processes, modifications to its TOP-003 specifications, etc.). Ultimately, the GO/GOP must provide the data; however, it is much more labor intensive than if the obligation to provide data is in the Reliability Standard.	
Likes 0	
Dislikes 0	
Response	
Jeremy Lawson - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company supports the EEI comments and agrees with the modifications to R8 that distinguish the BA's extreme cold weather Operating Process from the BA's Operating Plan.	
Likes 0	
Dislikes 0	
Response	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
We believe R8, Part 8.1 should be modified to read "A methodology for identifying an extreme cold weather period within **their** Balancing Authority Area;".	
Likes 0	
Dislikes 0	
Response	

Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
No Additional Comments	
Likes 0	
Dislikes 0	
Response	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	Yes
Document Name	
Comment	
EEI agrees with the modification to Requirement R8 that distinguish the BA's extreme cold weather Operating Process from the BA's Operating Plan.	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
The NAGF believes that the BA can decide how it can best implement this requirement, whether by using it as part of their Operating Plan or having a separate process to address cold weather efforts.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	

Comment	
AZPS agrees with the modification to R8.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
PNM and TNMP both agree with the modification to Requirement R8 that distinguish the BA's extreme cold weather Operating Process from the BA's Operating Plan.	
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 and Electric Company supports the removal of the link between R4 and R8 with the understanding that R4 and R8 will be the responsibility of the Balancing Authority.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	

Language has made this clear.

Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
WEC Energy Group agrees with the modification to Requirement R8 that distinguish the BA's extreme cold weather Operating Process from the BA's Operating Plan. WEC Energy Group also believes that the BA can decide how it can best implement this requirement, whether by using it as part of their Operating Plan or having a separate process to address cold weather efforts.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC)	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lenise Kimes - City and County of San Francisco - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
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 Collaborators	
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	

Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
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	
Matt Lewis - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tracy MacNicoll - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Stephen Whaite - Stephen Whaite On Behalf of: Lindsey Mannion, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
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	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 1, 6, 5; Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mia Wilson - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 1,3,5,6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Rebecca Zahler - Public Utility District No. 1 of Chelan County - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
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	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 2	OGE Energy - Oklahoma Gas and Electric Co., 3, Hargrove Donald; OGE Energy - Oklahoma Gas and Electric Co., 1, Pyle Terri
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1,6	
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	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
NA	
Likes 0	
Dislikes 0	
Response	
Mike Gabriel - Greybeard Compliance Services, LLC - 5	
Answer	
Document Name	
Comment	
We support the NAGF comments.	
Likes 0	

Dislikes 0	
Response	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	
Document Name	
Comment	
Does not apply to Reclamation	
Likes 0	
Dislikes 0	
Response	

General (Questions 5-7)

5. The SDT proposes that the modifications in EOP-011-4 and TOP-002-5 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.

Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
As detailed in prior SRC comments regarding draft 1 of TOP-002-5, MISO continues to be concerned that the approach taken in TOP-002-5 is not the most cost-effective approach due to the lack of corresponding requirements on the GO/GOP to provide the BA with information needed by the BA to fulfill its obligations. Historically, when this has happened, the BA has incurred additional costs to obtain the information needed. This increases the overall cost of compliance as the BA must develop and employ alternative processes to obtain the data needed (e.g., modifications to FERC tariffs, revisions to membership agreements, engagement in regional rulemaking processes, etc.). Ultimately, the GO/GOP ends up incurring the cost to provide the data to the BA; however, costs to the BA accrue because of delays and the need for quality assurance associated with lower quality data than if the obligation to provide data had been enshrined in a Reliability Standard or other regulatory rule.	
Likes 0	
Dislikes 0	
Response	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
Related to our Q1 response, without a scope of expectations, we cannot determine the cost effectiveness of these recommendations.	
Likes 0	
Dislikes 0	
Response	

Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	

1. NCPA supports others opposing comments that have been submitted.

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 authority for the TOP and BA to direct, or give Operating Instructions, is already well established in TOP-001 R1 through R5, and it seems this standard is fundamentally not needed. It further exposes TOs and DPs to unnecessary administrative and compliance burden to have load shedding plans that must be created and maintained. During audits, non-compliance penalties are assessed for small omissions, and potential violations based on the auditors' subjective authority to determine the quality of the documentation. When entities must comply to directives and Operating Instructions, maintaining written plans that, may or not be suitable for the situation, adds a significant level of cost without benefit. This is especially true of smaller entities who have limited load or resources.

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 4

Answer	No
Document Name	

Comment

NO, The SDT has not provided any cost estimate to support their proposal and has not provided a cost/benefit justification. It appears this entire proposal/endeavor will not improve reliability and simply just keeps more people busy doing more paperwork. Consequently, we feel it is not cost effective, not productive, and not prudent use of customer dollars.

Likes 0	
Dislikes 0	

Response

Michael Whitney - Northern California Power Agency - 3

Answer	No
Document Name	

Comment	
NCPA supports comments others' opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeremy Lawson - Northern California Power Agency - 5	
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	
WEC Energy Group agrees.	
Likes 0	

Dislikes 0	
Response	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	Yes
Document Name	
Comment	
It is not clear what the intent of requirement 2.2.8 is and whether this requires exclusion of natural gas infrastructure loads only during extreme cold weather periods? If this is a requirement, the implementation may not be cost-effective as intended.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
PNM and TNMP agree that the key recommendations and be implemented in a cost-effective manner.	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
AZPS agrees	
Likes 0	
Dislikes 0	
Response	

Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	

Answer	Yes
Document Name	
Comment	

Black Hills Corporation will not comment on cost effectiveness.

Likes 0	
Dislikes 0	
Response	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

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 does not think this answer will be known until everything is fully implemented.

Likes 0	
Dislikes 0	
Response	

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

Answer	Yes
Document Name	

Comment	
What is the definition of "cost-effective"? Who is responsible for determining if it is cost-effective? Is it a coordinated effort between the DP, TO and TOP?	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 1	OGE Energy - Oklahoma Gas and Electric Co., 3, Hargrove Donald
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rebecca Zahler - Public Utility District No. 1 of Chelan County - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mia Wilson - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 1, 6, 5; Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tracy MacNicoll - Utility Services, Inc. - 4	

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	
Matt Lewis - Lower Colorado River Authority - 1	
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 Collaborators	
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	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC)	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

Duke Energy's focus is to assure the effective and efficient reduction of risks to the reliability and security of the grid and will not provide comments on the cost effectiveness of the proposed changes.

Likes 0	
Dislikes 0	

Response

Wendy Kalidass - U.S. Bureau of Reclamation - 5

Answer	
Document Name	

Comment

Does not apply to Reclamation

Likes 0	
Dislikes 0	

Response

Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	
Document Name	

Comment

CEHE abstains.

Likes 0	
Dislikes 0	

Response

Mike Gabriel - Greybeard Compliance Services, LLC - 5	
Answer	
Document Name	
Comment	
We support the NAGF comments.	
Likes 0	
Dislikes 0	
Response	

David Jendras Sr - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
Ameren has no comment on the cost effectiveness of the project.	
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	
It seems that no matter how this Standard is written there will be some associated costs with implementation. ISO-NE does not have a recommendation for how to avoid those cost issues.	
Likes 0	
Dislikes 0	
Response	

6. Do you agree with the implementation plan proposed by the SDT? 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.

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC)	
Answer	No
Document Name	
Comment	
While requirement R8 is a newly written requirement that is specific to Distribution Providers, UFLS-only Distribution Providers, and Transmission Owners, some DPs, UFLS-only DPs, and TOs already assist with Load shedding. The SRC believes that the implementation plan should be revised to require that these entities that already assist with Load shedding be in compliance with all parts of requirement R8 except part 8.1.5 by the effective date of EOP-011-4. All entities required to comply with R8 should receive the full 30 months to comply with part 8.1.5, which contains the newly added provisions for the identification and prioritization of designated critical natural gas infrastructure loads that are essential to the reliability of the BES. Additionally, ERCOT makes the following comment individually; the SRC does not join this paragraph: ERCOT recommends a 24-month implementation timeframe for both standards to account for the coordination, budget revisions, staffing changes, and systems upgrades necessary to accomplish the new tasks. New forecasts and tools often require multiple projects to acquire the necessary input data and to process and display that data to users. This often requires extensive testing as well.	
Likes 0	
Dislikes 0	
Response	
Lenise Kimes - City and County of San Francisco - 1 - WECC	
Answer	No
Document Name	
Comment	
See #2 above. Agree with other implementation time frames.	
Likes 0	
Dislikes 0	
Response	
Jeremy Lawson - Northern California Power Agency - 5	
Answer	No
Document Name	

Comment

The SDT has not provided any cost estimate to support their proposal and has not proved a cost/benefit justification. It appears this entire proposal/endeavor will not improve reliability and simply just keep more people busy doing more paperwork. Consequently, we feel it is not cost effective, not productive, and not prudent us of customer dollars.

Likes 0	
Dislikes 0	

Response

Michael Whitney - Northern California Power Agency - 3

Answer	No
Document Name	

Comment

The SDT has not provided any cost estimate to support their proposal and has not proved a cost/benefit justification. It appears this entire proposal/endeavor will not improve reliability and simply just keep more people busy doing more paperwork. Consequently, we feel it is not cost effective, not productive, and not prudent us of customer dollars.

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 4

Answer	No
Document Name	

Comment

NO, NCPA supports various other opposing comments that have been submitted.

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	
No, we believe the rules of procedure may need to be changed around the TO and DP functions before the full implementation can be made.	
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: We have concerns with the phased implementation plan timelines for Requirements R1 Part 1.2.5 and Requirement R2 Part 2.2.8 and Part 2.2.9 being identical. The proposed text of Part 2.2.9 specifically states "in accordance with Requirement R1 Part 1.2.5"; therefore, as Part 2.2.9 is dependent upon R1 Part 1.2.5, we recommend modifying the implementation plan to account for this dependency.	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	No
Document Name	
Comment	
We have concerns with the phased implementation plan timelines for Requirements R1 Part 1.2.5 and Requirement R2 Part 2.2.8 and Part 2.2.9 being identical. The proposed text of Part 2.2.9 specifically states "in accordance with Requirement R1 Part 1.2.5"; therefore, as Part 2.2.9 is dependent upon R1 Part 1.2.5, we recommend modifying the implementation plan to account for this dependency.	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	

Answer	No
Document Name	
Comment	

The SDT has not provided any cost estimate to support their proposal and has not proved a cost/benefit justification. It appears this entire proposal/endeavor will not improve reliability and simply just keep more people busy doing more paperwork. Consequently, we feel it is not cost effective, not productive, and not a prudent use of customer dollars.

Likes 0	
Dislikes 0	
Response	

David Jendras Sr - Ameren - Ameren Services - 3

Answer	No
Document Name	
Comment	

None

Likes 0	
Dislikes 0	
Response	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	No
Document Name	
Comment	

See our response to Q1 and Q2.

Likes 0	
Dislikes 0	
Response	

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No

Document Name	
Comment	
As noted in question 2 above, for EOP-011-4, BPA recommends a longer, phased in approach, similar to PRC-005 (PSMP) or PRC-002 (Equipment Monitoring). This would include a timeframe to identify loads and an additional timeframe to design, schedule, and install any required elements.	
Likes 0	
Dislikes 0	
Response	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	No
Document Name	
Comment	
Reclamation recommends 36 months for existing and 60 months for implementation.	
Likes 0	
Dislikes 0	
Response	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	

Southern Company supports the EEI comments and the implementation timeframes proposed by the SDT.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
As noted in our response to Q1 we believe the drafting team should consider providing TOPs the flexibility to work with entities that are subject to R8 and allow an extension of the 30-month initial implementation period when justifiable conditions warrant.	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
No Additional Comments	
Likes 0	
Dislikes 0	
Response	
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	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
While the NAGF believes that a shorter implementation period would be better for TOP-002 R8, the NAGF supports the proposed implementation plan in order to get the changes made. Once the standard is approved, it would be very beneficial to see Balancing Authorities begin to implement this requirement as soon as possible to reduce the likelihood of another event impacting grid reliability similar to Winter Storms Uri and Elliott due to load forecast errors and unplanned generator outages/unavailability.	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
AZPS agrees with the proposed implementation plan.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
PNM and TNMP support the proposed implementation plan.	

Likes 0	
Dislikes 0	

Response

Alain Mukama - Hydro One Networks, Inc. - 1,3

Answer	Yes
Document Name	

Comment

It is not clear what the intent of requirement 2.2.8 is and whether this requires exclusion of natural gas infrastructure loads only during extreme cold weather periods? If this is a requirement, a 30 month implementation of such a system requirement may be more technically challenging and take a longer period of time to implement.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	Yes
Document Name	

Comment

Unlike other revised obligations, R7 is not specifically mentioned in the proposed implementation plan, inferring that it would become effective “six (6) months after the effective date.” AEP requests clarity from the SDT if our understanding is correct or not.

Likes 0	
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group

Answer	Yes
Document Name	

Comment

WEC Energy Group supports the proposed implementation plan.

Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
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	
Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
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	
Matt Lewis - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tracy MacNicoll - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Whaite - Stephen Whaite On Behalf of: Lindsey Mannion, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
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	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 1, 6, 5; Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Mia Wilson - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 1,3,5,6	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rebecca Zahler - Public Utility District No. 1 of Chelan County - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
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	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	

Comment	
Likes 1	OGE Energy - Oklahoma Gas and Electric Co., 3, Hargrove Donald
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1,6	
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	

Mike Gabriel - Greybeard Compliance Services, LLC - 5

Answer	
Document Name	
Comment	
We support the NAGF comments.	
Likes 0	
Dislikes 0	
Response	

7. Provide any additional comments for the SDT to consider, including the provided technical rationale document, if desired.

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	
Document Name	
Comment	
WEC Energy Group has no additional comments.	
Likes 0	
Dislikes 0	
Response	

Mike Magruder - Avista - Avista Corporation - 1	
Answer	
Document Name	
Comment	
We support EEI's submitted comments.	
Likes 0	
Dislikes 0	
Response	

Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
Answer	
Document Name	
Comment	
The term "automatic load shedding" appears in requirements 1.2.5, 1.2.5.2, 2.2.9, 8.1, and 8.1.2. This term is more narrowly scoped as pertaining to UFLS and UVLS in requirements 1.2.5.3, 1.2.5.4, 8.1.3, and 8.1.4. The term "automatic load shedding" should be replaced with "UFLS or UVLS" in each location that it appears in EOP-011-4 to provide additional clarity and consistency.	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	
Document Name	
Comment	
EOP-011-4 R1.2.5.5 should be removed and the requirement "Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES" be a DP only responsibility (R8.1.5.). The DP's are responsible to make these provisions in their load shedding plan which they are required to submit to the TOP. The TOP should have no responsibility to make provisions to identify and prioritize these loads itself as they do not have this information.	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	
Document Name	
Comment	
Part 8.2: As the definition for "reserve margin" varies dramatically across regions, MISO recommends using the term "reserves" instead as detailed below: **8.2** A methodology to determine adequate reserves during the extreme cold weather period…"	
Likes 0	

Dislikes 0	
Response	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	
Document Name	
Comment	
Reclamation observes that the nature of the cold weather modifications to reliability standards is not cost or time effective and is disruptive to the industry. The first round of cold weather modifications are not effective yet and already modifications for the third round are in progress. Reclamation recommends that an effort be made to offer a first-time quality product instead of multiple revisions on documents that are not even in effect.	
Likes 0	
Dislikes 0	
Response	
Michael Jones - National Grid USA - 1	
Answer	
Document Name	
Comment	
RE: EOP-011-4 Section C. Compliance, Section 1.2 Evidence Retention: Please consider if R8 should reference "Load shedding plan" instead of "Operating Plan(s)" for consistency with requirement R8. Also, please considering referencing R8 instead of "Requirements R8 and." RE: TOP-002-5 and EOP-011-4 Section C. Compliance: Please consider if there should be consistent use of the abbreviation "(CEA)" noting the difference in Section C. Compliance of TOP-002-5 vs. EOP-011-4.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	

AEP is concerned by R1.2.5.2's "circuits that serve designated critical loads which are essential to the reliability of the BES" as well as R8.1.2's "Load shed and circuits that serve designated critical loads which are essential to the reliability of the BES." The Transmission Operator lacks the insight-of, and visibility-into, fuel supply chain (regardless of fuel type) when the supply infrastructure is connected to traditional distribution voltage class. Transmission Operators have tools to determine if an electrical facility outage creates critical problems in their portion of the BES and can further study potential solutions which may include load shedding. It would not seem reasonable that a gas supplier would be capable of performing such an analysis on the electric system since they do not have the tools or the intimate knowledge of the electric grid topology. Likewise, Transmission Operators do not have intimate knowledge of the gas infrastructure or tools to study the impact of a loss of an electric feed to a gas facility. In addition, driven by market or cyber security concerns, there may be a reluctance to share information. It is important to note that Transmission Owners serve multiple distribution providers with connections or service to fuel supply infrastructure, making the needed insight even more lacking. While well intentioned, we believe adding "essential to the reliability of the BES" is a step back in clarity, and it is not clear exactly how such a determination could be made given the limited visibility. AEP requests that the SDT provide insight into exactly what is meant by this phrase as well as how such determinations should be made. In addition, R8's sub bullets which include "which are essential to the reliability of the BES" would require the Distribution Provider to make a determination that we do not believe they would have the insight to make. While AEP has chosen to vote Negative, AEP would be in a better position to vote Affirmative in future ballot periods if the SDT either a) removed the references "essential to the reliability of the BES" entirely, or b) revise the phrase to state "which may have a negative impact on the reliability of the BES as defined by the Distribution Provider, UFLS-Only Distribution Provider, or notified Transmission Owner *in working with the Reliability Coordinator or other applicable regulatory authorities.*"

"30 months" is referenced within the proposed revisions, however AEP requests that it be revised to instead state 30 *calendar* months.

Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	
Document Name	

Comment

None.

Likes 0	
Dislikes 0	

Response

Diana Torres - Imperial Irrigation District - 1,3,5,6

Answer	
Document Name	

Comment

None

Likes 0	
Dislikes 0	
Response	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	
Document Name	
Comment	
In general, the EOP-011 stated purpose is to address the effects of operating Emergencies (why is Emergencies capitalized, it is not in the NERC Glossary, should this be an operating Emergency or an operating BES Emergency?) but 1.2.6 specifically focusses on Cold weather and Extreme weather, neither of which is included in the NERC Glossary of Terms, only Extreme Cold Weather is in 2.2.8 (not capitalized). Is this different than 1.2.6.1 and 1.2.6.2? Is Extreme Cold Weather a subset of Extreme weather conditions? There are other situations where an energy emergency, possibly not due to cold weather and extreme weather conditions could result in similar effects. Should 1.2.6 refer to an Energy Emergency with references to those possibly caused by extreme weather conditions such as Extreme Cold Weather (outside of expected design temperatures) or extreme heat (Extreme Heat) causing increased load etc.? A BES Emergency causing loss of load, which also could impact natural gas infrastructure could have a similar effect to the reliability of the BES. Under 2.2.8, does this mean that this is only applicable to extreme cold weather (not capitalized) periods, which is not identified under 1.2.6.1, and is this meant to be armed only during extreme cold weather conditions? Would this apply to any energy emergency including extreme heat where critical natural gas loads are essential to the reliability of the BES? The reference to extreme cold should be removed from 2.2.8. For 2.2.10, similar comments to 1.2.6	
Likes 0	
Dislikes 0	
Response	
Mike Gabriel - Greybeard Compliance Services, LLC - 5	
Answer	
Document Name	
Comment	
We support the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	

Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	
Document Name	
Comment	
AZPS has no additional comments at this time.	
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	

Tacoma Power continues to have concerns about EOP-011-4 R1 and R2, as described below.

Reliance on non-NERC Registered Entities

The Reliability Guideline cited in the Technical Rationale proposes that electric transmission and distribution owners reach out to regulatory entities, natural gas companies and organizations, and secondary fuel suppliers. Reaching out to this many organizations and agencies, as well as receiving their responses, may be unattainable in the proposed implementation timeline and will be difficult to maintain the coordination. These organizations are not subject to NERC Standards and as a result, may not respond or prioritize coordination with TOPs. Tacoma Power recommends utilizing a note similar to CIP-013 R2 to address this concern. This note should specify compliance with R1.2.5.5 does not include the natural gas companies' or fuel suppliers' performance and adherence to the TOP requests. Example language to add after EOP-011-4 R1 or to the Measure M1: "Note: The following issues are beyond the scope of Requirement R1: 1) the natural gas companies' or secondary fuel suppliers' performance and adherence to TOP request(s) for information on critical natural gas infrastructure, and 2) accuracy of the information provided by these entities."

Avoiding Overlap Between UFLS and Manual Load Shedding

Rather than avoiding an overlap between UFLS and manual load shedding, the Standard should allow for a pro-rata share of UFLS armed load to be shed during other kinds of load shedding. The recent NERC Lesson Learned Report LL20220301 includes a detailed explanation of the problems that can occur when overlap is minimized.

With the current proposal, there are two main problems with requirement R1.2.5.3 and R8.1.2 to minimize overlap between UFLS and other load shedding:

1. When a significant amount of manual load shedding occurs without shedding any UFLS armed load, the proportion of load armed for UFLS increases. Unfortunately, excessive portions of load armed for UFLS can result in system instability.
    - For example, if a utility has 40% of load armed for UFLS and then they shed 20% of the non-UFLS load, the remaining portion of load armed for UFLS jumps to 50%. If an underfrequency event were to occur with 50% of load armed, it is possible that too much load would be shed, resulting in over frequency tripping of generators.
2. The standard requires having provisions, but it does not require that the provisions are actually effective. This is an example of evaluating compliance paperwork rather than evaluating actual system performance.

One possible way to monitor the pro-rata arming of UFLS load is for utilities to monitor in real time that they have adequate UFLS load shedding armed. Although implementing real-time monitor could be a significant effort for some utilities, this would have benefits for verifying that adequate load is armed for UFLS throughout the whole year. On Tacoma Power's system, the total percent of armed UFLS load is extremely dependent on the time of day and season. Tacoma's portion of load armed for UFLS varies from a minimum of 24% in June to a maximum of 42% in February.

Allowing for pro-rata overlap between UFLS and manual loads significantly increases the customer equity during manual load shedding. Under the current standard we have roughly 40% of our customers exempt from rolling blackouts due to being armed for UFLS, plus another 10% designated as critical for other reasons. This forces the remaining customers to have twice as much outage duration as would otherwise be fair.

Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
None	
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 additional comments.	
Likes 0	
Dislikes 0	
Response	

Melanie Wong - Seminole Electric Cooperative, Inc. - 5

Answer	
Document Name	
Comment	

The coordination efforts between multiple DPs in multiple TOs' areas and the staffing needed to create plans and processes and then implement and manage these plans will be burdensome and costly to the TOPs, DPs and TOs.

For EOP-011, Seminole proposes a 36-month implementation time frame. The coordination and agreements between multiple DPs and multiple DPs in multiple TOs' areas could possibly take a significant amount of time. For TOP-002, Seminole proposes an 18 month implementation time frame to remain consistent with other revisions.

Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	
Comment	

Texas RE recommends there be a requirement for the TOP to approve the Load shedding plans in receives in EOP-011-4 Requirement R8.

Texas RE noticed the Evidence Retention section in TOP-002-5 does not include a retention timeframe specifically for Operating Plans. The section does specifically mention voice recordings, operating logs, and email records, but not Operating Plans. Texas RE recommends specifying a retention timeframe for Operating Plans.

Likes 0	
Dislikes 0	

Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	
Document Name	
Comment	
Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	
Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	
Document Name	
Comment	
NPCC RSC supports the drafting team proposal.	
Likes 0	
Dislikes 0	
Response	

Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	
Document Name	
Comment	

The TO does not supply load and is only responsible for ownership and maintenance of Transmission Facilities (see Appendix 5B - statement of Compliance Registry Criteria (Revision 7) of the NERC Rules of Procedure). Requiring the TO to have a load shedding plan is a flawed concept and assumes an operational function. The TOP, BA, LSE (now obsolete) and DP are the only entities that have control of load. A TO manages assets, and may be directed by the TOP (whose footprint it resides in) to open or deenergize assets under its control for the purpose of shedding load when the TOP does not have direct supervisory control over those assets. What if 1) The TO declares that they have no way to properly shed load under their registration; or, 2) The TOP identifies a TO is required to assist, yet the TO has no operational staff or facilities to assist?

The Drafting Team may feel this would work out in application, however, once a requirement like this is approved, there will be concern that the TOP may have expanded authority over a TO's organization structure and functional obligations. This will put the smaller organizations at risk.

Lastly, "Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area" is not identified as an entity needing NERC registration under the ROP (Appendix 5B). Is it the drafting team's intent to require these DP entities to be identified and registered under NERC's ROP? How will R8 be enforced against the DPs who are not registered?

We think by expanding the applicability to TO and DP entities the Drafting Team has overstepped its authority. We believe that the standard should stop at the TO, RC and BA levels. In doing so, it would still meet the intent of the BOD resolution. Should the Drafting Team still feel strongly that the expansion of Applicability is warranted, then the ROP may have to be modified to address the additional scope.

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	

No Additional Comments

Likes 0	
Dislikes 0	
Response	

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	
Document Name	

Comment	
OPG supports NPCC RSC's comments.	
Likes 0	
Dislikes 0	
Response	
Romel Aquino - Edison International - Southern California Edison Company - 3	
Answer	
Document Name	
Comment	
See Comments Submitted by the Edison Electrical Institute	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
NA	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 4	
Answer	
Document Name	
Comment	

NO, NCPA supports various other opposing comments that have been submitted.

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	
Document Name	

Comment

For the proposed EOP-011-4, we question the addition of “which are essential to the reliability of the BES” in association with “designated critical loads” (see R1, Part 1.2.5.2; R8, Part 8.1.2). As noted in the Technical Rationale for EOP-011-3, that drafting team associated critical loads with “certain critical loads which may be essential to the integrity of the electric system, public health, or the welfare of the community.” By adding the phrase “which are essential to the reliability of the BES” to these requirements in the proposed EOP-011-4, this drafting team seems to be eliminating loads deemed critical to public health and the welfare of the community. Was that the intent?

Likes 0	
Dislikes 0	

Response

Kristine Ward - Seminole Electric Cooperative, Inc. - 1

Answer	
Document Name	

Comment

The coordination efforts between multiple DPs in multiple TOs area and the staffing needed to create plans, process, implement and manage is burdensome and costly to the TOPs, DPs and TOs. For EOP-011, propose 36 months implementation. The coordination and agreements between multiple DPs and multiple DP’s in multiple TOs areas, could possibly take a significant amount of time. For TOP-002, propose 18 months to remain consistent with other revisions.

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	
No additional comments.	
Likes 0	
Dislikes 0	
Response	
Michael Whitney - Northern California Power Agency - 3	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Lenise Kimes - City and County of San Francisco - 1 - WECC	
Answer	
Document Name	HHWPScreenshot_Example of upload to RCWestPortal_OPA.pdf
Comment	
Regarding TOP-002-5 R3 – Can uploading to the RC West site and adding that entity to the affected parties count? (See uploaded screenshot.) This is upon positive knowledge that the affected entity has access to the site.	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC)	
Answer	

Document Name	
Comment	

As detailed in its response to question 1, above, the SRC recommends that the term "automatic Load shedding" be replaced with "undervoltage Load shedding or underfrequency Load shedding" throughout EOP-011-4. The term "automatic Load shedding" encompasses more than just UVLS or UFLS Load shedding. Specifically, it may be interpreted to include other frameworks that may involve automatic load Shedding, such as Remedial Action Schemes (which are addressed by PRC-012-2), that are not necessarily used to assist with the mitigation of operating Emergencies and are therefore outside the scope of EOP-011-4.

As further detailed in comments submitted in response to draft 1 of TOP-002-5, the SRC continues to believe that the most effective method of accomplishing the objectives of TOP-002-5 involves a requirement for GOs and GOPs to provide appropriate information to BAs. However, in light of the approach the SDT has chosen to pursue, the SRC recommends that requirement R8, part 8.3 of TOP-002-5 be revised to require a three-day forecast instead of the proposed five-day hourly forecast. A three-day forecast would be more accurate and useful for BAs and would reduce the amount of additional data that BAs would need to receive from GOs and GOPs when compared to the proposed five-day hourly forecast. Additionally, producing an hourly forecast, regardless of whether it covers three days or five, would be extremely burdensome without a commensurate reliability benefit, especially given the existing BA workload during extreme cold weather periods. The SRC therefore recommends removal of the requirement that the forecast be an hourly forecast. This would allow the BA the flexibility to determine and produce the type of three-day forecast that will be most beneficial to reliability without being unduly burdensome. The SRC also recommends that requirement R8, part 8.3.2 be removed from the standard, as the additional administrative burden of including interchange scheduling in the forecast methodology would not produce a sufficient associated reliability benefit.

The SRC reiterates its recommendation from its comments on draft 1 of EOP-011-4 that requirement R2, part 2.2.8 be revised to apply to **known** critical natural gas infrastructure loads. The SRC recognizes that it is not the drafting team's intent for Responsible Entities to be held responsible for unknown critical natural gas infrastructure loads, and the SRC believes that this revision would clarify that intent.

Likes 0	
Dislikes 0	
Response	

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC

Answer	
Document Name	
Comment	

SMUD and BANC support the comments submitted by Tacoma Power regarding "Avoiding Overlap Between UFLS and Manual Load Shedding".

Likes 0	
Dislikes 0	

Response

Robert Hirchak – Cleco Corporation

Comments:
EOP-011-4 R 7 is duplicative and in conflict with PRC-006-5 R3, R8, and R9. The automatic UFLS plan is designed by the Planning Coordinator and annually updated by the Planning Coordinator. The TOP is not responsible for notifying and coordinating the Automatic UFLS plan. The TO, DP, and UFLS Only-DP should be reporting and notifying their automatic UFLS plan to affected Neighboring entities including the TOP.

The TOP is responsible for the manual Load Shed plan.

For TOP-002-5 R3, the BA should have a methodology (process) for conducting the next day plan, just as R8 requires a methodology For the 5 day hourly cold weather plan.

Consideration of Comments

Project Name:	2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination - Phase 2 | Draft 2 - EOP-011-4 and TOP-002-5
Comment Period Start Date:	8/24/2023
Comment Period End Date:	9/12/2023
Associated Ballot(s):	2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 EOP-011-4 | Non-binding Poll AB 2 NB 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 EOP-011-4 AB 2 ST 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 Implementation Plan AB 2 OT 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 TOP-002-5 | Non-binding Poll AB 2 NB 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 TOP-002-5 AB 2 ST

There were 62 sets of responses, including comments from approximately 152 different people from approximately 106 companies representing 10 of the Industry Segments as shown in the table on the following pages.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, contact Vice President of Engineering and Standards, Soo Jin Kim (via email) or at (404) 446-9742.

In response to industry comments, the Standard Drafting Team (SDT) has made a few clarifying non-substantive changes to EOP-011 and TOP-002. The SDT provides the following summary of the changes, which are discussed in more detail in the Technical Rationale and in the response to comments below.

For EOP-011-4 the changes include:

- “as defined by the Applicable Entity” clarified in Parts 1.2.5.5, 2.2.8 and 8.1.5 – Based on multiple comments received, the team added this phrase to clarify who is responsible for determining critical natural gas infrastructure loads as an electric entity, not a gas entity.
- Clarifying automatic load shed as undervoltage and underfrequency load shed – Based on multiple comments received, the team has clarified that automatic load shed in this context is undervoltage Load shed and underfrequency Load shed and does not include other things such as Remedial Action Schemes or Special Protection Schemes.
- Additional language in effective date regarding being compliant with R8 within 30 calendar months – Based on comments received the detail of 30 months was moved from the requirement language and added to the effective date section of the standard. This will also allow entities to be able to refer to one document, the standard, as it becomes effective and not also have to have the Implementation Plan up for reference also.

TOP-002 changes include:

- Removal of Interchange Scheduling from Part 8.2 – Based on comments received, the team removed this requirement in R8 Part 8.3 because this function is typically done in real time on an hourly basis. The need for the Balancing Authority to proactively look ahead and forecast their ability to import power from neighboring Control Areas is captured under Parts 8.3.1 and 8.3.3.

Questions

EOP-011-4 (Questions 1-3)

1. Do you agree with the new R7 for identification and notification?

2. Is the 30-month time frame in R8 adequate time for the physical changes that may be required to comply with these requirements?

3. The SDT has elected to add clarifying language in the applicable requirements in lieu of making “critical natural gas infrastructure load” a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities and their relative impact on the BES. Do you agree with this approach?

TOP-002-5 (Question 4)

4. The SDT modified the proposed Requirement R8 to remove the link between the required Operating Process and the Operating Plan required under Requirement R4. Do you agree with this modification?

General (Questions 5-7)

5. The SDT proposes that the modifications in EOP-011-4 and TOP-002-5 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.

6. Do you agree with the implementation plan proposed by the SDT? 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.

7. Provide any additional comments for the SDT 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
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
Jennie Wike	Jennie Wike		WECC	Tacoma Power	Jennie Wike	Tacoma Public Utilities	1,3,4,5,6	WECC
					John Merrell	Tacoma Public Utilities (Tacoma, WA)	1	WECC
					John Nierenberg	Tacoma Public Utilities (Tacoma, WA)	3	WECC
					Hien Ho	Tacoma Public Utilities (Tacoma, WA)	4	WECC
					Terry Gifford	Tacoma Public Utilities (Tacoma, WA)	6	WECC

					Ozan Ferrin	Tacoma Public Utilities (Tacoma, WA)	5	WECC
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,RF,SERC,Texas RE,WECC	ACES Collaborators	Bob Soloman	Hoosier Energy Electric Cooperative	1	RF
					Scott Brame	North Carolina Electric Membership Corporation	1,3,4,5	SERC
					Jason Procuniar	Buckeye Power, Inc.	4	RF
					Bill Pezalla	Old Dominion Electric Cooperative	3,4	SERC
					Nikki Carson-Marquis	Minnkota Power Cooperative, Inc.	1	MRO
					Nikki Carson-Marquis	Minnkota Power Cooperative, Inc.	1	MRO
					Jordan Mcclellan	Southern Illinois Power Cooperative	1	SERC
Eversource Energy	Joshua London	1		Eversource	Joshua London	Eversource Energy	1	NPCC

					Vicki O'Leary	Eversource Energy	3	NPCC
MRO	Jou Yang	1,2,3,4,5,6	MRO	MRO NSRF	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Chris Bills	City of Independence, Power and Light Department	5	MRO
					Fred Meyer	Algonquin Power Co.	3	MRO
					Christopher Bills	City of Independence Power & Light	3,5	MRO
					Larry Heckert	Alliant Energy Corporation Services, Inc.	4	MRO
					Marc Gomez	Southwestern Power Administration	1	MRO
					Matthew Harward	Southwest Power Pool, Inc. (RTO)	2	MRO
					Bryan Sherrow	Board of Public Utilities	1	MRO
					Terry Harbour	Berkshire Hathaway Energy -	1	MRO

						MidAmerican Energy Co.		
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Jamison Cawley	Nebraska Public Power District	1,3,5	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Shonda McCain	Omaha Public Power District	6	MRO
					George E Brown	Pattern Operators LP	5	MRO
					George Brown	Acciona Energy USA	5	MRO
					Jaimin Patel	Saskatchewan Power Cooperation	1	MRO
					Kimberly Bentley	Western Area Power Administration	1,6	MRO
					Jay Sethi	Manitoba Hydro	1,3,5,6	MRO
					Michael Ayotte	ITC Holdings	1	MRO

Entergy	Julie Hall	6		Entergy	Oliver Burke	Entergy - Entergy Services, Inc.	1	SERC
					Jamie Prater	Entergy	5	SERC
Electric Reliability Council of Texas, Inc.	Kennedy Meier	2		ISO/RTO Council Standards Review Committee (SRC)	Bobbi Welch	Midcontinent ISO, Inc.	2	NA - Not Applicable
					Darcy O'Connell	California ISO	2	WECC
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Harishkumar Subramani Vijay Kumar	Independent Electricity System Operator	2	NPCC
					John Pearson	ISO New England, Inc.	2	NPCC
					Kennedy Meier	Electric Reliability Council of Texas, Inc.	2	Texas RE
					Matthew Harward	Southwest Power Pool, Inc. (RTO)	2	NA - Not Applicable
					Thomas Foster	PJM Interconnection, L.L.C.	2	RF

FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	RF
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Jim Howell, Jr.	Southern Company - Southern Company Generation	5	SERC

					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Alain Mukama	Hydro One Networks, Inc.	1	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
					Randy Buswell	Vermont Electric Power Company	1	NPCC
					James Grant	NYISO	2	NPCC

					John Pearson	ISO New England, Inc.	2	NPCC
					Harishkumar Subramani Vijay Kumar	Independent Electricity System Operator	2	NPCC
					Randy MacDonald	New Brunswick Power Corporation	2	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					David Burke	Orange and Rockland	3	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
					David Kwan	Ontario Power Generation	4	NPCC

					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Sean Cavote	PSEG	4	NPCC
					Jason Chandler	Con Edison	5	NPCC
					Tracy MacNicoll	Utility Services	5	NPCC
					Shivaz Chopra	New York Power Authority	6	NPCC
					Vijay Puran	New York State Department of Public Service	6	NPCC
					ALAN ADAMSON	New York State Reliability Council	10	NPCC
					David Kiguel	Independent	7	NPCC
					Joel Charlebois	AESI	7	NPCC
					Joshua London	Eversource Energy	1	NPCC
Dominion - Dominion	Sean Bodkin	6		Dominion	Connie Lowe	Dominion - Dominion Resources, Inc.	3	NA - Not Applicable

Resources, Inc.					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
Stephen Whaite	Stephen Whaite			ReliabilityFirst Ballot Body Member and Proxies	Lindsey Mannion	ReliabilityFirst	10	RF
					Stephen Whaite	ReliabilityFirst	10	RF
Tim Kelley	Tim Kelley		WECC	SMUD and BANC	Nicole Looney	Sacramento Municipal Utility District	3	WECC
					Charles Norton	Sacramento Municipal Utility District	6	WECC
					Wei Shao	Sacramento Municipal Utility District	1	WECC
					Foung Mua	Sacramento Municipal Utility District	4	WECC
					Nicole Goi	Sacramento Municipal Utility District	5	WECC

					Kevin Smith	Balancing Authority of Northern California	1	WECC

EOP-011-4 (Questions 1-3)

1. Do you agree with the new R7 for identification and notification?

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
MRO NSRF disagrees with R7. As it is currently written, the elements outlined in R7 should be incorporated as a subcomponent of R1. For a Transmission Operator to successfully develop, maintain, and implement an Operating Plan, as mandated by R1, the Transmission Operator must also and initially (and as necessary or required moving forward) notify relevant entities, which is the action specified in R7.	
Likes 3	OGE Energy - Oklahoma Gas and Electric Co., 3, Hargrove Donald; OGE Energy - Oklahoma Gas and Electric Co., 1, Pyle Terri; JEA, 1, McClung Joseph
Dislikes 0	
Response	
Thank you for your comment. The identification and notification provisions in R7 have been structured as a separate requirement to allow for a specific triggering event for entities subject to R8 and for clarity in the Implementation Plan.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
Without fully knowing what expectations will result from our TOP (PJM), FirstEnergy cannot support this new requirement.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren is unsure how we are supposed to know what registered Distribution Providers are in our Transmission Operator Area. We suggest some sort of automatic notification when a new Distribution Provider becomes registered within our Transmission Operator Area, or an easily accessible list of Distribution Providers.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Functional mapping in CORES requires new entities to identify certain upstream relationships. The process is explained in the ERO Registration Procedure. For more information, please contact NERC Registration.	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
1. NCPA supports others opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Tri-State somewhat agrees with R7 but would like clarity on the following: }If an entity has unplanned or unusual circumstances that may not fall under “operating emergency” situations where they ask for manual load shed to occur when it normally wouldn’t will they still be required to notify the Distribution Providers/Transmission Owners under R7?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. If a Transmission Operator relies on a DP, UFLS-Only DP, or TO to assist with the mitigation of operating Emergencies in its Transmission Operator Area, then identification and notification of those entities would be required under R7.	
Marty Hostler - Northern California Power Agency - 4	
Answer	No
Document Name	
Comment	
NO, NCPA supports various other opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.	
Michael Whitney - Northern California Power Agency - 3	
Answer	No
Document Name	
Comment	
NCPA supports comments others' opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Lenise Kimes - City and County of San Francisco - 1 - WECC	
Answer	No
Document Name	
Comment	
The notification should be required to be given initially and upon changes, and reviewed at least annually.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The annual identification and notification in R7 will capture any changes.	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeremy Lawson - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	

Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
WEC Energy Group supports the new R7 language for identification and notification.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	Yes
Document Name	
Comment	
The current wording reads like it is missing what the entities are being notified of as the purpose reads to be part of the entity classification not that they are being notified that they are required to assist with mitigation.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. Requirement R8 refers back to R7 and provides a specific tie back to the purpose of the notification.	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
PNM and TNMP supports the new identification and notification language in R7.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
AZPS agrees with the new R7 for identification and notification.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes

Document Name	
Comment	
EEI supports the new R7 language for identification and notification.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
ISO-NE agrees with the SRC that the term “automatic Load shedding” be replaced with “undervoltage Load shedding or underfrequency Load shedding” throughout EOP-011-4. Thus eliminating normal SPS/RAS operations from the EOP-011 requirements	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT agrees and has made these changes for the final ballot.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	

The drafting team should consider whether the addition of sub-requirements could enhance clarity and provide more flexibility for this TOP task. For example, following the initial performance of R7 the TOP might annually review the list of entities previously identified and only notify any newly identified entities that their assistance is needed. For entities that have previously been notified, the need for their continued assistance could be communicated annually and the status of their implementation readiness requested. A provision could also be added to allow the TOP to extend the 30-month initial implementation for an entity subject to R8 when justifiable conditions warrant.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT discussed and has chosen to keep the current structure of R7 as the team believes annual notification is needed.	
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 agrees with the new R7 for identification and notification.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC)	
Answer	Yes
Document Name	

Comment	
The ISO/RTO Council (IRC) Standards Review Committee (SRC) (consisting, for purposes of these comments, of CAISO, ERCOT, IESO, ISO-NE, PJM, MISO, and SPP) agrees with the new requirement R7, but recommends that the term “automatic Load shedding” be replaced with “undervoltage Load shedding or underfrequency Load shedding” throughout EOP-011-4. The term “automatic Load shedding” encompasses more than just UVLS or UFLS Load shedding. Specifically, it may be interpreted to include other frameworks that may involve automatic load Shedding, such as Remedial Action Schemes (which are addressed by PRC-012-2), that are not necessarily used to assist with the mitigation of operating Emergencies and are therefore outside the scope of EOP-011-4.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT agrees and has made these changes for the final ballot.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rebecca Zahler - Public Utility District No. 1 of Chelan County - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 1,3,5,6	
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	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mia Wilson - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 1, 6, 5; Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Whaite - Stephen Whaite On Behalf of: Lindsey Mannion, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Tracy MacNicoll - Utility Services, Inc. - 4	
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	
Martin Sidor - NRG - NRG Energy, Inc. - 5,6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Matt Lewis - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
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	

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

Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
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	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District,	

3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	
Document Name	
Comment	
Does not apply to Reclamation.	
Likes 0	
Dislikes 0	
Response	
Mike Gabriel - Greybeard Compliance Services, LLC - 5	
Answer	
Document Name	

Comment	
We support the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE appreciates and supports the standard drafting team's (SDT) efforts in address the Joint Inquiry report for Winter Storm Uri. Texas RE recommends there be a requirement for the DP, DPUF, and TO to acknowledge receipt of the notification that they are required to assist with mitigation of operating Emergencies. Additionally, Texas RE is concerned with the 30-month implementation of a Load shed plan in Requirement R8. Texas RE requests the SDT's justification for a 30-month implementation of developing a load shed plan. Furthermore, Requirement R7 does not provide specific detail what is required assist with the mitigation of operating Emergencies so it is unclear why a 30-month implementation is necessary.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

The SDT discussed and has declined to add a requirement for DPs, UFLS-Only DPs, and TOs to acknowledge receipt of a notification under R7 appears to be administrative in nature and does not enhance reliability. (See Paragraph 81 criteria from Project 2013-02)

The 30-month implementation timeframe was selected to allow adequate time for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. Additional language was added to the Implementation Plan for the final ballot to clarify that this timeframe is not intended to extend the timeframe for an entity's existing responsibilities under EOP-011-2 or EOP-011-3; rather, the additional timeframe is intended to provide additional time to come into compliance with new and revised requirements specific to EOP-011-4.

Regarding R7, Requirement R8 refers back to R7 and provides a specific tie back to the purpose of the notification.

2. Is the 30-month time frame in R8 adequate time for the physical changes that may be required to comply with these requirements?	
Lenise Kimes - City and County of San Francisco - 1 - WECC	
Answer	No
Document Name	
Comment	
Thirty months is too long to make the plan. Possibly there could be a separate timetable applied. 6-12 months to establish and communicate the emergency plan to the TOP and the efforts needed to be able to implement it. This allows the TOP time comment and coordinate for any concerns ahead of time. Something like an additional 18 months if new equipment, etc. is needed to be able to implement/support the plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT discussed and has chosen to keep current timeline and structure of the Implementation Plan as the team believes the 30-month implementation timeframe is necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This change was made to provide adequate time for budgeting, acquiring, and installing new physical equipment.	
Michael Whitney - Northern California Power Agency - 3	
Answer	No
Document Name	
Comment	
NCPA supports comments others' opposing comments that have been submitted.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment.	
Marty Hostler - Northern California Power Agency - 4	
Answer	No
Document Name	
Comment	
NO, NCPA supports various other opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
1. NCPA supports others opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	

Answer	No
Document Name	
Comment	
For EOP-011, Seminole proposes a 36-month implementation time frame. The coordination and agreements between multiple DPs and multiple DPs in multiple TOs' areas could possibly take a significant amount of time. For TOP-002, Seminole proposes an 18 month implementation time frame to remain consistent with other revisions.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The team believes that the 30-month implementation time frame for EOP-011-4 (Part 1.2.5, 2.2.8 and 2.2.9) is sufficient for budgeting, acquiring, and installing new physical equipment. The team is proposing an 18-month implementation time frame for TOP-002-5.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren would like more clarification around the phrase "physical changes." Due to the long lead times in today's environment, it is hard to make a 30-month commitment if there are changes that require a longer time to implement.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The phrase "physical changes" refers to changes that may be required to UFLS circuits in response to 1.2.5.2, 1.2.5.5, 8.1.2, and 8.1.5.	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
Without fully knowing what expectations will result from our TOP (PJM), FirstEnergy cannot support this time frame	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA believes 30 months is too short of a timeframe to address physical infrastructure changes. Without knowing the scope of how many “critical natural gas infrastructure loads” there are throughout the entire Pacific Northwest and how many UFLS relays would need to be relocated, designed and installed, BPA cannot commit to a 30 month implementation. BPA reiterates its comments from the previous comment period and recommends a longer, phased in approach, similar to PRC-005 (PSMP) or PRC-002 (Equipment Monitoring). This would include a timeframe to identify loads and an additional timeframe to design, schedule, and install any required elements.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The team believes that the 30-month implementation time frame for EOP-011-4 (Part 1.2.5, 2.2.8 and 2.2.9) is sufficient for budgeting, acquiring, and installing new physical equipment.	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	No
Document Name	
Comment	
Reclamation does not agree. Addressing existing equipment upgrades as well as Implementation of new equipment are time and cost burden actions that can vary based on funding, equipment availability, manpower, industry limitations and other unforeseen items.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The team believes that the 30-month implementation time frame for EOP-011-4 (Part 1.2.5, 2.2.8 and 2.2.9) is sufficient for budgeting, acquiring, and installing new physical equipment.	
Jeremy Lawson - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 5,6	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC)	
Answer	Yes
Document Name	
Comment	
As detailed in its response to question 6, below, the SRC believes that entities that already assist with Load shed should only need a 30-month timeframe for part 8.1.5 and should have a shorter timeframe for the remaining parts of R8. Additionally, the SRC believes that the implementation plan adequately addresses the implementation timeframe for R8 for both new and existing entities, and that including the 30-month timeframe in R8 is therefore redundant. Consequently, the SRC recommends that references to the 30-month timeframe be removed from R8 in the interests of clarity and efficiency.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

Additional language was added to the Implementation Plan for the final ballot to clarify that the 30-month timeframe is not intended to extend the timeframe for an entity's existing responsibilities under EOP-011-2 or EOP-011-3; rather, the additional timeframe is intended to provide additional time to come into compliance with new and revised requirements specific to EOP-011-4. The 30-month timeframe has been removed from R8 for clarity. This has been replaced with language in the Implementation Plan and Effective Date section of EOP-011-4.	
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 believes that 30 months is adequate for those DPs, UFLS-Only DPs, and TOs that are identified in R7.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
The proposed R7 would require TOPs to "annually identify and notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through operator-controlled manual Load shedding or automatic Load shedding". The Distribution Providers, UFLS-Only Distribution Providers and	

Transmission Owners that are the recipients of such TOP notifications would then have 30-months to "develop, maintain, and implement a Load shedding plan" that must have the capability of being "operator-controlled" (as reflected in R8, Part 8.1). We interpret the term "operator-controlled" to mean controllable by a NERC defined System Operator (in this case, the TOP). If the TOP has an annual obligation to "identify and notify", but the recipient(s) of such notifications have 30-months to develop and implement an associated Load shedding plan (the "maintain" part would not kick in until after the initial Load-shedding plan is developed and implemented), a TOP could conceivably issue three annual notifications under R7 before a recipient completes its initial performance of R8. The drafting team should consider whether the 30-month interval for an initial performance of R8 is sufficiently covered within the implementation plan and can be removed from the requirement language.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Additional language was added to the Implementation Plan for the final ballot to clarify that this timeframe is not intended to extend the timeframe for an entity's existing responsibilities under EOP-011-2 or EOP-011-3; rather, the additional timeframe is intended to provide additional time to come into compliance with new and revised requirements specific to EOP-011-4. The 30-month timeframe has been removed from R8 for clarity. This has been replaced with language in the Implementation Plan and Effective Date section of EOP-011-4.	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
ISO-NE supports the 30-month time frame for physical changes.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the proposed 30-month time frame for DPs, UFLS-Only DPs, and TOs to make changes in conformance with Requirement R7 notifications.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
AZPS supports the 30-month time frame in R8 for physical changes that may be required to comply.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
PNM and TNMP supports the proposed 30-month time frame for DPs, UFLS-Only DPs, and TOs to make changes in conformance with Requirement R7 notifications.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	Yes
Document Name	
Comment	
It is not clear what the intent of requirement 2.2.8 is and whether this requires exclusion of natural gas infrastructure loads only during extreme cold weather periods? If this is a requirement, a 30 month implementation of such a system requirement may be more technically challenging and take a longer period of time to implement.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. In the second ballot, the SDT discussed whether the exclusion of critical natural gas infrastructure loads as Interruptible Load, curtailable Load, and demand response should be limited to certain situations or be a complete prohibition. The SDT has limited the exclusion of these loads from Interruptible Load, curtailable Load, and demand response only to periods of extreme cold weather as identified in the SAR. Entities should note that the proposed Standard represents a minimum requirement which can be exceeded by individual entities if deemed appropriate.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
While a 30 month time frame seems reasonable, AEP requests that it be revised to instead state 30 *calendar* months.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The 30-month timeframe has been removed from R8 for clarity. This has been replaced with language in the Implementation Plan and Effective Date section of EOP-011-4. This now refers to "calendar" months.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
WEC Energy Group supports the proposed 30-month time frame for DPs, UFLS-Only DPs, and TOs to make changes in conformance with Requirement R7 notifications.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	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	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
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	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
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 Collaborators	
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	
Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
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	
Matt Lewis - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Tracy MacNicoll - Utility Services, Inc. - 4	
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	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 1, 6, 5; Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mia Wilson - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC

Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 1,3,5,6	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rebecca Zahler - Public Utility District No. 1 of Chelan County - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
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	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 2	OGE Energy - Oklahoma Gas and Electric Co., 3, Hargrove Donald; OGE Energy - Oklahoma Gas and Electric Co., 1, Pyle Terri
Dislikes 0	

Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1,6	
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	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE agrees that 30 months is adequate for physical changes that may be required to comply with Requirement R7. Texas RE is concerned, however, with the 30-month time frame for non-physical changes. The concern is that the TOP would not be able to mitigate an Operating Emergency seen in the next year if it has to wait 30 months for the DP, DP UFLS, or TO's Load shed plan if there are no physical changes needed and there is simply an update to the plan itself. Texas RE recommends that if there are no physical changes needed, the timeline should be shorter.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The 30-month implementation timeframe was selected and allows adequate time for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. The team supports entities becoming compliant prior to the proposed date. The proposal above would make implementation significantly more confusing.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	

Comment	
The NAGF does not take a position on this issue.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Mike Gabriel - Greybeard Compliance Services, LLC - 5	
Answer	
Document Name	
Comment	
We support the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

3. The SDT has elected to add clarifying language in the applicable requirements in lieu of making “critical natural gas infrastructure load” a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities and their relative impact on the BES. Do you agree with this approach?

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	

MRO NSRF appreciates the SDT's effort to strike a balanced approach concerning the term "critical natural gas infrastructure load." However, MRO NSRF maintains that if the standard incorporates this term, it must be well-defined to facilitate the effective identification and prioritization by Transmission Operators. Although the specific operational equipment qualifying as "critical natural gas infrastructure load" may vary across or even within regions, the fundamental characteristics of what constitutes a “critical natural gas infrastructure load” and the reliability risks that they may pose to the Bulk Electric System (BES) remain constant.

Additionally, MRO NSRF is concerned about the practicality of implementing a requirement that explicitly relies on the coordination with natural gas facility owners and operators for successful implementation. The Technical Rational notes that achieving this coordination relies on the voluntary cooperation of these natural gas entities. At the same time, it acknowledges that the SDT (nor NERC) has the authority to enforce such cooperation. MRO NSRF finds it problematic to mandate, through an enforceable reliability standard, an action that entities cannot guarantee the completion of due to factors beyond their control.

Likes 3	OGE Energy - Oklahoma Gas and Electric Co., 3, Hargrove Donald; OGE Energy - Oklahoma Gas and Electric Co., 1, Pyle Terri; JEA, 1, McClung Joseph
Dislikes 0	
Response	

Thank you for your comment. The SDT has added additional language to requirements 1.2.5.5, 2.2.8, and 8.1.5 to clarify that the Applicable Entity will make the determination of criticality. The SDT maintains the position that it is most appropriate to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making “critical natural gas infrastructure load” a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
Although there may be varying definitions that exist across the NERC footprint for “critical natural gas infrastructure load,” NERC should nonetheless pursue a standardized definition to provide a minimum threshold as to what “critical natural gas infrastructure load” is. (Note: This would also allow for more restrictive regional or local definitions where desired.)	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has added additional language to requirements 1.2.5.5, 2.2.8, and 8.1.5 to clarify that the Applicable Entity will make the determination of criticality. The SDT maintains the position that it is most appropriate to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making “critical natural gas infrastructure load” a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation.	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	No
Document Name	
Comment	

By specifically identifying natural gas infrastructure loads, other critical industries are excluded. Reclamation recommends removing requirement R8.1.5.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT can only address critical natural gas infrastructure loads per the SAR. Requirements 8.1.5 is specific to critical natural gas infrastructure in response to specific recommendations from the joint inquiry report. Requirements 1.2.5.2 and 8.1.2 more broadly address "critical loads which are essential to the reliability of the BES."

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

BPA believes the obligation of Responsible Entities to comply with EOP-011's requirements should not depend on the extent to which natural gas providers are willing to voluntarily work with Responsible Entities to identify critical natural gas infrastructure loads. The SDT noted it does not have the scope to develop methods to compel natural gas facility owners and operators to cooperate and provide specific information; the same is true of the Responsible Entities.

With Transmission Entities having no legal or regulatory means to "require" natural gas facility owners to self- identify critical natural loads, BPA believes this sets industry up for failure when attempting to meet these revised requirements. This might need to go to a FERC level to require natural gas facility owners to self-identify critical natural loads to Transmission Entities. BPA cannot assure its compliance if it's based upon voluntary actions that natural gas companies might not be willing to complete. BPA understands that the information needed would be highly confidential, and represents a very high national security risk. Critical natural gas facility information will likely be closely guarded and not readily shared.

Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The SDT has added additional language to requirements 1.2.5.5, 2.2.8, and 8.1.5 to clarify that the Applicable Entity will make the determination of criticality. The SDT maintains the position that it is most appropriate to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making “critical natural gas infrastructure load” a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation.	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
AEP is unsure exactly what “clarifying language” is that Question 3 is referencing. If it is in regards to the addition of “critical loads which are essential to the reliability of the BES”, AEP disagrees with their proposed inclusion. Please see our response to Question 7 where our concerns are expressed in more detail.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the response to Question 7.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FirstEnergy believes this still does not address our concern toward clarity of what will be deemed critical and who will determine that designation.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. The SDT has added additional language to requirements 1.2.5.5, 2.2.8, and 8.1.5 to clarify that the Applicable Entity will make the determination of criticality. The SDT maintains the position that it is most appropriate to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making “critical natural gas infrastructure load” a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation.	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	
Tacoma Power appreciates the efforts of the SDT to balance the approach to identifying critical natural gas infrastructure and not limiting entities in their identification methods. However, if the Standard incorporates this term, it must be well-defined to facilitate the effective identification and prioritization by Transmission Operators. Tacoma Power concurs that specific operational equipment qualifying as "critical natural gas infrastructure load" may vary across or even within regions. This variation is why it’s important that the fundamental characteristics of what constitutes a “critical natural gas infrastructure load” and the reliability risks that they may pose to the Bulk Electric System (BES) remain constant. Tacoma Power is concerned without these characteristics defined, each entity or auditor will have a different definition of what is considered “critical.”	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has added additional language to requirements 1.2.5.5, 2.2.8, and 8.1.5 to clarify that the Applicable Entity will make the determination of criticality. The SDT maintains the position that it is most appropriate to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making “critical natural gas infrastructure load” a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation.	

David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren understands the flexibility to identify critical natural gas loads, but would like guidelines as to what is considered critical. Ameren would also like a definition of extreme cold weather in the standard or in the glossary of terms.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has added additional language to requirements 1.2.5.5, 2.2.8, and 8.1.5 to clarify that the Applicable Entity will make the determination of criticality. The SDT maintains the position that it is most appropriate to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making “critical natural gas infrastructure load” a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. The SDT discussed and decided against creating a definition for extreme cold weather allowing flexibility for entities to create their own definition based on their unique facts and circumstances.	

Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
1. NCPA supports others opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Tri-State supports the MRO NSRF comments for this question: "MRO NSRF appreciates the SDT's effort to strike a balanced approach concerning the term "critical natural gas infrastructure load." However, MRO NSRF maintains that if the standard incorporates this term, it must be well-defined to facilitate the effective identification and prioritization by Transmission Operators. Although the specific operational equipment qualifying as "critical natural gas infrastructure load" may vary across or even within regions, the fundamental characteristics of what constitutes a “critical natural gas infrastructure load” and the reliability risks that they may pose to the Bulk Electric System (BES) remain constant.” “Additionally, MRO NSRF is concerned about the practicality of implementing a requirement that explicitly relies on the coordination with natural gas facility owners and operators for successful implementation. The Technical Rational notes that achieving this coordination relies on the voluntary cooperation of these natural gas entities. At the same time, it acknowledges that the SDT (nor NERC) has the authority to enforce such cooperation. MRO NSRF finds it problematic to mandate, through an enforceable reliability standard, an action that entities cannot guarantee the completion of due to factors beyond their control.”	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has added additional language to requirements 1.2.5.5, 2.2.8, and 8.1.5 to clarify that the Applicable Entity will make the determination of criticality. The SDT maintains the position that it is most appropriate to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making “critical natural gas infrastructure load” a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation.	

Marty Hostler - Northern California Power Agency - 4	
Answer	No
Document Name	
Comment	
NO, NCPA supports various other opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Michael Whitney - Northern California Power Agency - 3	
Answer	No
Document Name	
Comment	
NCPA supports comments others' opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	

Comment	
Dominion Energy supports the EEI comments and is of the opinion that the SDT should add additional clarifying language to ensure that the Applicable Entity makes the final determination of these loads prior to a final ballot.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has added additional language to requirements 1.2.5.5, 2.2.8, and 8.1.5 to clarify that the Applicable Entity will make the determination of criticality.	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeremy Lawson - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
WEC Energy Group supports the SDT's approach and agrees that the added language is superior to defining "critical natural gas infrastructure load". WEC Energy Group also agrees that the SDT should not try to define this term since the equipment subject to being considered critical could change over time. In addition, allowing the BA, TOP and DP to work with the customer is more likely to provide better end results than a definition created by this SDT.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment.	
Rebecca Zahler - Public Utility District No. 1 of Chelan County - 5	
Answer	Yes
Document Name	
Comment	
This was clarified for 1.2.5.5., but was not clarified in 1.2.5.2. It is recommended similar clarification also be applied to 1.2.5.2 regarding the critical natural gas infrastructure.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Critical natural gas infrastructure is one type of designated critical load that may be addressed in Requirement 1.2.5.2.	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	Yes
Document Name	
Comment	
No omments	
Likes 0	
Dislikes 0	
Response	

Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
PNM and TNMP agrees the including language in the standard to support the term “critical natural gas infrastructure load” vice creating a new definition; however, we support EEI’s comment regarding the addition of “as defined by the responsible entity” to the standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has added additional language to requirements 1.2.5.5, 2.2.8, and 8.1.5 to clarify that the Applicable Entity will make the determination of criticality.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
AZPS agrees with the clarifying language.	
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	Yes
Document Name	
Comment	
The NAGF agrees that the SDT should not try to define this term since the equipment subject to being considered critical could change over time. In addition, allowing the BA, TOP and DP to work with the customer is more likely to provide better end results than a definition created by this SDT.	
Likes 1	OGE Energy - Oklahoma Gas and Electric Co., 1, Pyle Terri
Dislikes 0	
Response	
Thank you for your comment.	
Martin Sidor - NRG - NRG Energy, Inc. - 5,6	
Answer	Yes
Document Name	
Comment	
We agree as long as this approach is remembered down the road.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	

Comment	
EEI supports the SDT's approach and agrees that the added language is superior to defining "critical natural gas infrastructure load", however, to ensure further clarity and to align with the technical rational, we ask the SDT to consider the following edits to those instances where this phrase is used (see our proposed edits in bold face below). critical natural gas infrastructure loads which are essential to the reliability of the BES **as defined by the responsible TO/DP**	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has added additional language to requirements 1.2.5.5, 2.2.8, and 8.1.5 to clarify that the Applicable Entity will make the determination of criticality.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
The drafting team should consider whether all the entities subject to the proposed R8 will have the information needed to identify and prioritize "designated critical natural gas infrastructure loads which are essential to the reliability of the BES" (R8, Part 8.1.5). The proposed standard essentially assigns this task to five different entities (TOP in R1, Part 1.2.5.5; BA in R2, Part 2.2.8; and DP/UFLS-Only DP/TO in R8, Part 8.1.5) with no indication of coordination or shared understanding.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT has added additional language to requirements 1.2.5.5, 2.2.8, and 8.1.5 to clarify that the Applicable Entity will make the determination of criticality.	
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 agrees that the added language is superior to defining "critical natural gas infrastructure load".	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has added additional language to requirements 1.2.5.5, 2.2.8, and 8.1.5 to clarify that the Applicable Entity will make the determination of criticality.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
SMUD and BANC support the comments submitted by the EEI.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 1,3,5,6	
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	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mia Wilson - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 1, 6, 5; Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Whaite - Stephen Whaite On Behalf of: Lindsey Mannion, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Tracy MacNicoll - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Matt Lewis - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
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	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
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	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
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	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lenise Kimes - City and County of San Francisco - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC)	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Gabriel - Greybeard Compliance Services, LLC - 5	
Answer	
Document Name	
Comment	
We support the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

TOP-002-5 (Question 4)

4. The SDT modified the proposed Requirement R8 to remove the link between the required Operating Process and the Operating Plan required under Requirement R4. Do you agree with this modification?

Michael Whitney - Northern California Power Agency - 3	
Answer	No
Document Name	
Comment	
NCPA supports comments others' opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Marty Hostler - Northern California Power Agency - 4	
Answer	No
Document Name	
Comment	
NO, NCPA supports various other opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	No
Document Name	
Comment	
8.2 is awkward, and it is not clear if the load shedding plan should be submitted to the TOP for review and approval; or, if there must be provisions in the plan to submit the plan to the TOP for review. This will be a problem during enforcement, where an entity may submit their plan for approval by the TOP, for review, but fails to have a process for submitting the plan, in the plan. Implementation of the plan would reasonably be expected when there is a system emergency that requires load shedding; however, R8 could be read as 30 days to implement when notified by the TOP. This may sound like a petty issue; however, these issues always crop up and the wording should be improved. Regarding M8, and evidence suggested for developing, maintaining and implementing a Load Plan: There is nothing required to show the plan was approved by the TOP; or, if the TOP did not approve, the process requiring the resolution of the issues and subsequent resubmission and approval.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The SDT discussed your concern and believes that some clarification is in order. There is no intent to require the BA to submit the Operating Process for Extreme Cold Weather to the TOPs for review or approval. As such, there are no enforcement issues to resolve. Load shedding and system emergencies are subject to the Emergency Operating Plans under EOP-011. The Operating Process under TOP-002 is supplemental to the Operating Plan. Again, there is no requirement nor intent for the TOP to approve or implement a load plan under R8 of TOP-002.	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No

Document Name	
Comment	
1. NCPA supports others opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
TOP-002 provides requirements for the Operational Planning Analysis, which is performed on a daily basis. The detailed requirements for the Extreme Cold Weather plan enumerated in R8 will be performed only when specific criteria are met. BPA believes the details of the cold weather plan belongs in another standard, probably EOP-011.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT discussed your concern and clarifies the Operating Process under TOP-002 is supplemental to the Operating Plan, and the BAs Operational Planning Analysis. Its intent is to analyze conditions during upcoming extreme cold weather periods with the intent to mitigate the declaration of an emergency and implementation of emergency operating plans under EOP-011.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	

Comment	
Part 8.3: MISO remains concerned that the term "forecast" is typically used to denote weather forecasts only and would not typically encompass the items under Part 8.3 which is more akin to an Operating Plan described under requirement R4. We agree the Operating Plan should be adequate to meet the timeframe for the identified extreme cold weather period; however, requiring a **five-day forecast** for every "identified extreme cold weather period" may not be necessary. To provide flexibility, MISO suggests the language provided below: **8.3** A methodology to determine an adequate Operating Plan during the identified (or forecasted) extreme cold weather periods… As detailed in prior SRC comments submitted regarding draft 1 of TOP-002-5, MISO continues to be concerned that the approach taken in TOP-002-5 is not the most cost-effective approach due to the lack of corresponding requirements on the GO/GOP to provide the BA with information needed by the BA to fulfill its obligations. Historically, when this has happened, the BA has incurred additional costs and delays in obtaining the information needed as the BA must develop and employ alternative processes (e.g., modifications to FERC tariffs, revisions to membership agreements, engagement in regional rulemaking processes, modifications to its TOP-003 specifications, etc.). Ultimately, the GO/GOP must provide the data; however, it is much more labor intensive than if the obligation to provide data is in the Reliability Standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT discussed and decided to retain the five-day forecast requirement (see Technical Rationale for TOP-002). Additionally, the SDT discussed the issue of data specification, and in consultation with NERC, determined that all information required by the BA to perform its analysis is available under TOP-003. The current requirements in TOP-003 express the minimum required, however, the language "but not limited to" provides the avenue for the BA to obtain additional data points required to perform real-time assessments and real-time monitoring and other analysis required under TOP-002.	
Jeremy Lawson - Northern California Power Agency - 5	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company supports the EEI comments and agrees with the modifications to R8 that distinguish the BA's extreme cold weather Operating Process from the BA's Operating Plan.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
We believe R8, Part 8.1 should be modified to read “A methodology for identifying an extreme cold weather period within **their** Balancing Authority Area;”.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support. The SDT has made modifications to R8 to more expressly detail the intent.	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
No Additional Comments	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI agrees with the modification to Requirement R8 that distinguish the BA's extreme cold weather Operating Process from the BA's Operating Plan.	
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	Yes
Document Name	
Comment	
The NAGF believes that the BA can decide how it can best implement this requirement, whether by using it as part of their Operating Plan or having a separate process to address cold weather efforts.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
David Jendras Sr - Ameren - Ameren Services - 3	

Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
AZPS agrees with the modification to R8.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	

PNM and TNMP both agree with the modification to Requirement R8 that distinguish the BA’s extreme cold weather Operating Process from the BA’s Operating Plan.	
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 and Electric Company supports the removal of the link between R4 and R8 with the understanding that R4 and R8 will be the responsibility of the Balancing Authority.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
Language has made this clear.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
WEC Energy Group agrees with the modification to Requirement R8 that distinguish the BA's extreme cold weather Operating Process from the BA's Operating Plan. WEC Energy Group also believes that the BA can decide how it can best implement this requirement, whether by using it as part of their Operating Plan or having a separate process to address cold weather efforts.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC)	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lenise Kimes - City and County of San Francisco - 1 - WECC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
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 Collaborators	
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	
Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
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	
Matt Lewis - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tracy MacNicoll - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Stephen Whaite - Stephen Whaite On Behalf of: Lindsey Mannion, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
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	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 1, 6, 5; Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mia Wilson - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rebecca Zahler - Public Utility District No. 1 of Chelan County - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
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	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 2	OGE Energy - Oklahoma Gas and Electric Co., 3, Hargrove Donald; OGE Energy - Oklahoma Gas and Electric Co., 1, Pyle Terri
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1,6	
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	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
NA	
Likes 0	
Dislikes 0	
Response	
Mike Gabriel - Greybeard Compliance Services, LLC - 5	
Answer	
Document Name	
Comment	
We support the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Alain Mukama - Hydro One Networks, Inc. - 1,3	

Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	
Document Name	
Comment	
Does not apply to Reclamation	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

General (Questions 5-7)

5. The SDT proposes that the modifications in EOP-011-4 and TOP-002-5 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.

Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
As detailed in prior SRC comments regarding draft 1 of TOP-002-5, MISO continues to be concerned that the approach taken in TOP-002-5 is not the most cost-effective approach due to the lack of corresponding requirements on the GO/GOP to provide the BA with information needed by the BA to fulfill its obligations. Historically, when this has happened, the BA has incurred additional costs to obtain the information needed. This increases the overall cost of compliance as the BA must develop and employ alternative processes to obtain the data needed (e.g., modifications to FERC tariffs, revisions to membership agreements, engagement in regional rulemaking processes, etc.). Ultimately, the GO/GOP ends up incurring the cost to provide the data to the BA; however, costs to the BA accrue because of delays and the need for quality assurance associated with lower quality data than if the obligation to provide data had been enshrined in a Reliability Standard or other regulatory rule.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT discussed additional reporting requirements for the GO/GOP and the team determined that the data specifications under TOP-003 provide the best avenue for BAs to request and receive any data necessary.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No

Document Name	
Comment	
Related to our Q1 response, without a scope of expectations, we cannot determine the cost effectiveness of these recommendations.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
1. NCPA supports others opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	No
Document Name	
Comment	
The authority for the TOP and BA to direct, or give Operating Instructions, is already well established in TOP-001 R1 through R5, and it seems this standard is fundamentally not needed. It further exposes TOs and DPs to unnecessary administrative and compliance burden to have	

load shedding plans that must be created and maintained. During audits, non-compliance penalties are assessed for small omissions, and potential violations based on the auditors' subjective authority to determine the quality of the documentation. When entities must comply to directives and Operating Instructions, maintaining written plans that, may or not be suitable for the situation, adds a significant level of cost without benefit. This is especially true of smaller entities who have limited load or resources.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT developed these new requirements to ensure BAs consider past extreme cold weather.	
Marty Hostler - Northern California Power Agency - 4	
Answer	No
Document Name	
Comment	
NO, The SDT has not provided any cost estimate to support their proposal and has not provided a cost/benefit justification. It appears this entire proposal/endeavor will not improve reliability and simply just keeps more people busy doing more paperwork. Consequently, we feel it is not cost effective, not productive, and not prudent use of customer dollars.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SAR scope requires modifications for reliability purposes. The SDT is not aware of any more cost-effective solutions to address the recommendations within the scope of the SAR.	
Michael Whitney - Northern California Power Agency - 3	
Answer	No
Document Name	

Comment	
NCPA supports comments others' opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeremy Lawson - Northern California Power Agency - 5	
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	
WEC Energy Group agrees.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	Yes
Document Name	
Comment	
It is not clear what the intent of requirement 2.2.8 is and whether this requires exclusion of natural gas infrastructure loads only during extreme cold weather periods? If this is a requirement, the implementation may not be cost-effective as intended.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. In the second ballot, the SDT discussed whether the exclusion of critical natural gas infrastructure loads as Interruptible Load, curtailable Load, and demand response should be limited to certain situations or be a complete prohibition. The SDT has	

limited the exclusion of these loads from Interruptible Load, curtailable Load, and demand response only to periods of extreme cold weather as identified in the SAR. Entities should note that the proposed Standard represents a minimum requirement which can be exceeded by individual entities if deemed appropriate.	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
PNM and TNMP agree that the key recommendations and be implemented in a cost-effective manner.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
AZPS agrees	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Micah Runner - Black Hills Corporation - 1	

Answer	Yes
Document Name	
Comment	
Black Hills Corporation will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	

Black Hills Corporation will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
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 does not think this answer will be known until everything is fully implemented.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Lenise Kimes - City and County of San Francisco - 1 - WECC	
Answer	Yes
Document Name	
Comment	
What is the definition of "cost-effective"? Who is responsible for determining if it is cost-effective? Is it a coordinated effort between the DP, TO and TOP?	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The intent of this question was for individual entities to provide comments on cost effectiveness based on their unique situation and the requirements they are required to comply with. The SDT is not aware of any more cost-effective solutions to address the recommendations within the scope of the SAR.

Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ben Hammer - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 1	OGE Energy - Oklahoma Gas and Electric Co., 3, Hargrove Donald
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rebecca Zahler - Public Utility District No. 1 of Chelan County - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 1,3,5,6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mia Wilson - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 1, 6, 5; Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Tracy MacNicoll - Utility Services, Inc. - 4	
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	

Matt Lewis - Lower Colorado River Authority - 1	
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 Collaborators	
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	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC)	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
Duke Energy’s focus is to assure the effective and efficient reduction of risks to the reliability and security of the grid and will not provide comments on the cost effectiveness of the proposed changes.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment.	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	
Document Name	
Comment	
Does not apply to Reclamation	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	
Document Name	
Comment	
CEHE abstains.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

Mike Gabriel - Greybeard Compliance Services, LLC - 5	
Answer	
Document Name	
Comment	
We support the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
Ameren has no comment on the cost effectiveness of the project.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	
Document Name	

Comment	
It seems that no matter how this Standard is written there will be some associated costs with implementation. ISO-NE does not have a recommendation for how to avoid those cost issues.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

6. Do you agree with the implementation plan proposed by the SDT? 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.

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC)	
Answer	No
Document Name	
Comment	
While requirement R8 is a newly written requirement that is specific to Distribution Providers, UFLS-only Distribution Providers, and Transmission Owners, some DPs, UFLS-only DPs, and TOs already assist with Load shedding. The SRC believes that the implementation plan should be revised to require that these entities that already assist with Load shedding be in compliance with all parts of requirement R8 except part 8.1.5 by the effective date of EOP-011-4. All entities required to comply with R8 should receive the full 30 months to comply with part 8.1.5, which contains the newly added provisions for the identification and prioritization of designated critical natural gas infrastructure loads that are essential to the reliability of the BES. Additionally, ERCOT makes the following comment individually; the SRC does not join this paragraph: ERCOT recommends a 24-month implementation timeframe for both standards to account for the coordination, budget revisions, staffing changes, and systems upgrades necessary to accomplish the new tasks. New forecasts and tools often require multiple projects to acquire the necessary input data and to process and display that data to users. This often requires extensive testing as well.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT discussed your suggested changes to the Implementation Plan and determined it is not necessary to make these changes, since the DPs, UFLS-only DPs, and TOs should have sufficient time to make any necessary adjustments to their Load-shed program with the timeframes already specified in the Implementation Plan.	

Lenise Kimes - City and County of San Francisco - 1 - WECC	
Answer	No
Document Name	
Comment	
See #2 above. Agree with other implementation time frames.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT discussed your suggested changes to the Implementation Plan and determined it is not necessary to make these changes, since the DPs, UFLS-only DPs, and TOs should have sufficient time to make any necessary adjustments to their Load-shed program with the timeframes already specified in the Implementation Plan.	
Jeremy Lawson - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
The SDT has not provided any cost estimate to support their proposal and has not proved a cost/benefit justification. It appears this entire proposal/endeavor will not improve reliability and simply just keep more people busy doing more paperwork. Consequently, we feel it is not cost effective, not productive, and not prudent us of customer dollars.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT focused on achieving the reliability benefits outlined in the SAR.	

Michael Whitney - Northern California Power Agency - 3	
Answer	No
Document Name	
Comment	
The SDT has not provided any cost estimate to support their proposal and has not proved a cost/benefit justification. It appears this entire proposal/endeavor will not improve reliability and simply just keep more people busy doing more paperwork. Consequently, we feel it is not cost effective, not productive, and not prudent us of customer dollars.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT focused on achieving the reliability benefits outlined in the SAR.	
Marty Hostler - Northern California Power Agency - 4	
Answer	No
Document Name	
Comment	
NO, NCPA supports various other opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT addressed all comments received.	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	No

Document Name	
Comment	
No, we believe the rules of procedure may need to be changed around the TO and DP functions before the full implementation can be made.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Changes to the Rules of Procedure are beyond the scope of this SDT. The SDT believes entities are able to implement the requirements of the standard under the existing ROP.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
AEPC has signed on to ACES comments: We have concerns with the phased implementation plan timelines for Requirements R1 Part 1.2.5 and Requirement R2 Part 2.2.8 and Part 2.2.9 being identical. The proposed text of Part 2.2.9 specifically states “in accordance with Requirement R1 Part 1.2.5”; therefore, as Part 2.2.9 is dependent upon R1 Part 1.2.5, we recommend modifying the implementation plan to account for this dependency.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The 30 months implementation date is appropriate for both the BA and TOP to develop its own load shedding plans. The BAs load shedding plans are not at the same granularity as the TOPs, and are generally not facility specific. The BAs load shedding	

plan is for its entire Balancing Authority Area (BAA), and consistent with the current construct, requires the TOPs within the BAA to shed the TOP's share of aggregated load within its own TOP area and according to the TOPs plan. Therefore, the BAs ability to develop a lead shedding plan for its Balancing Authority Area is not dependent on the TOP to first develop its load shedding plan for the specific facilities within its TOP area. Rather, the BA and TOPs can create their own specific load shedding plans within the 30 months implementation timeframe; and upon implementation, the BA can require the TOP to shed its aggregated load share pursuant to the new requirements.

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	No
Document Name	
Comment	
We have concerns with the phased implementation plan timelines for Requirements R1 Part 1.2.5 and Requirement R2 Part 2.2.8 and Part 2.2.9 being identical. The proposed text of Part 2.2.9 specifically states "in accordance with Requirement R1 Part 1.2.5"; therefore, as Part 2.2.9 is dependent upon R1 Part 1.2.5, we recommend modifying the implementation plan to account for this dependency.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The 30 months implementation date is appropriate for both the BA and TOP to develop its own load shedding plans. The BAs load shedding plans are not at the same granularity as the TOPs, and are generally not facility specific. The BAs load shedding plan is for its entire Balancing Authority Area (BAA), and consistent with the current construct, requires the TOPs within the BAA to shed the TOP's share of aggregated load within its own TOP area and according to the TOPs plan. Therefore, the BAs ability to develop a lead shedding plan for its Balancing Authority Area is not dependent on the TOP to first develop its load shedding plan for the specific facilities within its TOP area. Rather, the BA and TOPs can create their own specific load shedding plans within the 30 months implementation timeframe; and upon implementation, the BA can require the TOP to shed its aggregated load share pursuant to the new requirements.	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No

Document Name	
Comment	
The SDT has not provided any cost estimate to support their proposal and has not proved a cost/benefit justification. It appears this entire proposal/endeavor will not improve reliability and simply just keep more people busy doing more paperwork. Consequently, we feel it is not cost effective, not productive, and not a prudent use of customer dollars.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT focused on achieving the reliability benefits outlined in the SAR.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	

See our response to Q1 and Q2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to Q1 and Q2.	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
As noted in question 2 above, for EOP-011-4, BPA recommends a longer, phased in approach, similar to PRC-005 (PSMP) or PRC-002 (Equipment Monitoring). This would include a timeframe to identify loads and an additional timeframe to design, schedule, and install any required elements.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT discussed your suggested changes to the Implementation Plan and determined it is not necessary to make these changes, since the DPs, UFLS-only DPs, and TOs should have sufficient time to make any necessary adjustments to their Load-shed program with the timeframes already specified in the Implementation Plan.	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	No
Document Name	
Comment	

Reclamation recommends 36 months for existing and 60 months for implementation.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT discussed your suggested changes to the Implementation Plan and determined it is not necessary to make these changes, since the DPs, UFLS-only DPs, and TOs should have sufficient time to make any necessary adjustments to their Load-shed program with the timeframes already specified in the Implementation Plan.	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company supports the EEI comments and the implementation timeframes proposed by the SDT.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
As noted in our response to Q1 we believe the drafting team should consider providing TOPs the flexibility to work with entities that are subject to R8 and allow an extension of the 30-month initial implementation period when justifiable conditions warrant.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
No Additional Comments	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.	
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 comment.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
While the NAGF believes that a shorter implementation period would be better for TOP-002 R8, the NAGF supports the proposed implementation plan in order to get the changes made. Once the standard is approved, it would be very beneficial to see Balancing Authorities begin to implement this requirement as soon as possible to reduce the likelihood of another event impacting grid reliability similar to Winter Storms Uri and Elliott due to load forecast errors and unplanned generator outages/unavailability.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. While the Implementation plan is unchanged, the SDT agrees that an expedient implementation is in the best interest of grid reliability.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
AZPS agrees with the proposed implementation plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
PNM and TNMP support the proposed implementation plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Alain Mukama - Hydro One Networks, Inc. - 1,3	

Answer	Yes
Document Name	
Comment	
It is not clear what the intent of requirement 2.2.8 is and whether this requires exclusion of natural gas infrastructure loads only during extreme cold weather periods? If this is a requirement, a 30 month implementation of such a system requirement may be more technically challenging and take a longer period of time to implement.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. In the second ballot, the SDT discussed whether the exclusion of critical natural gas infrastructure loads as Interruptible Load, curtailable Load, and demand response should be limited to certain situations or be a complete prohibition. The SDT has limited the exclusion of these loads from Interruptible Load, curtailable Load, and demand response only to periods of extreme cold weather as identified in the SAR. Entities should note that the proposed Standard represents a minimum requirement which can be exceeded by individual entities if deemed appropriate.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Unlike other revised obligations, R7 is not specifically mentioned in the proposed implementation plan, inferring that it would become effective "six (6) months after the effective date." AEP requests clarity from the SDT if our understanding is correct or not.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The portions of EOP-011 not specifically identified with longer implementation timeframes are intended to be effective six (6) months after regulatory approval, which is the effective date of the standard.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
WEC Energy Group supports the proposed implementation plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	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	
Constantin Chitescu - Ontario Power Generation Inc. - 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	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
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	
Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
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	

Matt Lewis - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tracy MacNicoll - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Whaite - Stephen Whaite On Behalf of: Lindsey Mannion, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
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	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 1, 6, 5; Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mia Wilson - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rebecca Zahler - Public Utility District No. 1 of Chelan County - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
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	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 1	OGE Energy - Oklahoma Gas and Electric Co., 3, Hargrove Donald
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1,6	
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	
Mike Gabriel - Greybeard Compliance Services, LLC - 5	

Answer	
Document Name	
Comment	
We support the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

7. Provide any additional comments for the SDT to consider, including the provided technical rationale document, if desired.

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	
Document Name	
Comment	
WEC Energy Group has no additional comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Mike Magruder - Avista - Avista Corporation - 1	

Answer	
Document Name	
Comment	
We support EEI's submitted comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
Answer	
Document Name	
Comment	
The term "automatic load shedding" appears in requirements 1.2.5, 1.2.5.2, 2.2.9, 8.1, and 8.1.2. This term is more narrowly scoped as pertaining to UFLS and UVLS in requirements 1.2.5.3, 1.2.5.4, 8.1.3, and 8.1.4. The term "automatic load shedding" should be replaced with "UFLS or UVLS" in each location that it appears in EOP-011-4 to provide additional clarity and consistency.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. These changes have been incorporated in the final ballot.	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	
Document Name	

Comment	
EOP-011-4 R1.2.5.5 should be removed and the requirement "Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES" be a DP only responsibility (R8.1.5.). The DP's are responsible to make these provisions in their load shedding plan which they are required to submit to the TOP. The TOP should have no responsibility to make provisions to identify and prioritize these loads itself as they do not have this information.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT has reviewed this comment and determined that the responsibility is correct.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	
Document Name	
Comment	
Part 8.2: As the definition for "reserve margin" varies dramatically across regions, MISO recommends using the term "reserves" instead as detailed below: **8.2** A methodology to determine adequate reserves during the extreme cold weather period…"	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT believes the current wording is correct.	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	

Document Name	
Comment	
Reclamation observes that the nature of the cold weather modifications to reliability standards is not cost or time effective and is disruptive to the industry. The first round of cold weather modifications are not effective yet and already modifications for the third round are in progress. Reclamation recommends that an effort be made to offer a first-time quality product instead of multiple revisions on documents that are not even in effect.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT is responding to FERC orders.	
Michael Jones - National Grid USA - 1	
Answer	
Document Name	
Comment	
RE: EOP-011-4 Section C. Compliance, Section 1.2 Evidence Retention: Please consider if R8 should reference "Load shedding plan" instead of "Operating Plan(s)" for consistency with requirement R8. Also, please considering referencing R8 instead of "Requirements R8 and." RE: TOP-002-5 and EOP-011-4 Section C. Compliance: Please consider if there should be consistent use of the abbreviation "(CEA)" noting the difference in Section C. Compliance of TOP-002-5 vs. EOP-011-4.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. The SDT has reviewed and updated the Compliance Section.	
Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	
AEP is concerned by R1.2.5.2's "circuits that serve designated critical loads which are essential to the reliability of the BES" as well as R8.1.2's "Load shed and circuits that serve designated critical loads which are essential to the reliability of the BES." The Transmission Operator lacks the insight-of, and visibility-into, fuel supply chain (regardless of fuel type) when the supply infrastructure is connected to traditional distribution voltage class. Transmission Operators have tools to determine if an electrical facility outage creates critical problems in their portion of the BES and can further study potential solutions which may include load shedding. It would not seem reasonable that a gas supplier would be capable of performing such an analysis on the electric system since they do not have the tools or the intimate knowledge of the electric grid topology. Likewise, Transmission Operators do not have intimate knowledge of the gas infrastructure or tools to study the impact of a loss of an electric feed to a gas facility. In addition, driven by market or cyber security concerns, there may be a reluctance to share information. It is important to note that Transmission Owners serve multiple distribution providers with connections or service to fuel supply infrastructure, making the needed insight even more lacking. While well intentioned, we believe adding "essential to the reliability of the BES" is a step back in clarity, and it is not clear exactly how such a determination could be made given the limited visibility. AEP requests that the SDT provide insight into exactly what is meant by this phrase as well as how such determinations should be made. In addition, R8's sub bullets which include "which are essential to the reliability of the BES" would require the Distribution Provider to make a determination that we do not believe they would have the insight to make. While AEP has chosen to vote Negative, AEP would be in a better position to vote Affirmative in future ballot periods if the SDT either a) removed the references "essential to the reliability of the BES" entirely, or b) revise the phrase to state "which may have a negative impact on the reliability of the BES as defined by the Distribution Provider, UFLS-Only Distribution Provider, or notified Transmission Owner *in working with the Reliability Coordinator or other applicable regulatory authorities.*" "30 months" is referenced within the proposed revisions, however AEP requests that it be revised to instead state 30 *calendar* months.	
Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	
Response	

Thank you for your comments. The SDT has reviewed the wording of R1 and debated whether "essential to the reliability of the BES" is a necessary statement. The SDT included this language based on previous industry comments to ensure there is not an overly broad interpretation of critical natural gas infrastructure loads such that loads would be identified that are not impacting BES reliability. The SDT has clarified the 30 months to 30 calendar months.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 1,3,5,6	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	

Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	
Document Name	
Comment	
In general, the EOP-011 stated purpose is to address the effects of operating Emergencies (why is Emergencies capitalized, it is not in the NERC Glossary, should this be an operating Emergency or an operating BES Emergency?) but 1.2.6 specifically focusses on Cold weather and Extreme weather, neither of which is included in the NERC Glossary of Terms, only Extreme Cold Weather is in 2.2.8 (not capitalized). Is this different than 1.2.6.1 and 1.2.6.2? Is Extreme Cold Weather a subset of Extreme weather conditions? There are other situations where an energy emergency, possibly not due to cold weather and extreme weather conditions could result in similar effects. Should 1.2.6 refer to an Energy Emergency with references to those possibly caused by extreme weather conditions such as Extreme Cold Weather (outside of expected design temperatures) or extreme heat (Extreme Heat) causing increased load etc.? A BES Emergency causing loss of load, which also could impact natural gas infrastructure could have a similar effect to the reliability of the BES. Under 2.2.8, does this mean that this is only applicable to extreme cold weather (not capitalized) periods, which is not identified under 1.2.6.1, and is this meant to be armed only during extreme cold weather conditions? Would this apply to any energy emergency including extreme heat where critical natural gas loads are essential to the reliability of the BES? The reference to extreme cold should be removed from 2.2.8. For 2.2.10, similar comments to 1.2.6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT is limited by the SAR to address only certain extreme cold weather impacts to BES. If there are additional circumstances which could negatively impact BES reliability, a new SAR should be filed so they can be investigated, and standards can be amended as necessary. The SDT did review the use of “Emergency” and maintains it is consistent and correct.	
Mike Gabriel - Greybeard Compliance Services, LLC - 5	
Answer	

Document Name	
Comment	
We support the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	
Document Name	
Comment	

AZPS has no additional comments at this time.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
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	

Tacoma Power continues to have concerns about EOP-011-4 R1 and R2, as described below.

Reliance on non-NERC Registered Entities

The Reliability Guideline cited in the Technical Rationale proposes that electric transmission and distribution owners reach out to regulatory entities, natural gas companies and organizations, and secondary fuel suppliers. Reaching out to this many organizations and agencies, as well as receiving their responses, may be unattainable in the proposed implementation timeline and will be difficult to maintain the coordination. These organizations are not subject to NERC Standards and as a result, may not respond or prioritize coordination with TOPs. Tacoma Power recommends utilizing a note similar to CIP-013 R2 to address this concern. This note should specify compliance with R1.2.5.5 does not include the natural gas companies' or fuel suppliers' performance and adherence to the TOP requests. Example language to add after EOP-011-4 R1 or to the Measure M1: "Note: The following issues are beyond the scope of Requirement R1: 1) the natural gas companies' or secondary fuel suppliers' performance and adherence to TOP request(s) for information on critical natural gas infrastructure, and 2) accuracy of the information provided by these entities."

Avoiding Overlap Between UFLS and Manual Load Shedding

Rather than avoiding an overlap between UFLS and manual load shedding, the Standard should allow for a pro-rata share of UFLS armed load to be shed during other kinds of load shedding. The recent NERC Lesson Learned Report LL20220301 includes a detailed explanation of the problems that can occur when overlap is minimized.

With the current proposal, there are two main problems with requirement R1.2.5.3 and R8.1.2 to minimize overlap between UFLS and other load shedding:

1. When a significant amount of manual load shedding occurs without shedding any UFLS armed load, the proportion of load armed for UFLS increases. Unfortunately, excessive portions of load armed for UFLS can result in system instability.
   - For example, if a utility has 40% of load armed for UFLS and then they shed 20% of the non-UFLS load, the remaining portion of load armed for UFLS jumps to 50%. If an underfrequency event were to occur with 50% of load armed, it is possible that too much load would be shed, resulting in over frequency tripping of generators.
2. The standard requires having provisions, but it does not require that the provisions are actually effective. This is an example of evaluating compliance paperwork rather than evaluating actual system performance.

One possible way to monitor the pro-rata arming of UFLS load is for utilities to monitor in real time that they have adequate UFLS load shedding armed. Although implementing real-time monitor could be a significant effort for some utilities, this would have benefits for verifying that adequate load is armed for UFLS throughout the whole year. On Tacoma Power's system, the total percent of armed UFLS load is extremely dependent on the time of day and season. Tacoma's portion of load armed for UFLS varies from a minimum of 24% in June to a maximum of 42% in February.

Allowing for pro-rata overlap between UFLS and manual loads significantly increases the customer equity during manual load shedding. Under the current standard we have roughly 40% of our customers exempt from rolling blackouts due to being armed for UFLS, plus another 10% designated as critical for other reasons. This forces the remaining customers to have twice as much outage duration as would otherwise be fair.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The SDT discusses many of these concerns in the technical rationale. The SDT does not intend for EOP-011 compliance to prevent utilities from managing their load shedding process to maximize reliability.

David Jendras Sr - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
None	
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 additional comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	
Document Name	

Comment	
The coordination efforts between multiple DPs in multiple TOs' areas and the staffing needed to create plans and processes and then implement and manage these plans will be burdensome and costly to the TOPs, DPs and TOs. For EOP-011, Seminole proposes a 36-month implementation time frame. The coordination and agreements between multiple DPs and multiple DPs in multiple TOs' areas could possibly take a significant amount of time. For TOP-002, Seminole proposes an 18 month implementation time frame to remain consistent with other revisions.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The team believes that the 30-month implementation time frame for EOP-011-4 (Part 1.2.5, 2.2.8 and 2.2.9) is sufficient for budgeting, acquiring, and installing new physical equipment. The team is proposing an 18-month implementation time frame for TOP-002-5.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE recommends there be a requirement for the TOP to approve the Load shedding plans in receives in EOP-011-4 Requirement R8. Texas RE noticed the Evidence Retention section in TOP-002-5 does not include a retention timeframe specifically for Operating Plans. The section does specifically mention voice recordings, operating logs, and email records, but not Operating Plans. Texas RE recommends specifying a retention timeframe for Operating Plans.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comments. The SDT does not believe that the TOP is in a position to approve a load shedding plan that they receive. The Evidence Retention section of TOP-002-5 has been clarified based on your comments.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	
Document Name	
Comment	
Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	
Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	
Document Name	
Comment	
NPCC RSC supports the drafting team proposal.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	
Document Name	
Comment	
The TO does not supply load and is only responsible for ownership and maintenance of Transmission Facilities (see Appendix 5B - statement of Compliance Registry Criteria (Revision 7) of the NERC Rules of Procedure). Requiring the TO to have a load shedding plan is a flawed concept and assumes an operational function. The TOP, BA, LSE (now obsolete) and DP are the only entities that have control of load. A TO manages assets, and may be directed by the TOP (whose footprint it resides in) to open or deenergize assets under its control for the purpose of shedding load when the TOP does not have direct supervisory control over those assets. What if 1) The TO declares that they have no way to properly shed load under their registration; or, 2) The TOP identifies a TO is required to assist, yet the TO has no operational staff or facilities to assist?	

The Drafting Team may feel this would work out in application, however, once a requirement like this is approved, there will be concern that the TOP may have expanded authority over a TO's organization structure and functional obligations. This will put the smaller organizations at risk. Lastly, "Distribution Provider identified in the Transmission Operator’s Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area" is not identified as an entity needing NERC registration under the ROP (Appendix 5B). Is it the drafting team's intent to require these DP entities to be identified and registered under NERC's ROP? How will R8 be enforced against the DPs who are not registered? We think by expanding the applicability to TO and DP entities the Drafting Team has overstepped its authority. We believe that the standard should stop at the TO, RC and BA levels. In doing so, it would still meet the intent of the BOD resolution. Should the Drafting Team still feel strongly that the expansion of Applicability is warranted, then the ROP may have to be modified to address the additional scope.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT is of the opinion that the currently proposed standards are within the existing NERC framework.	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	
Document Name	
Comment	
No Additional Comments	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	

Answer	
Document Name	
Comment	
OPG supports NPCC RSC's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Romel Aquino - Edison International - Southern California Edison Company - 3	
Answer	
Document Name	
Comment	
See Comments Submitted by the Edison Electrical Institute	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	

NA	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 4	
Answer	
Document Name	
Comment	
NO, NCPA supports various other opposing comments that have been submitted.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
For the proposed EOP-011-4, we question the addition of “which are essential to the reliability of the BES” in association with “designated critical loads” (see R1, Part 1.2.5.2; R8, Part 8.1.2). As noted in the Technical Rationale for EOP-011-3, that drafting team associated critical loads with “certain critical loads which may be essential to the integrity of the electric system, public health, or the welfare of the	

community." By adding the phrase "which are essential to the reliability of the BES" to these requirements in the proposed EOP-011-4, this drafting team seems to be eliminating loads deemed critical to public health and the welfare of the community. Was that the intent?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The scope of the SDT work is limited to extreme cold weather by the SAR to address BPS reliability.	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	
The coordination efforts between multiple DPs in multiple TOs area and the staffing needed to create plans, process, implement and manage is burdensome and costly to the TOPs, DPs and TOs. For EOP-011, propose 36 months implementation. The coordination and agreements between multiple DPs and multiple DP's in multiple TOs areas, could possibly take a significant amount of time. For TOP-002, propose 18 months to remain consistent with other revisions.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The team believes that the 30-month implementation time frame for EOP-011-4 (Part 1.2.5, 2.2.8 and 2.2.9) is sufficient for budgeting, acquiring, and installing new physical equipment. The team is proposing an 18-month implementation time frame for TOP-002-5.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	

Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	
Michael Whitney - Northern California Power Agency - 3	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Lenise Kimes - City and County of San Francisco - 1 - WECC	
Answer	
Document Name	HHWPScreenshot_Example of upload to RCWestPortal_OPA.pdf
Comment	

Regarding TOP-002-5 R3 – Can uploading to the RC West site and adding that entity to the affected parties count? (See uploaded screenshot.) This is upon positive knowledge that the affected entity has access to the site.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Requirement R3 is out of scope of this effort. We encourage you to reach out to your auditing agency for clarification on compliance.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC)	
Answer	
Document Name	
Comment	
As detailed in its response to question 1, above, the SRC recommends that the term "automatic Load shedding" be replaced with "undervoltage Load shedding or underfrequency Load shedding" throughout EOP-011-4. The term "automatic Load shedding" encompasses more than just UVLS or UFLS Load shedding. Specifically, it may be interpreted to include other frameworks that may involve automatic load Shedding, such as Remedial Action Schemes (which are addressed by PRC-012-2), that are not necessarily used to assist with the mitigation of operating Emergencies and are therefore outside the scope of EOP-011-4. As further detailed in comments submitted in response to draft 1 of TOP-002-5, the SRC continues to believe that the most effective method of accomplishing the objectives of TOP-002-5 involves a requirement for GOs and GOPs to provide appropriate information to BAs. However, in light of the approach the SDT has chosen to pursue, the SRC recommends that requirement R8, part 8.3 of TOP-002-5 be revised to require a three-day forecast instead of the proposed five-day hourly forecast. A three-day forecast would be more accurate and useful for BAs and would reduce the amount of additional data that BAs would need to receive from GOs and GOPs when compared to the proposed five-day hourly forecast. Additionally, producing an hourly forecast, regardless of whether it covers three days or five, would be extremely	

burdensome without a commensurate reliability benefit, especially given the existing BA workload during extreme cold weather periods. The SRC therefore recommends removal of the requirement that the forecast be an hourly forecast. This would allow the BA the flexibility to determine and produce the type of three-day forecast that will be most beneficial to reliability without being unduly burdensome. The SRC also recommends that requirement R8, part 8.3.2 be removed from the standard, as the additional administrative burden of including interchange scheduling in the forecast methodology would not produce a sufficient associated reliability benefit.

The SRC reiterates its recommendation from its comments on draft 1 of EOP-011-4 that requirement R2, part 2.2.8 be revised to apply to **known** critical natural gas infrastructure loads. The SRC recognizes that it is not the drafting team's intent for Responsible Entities to be held responsible for unknown critical natural gas infrastructure loads, and the SRC believes that this revision would clarify that intent.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The SDT has replaced "automatic Load shedding" with more specific wording to avoid this misinterpretation.

Additionally, the SDT discussed the issue of data specification, and in consultation with NERC, determined that all information required by the BA to perform its analysis is available under TOP-003. The current requirements in TOP-003 express the minimum required, however, the language "but not limited to" provides the avenue for the BA to obtain additional data points required to perform real-time assessments and real-time monitoring and other analysis required under TOP-002.

The SDT has debated the benefits of a five-day forecast versus a three-day forecast. The intent of the forecast is to ensure that entities have ample time to prepare units for operation when extreme cold weather is forecasted.

The SDT has added additional language to requirements 1.2.5.5, 2.2.8, and 8.1.5 to clarify that the Applicable Entity will make the determination of criticality.

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District,

3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	
Document Name	
Comment	
SMUD and BANC support the comments submitted by Tacoma Power regarding "Avoiding Overlap Between UFLS and Manual Load Shedding".	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	

Standards Announcement

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

Formal Comment Period Open through September 12, 2023

Now Available

A 20-day formal comment period for **Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination – Phase II** is open through **8 p.m. Eastern, Tuesday, September 12, 2023** for the following standards and implementation plan:

- EOP-011-4 – Emergency Operations
- TOP-002-5 – Operations Planning
- Implementation Plan

The standard drafting team's considerations of the responses received from the previous comment period are reflected in this draft of the standard.

Reminder Regarding Corporate RBB Memberships

Under the NERC Rules of Procedure, each entity and its affiliates is collectively permitted one voting membership per Registered Ballot Body Segment. Each entity that undergoes a change in corporate structure (such as a merger or acquisition) that results in the entity or affiliated entities having more than the one permitted representative in a particular Segment must withdraw the duplicate membership(s) prior to joining new ballot pools or voting on anything as part of an existing ballot pool. Contact ballotadmin@nerc.net to assist with the removal of any duplicate registrations.

Commenting

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

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

Next Steps

Additional ballots for the standard(s) and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **September 1 – 12, 2023.**

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

For more information or assistance, contact Manager of Standards Development, Alison Oswald (via email) or at 404-275-9410. 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

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/298)
Ballot Name: 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 EOP-011-4 AB 2 ST
Voting Start Date: 9/1/2023 12:01:00 AM
Voting End Date: 9/12/2023 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 252
Total Ballot Pool: 280
Quorum: 90
Quorum Established Date: 9/12/2023 2:27:20 PM
Weighted Segment Value: 73.4

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	75	1	40	0.702	17	0.298	0	11	7
Segment: 2	8	0.7	6	0.6	1	0.1	0	0	1
Segment: 3	63	1	37	0.712	15	0.288	0	6	5
Segment: 4	14	1	7	0.636	4	0.364	1	1	1
Segment: 5	68	1	34	0.68	16	0.32	0	9	9
Segment: 6	44	1	25	0.694	11	0.306	0	4	4
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	7	0.5	5	0.5	0	0	0	1	1
Totals:	280	6.3	155	4.624	64	1.676	1	32	28

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	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		None	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Micah Runner		Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Third-Party Comments
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Abstain	N/A
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Affirmative	N/A
1	Duke Energy	Katherine Street		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Alan Kloster	Affirmative	N/A
1	Eversource Energy	Joshua London		Negative	Comments Submitted
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis		Abstain	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-Quebec (HQ)	Nicolas Turcotte		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Joseph McClung		Negative	Third-Party Comments
1	KAMO Electric Cooperative	Micah Breedlove		None	N/A
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
1	Long Island Power Authority	Isidoro Behar		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
1	Lower Colorado River Authority	Matt Lewis		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
1	Muscatine Power and Water	Andrew Kurriger		Negative	Third-Party Comments
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Abstain	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
1	Oncor Electric Delivery	Byron Booker	Gul Khan	Affirmative	N/A
1	Orlando Utilities Commission	Aaron Staley		Negative	Third-Party Comments
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Abstain	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
1	Platte River Power Authority	Marissa Archie		Negative	Third-Party Comments
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Negative	Third-Party Comments
1	Puget Sound Energy, Inc.	Anna Lavik		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Sarah Blankenship	Israel Perez	Affirmative	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	SaskPower	Wayne Guttormson		None	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Negative	Comments Submitted
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Negative	Comments Submitted
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	David Plumb		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	Western Area Power Administration	Sean Erickson	Kimberly Bentley	None	N/A
1	Xcel Energy, Inc.	Eric Barry		Negative	Third-Party Comments
2	California ISO	Darcy O'Connell	Val Neiberger	Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	Independent Electricity System Operator	Harishkumar Subramani Vijay Kumar		Affirmative	N/A
2	ISO New England, Inc.	John Pearson	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Negative	Comments Submitted
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Matthew Harward		Affirmative	N/A
3	AEP	Kent Feliks		Negative	Comments Submitted
3	Ameren - Ameren Services	David Jendras Sr		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
3	BC Hydro and Power Authority	Alan Xu		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs	Rachel Schuldt	Affirmative	N/A
3	Bonneville Power Administration	Ron Sporseen		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Negative	Third-Party Comments
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Bill Garvey		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		None	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Alan Kloster	Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Negative	Comments Submitted
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Florida Municipal Power Agency	Navid Nowakhtar	LaKenya Vannorman	None	N/A
3	Georgia System Operations Corporation	Scott McGough		Abstain	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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
3	National Grid USA	Brian Shanahan		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney		Negative	Comments Submitted
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Negative	Third-Party Comments
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Platte River Power Authority	Richard Kiess		Negative	Third-Party Comments
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		None	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Santee Cooper	Vicky Budreau		Abstain	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		Negative	Comments Submitted
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Negative	Third-Party Comments
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	WEC Energy Group, Inc.	Christine Kane		Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Negative	Third-Party Comments
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Abstain	N/A
4	Austin Energy	Tony 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		Negative	Comments Submitted
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
4	Northern California Power Agency	Marty Hostler		Negative	Comments Submitted
4	Oklahoma Municipal Power Authority	Michael Watt		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Negative	Third-Party Comments
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	No Comment Submitted
4	Seminole Electric Cooperative, Inc.	Ken Habgood		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Negative	Comments Submitted
4	Utility Services, Inc.	Tracy MacNicoll		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	AES - AES Corporation	Ruchi Shah		None	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Comments Submitted
5	APS - Arizona Public Service Co.	Brandon Smith		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		None	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier	Carly Miller	Affirmative	N/A
5	Bonneville Power Administration	Christopher Siewert		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Cogentrix Energy Power Management, LLC	Gerry Adamski		None	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Negative	Third-Party Comments
5	Con Ed - Consolidated Edison Co. of New York	Helen Wang		Affirmative	N/A
5	Constellation	Alison MacKellar		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Dominion - Dominion Resources, Inc.	Anna Salmon		None	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Enel Green Power	Natalie Johnson		Abstain	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Abstain	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi		Abstain	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	JEA	John Babik		Negative	Comments Submitted
5	Lincoln Electric System	Brittany Millard		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	Manitoba Hydro	Kristy-Lee Young		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Negative	Third-Party Comments
5	National Grid USA	Robin Berry		Abstain	N/A
5	NB Power Corporation	David Melanson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Nebraska Public Power District	Ronald Bender		Negative	Third-Party Comments
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	NextEra Energy	Richard Vendetti		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Affirmative	N/A
5	Northern California Power Agency	Jeremy Lawson		Negative	Comments Submitted
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		None	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Third-Party Comments
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Dania Colon		Affirmative	N/A
5	Pattern Operators LP	George E Brown		Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Negative	Third-Party Comments
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG Nuclear LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Negative	Third-Party Comments
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Salt River Project	Jennifer Bennett	Israel Perez	Affirmative	N/A
5	Santee Cooper	Don Cribb		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Negative	Comments Submitted
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Jim Howell, Jr.		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	Tennessee Valley Authority	Nehtisha Rollis		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		None	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		Negative	Third-Party Comments
6	AEP	Justin Kuehne		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Imane Mrini		Affirmative	N/A
6	Black Hills Corporation	Claudine Bates		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		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		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	John Sturgeon		Affirmative	N/A
6	Edison International - Southern California Edison Company	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		Negative	Comments Submitted
6	Great River Energy	Brian Meloy		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	Kelly Bertholet		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Muscatine Power and Water	Nicholas Burns		Negative	Third-Party Comments
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Abstain	N/A
6	NiSource - Northern Indiana Public Service Co.	Joseph OBrien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments
6	Platte River Power Authority	Sabrina Martz		Negative	Third-Party Comments
6	Portland General Electric Co.	Stefanie Burke		None	N/A
6	Powerex Corporation	Raj Hundal		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		None	N/A
6	Public Utility District No. 1 of Chelan County	Anne Kronshage		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	Mike Stussy		None	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Santee Cooper	Marty Watson		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Snohomish County PUD No. 1	John Liang		Negative	Third-Party Comments
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
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		Affirmative	N/A
6	Western Area Power Administration	Chrystal Dean		Affirmative	N/A
7	Oxy - Occidental Chemical	Venona Greaff		Affirmative	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		None	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Lindsey Mannion	Stephen Whaite	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

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Showing 1 to 280 of 280 entries

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/298)
Ballot Name: 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 TOP-002-5 AB 2 ST
Voting Start Date: 9/1/2023 12:01:00 AM
Voting End Date: 9/12/2023 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 250
Total Ballot Pool: 279
Quorum: 89.61
Quorum Established Date: 9/12/2023 2:27:41 PM
Weighted Segment Value: 82.42

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	74	1	44	0.83	9	0.17	0	14	7
Segment: 2	8	0.7	5	0.5	2	0.2	0	0	1
Segment: 3	63	1	42	0.857	7	0.143	0	9	5
Segment: 4	14	1	10	0.769	3	0.231	0	0	1
Segment: 5	68	1	39	0.813	9	0.188	0	11	9
Segment: 6	44	1	28	0.824	6	0.176	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	7	0.5	5	0.5	0	0	0	1	1
Totals:	279	6.3	174	5.193	36	1.107	0	40	29

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	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		None	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Micah Runner		Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Third-Party Comments
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Abstain	N/A
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Affirmative	N/A
1	Duke Energy	Katherine Street		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Alan Kloster	Affirmative	N/A
1	Eversource Energy	Joshua London		Abstain	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis		Abstain	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-Quebec (HQ)	Nicolas Turcotte		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Joseph McClung		Negative	Third-Party Comments
1	KAMO Electric Cooperative	Micah Breedlove		None	N/A
1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
1	Lower Colorado River Authority	Matt Lewis		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
1	Muscatine Power and Water	Andrew Kurriger		Negative	Third-Party Comments
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Abstain	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Byron Booker	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	Abstain	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
1	Platte River Power Authority	Marissa Archie		Negative	Third-Party Comments
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Negative	Third-Party Comments
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Sarah Blankenship	Israel Perez	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	SaskPower	Wayne Guttormson		None	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Negative	Comments Submitted
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Abstain	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	David Plumb		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	Comments Submitted
1	Western Area Power Administration	Sean Erickson	Kimberly Bentley	None	N/A
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
2	California ISO	Darcy O'Connell	Val Neiberger	Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
2	Independent Electricity System Operator	Harishkumar Subramani Vijay Kumar		Affirmative	N/A
2	ISO New England, Inc.	John Pearson	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Matthew Harward		Affirmative	N/A
3	AEP	Kent Feliks		Abstain	N/A
3	Ameren - Ameren Services	David Jendras Sr		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
3	BC Hydro and Power Authority	Alan Xu		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs	Rachel Schuldt	Affirmative	N/A
3	Bonneville Power Administration	Ron Sporseen		Negative	Comments Submitted
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	Dominion - Dominion Virginia Power	Bill Garvey		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		None	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Alan Kloster	Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Abstain	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Florida Municipal Power Agency	Navid Nowakhtar	LaKenya Vannorman	None	N/A
3	Georgia System Operations Corporation	Scott McGough		Abstain	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	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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
3	National Grid USA	Brian Shanahan		Abstain	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	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney		Negative	Comments Submitted
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Abstain	N/A
3	Platte River Power Authority	Richard Kiess		Negative	Third-Party Comments
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		None	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	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	Mathew Weber	Israel Perez	Affirmative	N/A
3	Santee Cooper	Vicky Budreau		Abstain	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		Negative	Comments Submitted
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		Negative	Third-Party Comments
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	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.	Ryan Walter		None	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	Austin Energy	Tony 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		Negative	Comments Submitted
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
4	Northern California Power Agency	Marty Hostler		Negative	Comments Submitted
4	Oklahoma Municipal Power Authority	Michael Watt		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Negative	Third-Party Comments
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Ken Habgood		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	Utility Services, Inc.	Tracy MacNicoll		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	AES - AES Corporation	Ruchi Shah		None	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Brandon Smith		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Avista - Avista Corporation	Glen Farmer		None	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier	Carly Miller	Affirmative	N/A
5	Bonneville Power Administration	Christopher Siewert		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Cogentrix Energy Power Management, LLC	Gerry Adamski		None	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Negative	Third-Party Comments
5	Con Ed - Consolidated Edison Co. of New York	Helen Wang		Affirmative	N/A
5	Constellation	Alison MacKellar		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Abstain	N/A
5	Dominion - Dominion Resources, Inc.	Anna Salmon		None	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Enel Green Power	Natalie Johnson		Abstain	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Affirmative	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi		Abstain	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		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	Manitoba Hydro	Kristy-Lee Young		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Negative	Third-Party Comments
5	National Grid USA	Robin Berry		Abstain	N/A
5	NB Power Corporation	David Melanson		Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender		Negative	Third-Party Comments
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	NextEra Energy	Richard Vendetti		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Northern California Power Agency	Jeremy Lawson		Negative	Comments Submitted
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		None	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Dania Colon		Affirmative	N/A
5	Pattern Operators LP	George E Brown		Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Negative	Third-Party Comments
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG Nuclear LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Negative	Third-Party Comments
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Salt River Project	Jennifer Bennett	Israel Perez	Affirmative	N/A
5	Santee Cooper	Don Cribb		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Negative	Comments Submitted
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Southern Company - Southern Company Generation	Jim Howell, Jr.		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	Tennessee Valley Authority	Nehtisha Rollis		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		None	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP	Justin 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	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Imane Mrini		Affirmative	N/A
6	Black Hills Corporation	Claudine Bates		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		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		None	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	John Sturgeon		Affirmative	N/A
6	Edison International - Southern California Edison Company	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		Negative	Comments Submitted
6	Great River Energy	Brian Meloy		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	Kelly Bertholet		Affirmative	N/A
6	Muscatine Power and Water	Nicholas Burns		Negative	Third-Party Comments
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Abstain	N/A
6	NiSource - Northern Indiana Public Service Co.	Joseph OBrien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		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		Negative	Third-Party Comments
6	Portland General Electric Co.	Stefanie Burke		None	N/A
6	Powerex Corporation	Raj Hundal		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		None	N/A
6	Public Utility District No. 1 of Chelan County	Anne Kronshage		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	Mike Stussy		None	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Santee Cooper	Marty Watson		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		Negative	Third-Party Comments
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		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	Western Area Power Administration	Chrystal Dean		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
7	Oxy - Occidental Chemical	Venona Greaff		Affirmative	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		None	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Lindsey Mannion	Stephen Whaite	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

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Showing 1 to 279 of 279 entries

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/298)
Ballot Name: 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 Implementation Plan AB 2 OT
Voting Start Date: 9/1/2023 12:01:00 AM
Voting End Date: 9/12/2023 8:00:00 PM
Ballot Type: OT
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 247
Total Ballot Pool: 278
Quorum: 88.85
Quorum Established Date: 9/12/2023 2:32:55 PM
Weighted Segment Value: 79.97

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	74	1	47	0.825	10	0.175	0	10	7
Segment: 2	7	0.6	5	0.5	1	0.1	0	0	1
Segment: 3	63	1	43	0.827	9	0.173	0	6	5
Segment: 4	14	1	9	0.692	4	0.308	0	0	1
Segment: 5	68	1	38	0.76	12	0.24	0	8	10
Segment: 6	44	1	27	0.794	7	0.206	0	4	6
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	7	0.3	3	0.3	0	0	0	3	1
Totals:	278	6	173	4.798	43	1.202	0	31	31

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Mark Riley		None	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Micah Runner		Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Third-Party Comments
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Abstain	N/A
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Affirmative	N/A
1	Duke Energy	Katherine Street		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Alan Kloster	Affirmative	N/A
1	Eversource Energy	Joshua London		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis		Abstain	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Joseph McClung		Negative	Third-Party Comments
1	KAMO Electric Cooperative	Micah Breedlove		None	N/A
1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
1	Lower Colorado River Authority	Matt Lewis		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
1	Muscatine Power and Water	Andrew Kurriger		Negative	Third-Party Comments
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Abstain	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Byron Booker	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	Abstain	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
1	Platte River Power Authority	Marissa Archie		Negative	Third-Party Comments
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Negative	Third-Party Comments
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Sarah Blankenship	Israel Perez	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	SaskPower	Wayne Guttormson		None	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Negative	Comments Submitted
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	David Plumb		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	Comments Submitted
1	Western Area Power Administration	Sean Erickson	Kimberly Bentley	None	N/A
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
2	Independent Electricity System Operator	Harishkumar Subramani Vijay Kumar		Affirmative	N/A
2	ISO New England, Inc.	John Pearson	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Matthew Harward		Affirmative	N/A
3	AEP	Kent Feliks		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
3	BC Hydro and Power Authority	Alan Xu		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs	Rachel Schuldt	Affirmative	N/A
3	Bonneville Power Administration	Ron Sporseen		Negative	Comments Submitted
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	Dominion - Dominion Virginia Power	Bill Garvey		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	DTE Energy - Detroit Edison Company	Marvin Johnson		None	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Alan Kloster	Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Florida Municipal Power Agency	Navid Nowakhtar	LaKenya Vannorman	None	N/A
3	Georgia System Operations Corporation	Scott McGough		Abstain	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	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	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	National Grid USA	Brian Shanahan		Abstain	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	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	Third-Party Comments
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney		Negative	Comments Submitted
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Abstain	N/A
3	Platte River Power Authority	Richard Kiess		Negative	Third-Party Comments
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		None	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Santee Cooper	Vicky Budreau		Abstain	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		Negative	Comments Submitted
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Negative	Third-Party Comments
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	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.	Ryan Walter		None	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	Austin Energy	Tony Hua		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
4	DTE Energy	Patricia Ireland		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Third-Party Comments
4	Northern California Power Agency	Marty Hostler		Negative	Comments Submitted
4	Oklahoma Municipal Power Authority	Michael Watt		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Negative	Third-Party Comments
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Ken Habgood		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	Utility Services, Inc.	Tracy MacNicoll		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		None	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Comments Submitted
5	APS - Arizona Public Service Co.	Brandon Smith		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		None	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Black Hills Corporation	Sheila Suurmeier	Carly Miller	Affirmative	N/A
5	Bonneville Power Administration	Christopher Siewert		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Cogentrix Energy Power Management, LLC	Gerry Adamski		None	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Negative	Third-Party Comments
5	Con Ed - Consolidated Edison Co. of New York	Helen Wang		Affirmative	N/A
5	Constellation	Alison MacKellar		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Abstain	N/A
5	Dominion - Dominion Resources, Inc.	Anna Salmon		None	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Enel Green Power	Natalie Johnson		Abstain	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Greybeard Compliance Services, LLC	Mike Gabriel		Affirmative	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi		Abstain	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		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	Manitoba Hydro	Kristy-Lee Young		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Negative	Third-Party Comments
5	National Grid USA	Robin Berry		Abstain	N/A
5	NB Power Corporation	David Melanson		Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender		Negative	Third-Party Comments
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	NextEra Energy	Richard Vendetti		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Third-Party Comments
5	Northern California Power Agency	Jeremy Lawson		Negative	Comments Submitted
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		None	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		None	N/A
5	Orlando Utilities Commission	Dania Colon		Affirmative	N/A
5	Pattern Operators LP	George E Brown		Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Negative	Third-Party Comments
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG Nuclear LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Negative	Third-Party Comments
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Salt River Project	Jennifer Bennett	Israel Perez	Affirmative	N/A
5	Santee Cooper	Don Cribb		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Negative	Comments Submitted
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Jim Howell, Jr.		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	Tennessee Valley Authority	Nehtisha Rollis		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		None	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		Affirmative	N/A
6	AEP	Justin 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	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Imane Mrini		Affirmative	N/A
6	Black Hills Corporation	Claudine Bates		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		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
6	Constellation	Kimberly Turco		None	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		Negative	Comments Submitted
6	Great River Energy	Brian Meloy		None	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	Kelly Bertholet		Affirmative	N/A
6	Muscatine Power and Water	Nicholas Burns		Negative	Third-Party Comments
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Abstain	N/A
6	NiSource - Northern Indiana Public Service Co.	Joseph OBrien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Portland General Electric Co.	Stefanie Burke		None	N/A
6	Powerex Corporation	Raj Hundal		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		None	N/A
6	Public Utility District No. 1 of Chelan County	Anne Kronshage		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	Mike Stussy		None	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Santee Cooper	Marty Watson		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		Negative	Third-Party Comments
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		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	Western Area Power Administration	Chrystal Dean		Affirmative	N/A
7	Oxy - Occidental Chemical	Venona Greaff		Affirmative	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	New York State Reliability Council	Wesley Yeomans		None	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Lindsey Mannion	Stephen Whaite	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A

Showing 1 to 278 of 278 entries

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BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/298)
Ballot Name: 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 EOP-011-4 | Non-binding Poll AB 2 NB
Voting Start Date: 9/1/2023 12:01:00 AM
Voting End Date: 9/12/2023 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 237
Total Ballot Pool: 270
Quorum: 87.78
Quorum Established Date: 9/12/2023 2:59:19 PM
Weighted Segment Value: 73.89

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	72	1	34	0.723	13	0.277	16	9
Segment: 2	7	0.5	5	0.5	0	0	1	1
Segment: 3	61	1	32	0.744	11	0.256	12	6
Segment: 4	14	1	8	0.667	4	0.333	1	1
Segment: 5	66	1	28	0.7	12	0.3	17	9
Segment: 6	42	1	21	0.75	7	0.25	8	6
Segment: 7	1	0.1	1	0.1	0	0	0	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	7	0.4	4	0.4	0	0	2	1
Totals:	270	6	133	4.584	47	1.416	57	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	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		None	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Micah Runner		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Bonneville Power Administration	Kamala Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Comments Submitted
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Abstain	N/A
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Affirmative	N/A
1	Duke Energy	Katherine Street		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Alan Kloster	Affirmative	N/A
1	Eversource Energy	Joshua London		Negative	Comments Submitted
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis		Abstain	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Abstain	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte		Abstain	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Joseph McClung		Negative	Comments Submitted
1	KAMO Electric Cooperative	Micah Breedlove		None	N/A
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
1	Lower Colorado River Authority	Matt Lewis		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	Andrew Kurriger		Negative	Comments Submitted
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	Comments Submitted
1	Oncor Electric Delivery	Byron Booker	Gul Khan	Affirmative	N/A
1	Orlando Utilities Commission	Aaron Staley		Negative	Comments Submitted
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Abstain	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
1	Platte River Power Authority	Marissa Archie		Negative	Comments Submitted
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		None	N/A
1	Public Utility District No. 1 of Chelan County	Glen Pruitt		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	Sarah Blankenship	Israel Perez	Affirmative	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	SaskPower	Wayne Guttormson		None	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Negative	Comments Submitted
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Negative	Comments Submitted
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	David Plumb		Abstain	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	Comments Submitted
1	Western Area Power Administration	Sean Erickson	Kimberly Bentley	None	N/A
1	Xcel Energy, Inc.	Eric Barry		None	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A
2	Independent Electricity System Operator	Harishkumar Subramani Vijay Kumar		Affirmative	N/A
2	ISO New England, Inc.	John Pearson	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Matthew Harward		Affirmative	N/A
3	AEP	Kent Feliks		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Ameren - Ameren Services	David Jendras Sr		Abstain	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
3	BC Hydro and Power Authority	Alan Xu		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs	Rachel Schuldt	Affirmative	N/A
3	Bonneville Power Administration	Ron Sporseen		Negative	Comments Submitted
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Negative	Comments Submitted
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Bill Garvey		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		None	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Alan Kloster	Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Negative	Comments Submitted
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Florida Municipal Power Agency	Navid Nowakhtar	LaKenya Vannorman	None	N/A
3	Georgia System Operations Corporation	Scott McGough		Abstain	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	Lincoln Electric System	Sam Christensen		Abstain	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	Muscatine Power and Water	Seth Shoemaker		Negative	Comments Submitted
3	National Grid USA	Brian Shanahan		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney		Negative	Comments Submitted
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Negative	Comments Submitted
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Abstain	N/A
3	Platte River Power Authority	Richard Kiess		Negative	Comments Submitted
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		None	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Santee Cooper	Vicky Budreau		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Seminole Electric Cooperative, Inc.	Marc Sedor		Negative	Comments Submitted
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		None	N/A
3	WEC Energy Group, Inc.	Christine Kane		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Abstain	N/A
4	Austin Energy	Tony 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		Negative	Comments Submitted
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Northern California Power Agency	Marty Hostler		Negative	Comments Submitted
4	Oklahoma Municipal Power Authority	Michael Watt		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Negative	Comments Submitted
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Ken Habgood		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Negative	Comments Submitted
4	Utility Services, Inc.	Tracy MacNicoll		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	AES - AES Corporation	Ruchi Shah		None	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Brandon Smith		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		None	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	Black Hills Corporation	Sheila Suurmeier	Carly Miller	Affirmative	N/A
5	Bonneville Power Administration	Christopher Siewert		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Cogentrix Energy Power Management, LLC	Gerry Adamski		None	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Negative	Comments Submitted
5	Con Ed - Consolidated Edison Co. of New York	Helen Wang		Affirmative	N/A
5	Constellation	Alison MacKellar		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Abstain	N/A
5	Dominion - Dominion Resources, Inc.	Anna Salmon		None	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Enel Green Power	Natalie Johnson		Abstain	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Abstain	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	JEA	John Babik		Negative	Comments Submitted
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Negative	Comments Submitted
5	National Grid USA	Robin Berry		Abstain	N/A
5	NB Power Corporation	David Melanson		Affirmative	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	Richard Vendetti		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Affirmative	N/A
5	Northern California Power Agency	Jeremy Lawson		Negative	Comments Submitted
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		None	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Comments Submitted
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Dania Colon		Affirmative	N/A
5	Pattern Operators LP	George E Brown		Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Negative	Comments Submitted
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Abstain	N/A
5	PSEG Nuclear LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Negative	Comments Submitted
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Salt River Project	Jennifer Bennett	Israel Perez	Affirmative	N/A
5	Santee Cooper	Don Cribb		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Negative	Comments Submitted
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Jim Howell, Jr.		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	Tennessee Valley Authority	Denise Rollis		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Tri-State G and T Association, Inc.	Sergio Banuelos		None	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Negative	Comments Submitted
5	WEC Energy Group, Inc.	Clarice Zellmer		Affirmative	N/A
6	AEP	Justin Kuehne		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Imane Mrini		Affirmative	N/A
6	Black Hills Corporation	Claudine Bates		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Negative	Comments Submitted
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
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		Negative	Comments Submitted
6	Great River Energy	Brian Meloy		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Muscatine Power and Water	Nicholas Burns		Negative	Comments Submitted
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Abstain	N/A
6	NiSource - Northern Indiana Public Service Co.	Joseph OBrien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Negative	Comments Submitted
6	Platte River Power Authority	Sabrina Martz		Negative	Comments Submitted
6	Portland General Electric Co.	Stefanie Burke		None	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		None	N/A
6	Public Utility District No. 1 of Chelan County	Anne Kronshage		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Public Utility District No. 2 of Grant County, Washington	Mike Stussy		None	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Santee Cooper	Marty Watson		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Negative	Comments Submitted
6	Tennessee Valley Authority	Armando Rodriguez		None	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Affirmative	N/A
6	Western Area Power Administration	Chrystal Dean		Affirmative	N/A
7	Oxy - Occidental Chemical	Venona Greaff		Affirmative	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		None	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Lindsey Mannion	Stephen Whaite	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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 270 of 270 entries

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/298)
Ballot Name: 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 TOP-002-5 | Non-binding Poll AB 2 NB
Voting Start Date: 9/1/2023 12:01:00 AM
Voting End Date: 9/12/2023 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 236
Total Ballot Pool: 268
Quorum: 88.06
Quorum Established Date: 9/12/2023 2:49:37 PM
Weighted Segment Value: 81.29

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	72	1	37	0.841	7	0.159	19	9
Segment: 2	7	0.5	4	0.4	1	0.1	1	1
Segment: 3	60	1	33	0.825	7	0.175	15	5
Segment: 4	14	1	9	0.75	3	0.25	1	1
Segment: 5	65	1	31	0.795	8	0.205	18	8
Segment: 6	42	1	20	0.769	6	0.231	9	7
Segment: 7	1	0.1	1	0.1	0	0	0	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	7	0.4	4	0.4	0	0	2	1
Totals:	268	6	139	4.88	32	1.12	65	32

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	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		None	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Micah Runner		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Bonneville Power Administration	Kamala Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Abstain	N/A
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Affirmative	N/A
1	Duke Energy	Katherine Street		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Alan Kloster	Affirmative	N/A
1	Eversource Energy	Joshua London		Abstain	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis		Abstain	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Abstain	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte		Abstain	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Joseph McClung		Negative	Comments Submitted
1	KAMO Electric Cooperative	Micah Breedlove		None	N/A
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
1	Lower Colorado River Authority	Matt Lewis		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	Andrew Kurriger		Negative	Comments Submitted
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Byron Booker	Gul Khan	Affirmative	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Abstain	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
1	Platte River Power Authority	Marissa Archie		Negative	Comments Submitted
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		None	N/A
1	Public Utility District No. 1 of Chelan County	Glen Pruitt		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	Sarah Blankenship	Israel Perez	Affirmative	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	SaskPower	Wayne Guttormson		None	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Negative	Comments Submitted
1	Sempra - San Diego Gas and Electric	Mohamed 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		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	David Plumb		Abstain	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	Comments Submitted
1	Western Area Power Administration	Sean Erickson	Kimberly Bentley	None	N/A
1	Xcel Energy, Inc.	Eric Barry		None	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
2	Independent Electricity System Operator	Harishkumar Subramani Vijay Kumar		Affirmative	N/A
2	ISO New England, Inc.	John Pearson	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Matthew Harward		Affirmative	N/A
3	AEP	Kent Feliks		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Ameren - Ameren Services	David Jendras Sr		Abstain	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Abstain	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
3	BC Hydro and Power Authority	Alan Xu		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs	Rachel Schuldt	Affirmative	N/A
3	Bonneville Power Administration	Ron Sporseen		Negative	Comments Submitted
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	Dominion - Dominion Virginia Power	Bill Garvey		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Alan Kloster	Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Abstain	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Florida Municipal Power Agency	Navid Nowakhtar	LaKenya Vannorman	None	N/A
3	Georgia System Operations Corporation	Scott McGough		Abstain	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	Lincoln Electric System	Sam Christensen		Abstain	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	Muscatine Power and Water	Seth Shoemaker		Negative	Comments Submitted
3	National Grid USA	Brian Shanahan		Abstain	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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney		Negative	Comments Submitted
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Abstain	N/A
3	Platte River Power Authority	Richard Kiess		Negative	Comments Submitted
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		None	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Santee Cooper	Vicky Budreau		Abstain	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		Negative	Comments Submitted
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		None	N/A
3	WEC Energy Group, Inc.	Christine Kane		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Tony Hua		Abstain	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		Negative	Comments Submitted
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
4	Northern California Power Agency	Marty Hostler		Negative	Comments Submitted
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 D. Martinsen		Negative	Comments Submitted
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Ken Habgood		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	Utility Services, Inc.	Tracy MacNicoll		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		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.	Brandon Smith		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		None	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	Black Hills Corporation	Sheila Suurmeier	Carly Miller	Affirmative	N/A
5	Bonneville Power Administration	Christopher Siewert		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Cogentrix Energy Power Management, LLC	Gerry Adamski		None	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Negative	Comments Submitted
5	Con Ed - Consolidated Edison Co. of New York	Helen Wang		Affirmative	N/A
5	Constellation	Alison MacKellar		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Abstain	N/A
5	Dominion - Dominion Resources, Inc.	Anna Salmon		None	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Enel Green Power	Natalie Johnson		Abstain	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Affirmative	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi		Abstain	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Negative	Comments Submitted
5	National Grid USA	Robin Berry		Abstain	N/A
5	NB Power Corporation	David Melanson		Affirmative	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	Richard Vendetti		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Affirmative	N/A
5	Northern California Power Agency	Jeremy Lawson		Negative	Comments Submitted
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		None	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Orlando Utilities Commission	Dania Colon		Affirmative	N/A
5	Pattern Operators LP	George E Brown		Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Negative	Comments Submitted
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Abstain	N/A
5	PSEG Nuclear LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Negative	Comments Submitted
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Salt River Project	Jennifer Bennett	Israel Perez	Affirmative	N/A
5	Santee Cooper	Don Cribb		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Negative	Comments Submitted
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Abstain	N/A
5	Southern Company - Southern Company Generation	Jim Howell, Jr.		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	Tennessee Valley Authority	Nehtisha Rollis		Abstain	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		None	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	WEC Energy Group, Inc.	Clarice Zellmer		Affirmative	N/A
6	AEP	Justin Kuehne		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Imane Mrini		Abstain	N/A
6	Black Hills Corporation	Claudine Bates		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Michael Foley		Affirmative	N/A
6	Constellation	Kimberly Turco		None	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	John Sturgeon		Affirmative	N/A
6	Edison International - Southern California Edison Company	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		Negative	Comments Submitted
6	Great River Energy	Brian Meloy		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Muscatine Power and Water	Nicholas Burns		Negative	Comments Submitted
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Abstain	N/A
6	NiSource - Northern Indiana Public Service Co.	Joseph OBrien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Negative	Comments Submitted
6	Portland General Electric Co.	Stefanie Burke		None	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		None	N/A
6	Public Utility District No. 1 of Chelan County	Anne Kronshage		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	Mike Stussy		None	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Santee Cooper	Marty Watson		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.	Kati Barr		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
6	Western Area Power Administration	Chrystal Dean		Affirmative	N/A
7	Oxy - Occidental Chemical	Venona Greaff		Affirmative	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		None	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Lindsey Mannion	Stephen Whaite	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A

Showing 1 to 268 of 268 entries

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard 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
45-day formal comment period with ballot –Phase 2	2/28/23 – 4/13/23
20-day comment period and additional ballot – Phase 2	8/24/23 – 9/12/23

Anticipated Actions	Date
8-day final ballot	9/29/23 – 10/6/23
NERC Board of Trustees (Board) adoption	October 2023

A. Introduction

1. **Title:** **Emergency Operations**

2. **Number:** **EOP-011-4**

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

   4.1.4 Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

   4.1.5 UFLS-Only Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

   4.1.6 Transmission Owner identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

5. **Effective Date:** See Implementation Plan for Project 2021-07. As provided therein, each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner that receives notification from the Transmission Operator that it is required to assist in the mitigation of operating Emergencies in the Transmission Operator Area under Requirement R7 shall become compliant with Requirement R8 within 30 calendar months of the notification.

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 shed, undervoltage load shed (UVLS), or underfrequency load shed (UFLS) 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, UVLS, or UFLS and circuits that serve designated critical loads which are essential to the reliability of the BES;

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

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;

1.2.5.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity; and

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 excluding critical natural gas infrastructure loads which are essential to the reliability of the BES, as defined by the Applicable Entity, as Interruptible Load, curtailable Load, and demand response during extreme cold weather periods within each Balancing Authority Area;

2.2.9. Provisions for Transmission Operators to implement operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding in accordance with Requirement R1 Part 1.2.5; and

2.2.10. Provisions to determine reliability impacts of:

2.2.10.1. Cold weather conditions; and

2.2.10.2. 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.

R7. Each Transmission Operator shall annually identify and notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Long-term Planning]*

M7. Each Transmission Operator will have documentation, such as dated emails or other correspondences that it identified and notified Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners annually in accordance with Requirement R7.

R8. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area shall develop, maintain, and implement a Load shedding plan. The Load shedding plan shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

8.1. Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding during an Emergency that accounts for each of the following:

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

8.1.2. Provisions to minimize the overlap of circuits that are designated for manual, undervoltage, or underfrequency Load shed and circuits that serve designated critical loads which are essential to the reliability of the BES;

8.1.3. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS;

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

8.1.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity.

8.2. Provisions to provide the Load shedding plan to the Transmission Operator for review.

M8. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area will have a dated Load shedding plan(s) developed in accordance with Requirement R8 and evidence that the Load shedding plan(s) was provided to its Transmission Operator; evidence such as a review or revision history to indicate that the Load shedding 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 Load shedding plan(s) was implemented for times when an Emergency has occurred, in accordance with 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 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.
- 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.
- The Reliability Coordinator shall maintain evidence of compliance since the last audit for Requirements R3, R5, and R6.
- The Transmission Operator shall maintain evidence of compliance since the last audit for Requirement R7.
- The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner shall retain the current Load shedding plan, evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R8.

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	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	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 #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		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	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 #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			Operator within 30 calendar days.	
R4	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	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 #	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	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	N/A	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities more than one, but fewer than 30 days late.	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities 30 days or more, but fewer than 60 days late.	The Transmission Operator did not identify or notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding. OR The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities 60 days or more late.

R8	N/A	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to maintain it in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to provide it to its Transmission Operator in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner failed to develop a Load shedding plan(s) in accordance with Requirement R8. OR The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to implement it in accordance with Requirement R8.

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	October 26, 2022	Adopted by Board of Trustees	Revised under Project 2021-07
3	February 16, 2023	FERC approved EOP-011-3. *N. Am. Elec. Reliability Corp.*, 182 FERC 61,094	
4	TBD		Revised under Project 2021-07

Attachment 1-EOP-011-4
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
45-day formal comment period with ballot –Phase 2	2/28/23 – 4/13/23
20-day comment period and additional ballot – Phase 2	8/24/23 – 9/12/23

Anticipated Actions	Date
8-day final ballot	9/29/23 – 10/6/23
NERC Board of Trustees (Board) adoption	October 2023

A. Introduction

1. **Title:** **Emergency Operations**
2. **Number:** **EOP-011-4**
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

   4.1.4 Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

   4.1.5 UFLS-Only Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

   4.1.6 Transmission Owner identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

5. **Effective Date:** See Implementation Plan for Project 2021-07. As provided therein, each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner that receives notification from the Transmission Operator that it is required to assist in the mitigation of operating Emergencies in the Transmission Operator Area under Requirement R7 shall become compliant with Requirement R8 within 30 calendar months of the notification.

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 or automatic Load shedding~~shed, undervoltage load shed (UVLS), or underfrequency load shed (UFLS) 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 ~~or automatic~~ Load shed, UVLS, or UFLS and circuits that serve designated critical loads which are essential to the reliability of the BES;

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~~)~~;

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;

1.2.5.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES~~; and~~ as defined by the Applicable Entity; and

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 excluding critical natural gas infrastructure loads which are essential to the reliability of the BES, as defined by the Applicable Entity, as Interruptible Load, curtailable Load, and demand response during extreme cold weather periods within each Balancing Authority Area;

2.2.9. Provisions for Transmission Operators to implement operator-controlled manual Load shedding~~ or automatic~~, undervoltage Load shedding, or underfrequency Load shedding in accordance with Requirement R1 Part 1.2.5; and

2.2.10. Provisions to determine reliability impacts of:

2.2.10.1. Cold weather conditions; and

2.2.10.2. 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.

R7. Each Transmission Operator shall annually identify and notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through operator-controlled manual Load shedding~~ or automatic~~, undervoltage Load shedding, or underfrequency Load shedding. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Long-term Planning]*

M7. Each Transmission Operator will have documentation, such as dated emails or other correspondences that it identified and notified Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners annually in accordance with Requirement R7.

R8. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area shall develop, maintain, and implement a Load shedding plan~~, within 30 months of being notified by the Transmission Operator~~. The Load shedding plan shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

8.1. Operator-controlled manual Load shedding~~ or automatic~~, undervoltage Load shedding, or underfrequency Load shedding during an Emergency that accounts for each of the following:

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

8.1.2. Provisions to minimize the overlap of circuits that are designated for manual, undervoltage, or ~~automatic~~underfrequency Load shed and circuits that serve designated critical loads which are essential to the reliability of the BES;

8.1.3. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS;

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

8.1.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES~~.~~ as defined by the Applicable Entity.

8.2. Provisions to provide the Load shedding plan to the Transmission Operator for review.

M8. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating

Emergencies in its Transmission Operator Area will have a dated Load shedding plan(s) developed in accordance with Requirement R8 and evidence that the Load shedding plan(s) was provided to its Transmission Operator; evidence such as a review or revision history to indicate that the Load shedding 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 Load shedding plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R8.

C. Compliance

1. Compliance Monitoring Process

~~1.1.~~ Compliance Enforcement Authority

~~1.2.~~1.1. : "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.

~~1.3.~~ Evidence Retention

~~1.4.~~1.2. : 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.
- 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~~.
- The Reliability Coordinator shall maintain evidence of compliance since the last audit for Requirements R3, R5, and R6.
- The Transmission Operator shall maintain evidence of compliance since the last audit for Requirement R7.
- The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner shall retain the current ~~Operating Plan(s),~~Load shedding plan, evidence of review or revision history plus each version

issued since the last audit and evidence of compliance since the last audit for Requirements R8~~ and~~.

~~1.5.~~ Compliance Monitoring and Enforcement Program:

~~1.6.~~**1.3.** 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	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	N/A	The Balancing Authority developed a Reliability Coordinator- reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to maintain it.	The Balancing Authority developed an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to have it reviewed by its Reliability Coordinator.	The Balancing Authority failed to develop an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				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	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 #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			Operator within 30 calendar days.	
R4	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	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 #	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	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	N/A	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area	The Transmission Operator did not identify or notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its

		through Operator-controlled manual Load shedding~~-~~, undervoltage Load shedding, or ~~automatic~~underfrequency Load shedding, but notified one or more of those entities more than ~~1~~one, but fewer than 30 days late.	through Operator-controlled manual Load shedding ~~or automatic~~, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities 30 days or more, but fewer than 60 days late.	Transmission Operator Area through Operator-controlled manual Load shedding ~~or automatic~~, undervoltage Load shedding, or underfrequency Load shedding. OR The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding ~~or automatic~~, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities 60 days or more late.

R8	N/A	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to maintain it in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to provide it to its Transmission Operator in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner failed to develop a Load shedding plan(s) in accordance with Requirement R8. OR The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to implement it in accordance with Requirement R8.

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	October 26, 2022	Adopted by Board of Trustees	Revised under Project 2021-07
3	February 16, 2023	FERC approved EOP-011-3. *N. Am. Elec. Reliability Corp.*, 182 FERC 61,094	
4	TBD		Revised under Project 2021-07

Attachment 1-EOP-011-4
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
45-day formal comment period with ballot –Phase 2	2/28/23 – 4/13/23
20-day comment period and additional ballot – Phase 2	8/24/23 – 9/12/23

Anticipated Actions	Date
8-day final ballot	9/29/23 – 10/6/23
NERC Board of Trustees (Board) adoption	October 2023

A. Introduction

1. **Title:** **Emergency Operations**

2. **Number:** **EOP-011-~~3~~4**

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

~~**1. Effective Date:** See Implementation Plan for Project 2021-07.~~

   4.1.4 Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

   4.1.5 UFLS-Only Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

   4.1.6 Transmission Owner identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

5. **Effective Date:** See Implementation Plan for Project 2021-07. As provided therein, each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner that receives notification from the Transmission Operator that it is required to assist in the mitigation of operating Emergencies in the Transmission Operator Area under Requirement R7 shall become compliant with Requirement R8 within 30 calendar months of the notification.

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~~shed, undervoltage load shed (UVLS), or underfrequency load shed (UFLS) 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, UVLS, or UFLS and circuits that serve designated critical loads which are essential to the reliability of the BES;

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~~UVLS;

~~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~~.~~;

1.2.5.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity; and

1.2.6. Provisions to determine reliability impacts of:

1.2.6.1. ~~cold~~Cold weather conditions; and

1.2.6.2. ~~extreme~~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~~Capability and availability;

2.2.3.2. ~~fuel~~Fuel supply and inventory concerns;

2.2.3.3. ~~fuel~~Fuel switching capabilities; and

2.2.3.4. ~~environmental~~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 excluding critical natural gas infrastructure loads which are essential to the reliability of the BES, as defined by the Applicable Entity, as Interruptible Load, curtailable Load, and demand response during extreme cold weather periods within each Balancing Authority Area;

~~**2.2.8.**~~**2.2.9.** Provisions for Transmission Operators to implement operator-controlled manual Load ~~shed~~shedding, undervoltage Load shedding, or underfrequency Load shedding in accordance with Requirement R1 Part 1.2.5; and

~~**2.2.9.**~~**2.2.10.** Provisions to determine reliability impacts of:

~~**2.2.9.1.**~~**2.2.10.1.** ~~cold~~Cold weather conditions; and

~~**2.2.9.2.**~~**2.2.10.2.** ~~extreme~~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.

R7. Each Transmission Operator shall annually identify and notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Long-term Planning]*

M7. Each Transmission Operator will have documentation, such as dated emails or other correspondences that it identified and notified Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners annually in accordance with Requirement R7.

R8. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area shall develop, maintain, and implement a Load shedding plan. The Load shedding plan shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

8.1. Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding during an Emergency that accounts for each of the following:

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

8.1.2. Provisions to minimize the overlap of circuits that are designated for manual, undervoltage, or underfrequency Load shed and circuits that serve designated critical loads which are essential to the reliability of the BES;

8.1.3. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS;

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

8.1.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity.

8.2. Provisions to provide the Load shedding plan to the Transmission Operator for review.

M8. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area will have a dated Load shedding plan(s) developed in accordance with Requirement R8 and evidence that the Load shedding plan(s) was provided to its Transmission Operator; evidence such as a review or revision history to indicate that the Load shedding 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 Load shedding plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R8.

C. Compliance

1. Compliance Monitoring Process

~~1.1.~~ **Compliance Enforcement Authority**

1.1. : "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**

1.2. : 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:**

1.3. 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	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	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 #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		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	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 #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			Operator within 30 calendar days.	
R4	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	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 #	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	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	N/A	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities more than one, but fewer than 30 days late.	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities 30 days or more, but fewer than 60 days late.	The Transmission Operator did not identify or notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding. OR The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities 60 days or more late.

R8	N/A	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to maintain it in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to provide it to its Transmission Operator in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner failed to develop a Load shedding plan(s) in accordance with Requirement R8. OR The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to implement it in accordance with Requirement R8.

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
~~2~~3	October ~~28,~~26, 2022	Adopted by Board of Trustees~~FERC Approved EOP-011-3 Docket Number RD23-1-000~~	Revised under Project 2021-07
3	February 16,~~2022~~ 2023	FERC approved EOP-011-3. *N. Am. Elec. Reliability Corp.*, 182 FERC 61,094~~Adopted by Board of Trustees~~	~~Revised under Project 2021-07~~
~~3~~4	TBD	~~Effective Date~~	Revised under Project 2021-07

Attachment 1-EOP-011-~~3~~4 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 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)	11/17/2021
SAR posted for comment	11/22/21 – 12/21/21
45-day formal comment period with ballot –Phase 2	2/28/23 – 4/13/23
20-day formal comment period with additional ballot – Phase 2	8/24/23 – 9/12/23

Anticipated Actions	Date
8-day final ballot	9/29/23 – 10/6/23
Board adoption	October 2023

A. Introduction

1. **Title: Operations Planning**
2. **Number: TOP-002-5**
3. **Purpose:** To ensure that Transmission Operators and Balancing Authorities have plans for operating within specified limits.
4. **Applicability:**
   4.1. Transmission Operator
   4.2. Balancing Authority
5. **Effective Date:**
   See Implementation Plan.
6. **Background:**
   See Project 2021-07 project page.

B. Requirements and Measures

R1. Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Each Transmission Operator shall have evidence of a completed Operational Planning Analysis. Such evidence could include, but is not limited to dated power flow study results.

R2. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Transmission Operator shall have evidence that it has an Operating Plan to address potential System Operating Limits (SOLs) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1. Such evidence could include, but it is not limited to plans for precluding operating in excess of each SOL that was identified as a result of the Operational Planning Analysis.

R3. Each Transmission Operator shall notify entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Transmission Operator shall have evidence that it notified entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in the plan(s). Such evidence could include, but is not limited to dated operator logs, or email records.

R4. Each Balancing Authority shall have an Operating Plan(s) for the next day that addresses: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1 Expected generation resource commitment and dispatch;

4.2 Interchange scheduling;

4.3 Demand patterns; and

4.4 Capacity and energy reserve requirements, including deliverability capability.

M4. Each Balancing Authority shall have evidence that it has developed a plan to operate within the criteria identified. Such evidence could include, but is not limited to dated operator logs or email records.

R5. Each Balancing Authority shall notify entities identified in the Operating Plan(s) cited in Requirement R4 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Each Balancing Authority shall have evidence that it notified entities identified in the plan(s) cited in Requirement R4 as to their role in the plan(s). Such evidence could include, but is not limited to dated operator logs or email records.

R6. Each Transmission Operator shall provide its Operating Plan(s) for next day operations identified in Requirement R2 to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M6. Each Transmission Operator shall have evidence that it provided its Operating Plan(s) for next day operations identified in Requirement R2 to its Reliability Coordinator. Such evidence could include, but is not limited to dated operator logs or email records.

R7. Each Balancing Authority shall provide its Operating Plan(s) for next day operations identified in Requirement R4 to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M7. Each Balancing Authority shall have evidence that it provided its Operating Plan(s) for next day operations identified in Requirement R4 to its Reliability Coordinator. Such evidence could include, but is not limited to dated operator logs or email records.

R8. Each Balancing Authority shall have an extreme cold weather Operating Process for its Balancing Authority Area, addressing preparations for and operations during extreme cold weather periods. The extreme cold weather Operating Process shall include, but is not limited to: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

8.1 A methodology for identifying an extreme cold weather period within each Balancing Authority Area;

8.2 A methodology to determine an adequate reserve margin during the extreme cold weather period considering the generating unit(s) operating limitations in previous extreme cold weather periods that includes, but is not limited to:

8.2.1 Capability and availability;

8.2.2 Fuel supply and inventory concerns;

8.2.3 Start-up issues;

8.2.4 Fuel switching capabilities; and

8.2.5 Environmental constraints.

8.3 A methodology to determine a five-day hourly forecast during the identified extreme cold weather periods that includes, but is not limited to:

8.3.1 Expected generation resource commitment and dispatch;

8.3.2 Demand patterns;

8.3.3 Capacity and energy reserve requirements, including deliverability capability; and

8.3.4 Weather forecast.

M8. Each Balancing Authority shall have evidence that it has developed an extreme cold weather Operating Process in accordance with Requirement R8.

C. Compliance

1. **Compliance Monitoring Process**

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

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

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

   - Each Transmission Operator and Balancing Authority shall keep data or evidence to show compliance for each applicable Requirement for a rolling 90-calendar days period for analyses, the most recent 90-calendar days for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
   - The Balancing Authority shall retain the current Operating Process(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 R8.

   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	N/A	N/A	N/A	The Transmission Operator did not have an Operational Planning Analysis allowing it to assess whether its planned operations for the next day within its Transmission Operator Area exceeded any of its System Operating Limits (SOLs).
R2	N/A	N/A	N/A	The Transmission Operator did not have an Operating Plan to address potential System Operating Limit (SOL) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1.
R3	The Transmission Operator did not notify one impacted entity or 5% or less of the entities, whichever is greater identified in the	The Transmission Operator did not notify two entities or more than 5% and less than or equal to 10% of the impacted entities, whichever is greater, identified in the	The Transmission Operator did not notify three impacted entities or more than 10% and less than or equal to 15% of the entities, whichever is greater, identified in the	The Transmission Operator did not notify four or more entities or more than 15% of the impacted NERC identified in the Operating Plan(s) as to their role in the plan(s).

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Operating Plan(s) as to their role in the plan(s).	Operating Plan(s) as to their role in the plan(s).	Operating Plan(s) as to their role in the plan(s).	
R4	The Balancing Authority has an Operating Plan, but it does not address one of the criteria in Requirement R4.	The Balancing Authority has an Operating Plan, but it does not address two of the criteria in Requirement R4.	The Balancing Authority has an Operating Plan, but it does not address three of the criteria in Requirement R4.	The Balancing Authority did not have an Operating Plan.
R5	The Balancing Authority did not notify one impacted entity or 5% or less of the entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Balancing Authority did not notify two entities or more than 5% and less than or equal to 10% of the impacted entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Balancing Authority did not notify three impacted entities or more than 10% and less than or equal to 15% of the entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Balancing Authority did not notify four or more entities or more than 15% of the impacted entities identified in the Operating Plan(s) as to their role in the plan(s).
R6	N/A	N/A	N/A	The Transmission Operator did not provide its Operating Plan(s) for next day operations as identified in Requirement R2 to its Reliability Coordinator.
R7	N/A	N/A	N/A	The Balancing Authority did not provide its Operating Plan(s) for next day operations as

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				identified in Requirement R4 to its Reliability Coordinator.
R8	N/A	The Balancing Authority had an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods, but it did not address one of the Requirements or sub-Requirements of R8 Parts 8.1 through 8.3.	The Balancing Authority had an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods, but it did not address two of the Requirements or sub-Requirements of R8 Parts 8.1 through 8.3.	The Balancing Authority did not have an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Extreme Cold Weather Preparedness Technical Rationale and Justification for TOP-002-5

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	August 2, 2006	Adopted by Board of Trustees	Revised
2	November 1, 2006	Adopted by Board of Trustees	Revised
2	June 14, 2007	Fixed typo in R11., (subject to …)	Errata
2a	February 10, 2009	Added Appendix 1 – Interpretation of R11 approved by BOT on February 10, 2009	Interpretation
2a	December 2, 2009	Interpretation of R11 approved by FERC on December 2, 2009	Same Interpretation
2b	November 4, 2010	Added Appendix 2 – Interpretation of R10 adopted by the Board of Trustees	
2b	October 20, 2011	FERC Order issued approving the Interpretation of R10 (FERC's Order became effective on October 20, 2011)	
2.1b	March 8, 2012	Errata adopted by Standards Committee; (Removed unnecessary language from the Effective Date section. Deleted retired sub-requirements from Requirement R14)	Errata

Version	Date	Action	Change Tracking
2.1b	April 11, 2012	Additional errata adopted by Standards Committee; (Deleted language from retired sub-requirement from Measure M7)	Errata
2.1b	September 13, 2012	FERC approved	Errata
3	May 6, 2012	Revisions under Project 2007-03	Revised
3	May 9, 2012	Adopted by Board of Trustees	Revised
4	April 2014	Revisions under Project 2014-03	Revised
4	November 13, 2014	Adopted by NERC Board of Trustees	Revisions under Project 2014-03
4	November 19, 2015	FERC approved TOP-002-4. Docket No. RM15-16-000. Order No. 817.	
5	TBD	Revisions under Project 2021-07	Revised

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)	11/17/2021
SAR posted for comment	11/22/21 – 12/21/21
45-day formal comment period with ballot –Phase 2	2/28/23 – 4/13/23
20-day formal comment period with additional ballot – Phase 2	8/24/23 – 9/12/23

Anticipated Actions	Date
8-day final ballot	9/29/23 – 10/6/23
Board adoption	October 2023

A. Introduction

1. **Title: Operations Planning**
2. **Number: TOP-002-5**
3. **Purpose:** To ensure that Transmission Operators and Balancing Authorities have plans for operating within specified limits.
4. **Applicability:**
   4.1. Transmission Operator
   4.2. Balancing Authority
5. **Effective Date:**
   See Implementation Plan.
6. **Background:**
   See Project 2021-07 project page.

B. Requirements and Measures

R1. Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Each Transmission Operator shall have evidence of a completed Operational Planning Analysis. Such evidence could include, but is not limited to dated power flow study results.

R2. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Transmission Operator shall have evidence that it has an Operating Plan to address potential System Operating Limits (SOLs) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1. Such evidence could include, but it is not limited to plans for precluding operating in excess of each SOL that was identified as a result of the Operational Planning Analysis.

R3. Each Transmission Operator shall notify entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Transmission Operator shall have evidence that it notified entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in the plan(s). Such evidence could include, but is not limited to dated operator logs, or email records.

R4. Each Balancing Authority shall have an Operating Plan(s) for the next day that addresses: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1 Expected generation resource commitment and dispatch;

4.2 Interchange scheduling;

4.3 Demand patterns; and

4.4 Capacity and energy reserve requirements, including deliverability capability.

M4. Each Balancing Authority shall have evidence that it has developed a plan to operate within the criteria identified. Such evidence could include, but is not limited to dated operator logs or email records.

R5. Each Balancing Authority shall notify entities identified in the Operating Plan(s) cited in Requirement R4 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Each Balancing Authority shall have evidence that it notified entities identified in the plan(s) cited in Requirement R4 as to their role in the plan(s). Such evidence could include, but is not limited to dated operator logs or email records.

R6. Each Transmission Operator shall provide its Operating Plan(s) for next day operations identified in Requirement R2 to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M6. Each Transmission Operator shall have evidence that it provided its Operating Plan(s) for next day operations identified in Requirement R2 to its Reliability Coordinator. Such evidence could include, but is not limited to dated operator logs or email records.

R7. Each Balancing Authority shall provide its Operating Plan(s) for next day operations identified in Requirement R4 to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M7. Each Balancing Authority shall have evidence that it provided its Operating Plan(s) for next day operations identified in Requirement R4 to its Reliability Coordinator. Such evidence could include, but is not limited to dated operator logs or email records.

R8. Each Balancing Authority shall have an extreme cold weather Operating Process for its Balancing Authority Area, addressing preparations for and operations during extreme cold weather periods. The extreme cold weather Operating Process shall include, but is not limited to: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

8.1 A methodology for identifying an extreme cold weather period within each Balancing Authority Area;

8.2 A methodology to determine an adequate reserve margin during the extreme cold weather period considering the generating unit(s) operating limitations in previous extreme cold weather periods that includes, but is not limited to:

8.2.1 Capability and availability;

8.2.2 Fuel supply and inventory concerns;

8.2.3 Start-up issues;

8.2.4 Fuel switching capabilities; and

8.2.5 Environmental constraints.

8.3 A methodology to determine a five-day hourly forecast during the identified extreme cold weather periods that includes, but is not limited to:

8.3.1 Expected generation resource commitment and dispatch;

8.3.2 ~~Interchange scheduling~~Demand patterns;

8.3.3 ~~Demand patterns;~~

~~**8.3.4**~~ Capacity and energy reserve requirements, including deliverability capability; and

8.3.~~5~~4 Weather forecast.

M8. Each Balancing Authority shall have evidence that it has developed an extreme cold weather Operating Process in accordance with Requirement R8.

C. Compliance

1. Compliance Monitoring Process

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

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

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

- Each Transmission Operator and Balancing Authority shall keep data or evidence to show compliance for each applicable Requirement for a rolling 90-calendar days period for analyses, the most recent 90-calendar days for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

~~If a Transmission Operator or~~ The Balancing Authority ~~is found non-compliant, it~~ shall ~~keep information related to~~retain the ~~non-compliance until found compliant or the time period specified above, whichever is longer.~~

- ~~The Compliance Enforcement Authority shall keep~~current Operating Process(s), evidence of review or revision history plus each version issued since the last audit ~~records~~ and ~~all requested and submitted subsequent audit records.~~ evidence of compliance since the last audit for Requirement R8.

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

~~Table of Compliance Elements~~

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Transmission Operator did not have an Operational Planning Analysis allowing it to assess whether its planned operations for the next day within its Transmission Operator Area exceeded any of its System Operating Limits (SOLs).
R2	N/A	N/A	N/A	The Transmission Operator did not have an Operating Plan to address potential System Operating Limit (SOL) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1.
R3	The Transmission Operator did not notify one impacted entity or 5% or less of the entities, whichever is greater identified in the	The Transmission Operator did not notify two entities or more than 5% and less than or equal to 10% of the impacted entities, whichever is	The Transmission Operator did not notify three impacted entities or more than 10% and less than or equal to 15% of the entities, whichever is	The Transmission Operator did not notify four or more entities or more than 15% of the impacted NERC identified in the

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	Operating Plan(s) as to their role in the plan(s).	greater, identified in the Operating Plan(s) as to their role in the plan(s).	greater, identified in the Operating Plan(s) as to their role in the plan(s).	Operating Plan(s) as to their role in the plan(s).
R4	The Balancing Authority has an Operating Plan, but it does not address one of the criteria in Requirement R4.	The Balancing Authority has an Operating Plan, but it does not address two of the criteria in Requirement R4.	The Balancing Authority has an Operating Plan, but it does not address three of the criteria in Requirement R4.	The Balancing Authority did not have an Operating Plan.
R5	The Balancing Authority did not notify one impacted entity or 5% or less of the entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Balancing Authority did not notify two entities or more than 5% and less than or equal to 10% of the impacted entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Balancing Authority did not notify three impacted entities or more than 10% and less than or equal to 15% of the entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Balancing Authority did not notify four or more entities or more than 15% of the impacted entities identified in the Operating Plan(s) as to their role in the plan(s).
R6	N/A	N/A	N/A	The Transmission Operator did not provide its Operating Plan(s) for next day operations as identified in Requirement R2 to its Reliability Coordinator.
R7	N/A	N/A	N/A	The Balancing Authority did not provide its Operating Plan(s) for

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				next day operations as identified in Requirement R4 to its Reliability Coordinator.
R8	N/A	The Balancing Authority had an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods, but it did not address one of the Requirements or sub-Requirements of R8 Parts 8.1 through 8.3.	The Balancing Authority had an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods, but it did not address two of the Requirements or sub-Requirements of R8 Parts 8.1 through 8.3.	The Balancing Authority did not have an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Extreme Cold Weather Preparedness Technical Rationale and Justification for TOP-002-5

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	August 2, 2006	Adopted by Board of Trustees	Revised
2	November 1, 2006	Adopted by Board of Trustees	Revised
2	June 14, 2007	Fixed typo in R11., (subject to …)	Errata
2a	February 10, 2009	Added Appendix 1 – Interpretation of R11 approved by BOT on February 10, 2009	Interpretation
2a	December 2, 2009	Interpretation of R11 approved by FERC on December 2, 2009	Same Interpretation
2b	November 4, 2010	Added Appendix 2 – Interpretation of R10 adopted by the Board of Trustees	
2b	October 20, 2011	FERC Order issued approving the Interpretation of R10 (FERC’s Order became effective on October 20, 2011)	
2.1b	March 8, 2012	Errata adopted by Standards Committee; (Removed unnecessary language from the Effective Date section. Deleted retired sub-requirements from Requirement R14)	Errata

Version	Date	Action	Change Tracking
2.1b	April 11, 2012	Additional errata adopted by Standards Committee; (Deleted language from retired sub-requirement from Measure M7)	Errata
2.1b	September 13, 2012	FERC approved	Errata
3	May 6, 2012	Revisions under Project 2007-03	Revised
3	May 9, 2012	Adopted by Board of Trustees	Revised
4	April 2014	Revisions under Project 2014-03	Revised
4	November 13, 2014	Adopted by NERC Board of Trustees	Revisions under Project 2014-03
4	November 19, 2015	FERC approved TOP-002-4. Docket No. RM15-16-000. Order No. 817.	
5	TBD	Revisions under Project 2021-07	Revised

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)	11/17/2021
SAR posted for comment	11/22/21 – 12/21/21
45-day formal comment period with ballot –Phase 2	2/28/23 – 4/13/23
20-day formal comment period with additional ballot – Phase 2	8/24/23 – 9/12/23

Anticipated Actions	Date
8-day final ballot	9/29/23 – 10/6/23
Board adoption	October 2023

A. Introduction

1. **Title: Operations Planning**

2. **Number: TOP-002-~~4~~5**

3. **Purpose:** To ensure that Transmission Operators and Balancing Authorities have plans for operating within specified limits.

4. **Applicability:**

   4.1. Transmission Operator

   4.2. Balancing Authority

5. **Effective Date:**

   See Implementation Plan.

6. **Background:**

   ~~See Project 2014-03 project page.~~

   See Project 2021-07 project page.

B. Requirements and Measures

R1. Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Each Transmission Operator shall have evidence of a completed Operational Planning Analysis. Such evidence could include, but is not limited to dated power flow study results.

R2. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Transmission Operator shall have evidence that it has an Operating Plan to address potential System Operating Limits (SOLs) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1. Such evidence could include, but it is not limited to plans for precluding operating in excess of each SOL that was identified as a result of the Operational Planning Analysis.

R3. Each Transmission Operator shall notify entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Transmission Operator shall have evidence that it notified entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in the plan(s). Such

evidence could include, but is not limited to dated operator logs, or ~~e-mail~~email records.

R4. Each Balancing Authority shall have an Operating Plan(s) for the next~~-~~ day that addresses: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1 Expected generation resource commitment and dispatch;

4.2 Interchange scheduling;

4.3 Demand patterns~~.~~; and

4.4 Capacity and energy reserve requirements, including deliverability capability.

M4. Each Balancing Authority shall have evidence that it has developed a plan to operate within the criteria identified. ~~-~~Such evidence could include, but is not limited to dated operator logs or ~~e-mail~~email records.

R5. Each Balancing Authority shall notify entities identified in the Operating Plan(s) cited in Requirement R4 as to their role in those plan(s). ~~-~~*[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Each Balancing Authority shall have evidence that it notified entities identified in the plan(s) cited in Requirement R4 as to their role in the plan(s). ~~-~~Such evidence could include, but is not limited to dated operator logs or ~~e-mail~~email records.

R6. Each Transmission Operator shall provide its Operating Plan(s) for next~~-~~ day operations identified in Requirement R2 to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M6. Each Transmission Operator shall have evidence that it provided its Operating Plan(s) for next~~-~~ day operations identified in Requirement R2 to its Reliability Coordinator. Such evidence could include, but is not limited to dated operator logs or ~~e-mail~~email records.

R7. Each Balancing Authority shall provide its Operating Plan(s) for next~~-~~ day operations identified in Requirement R4 to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M7. Each Balancing Authority shall have evidence that it provided its Operating Plan(s) for next~~-~~ day operations identified in Requirement R4 to its Reliability Coordinator. Such evidence could include, but is not limited to dated operator logs or ~~e-mail~~email records.

R8. Each Balancing Authority shall have an extreme cold weather Operating Process for its Balancing Authority Area, addressing preparations for and operations during extreme cold weather periods. The extreme cold weather Operating Process shall include, but is not limited to: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

8.1 A methodology for identifying an extreme cold weather period within each Balancing Authority Area;

8.2 A methodology to determine an adequate reserve margin during the extreme cold weather period considering the generating unit(s) operating limitations in previous extreme cold weather periods that includes, but is not limited to:

- **8.2.1** Capability and availability;
- **8.2.2** Fuel supply and inventory concerns;
- **8.2.3** Start-up issues;
- **8.2.4** Fuel switching capabilities; and
- **8.2.5** Environmental constraints.

8.3 A methodology to determine a five-day hourly forecast during the identified extreme cold weather periods that includes, but is not limited to:

- **8.3.1** Expected generation resource commitment and dispatch;
- **8.3.2** Demand patterns;
- **8.3.3** Capacity and energy reserve requirements, including deliverability capability; and
- **8.3.4** Weather forecast.

M8. Each Balancing Authority shall have evidence that it has developed an extreme cold weather Operating Process in accordance with Requirement R8.

C. Compliance

1. Compliance Monitoring Process

~~1.1.~~ Compliance Enforcement Authority

~~1.2.~~1.1. ~~As defined in the NERC Rules of Procedure,~~: "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 NERC~~mandatory and enforceable Reliability Standards in their respective jurisdictions.

~~1.3. Compliance Monitoring and Assessment Processes~~

~~As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" 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.~~

~~1.4.~~ ~~Data~~Evidence Retention

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

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

- Each Transmission Operator and Balancing Authority shall keep data or evidence to show compliance for each applicable Requirement for a rolling 90-calendar days period for analyses, the most recent 90-calendar days for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

~~If a Transmission Operator or~~The Balancing Authority ~~is found non-compliant, it~~ shall ~~keep information related to the non-~~retain the current Operating Process(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance ~~until found compliant or the time period specified above, whichever is longer.~~

- ~~The Compliance Enforcement Authority shall keep~~since the last audit ~~records and all requested and submitted subsequent audit records~~ for Requirement R8.

~~1.5. Additional Compliance Information~~

~~None.~~

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	N/A	N/A	N/A	The Transmission Operator did not have an Operational Planning Analysis allowing it to assess whether its planned operations for the next day within its Transmission Operator Area exceeded any of its System Operating Limits (SOLs).
R2	N/A	N/A	N/A	The Transmission Operator did not have an Operating Plan to address potential System Operating Limit (SOL) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1.
R3	The Transmission Operator did not notify one impacted entity or 5% or less of the entities, whichever is greater identified in the	The Transmission Operator did not notify two entities or more than 5% and less than or equal to 10% of the impacted entities, whichever is greater, identified in the	The Transmission Operator did not notify three impacted entities or more than 10% and less than or equal to 15% of the entities, whichever is greater, identified in the	The Transmission Operator did not notify four or more entities or more than 15% of the impacted NERC identified in the Operating Plan(s) as to their role in the plan(s).

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Operating Plan(s) as to their role in the plan(s).	Operating Plan(s) as to their role in the plan(s).	Operating Plan(s) as to their role in the plan(s).	
R4	The Balancing Authority has an Operating Plan, but it does not address one of the criteria in Requirement R4.	The Balancing Authority has an Operating Plan, but it does not address two of the criteria in Requirement R4.	The Balancing Authority has an Operating Plan, but it does not address three of the criteria in Requirement R4.	The Balancing Authority did not have an Operating Plan.
R5	The Balancing Authority did not notify one impacted entity or 5% or less of the entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Balancing Authority did not notify two entities or more than 5% and less than or equal to 10% of the impacted entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Balancing Authority did not notify three impacted entities or more than 10% and less than or equal to 15% of the entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s).	The Balancing Authority did not notify four or more entities or more than 15% of the impacted entities identified in the Operating Plan(s) as to their role in the plan(s).
R6	N/A	N/A	N/A	The Transmission Operator did not provide its Operating Plan(s) for next day operations as identified in Requirement R2 to its Reliability Coordinator.
R7	N/A	N/A	N/A	The Balancing Authority did not provide its Operating Plan(s) for next day operations as

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				identified in Requirement R4 to its Reliability Coordinator.
R8	N/A	The Balancing Authority had an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods, but it did not address one of the Requirements or sub-Requirements of R8 Parts 8.1 through 8.3.	The Balancing Authority had an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods, but it did not address two of the Requirements or sub-Requirements of R8 Parts 8.1 through 8.3.	The Balancing Authority did not have an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

~~Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.~~

Extreme Cold Weather Preparedness Technical Rationale and Justification for TOP-002-5

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	August 2, 2006	Adopted by Board of Trustees	Revised
2	November 1, 2006	Adopted by Board of Trustees	Revised
2	June 14, 2007	Fixed typo in R11., (subject to …)	Errata
2a	February 10, 2009	Added Appendix 1 – Interpretation of R11 approved by BOT on February 10, 2009	Interpretation
2a	December 2, 2009	Interpretation of R11 approved by FERC on December 2, 2009	Same Interpretation
2b	November 4, 2010	Added Appendix 2 – Interpretation of R10 adopted by the Board of Trustees	
2b	October 20, 2011	FERC Order issued approving the Interpretation of R10 (FERC's Order became effective on October 20, 2011)	
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2.1b	April 11, 2012	Additional errata adopted by Standards Committee; (Deleted language from retired sub-requirement from Measure M7)	Errata
2.1b	September 13, 2012	FERC approved	Errata
3	May 6, 2012	Revisions under Project 2007-03	Revised
3	May 9, 2012	Adopted by Board of Trustees	Revised

4	April 2014	Revisions under Project 2014-03	Revised
4	November 13, 2014	Adopted by NERC Board of Trustees	Revisions under Project 2014-03
4	November 19, 2015	FERC approved TOP-002-4. Docket No. RM15-16-000. -Order No. 817.	
5	TBD	Revisions under Project 2021-07	Revised

~~Guidelines and Technical Basis~~

~~Rationale:~~

~~During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.~~

~~Rationale for Definitions:~~

~~Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.~~

~~Rationale for R1:~~

~~Terms deleted in Requirement R1 as they are now contained in the revised definition of Operational Planning Analysis~~

~~Rationale for R2:~~

~~The change to Requirement R2 is in response to NOPR paragraph 42 and in concert with proposed changes made to proposed TOP-001-4~~

~~Rationale for R3:~~

~~Changes in response to IERP recommendation~~

~~Rationale for R4 and R5:~~

~~These Requirements were added to address IERP recommendations~~

~~Rationale for R6 and R7:~~

~~Added in response to SW Outage Report recommendation 1~~

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 – Reliability Standards EOP-011-4 and TOP-002-5

Applicable Standard(s)

- EOP-011-4 Emergency Operations
- TOP-002-5 Operations Planning

Requested Retirement(s)

- EOP-011-3
- TOP-002-4

Prerequisite Standard(s)

- None

Proposed Definition(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 (the "Joint Inquiry 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 outaged megawatts (MW) of load after the August 2003 Northeast blackout and the August 1996 West Coast

[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 Joint Inquiry Report").

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). At the time the Event occurred, the Event was the fourth in the previous 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 Joint Inquiry Report for new or enhanced NERC Reliability Standards. Phase 1 of this project developed Reliability Standards EOP-011-3 and EOP-012-1. This implementation plan addresses Reliability Standards EOP-011-4 and TOP-002-5, which were developed to address the Phase 2 recommendations.

Proposed Reliability Standard EOP-011-4 is a revised Reliability Standard that builds upon changes first made in Reliability Standard EOP-011-3 to address Recommendation 1j of the Joint Inquiry Report regarding minimizing the overlap of manual Load shed and automatic Load shed programs such as underfrequency Load shed (UFLS) and undervoltage Load shed (UVLS). Proposed EOP-011-4 includes new requirements for excluding critical natural gas loads from load shed programs during periods where their participation could adversely impact the BES and for relevant entities to develop Operating Plan(s) addressing load shed considerations in response to Recommendations 1h and 1i of the Joint Inquiry Report.

Proposed Reliability Standard TOP-002-5 is a revised Reliability Standard that would require the Balancing Authority to specifically address extreme cold weather in its Operating Plans, including developing a methodology to determine the number of resources that can reasonably be expected to be available during extreme cold weather conditions. These revisions were developed to address Key Recommendation 1g of the Joint Inquiry Report.

General Considerations

This implementation plan reflects consideration that entities will need time to develop and implement new Requirements as follows:

For proposed Reliability Standard EOP-011-4, this plan reflects consideration of the interaction that will be required between applicable entities and natural gas entities, as well as the fact that several

entities (Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner) will have obligations under this standard for the first time under proposed Requirement R8.

For proposed TOP-002-5, this implementation plan reflects consideration of the time needed to develop and implement a new extreme cold weather Operating Process under proposed Requirement R8.

The implementation timeframe is not intended to extend the timeframe for an entity's existing responsibilities regarding load shedding under EOP-011-2 or EOP-011-3; rather, the additional timeframe is intended to provide additional time to come into compliance with new and revised requirements specific to EOP-011-4.

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.

Reliability Standard EOP-011-4

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 six (6) 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 six (6) 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-011-4 – Requirement R1 Part 1.2.5

Entities shall not be required to comply with the new and revised provisions (i.e., specific to UVLS, UFLS and critical natural gas infrastructure loads) in Requirement R1 Part 1.2.5 until 30 months after the effective date of Reliability Standard EOP-011-4.

Compliance Date for EOP-011-4 – Requirement R2 Part 2.2.8 and Part 2.2.9

Entities shall not be required to comply with the new and revised provisions (i.e., specific to UVLS, UFLS and critical natural gas infrastructure loads) in Requirement R2 Part 2.2.8 and Part 2.2.9 until 30 months after the effective date of Reliability Standard EOP-011-4.

Compliance Date for EOP-011-4 – Requirement R8

Entities shall not be required to comply with Requirement R8 until the later of: (1) 30 calendar months following notification by a Transmission Operator under EOP-011-4 Requirement R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area; or (2) 30 months after the effective date of Reliability Standard EOP-011-4.

Reliability Standard TOP-002-5

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.

Retirement Date

Reliability Standards EOP-011-3 and TOP-002-4

Reliability Standards EOP-011-3 and TOP-002-4 shall be retired immediately prior to the effective date of Reliability Standards EOP-011-4 and TOP-002-5 in the particular jurisdiction in which the revised standards are becoming effective.

Time Period to Address New Designations under EOP-011-4 Requirements R7, R8

Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner that receives notification from the Transmission Operator that it is required to assist in the mitigation of operating Emergencies in the Transmission Operator Area under Requirement R7 shall become compliant with Requirement R8 within 30 calendar months of the notification.

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Implementation Plan

Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 – Reliability Standards EOP-011-4 and TOP-002-5

Applicable Standard(s)

- EOP-011-4 Emergency Operations
- TOP-002-5 Operations Planning

Requested Retirement(s)

- EOP-011-3
- TOP-002-4

Prerequisite Standard(s)

- None

Proposed Definition(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 (the "Joint Inquiry 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 outaged megawatts (MW) of load after the August 2003 Northeast blackout and the August 1996 West Coast

[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 Joint Inquiry Report").

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). At the time the Event occurred, the Event was the fourth in the previous 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 Joint Inquiry Report for new or enhanced NERC Reliability Standards. Phase 1 of this project developed Reliability Standards EOP-011-3 and EOP-012-1. This implementation plan addresses Reliability Standards EOP-011-4 and TOP-002-5, which were developed to address the Phase 2 recommendations.

Proposed Reliability Standard EOP-011-4 is a revised Reliability Standard that builds upon changes first made in Reliability Standard EOP-011-3 to address Recommendation 1j of the Joint Inquiry Report regarding minimizing the overlap of manual Load shed and automatic Load shed programs such as underfrequency Load shed (UFLS) and undervoltage Load shed (UVLS). Proposed EOP-011-4 includes new requirements for excluding critical natural gas loads from load shed programs during periods where their participation could adversely impact the BES and for relevant entities to develop Operating Plan(s) addressing load shed considerations in response to Recommendations 1h and 1i of the Joint Inquiry Report.

Proposed Reliability Standard TOP-002-5 is a revised Reliability Standard that would require the Balancing Authority to specifically address extreme cold weather in its Operating Plans, including developing a methodology to determine the number of resources that can reasonably be expected to be available during extreme cold weather conditions. These revisions were developed to address Key Recommendation 1g of the Joint Inquiry Report.

General Considerations

This implementation plan reflects consideration that entities will need time to develop and implement new Requirements as follows:

For proposed Reliability Standard EOP-011-4, this plan reflects consideration of the interaction that will be required between applicable entities and natural gas entities, as well as the fact that several

entities (Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner) will have obligations under this standard for the first time under proposed Requirement R8.

For proposed TOP-002-5, this implementation plan reflects consideration of the time needed to develop and implement a new extreme cold weather Operating Process under proposed Requirement R8.

The implementation timeframe is not intended to extend the timeframe for an entity's existing responsibilities regarding load shedding under EOP-011-2 or EOP-011-3; rather, the additional timeframe is intended to provide additional time to come into compliance with new and revised requirements specific to EOP-011-4.

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.

Reliability Standard EOP-011-4

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 six (6) 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 six (6) 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-011-4 – Requirement R1 Part 1.2.5

Entities shall not be required to comply with the new and revised provisions (i.e~~.~~., specific to UVLS, UFLS and critical natural gas infrastructure loads) in Requirement R1 Part 1.2.5 until 30 months after the effective date of Reliability Standard EOP-011-4.

Compliance Date for EOP-011-4 – Requirement R2 Part 2.2.8 and Part 2.2.9

Entities shall not be required to comply with the new and revised provisions (i.e~~.~~., specific to UVLS, UFLS and critical natural gas infrastructure loads) in Requirement R2 Part 2.2.8 and Part 2.2.9 until 30 months after the effective date of Reliability Standard EOP-011-4.

Compliance Date for EOP-011-4 – Requirement R8

Entities shall not be required to comply with Requirement R8 until the later of: (1) 30 calendar months following notification by a Transmission Operator ~~per~~under EOP-011-4 Requirement R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area; or (2) 30 months after the effective date of Reliability Standard EOP-011-4.

Reliability Standard TOP-002-5

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.

Retirement Date

Reliability Standards EOP-011-3 and TOP-002-4

Reliability Standards EOP-011-3 and TOP-002-4 shall be retired immediately prior to the effective date of Reliability Standards EOP-011-4 and TOP-002-5 in the particular jurisdiction in which the revised standards are becoming effective.

Time Period to Address New Designations under EOP-011-4 Requirements R7, R8

Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner that receives notification from the Transmission Operator that it is required to assist in the mitigation of operating Emergencies in the Transmission Operator Area under Requirement R7 shall become compliant with Requirement R8 within 30 calendar months of the notification.

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-011-4

VRF Justification for EOP-011-4, Requirement R1

The VRF did not change from the previous EOP-011-3 Reliability Standard.

VSL Justification for EOP-011-4, Requirement R1

The VSL did not change from the previous EOP-011-3 Reliability Standard.

VRF Justification for EOP-011-4, Requirement R2

The VRF did not change from the previous EOP-011-3 Reliability Standard.

VSL Justification for EOP-011-4, Requirement R2

The VSL did not change from the previous EOP-011-3 Reliability Standard.

VRF Justification for EOP-011-4, Requirement R3

The VRF did not change from the previous EOP-011-3 Reliability Standard.

VSL Justification for EOP-011-4, Requirement R3

The VSL did not change from the previous EOP-011-3 Reliability Standard.

VRF Justification for EOP-011-4, Requirement R4

The VRF did not change from the previous EOP-011-3 Reliability Standard.

VSL Justification for EOP-011-4, Requirement R4

The VSL did not change from the previous EOP-011-3 Reliability Standard.

VRF Justification for EOP-011-4, Requirement R5

The VRF did not change from the previous EOP-011-3 Reliability Standard.

VSL Justification for EOP-011-4, Requirement R5

The VSL did not change from the previous EOP-011-3 Reliability Standard.

VRF Justification for EOP-011-4, Requirement R6

The VRF did not change from the previous EOP-011-3 Reliability Standard.

VSL Justification for EOP-011-4, Requirement R6

The VSL did not change from the previous EOP-011-3 Reliability Standard.

VRF Justifications for EOP-011-4, Requirement R7	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to the fact that identifying and notifying entities that are required to assist with the mitigation of operating Emergencies through operator-controlled manual Load shedding or automatic Load shedding 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. Therefore, it is in line with the definition of a Lower 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	The assignment of Lower VRF is consistent with the VRF assignments for other requirements in the proposed 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 Lower VRF requirement per the criteria filed with FERC as part of the ERO’s Sanctions Guidelines.
FERC VRF G5 Discussion	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective.

VRF Justifications for EOP-011-4, Requirement R7	
Proposed VRF	**Lower**
Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	Therefore, the VRF reflects the risk of the whole requirement.

VSLs for EOP-011-4, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
N/A	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities more than one, but fewer than 30 days late.	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities 30 days or more, but fewer than 60 days late.	The Transmission Operator did not identify or notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding. OR The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of

			those entities 60 days or more late.

VSL Justifications for EOP-011-4, 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 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-011-4, Requirement R8	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate due to the fact that a lack of a Load shedding plan 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. Therefore, it is in line with the definition of a High 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	The assignment of High VRF is consistent with the VRF assignments for other requirements in the proposed 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 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-011-4, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
N/A	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to maintain it in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to provide it to its Transmission Operator in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner failed to develop a Load shedding plan(s) in accordance with Requirement R8. OR The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to implement it in accordance with Requirement R8.

TOP-002-5

VRF Justification for TOP-002-5, Requirement R1
The VRF did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VSL Justification for TOP-002-5, Requirement R1
The VSL did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VRF Justification for TOP-002-5, Requirement R2
The VRF did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VSL Justification for TOP-002-5, Requirement R2

The VSL did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VRF Justification for TOP-002-5, Requirement R3
The VRF did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VSL Justification for TOP-002-5, Requirement R3
The VSL did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VRF Justification for TOP-002-5, Requirement R4
The VRF did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VSL Justification for TOP-002-5, Requirement R4
The VSL did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VRF Justification for TOP-002-5, Requirement R5
The VRF did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VSL Justification for TOP-002-5, Requirement R5
The VSL did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VRF Justification for TOP-002-5, Requirement R6
The VRF did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VSL Justification for TOP-002-5, Requirement R6
The VSL did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VRF Justification for TOP-002-5, Requirement R7
The VRF did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VSL Justification for TOP-002-5, Requirement R7
The VSL did not change from the previously FERC approved TOP-002-4 Reliability Standard.

VRF Justifications for TOP-002-5, Requirement R8	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that not having an Operating Process to identify cold weather and calculate appropriate demand and reserves while accounting for generating unit operation limitations 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	The assignment of Medium VRF is consistent with the VRF assignments for other requirements in the proposed 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 TOP-002-5, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
N/A	The Balancing Authority had an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods, but it did not address one of the Requirements or sub-Requirements of R8 Parts 8.1 through 8.3.	The Balancing Authority had an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods, but it did not address two of the Requirements or sub-Requirements of R8 Parts 8.1 through 8.3.	The Balancing Authority did not have an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods.

VSL Justifications for TOP-002-5, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed 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.

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Extreme Cold Weather Preparedness

Technical Rationale and Justification for EOP-011-4

September 2023

RELIABILITY | RESILIENCE | SECURITY




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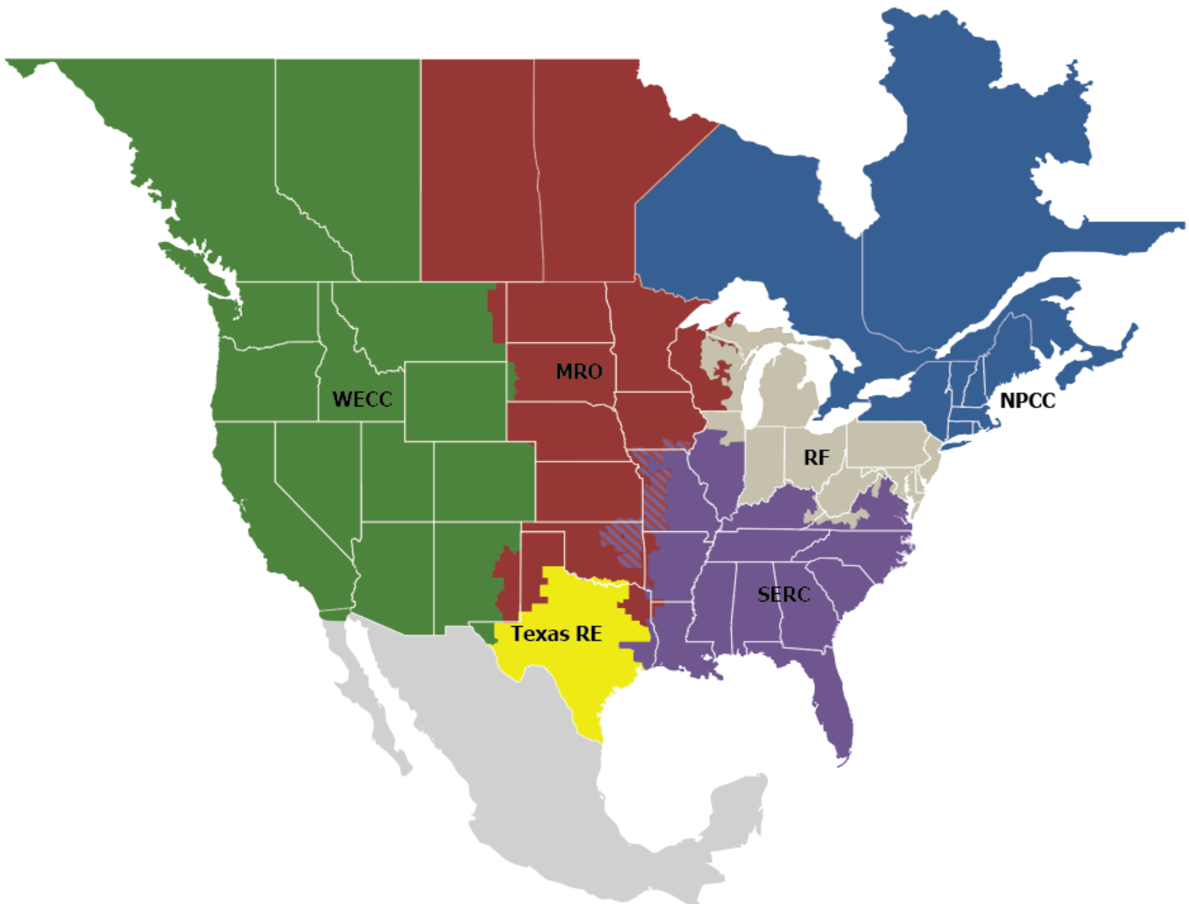
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of 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 proposed Reliability Standard EOP-011-4. 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-011-4 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 10 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 was completed by September 30, 2022, and submitted 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, R7, and R8

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. *Operator-controlled manual Load shedding undervoltage load shed (UVLS), or underfrequency load shed (UFLS) 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, UVLS, or UFLS and circuits that serve designated critical loads which are essential to the reliability of the BES;*

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

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;*

1.2.5.5. *Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity; and*

1.2.6. *Provisions to determine reliability impacts of:*

1.2.6.1. *Cold weather conditions; and*

1.2.6.2. *Extreme weather conditions.*

R7. *Each Transmission Operator shall annually identify and notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding.*

R8. *Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area shall develop, maintain, and implement a Load shedding plan. The Load shedding plan shall include the following, as applicable:*

8.1. *Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load* *shedding during an Emergency that accounts for each of the following:*

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

8.1.2. *Provisions to minimize the overlap of circuits that are designated for manual, undervoltage, or underfrequency Load shed and circuits that serve designated critical loads which are essential to the reliability of the BES;*

8.1.3. *Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS;*

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

8.1.5. *Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity.*

8.2. *Provisions to provide the Load shedding plan to the Transmission Operator for review.*

<u>Key Recommendation 1i:</u> 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)*

Applicability, Requirement R7 and R8

Expansion of Applicability

In many cases, Transmission Operators are dependent on Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners to implement portions of Requirement R1.2.5. The Project 2021-07 standard drafting team (SDT) determined that it is necessary to expand the Applicability of EOP-011-4 to these Functional Entities in order to address all entities responsible for performing operator-controlled manual Load shedding, UFLS, or UVLS per Key Recommendation 1i. Planning Coordinators and Transmission Planners were purposely excluded from applicability even though they are mentioned in Key Recommendation 1i because they are not responsible for performing operator-controlled manual Load shedding, UFLS, or UVLS.

EOP-011-4 Requirement R7 is a new requirement that was added to require that Transmission Operators annually identify and notify any Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners that are required to assist with mitigation of operating Emergencies in their Transmission Operator Area. The Transmission Operator has the overarching responsibility to mitigate operating Emergencies. If a Transmission Operator relies on other functional entities in accomplishing various aspects of manual Load shedding, UFLS, or UVLS, they must be identified and notified per R7. Those identified and notified entities are subject to Requirement R8. The initial performance of R7 is required upon the effective date of EOP-011-4, which is on the first day of the first calendar quarter that is six 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. This approach to Requirement R7 ensures that newly applicable entities who will be subject to Requirement R8 are identified and notified in a timely manner thus minimizing any delay in implementing Requirement R8. Requirement R7 includes an annual provision to ensure that any additional entities, or changes to existing entities, required to assist with the mitigation of Operating emergencies are appropriately identified and notified on an ongoing basis.

EOP-011-4 Requirement R8 is a new requirement that is specific to Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners identified by the Transmission Operator in Requirement R7. It includes the relevant portions of Requirement R1.2.5 that address operator-controlled manual Load shedding, ULFS or UVLS. The SDT found it appropriate to place these requirements specifically on Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners because many times they are the entities performing operator-controlled manual Load shedding, UFLS or UVLS and have the capability of ensuring that these requirements are appropriately implemented for the Loads they represent. Entities that are subject to R8 have 30 months after being notified by a Transmission Operator in R7 to become compliant with these requirements.

Requirement R1, Part 1.2.5 and Requirement R8, Part 8.1

EOP-011-4 Requirement R1.2.5.5 was added to require Transmission Operators to include provisions to identify and prioritize critical natural gas infrastructure Loads which are essential to the reliability of the BES in their Operating Plan(s). EOP-011-4 Requirement R8.1.5 mirrors this requirement and is applicable to Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners. In addition to the following content, entities are encouraged to review guidance from *Reliability Guideline: Gas and Electrical Operational Coordination Considerations* in developing their approach to identify and prioritize critical natural gas infrastructure loads.

Manual, Undervoltage, and Underfrequency

EOP-011-4 Requirement 1.2.5 was modified to include undervoltage load shed and underfrequency load shed in addition to "operator-controlled manual Load shedding." The addition of UVLS and UFLS throughout Requirement R1.2.5 requires these specific load shed processes to account for minimization of overlap between the different processes. An additional result of this modification is that Requirement R1.2.5.5, which requires the identification and prioritization of critical natural gas Loads, by the Applicable Entity (Distribution Provider or Transmission Owner serving the end-use customer), which are essential to the reliability of the BES, is also applicable to Load shedding, be it manual or UVLS or UFLS. It is important to identify and prioritize critical natural gas Loads not just for the purposes of manual Load shed but also in consideration of Load shedding schemes. This modification does not prohibit the inclusion of critical natural gas Loads in Load shedding, but it does require the prioritization of critical natural gas Loads which are essential to the reliability of the BES. This change was also incorporated into the new EOP-011-4 Requirement R8.1.

Critical Natural Gas Infrastructure Loads

The SDT has elected to add clarifying language in the applicable requirements and expand content in this Technical Rationale document in lieu of making "critical natural gas infrastructure Load" a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may necessarily have been overly broad; and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.

A reasonable application of this term should be informed by the entity's approved governing documents and guidance established by applicable regulatory authorities. A practical example of guidance that provides reasonable direction and flexibility has been developed by the Public Utility Commission of Texas in response to Winter Storm Uri (*Guidance Document for Power Delivery and Restoration During Energy Emergencies*). It is essential for entities to recognize that being overly broad in the application of this term may negatively impact reliability. If everything is critical, then nothing is truly critical.

The various regions covered by NERC requirements will have large variances in natural gas infrastructure that might be considered essential to the reliability of the BES. For example, Texas considers a single forced stoppage of natural gas transportation capacity a "major" event only if it disrupts greater than 200 MMcf per day. The entire state of Vermont used less than 70 times that amount of gas over the course of the entire year in 2021 and would therefore likely consider any infrastructure that moves a small fraction of the Texas quantity of gas "critical." Some locations would consider large gas collection sites (wellheads) as critical while others simply have no gas collection systems. Gas compression stations may be critical in some locations while others, potentially located near large underground high-pressure storage sites, may not be considered as critical. Entities should develop critical load classifications and criteria for prioritizing critical loads for BES reliability based on the unique features of its system.

Identification of Critical Natural Gas Infrastructure Loads

Critical natural gas Loads must be identified so that they can then be prioritized from an operator-controlled manual Load shedding, UFLS, and UVLS perspective. The identification and prioritization of critical natural gas loads requires coordination with natural gas facility owners and operators. This can be accomplished in a number of ways and the SDT did not prescribe specific methods in the drafting of EOP-011-4. Methods may include:

- Distribution of criteria to natural gas infrastructure entities soliciting information to identify critical facilities that would likely adversely affect BES reliability if de-energized;
- Reliance on self-identification of critical gas infrastructure driven by local jurisdictional requirements;
- Use of historical information and coordination with resources and gas suppliers from existing Operating Plans.

The SDT recognizes that entities are dependent upon the cooperation of natural gas facility owners and operators to complete this task. However, it is outside the scope of the SDT to develop methods to compel natural gas owners and operators to cooperate and provide specific information to various entities.

It is also recognized that BES registered entities are not expected to become experts in natural gas infrastructure, nor are natural gas entities expected to become experts in electrical generation. However, the Applicable Entity (Distribution Provider or Transmission Owner serving the end-use customer), in working with natural gas facility owners, is responsible for defining those facilities that are critical to maintain the BES reliability, therefore placing the correct ownership on the entity to make that identification and not on entity that is unfamiliar with the configuration. Those natural gas Loads determined to be critical to the reliability of the BES may also change gradually over time as changes occur in the BES and natural gas supply system, requiring regular review of prioritization schemes. The goal of pre-event planning and emergency response is to promote sufficient knowledge so that discussions of natural gas facility criticality can be conducted prior to and during extreme cold weather events. This allows Reliability Coordinators, Balancing Authorities, Regional Entities, Transmission Operators, Transmission Owners, and Distribution Providers to adjust Load shedding schemes as necessary to maximize availability of natural gas resources and to minimize impacts on the BES.

Prioritization of Critical Natural Gas Infrastructure Loads

The SDT recognizes that it is not reasonable to set a broad expectation of “protecting” critical natural gas Loads as initially recommended in the Joint Inquiry Report. Instead, it is more appropriate for entities to consider how critical natural gas infrastructure Loads are prioritized under various conditions. 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. Continued communication between electricity and natural gas providers is crucial to maintain situational awareness to avoid unintended consequences of Load shedding of critical natural gas infrastructure Loads. Prioritization should take into account the relative criticality of various loads within the natural gas supply chain and their potential impact to BES reliability. For example, critical natural gas Loads such as compression facilities that directly impact gas pipelines serving gas-fired generators should be prioritized above gas production facilities.

Most entities will find it appropriate to completely exclude a subset of the most critical natural gas infrastructure Loads that directly impact BES generators from manual, UFLS, and UVLS. It is recommended to prioritize other critical natural gas Loads so that they are only shed if necessary, based on the Load shed magnitude.

An example method of prioritizing critical natural gas Loads may include:

- Identifying critical natural gas infrastructure Loads with the highest level of criticality and potential impact to BES reliability such that they can be completely excluded from operator-controlled manual Load shed, UFLS and UVLS programs;
- Prioritizing other critical natural gas infrastructure Loads not included in UFLS or UVLS programs such that they are only shed if necessary, based on the Load shed magnitude; and
- Prioritizing other critical natural gas infrastructure Loads included in UFLS or UVLS programs such that they are allocated to the lower frequency, or longer time-delay, steps in a UFLS program to ensure that they are less likely to be interrupted.

Requirement R2

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 excluding critical natural gas infrastructure loads which are essential to the reliability of the BES, as defined by the Applicable Entity, as Interruptible Load, curtailable Load, and demand response during extreme cold weather periods within each Balancing Authority Area;*

2.2.9. *Provisions for Transmission Operators to implement operator-controlled manual Load shedding undervoltage Load shedding, or underfrequency Load shedding in accordance with Requirement R1 Part 1.2.5; and*

2.2.10. *Provisions to determine reliability impacts of:*

2.2.10.1. *cold weather conditions; and*

2.2.10.2. *extreme weather conditions.*

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.*

Requirement R2, Part 2.2.8

EOP-011-4 Requirement 2.2.8 was added to address Key Recommendation 1h by prohibiting the use of certain critical natural gas infrastructure loads for demand response. This prohibition does not apply to all natural gas infrastructure loads. Instead, the Balancing Authority is only required to exclude those critical natural gas infrastructure loads which are essential to the reliability of the BES. Additionally, it is recognized that a complete prohibition is not necessary at all times given that the natural gas system does not have the same limitations and criticality during all seasons and weather conditions. For this reason, the SDT has limited the exclusion of these loads from Interruptible Load, curtailable Load, and demand response only to periods of extreme cold weather.

Requirement R2, Part 2.2.9

Key Recommendation 1i requires the Balancing Authorities to include in their Operating Plan(s) for their Balancing Authority Areas provisions for operator-controlled manual Load shedding that identifies and protects critical natural gas infrastructure loads in their respective areas. Further, the recommendation also includes provisions within these operating plans to require manual, UVLS, and UFLS Load shed entities within their respective footprints to protect identified critical natural gas infrastructure loads from manual, UVLS, and UFLS Load shedding.

The current provision, Requirement R2 Part 2.2.9, which references Transmission Operator responsibilities under R1 Part 1.2.5, satisfies the requirements of Key Recommendation 1i with respect to the Balancing Authority. Requirement R1 Part 1.2.5 requires that Transmission Operators have provisions to identify and prioritize critical natural gas infrastructure loads which are essential to the reliability of the BES from a manual Load shedding, UVLS and UFLS Load shedding perspective. The Balancing Authority relies on the Transmission Operator when it directs Load shedding. In addition, as described above, Requirement R8 extends these requirements to the applicable

Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners who are identified in a Transmission Operator's Operating Plan to assist with the mitigation of Operating emergencies. Therefore, the objectives of the recommendation that Load shedding entities identify and protect critical natural gas infrastructure loads are satisfied.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Extreme Cold Weather Preparedness

Technical Rationale and Justification for EOP-011-4

~~August~~September 2023

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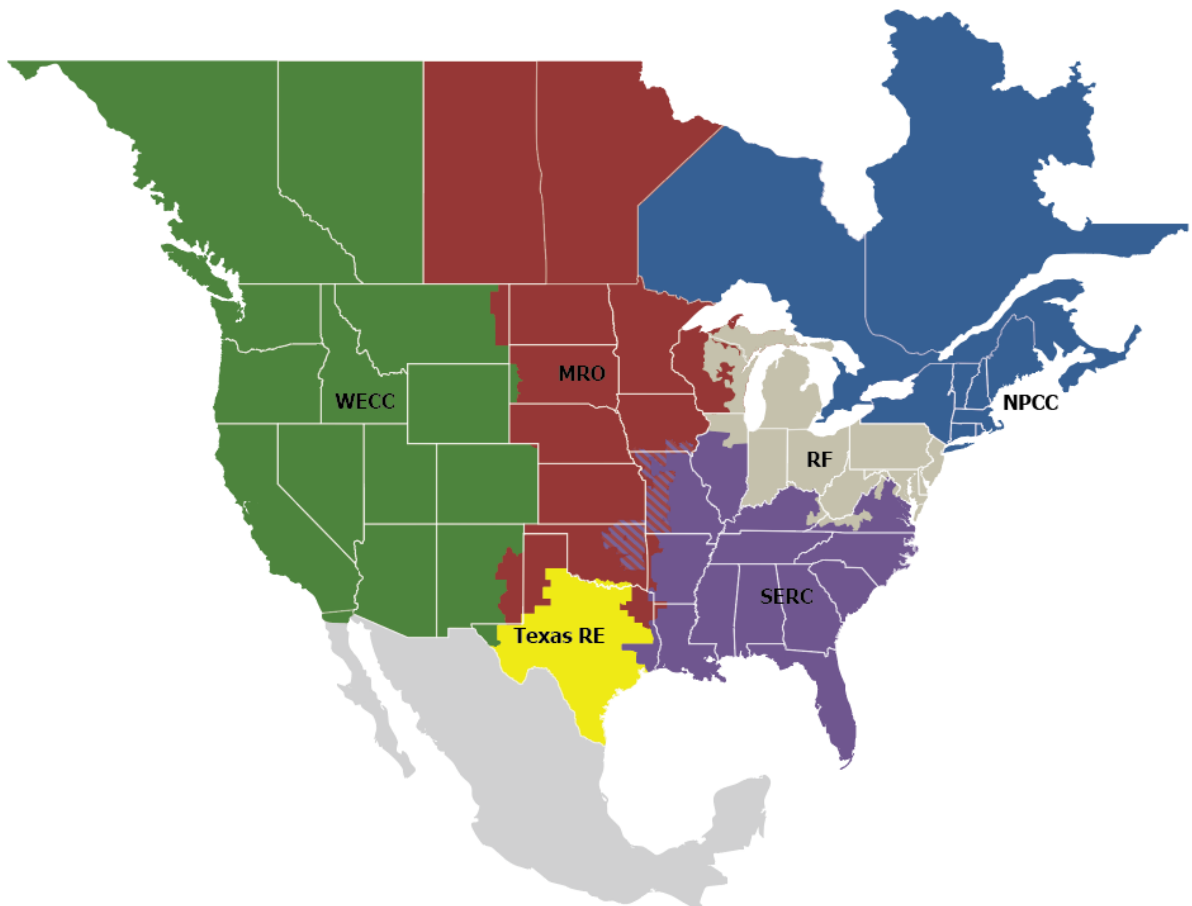
Preface

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 proposed Reliability Standard EOP-011-4. 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-011-4 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 10 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 was completed by September 30, 2022, and submitted 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, R7, and R8

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. *Operator-controlled manual Load shedding ~~and automatic Load shedding~~undervoltage load shed (UVLS), or underfrequency load shed (UFLS) 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, UVLS, or ~~automatic Load shed~~UFLS and circuits that serve designated critical loads which are essential to the reliability of the BES;*

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~~);~~;*

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;*

1.2.5.5. *Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity; and*

1.2.6. *Provisions to determine reliability impacts of:*

1.2.6.1. *Cold weather conditions; and*

1.2.6.2. *Extreme weather conditions.*

R7. *Each Transmission Operator shall annually identify and notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through ~~Operator~~operator-controlled manual Load shedding~~ or automatic~~, undervoltage Load shedding~~.~~, or underfrequency Load shedding.*

R8. *Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area~~,~~ shall develop, maintain, and implement a Load shedding plan~~, within~~*

~~30 months of being notified by the Transmission Operator~~. The Load shedding plan shall include the following, as applicable:

8.1. *Operator-controlled manual Load shedding ~~and automatic~~, undervoltage Load shedding, or underfrequency Load shedding during an Emergency that accounts for each of the following:*

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

8.1.2. *Provisions to minimize the overlap of circuits that are designated for manual, undervoltage, or ~~automatic~~underfrequency Load shed and circuits that serve designated critical loads which are essential to the reliability of the BES;*

8.1.3. *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~~);~~;*

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

8.1.5. *Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity.*

8.2. *Provisions to provide the Load shedding plan to the Transmission Operator for review.*

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)*

Applicability, Requirement R7 and R8

Expansion of Applicability

In many cases, Transmission Operators are dependent on Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners to implement portions of Requirement R1.2.5. The Project 2021-07 standard drafting team (SDT) determined that it is necessary to expand the Applicability of EOP-011-4 to these Functional Entities in order to

address all entities responsible for performing operator-controlled manual Load shedding, UFLS, or UVLS~~automatic Load shedding~~ per Key Recommendation 1i. Planning Coordinators and Transmission Planners were purposely excluded from applicability even though they are mentioned in Key Recommendation 1i because they are not responsible for performing operator-controlled manual Load shedding, UFLS, or UVLS~~automatic Load shedding~~.
EOP-011-4 Requirement R7 is a new requirement that was added to require that Transmission Operators annually identify and notify any Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners that are required to assist with mitigation of operating Emergencies in their Transmission Operator Area. The Transmission Operator has the overarching responsibility to mitigate operating Emergencies. If a Transmission Operator relies on other functional entities in accomplishing various aspects of manual Load shedding, UFLS, or UVLS~~automatic Load shedding~~, they must be identified and notified per R7. Those identified and notified entities are subject to Requirement R8. The initial performance of R7 is required upon the effective date of EOP-011-4, which is on the first day of the first calendar quarter that is six 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. This approach to Requirement R7 ensures that newly applicable entities who will be subject to Requirement R8 are identified and notified in a timely manner thus minimizing any delay in implementing Requirement R8. Requirement R7 includes an annual provision to ensure that any additional entities, or changes to existing entities, required to assist with the mitigation of Operating emergencies are appropriately identified and notified on an ongoing basis.

EOP-011-4 Requirement R8 is a new requirement that is specific to Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners identified by the Transmission Operator in Requirement R7. It includes the relevant portions of Requirement R1.2.5 that address operator-controlled manual Load shedding, ULFS or UVLS~~automatic Load shedding~~. The SDT found it appropriate to place these requirements specifically on Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners because many times they are the entities performing operator-controlled manual Load shedding, UFLS or UVLS~~automatic Load shedding~~ and have the capability of ensuring that these requirements are appropriately implemented for the Loads they represent. Entities that are subject to R8 have 30 months after being notified by a Transmission Operator in R7 to become compliant with these requirements.

Requirement R1, Part 1.2.5 and Requirement R8, Part 8.1

EOP-011-4 Requirement R1.2.5.5 was added to require Transmission Operators to include provisions to identify and prioritize critical natural gas infrastructure Loads which are essential to the reliability of the BES in their Operating Plan(s). EOP-011-4 Requirement R8.1.5 mirrors this requirement and is applicable to Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners. In addition to the following content, entities are encouraged to review guidance from *Reliability Guideline: Gas and Electrical Operational Coordination Considerations* in developing their approach to identify and prioritize critical natural gas infrastructure loads.

Manual, Undervoltage, and ~~Automatic~~Underfrequency

EOP-011-4 Requirement 1.2.5 was modified to include ~~"automatic Load shedding"~~undervoltage load shed and underfrequency load shed in addition to "operator-controlled manual Load shedding." ~~The~~The addition of UVLS and UFLS throughout Requirement R1.2.5 requires these specific load shed processes to account for minimization of overlap between the different processes. An additional result of this modification is that Requirement R1.2.5.5, which requires the identification and prioritization of critical natural gas Loads, by the Applicable Entity (Distribution Provider or Transmission Owner serving the end-use customer), which are essential to the reliability of the BES, is also applicable to ~~automatic~~ Load shedding, be it manual or UVLS or UFLS. It is important to identify and prioritize critical natural gas Loads not just for the purposes of manual Load shed but also in consideration of ~~automatic~~ Load shedding schemes. This modification does not prohibit the inclusion of critical natural gas Loads in ~~automatic~~ Load shedding, but it does require the prioritization of critical natural gas Loads which are essential to the reliability of the BES. This change was also incorporated into the new EOP-011-4 Requirement R8.1.

Critical Natural Gas Infrastructure Loads

The SDT has elected to add clarifying language in the applicable requirements and expand content in this Technical Rationale document in lieu of making "critical natural gas infrastructure Load" a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may necessarily have been overly broad; and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.

A reasonable application of this term should be informed by the entity's approved governing documents and guidance established by applicable regulatory authorities. A practical example of guidance that provides reasonable direction and flexibility has been developed by the Public Utility Commission of Texas in response to Winter Storm Uri (*Guidance Document for Power Delivery and Restoration During Energy Emergencies*). It is essential for entities to recognize that being overly broad in the application of this term may negatively impact reliability. If everything is critical, then nothing is truly critical.

The various regions covered by NERC requirements will have large variances in natural gas infrastructure that might be considered essential to the reliability of the BES. For example, Texas considers a single forced stoppage of natural gas transportation capacity a "major" event only if it disrupts greater than 200 MMcf per day. The entire state of Vermont used less than 70 times that amount of gas over the course of the entire year in 2021 and would therefore likely consider any infrastructure that moves a small fraction of the Texas quantity of gas "critical." Some locations would consider large gas collection sites (wellheads) as critical while others simply have no gas collection systems. Gas compression stations may be critical in some locations while others, potentially located near large underground high-pressure storage sites, may not be considered as critical. Entities should develop critical load classifications and criteria for prioritizing critical loads for BES reliability based on the unique features of its system.

Identification of Critical Natural Gas Infrastructure Loads

Critical natural gas Loads must be identified so that they can then be prioritized from an operator-controlled manual Load shedding, UFLS, and UVLS~~automatic Load shedding~~ perspective. The identification and prioritization of critical natural gas loads requires coordination with natural gas facility owners and operators. This can be accomplished in a number of ways and the SDT did not prescribe specific methods in the drafting of EOP-011-4. Methods may include:

- Distribution of criteria to natural gas infrastructure entities soliciting information to identify critical facilities that would likely adversely affect BES reliability if de-energized;
- Reliance on self-identification of critical gas infrastructure driven by local jurisdictional requirements;
- Use of historical information and coordination with resources and gas suppliers from existing Operating Plans.

The SDT recognizes that entities are dependent upon the cooperation of natural gas facility owners and operators to complete this task. However, it is outside the scope of the SDT to develop methods to compel natural gas owners and operators to cooperate and provide specific information to various entities.

It is also recognized that BES registered entities are not expected to become experts in natural gas infrastructure, nor are natural gas entities expected to become experts in electrical generation. However, the Applicable Entity (Distribution Provider or Transmission Owner serving the end-use customer), in working with natural gas facility owners, is responsible for defining those facilities that are critical to maintain the BES reliability, therefore placing the correct ownership on the entity to make that identification and not on entity that is unfamiliar with the configuration. Those natural gas Loads determined to be critical to the reliability of the BES may also change gradually over time as changes occur in the BES and natural gas supply system, requiring regular review of prioritization schemes. The goal of pre-event planning and emergency response is to promote sufficient knowledge so that discussions of natural gas facility criticality can be conducted prior to and during extreme cold weather events. This allows Reliability Coordinators, Balancing Authorities, Regional Entities, Transmission Operators, Transmission

Owners, and Distribution Providers to adjust Load shedding schemes as necessary to maximize availability of natural gas resources and to minimize impacts on the BES.

Prioritization of Critical Natural Gas Infrastructure Loads

The SDT recognizes that it is not reasonable to set a broad expectation of "protecting" critical natural gas Loads as initially recommended in the Joint Inquiry Report. Instead, it is more appropriate for entities to consider how critical natural gas infrastructure Loads are prioritized under various conditions. 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. Continued communication between electricity and natural gas providers is crucial to maintain situational awareness to avoid unintended consequences of Load shedding of critical natural gas infrastructure Loads. Prioritization should take into account the relative criticality of various loads within the natural gas supply chain and their potential impact to BES reliability. For example, critical natural gas Loads such as compression facilities that directly impact gas pipelines serving gas-fired generators should be prioritized above gas production facilities.

Most entities will find it appropriate to completely exclude a subset of the most critical natural gas infrastructure Loads that directly impact BES generators from manual, UFLS, and UVLS~~automatic Load shed~~. It is recommended to prioritize other critical natural gas Loads so that they are only shed if necessary, based on the Load shed magnitude.

An example method of prioritizing critical natural gas Loads may include:

- Identifying critical natural gas infrastructure Loads with the highest level of criticality and potential impact to BES reliability such that they can be completely excluded from operator-controlled manual Load shed, UFLS and UVLS~~automatic Load shed~~ programs;
- Prioritizing other critical natural gas infrastructure Loads not included in UFLS or UVLS~~automatic Load shed~~ programs such that they are only shed if necessary, based on the Load shed magnitude; and
- Prioritizing other critical natural gas infrastructure Loads included in UFLS or UVLS~~automatic Load shed~~ programs such that they are allocated to the lower frequency, or longer time-delay, steps in a UFLS program to ensure that they are less likely to be interrupted.

Requirement R2

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 excluding critical natural gas infrastructure loads which are essential to the reliability of the BES, as defined by the Applicable Entity, as Interruptible Load, curtailable Load, and demand response during extreme cold weather periods within each Balancing Authority Area;*

2.2.9. *Provisions for Transmission Operators to implement operator-controlled manual Load shedding ~~or automatic~~undervoltage Load shedding, or underfrequency Load shedding in accordance with Requirement R1 Part 1.2.5; and*

2.2.10. *Provisions to determine reliability impacts of:*

2.2.10.1. *cold weather conditions; and*

2.2.10.2. *extreme weather conditions.*

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.

Requirement R2, Part 2.2.8

EOP-011-4 Requirement 2.2.8 was added to address Key Recommendation 1h by prohibiting the use of certain critical natural gas infrastructure loads for demand response. This prohibition does not apply to all natural gas infrastructure loads. Instead, the Balancing Authority is only required to exclude those critical natural gas infrastructure loads which are essential to the reliability of the BES. Additionally, it is recognized that a complete prohibition is not necessary at all times given that the natural gas system does not have the same limitations and criticality during all seasons and weather conditions. For this reason, the SDT has limited the exclusion of these loads from Interruptible Load, curtailable Load, and demand response only to periods of extreme cold weather.

Requirement R2, Part 2.2.9

Key Recommendation 1i requires the Balancing Authorities to include in their Operating Plan(s) for their Balancing Authority Areas provisions for operator-controlled manual Load shedding that identifies and protects critical natural gas infrastructure loads in their respective areas. Further, the recommendation also includes provisions within these operating plans to require manual, UVLS, and ~~automatic~~UFLS Load shed entities within their respective footprints to protect identified critical natural gas infrastructure loads from manual, UVLS, and ~~automatic~~UFLS Load shedding.

The current provision, Requirement R2 Part 2.2.9, which references Transmission Operator responsibilities under R1 Part 1.2.5, satisfies the requirements of Key Recommendation 1i with respect to the Balancing Authority. Requirement R1 Part 1.2.5 requires that Transmission Operators have provisions to identify and prioritize critical natural gas infrastructure loads which are essential to the reliability of the BES from a manual Load shedding, UVLS and ~~automatic~~UFLS Load shedding perspective. The Balancing Authority relies on the Transmission Operator when it directs Load shedding. In addition, as described above, Requirement R8 extends these requirements to the applicable Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners who are identified in a Transmission Operator's Operating Plan to assist with the mitigation of Operating emergencies. Therefore, the objectives of the recommendation that Load shedding entities identify and protect critical natural gas infrastructure loads are satisfied.

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NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Extreme Cold Weather Preparedness

Technical Rationale and Justification for TOP-002-5

September 2023

RELIABILITY | RESILIENCE | SECURITY




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Table of Contents

Preface

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

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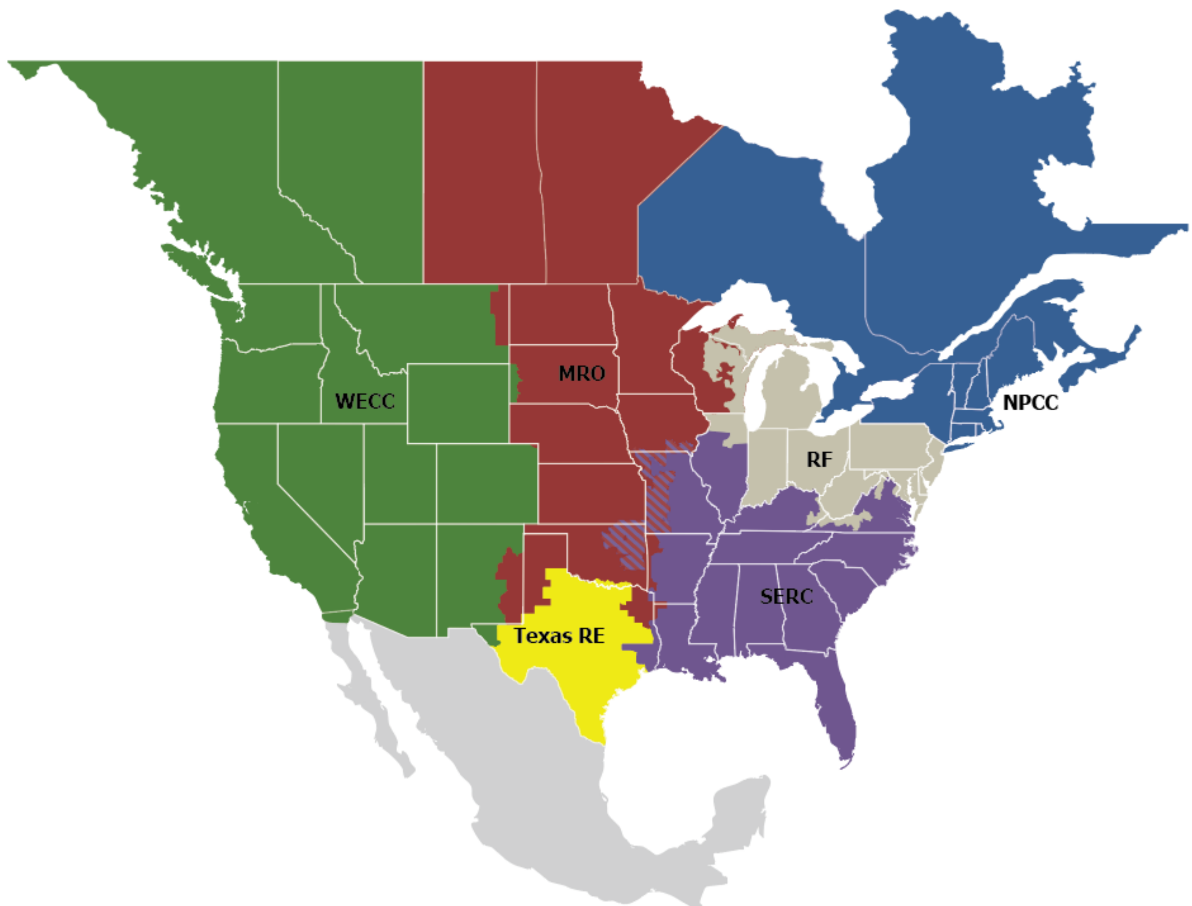

MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
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Introduction

This document explains the technical rationale and justification for the proposed Reliability Standard TOP-002-5. 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 TOP-002-5 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:

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- 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 R8

R8. *Each Balancing Authority shall have an extreme cold weather Operating Process for its Balancing Authority Area, addressing preparations for and operations during extreme cold weather periods. The extreme cold weather Operating Process shall include, but is not limited to:*

8.1 A methodology for identifying an extreme cold weather period within each Balancing Authority Area;

8.2 A methodology to determine an adequate reserve margin during the extreme cold weather period considering the generating unit(s) operating limitations in previous extreme cold weather periods that includes, but is not limited to:

8.2.1 Capability and availability;

8.2.2Fuel supply and inventory concerns

8.2.3 Start-up issues;

8.2.4 Fuel switching capabilities; and

8.2.5 Environmental constraints.

8.3 A methodology to determine a five-day hourly forecast during the identified extreme cold weather periods that includes, but is not limited to:

8.3.1 Expected generation resource commitment and dispatch;

8.3.2 Demand patterns;

8.3.3 Capacity and energy reserve requirements, including deliverability capability; and

8.3.4 Weather forecast.

Key Recommendation 1g: *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.

General Considerations

There have been several past events during extreme cold weather where load and resource balancing issues have occurred, due to both unexpected generator trips and higher loads than forecasted. A proactive Operating Process required prior to the onset of extreme cold weather events would formalize the Balancing Authority's extreme cold weather preparations for those periods, including forecasting load needs and adequate reserve requirements. Initial drafts to incorporate the Operating Process tied the process to the Operating Plan described in Requirement R4. To remove any ambiguity whether a cold weather Operating Process must be developed for all Operating Plans during all seasons, the standard drafting team (SDT) structured Requirement R8 to be stand-alone. Therefore, the Operating Process contained in Requirement R8 will address preparations and operations for extreme cold weather periods and is not required for other seasonal conditions. The Operating Process is specific to extreme cold weather operations to formalize the process to review and respond to oncoming conditions that may affect generation availability and capability, forecasted load, and determining whether additional capability/reserves should be ready to serve loads during extreme cold weather. The content of Requirement R8 is similar to what is required in the Operating Plan in Requirement in R4 with the exception of Interchange Scheduling which is not required here because this function is typically done in real time on an hourly basis. The need for the Balancing Authority to proactively look ahead and forecast their ability to import power from neighboring Control Areas is captured under Parts 8.3.1 and 8.3.3.

The Project 2021-07 SDT does not believe that prescriptive processes must be used for every Balancing Authority to develop their methodology. This is based in part on the differences in the size of Balancing Authorities (for reference, in 2020, 14 Balancing Authorities had peak loads of less than 200 MWs, while two had peak loads of more than 100,000 MWs[1]). The differences between Balancing Authority footprints, loads, and market structures or lack thereof, make a single consistent methodology inappropriate. Requirement R8, Parts R8.2 and R8.3 contain criteria, including data requirements, the Balancing Authority will use as part of its methodologies. Due to the criteria being the minimum required, the SDT team has included "but not limited to" language to allow the Balancing Authority that flexibility in needed information and process that is vital to ensure the methodologies can effectively accomplish the reliability need, and reflect the intent of the standard to require inclusion of the various listed items but not exclude other items that the Balancing Authority may consider valuable and germane to include in its methodologies. The SDT spent considerable time discussing the appropriate look ahead time frame for the Operating Process with suggestions ranging from seven days to three days. It was determined that seven days was too long of a period as weather forecasts are typically not reliable for this longer duration and three days was too short of a period as this would not allow for the forecast to span a longer holiday weekend. Furthermore, the SDT determined that five days would provide sufficient visibility into projected reserve margin requirements.

The SDT developed the proposed requirement to ensure that the Balancing Authorities address the increased uncertainty related to these extreme weather events in a manner appropriate and adequate for their Balancing Authority Area. Each Balancing Authority can develop a methodology consistent with the Requirement they feel provides the best solutions to sustain an adequate level of reliability during an upcoming extreme cold weather event.

[1]Source: OY 2022 BAL-003 Frequency Bias Settings 01 Jun 2022
https://www.nerc.com/comm/OC/RS%20Landing%20Page%20DL/Frequency%20Response%20Standard%20Resources/OY_2022_Frequency_Bias_Annual_Calculations_REVISION_4.26.22.pdf

Technical Rationale from TOP-002-4

This section contains a "cut and paste" of the Technical Rationale components of the former Guidelines and Technical Basis (GTB) as-is from TOP-002-4 standard to preserve any historical references.

Rationale for Definitions:
Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.

Rationale for R1:
Terms deleted in Requirement R1 as they are now contained in the revised definition of Operational Planning Analysis

Rationale for R2:
The change to Requirement R2 is in response to NOPR paragraph 42 and in concert with proposed changes made to proposed TOP-001-4

Rationale for R3:
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Rationale for R4 and R5:
These Requirements were added to address IERP recommendations

Rationale for R6 and R7:
Added in response to SW Outage Report recommendation 1

This section contains a "cut and paste" of the "Associated Documents" section as is in TOP-002-4 Standard to preserve any historical references:
Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario, but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow, but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA.

When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of “the Operating Plan document” for compliance purposes.

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Extreme Cold Weather Preparedness

Technical Rationale and Justification for TOP-002-5

~~August~~September 2023

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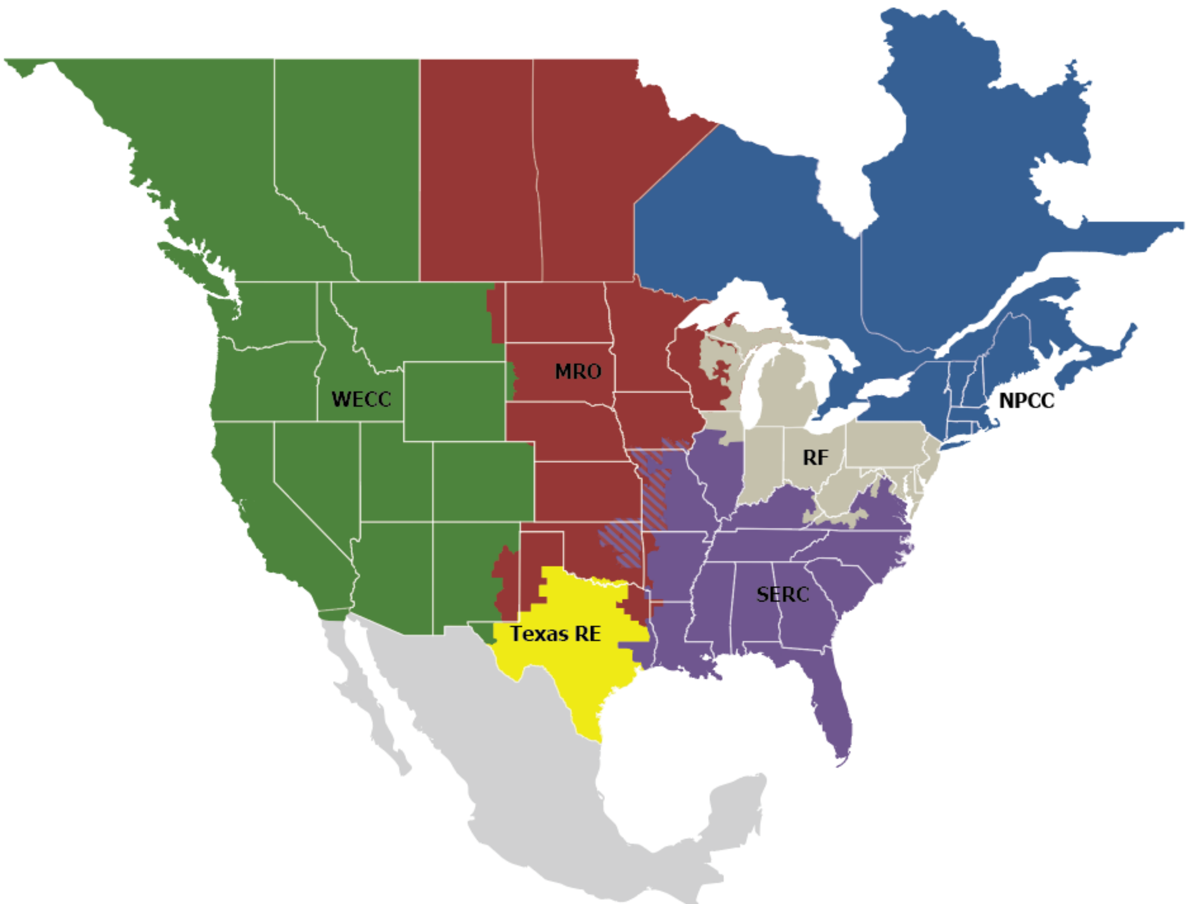

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This section contains a "cut and paste" of the "Associated Documents" section as is in TOP-002-4 Standard to preserve any historical references:

Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario, but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow, but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA.

When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of “the Operating Plan document” for compliance purposes.

Standards Announcement

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

Final Ballots Open through October 6, 2023

Now Available

Final ballots are open through **8 p.m. Eastern, Friday, October 6, 2023** for the following standards and implementation plan:

- EOP-011-4 – Emergency Operations
- TOP-002-5 – Operations Planning
- Implementation Plan

In response to industry comments, the standard drafting team has made a few clarifying non-substantive changes to EOP-011 and TOP-002. The SDT has provided a summary of these changes in the Consideration of Comments.

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.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

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

For more information or assistance, contact Manager of Standards Development, Alison Oswald (via email) or at 404-275-9410.

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 | Phase 2 EOP-011-4 FN 3 ST
Voting Start Date: 9/29/2023 9:02:38 AM
Voting End Date: 10/6/2023 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 3
Total # Votes: 259
Total Ballot Pool: 280
Quorum: 92.5
Quorum Established Date: 9/29/2023 11:37:08 AM
Weighted Segment Value: 73.29

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	75	1	43	0.717	17	0.283	0	11	4
Segment: 2	8	0.8	7	0.7	1	0.1	0	0	0
Segment: 3	63	1	38	0.704	16	0.296	0	6	3
Segment: 4	14	1	7	0.583	5	0.417	0	1	1
Segment: 5	68	1	36	0.692	16	0.308	0	8	8
Segment: 6	44	1	25	0.694	11	0.306	0	4	4
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	7	0.5	5	0.5	0	0	0	1	1
Totals:	280	6.4	162	4.69	66	1.71	0	31	21

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Micah Runner		Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Abstain	N/A
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Affirmative	N/A
1	Duke Energy	Katherine Street		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Alan Kloster	Affirmative	N/A
1	Eversource Energy	Joshua London		Negative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	N/A
1	Georgia Transmission Corporation	Greg Davis		Abstain	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Joseph McClung		Negative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		None	N/A
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
1	Long Island Power Authority	Isidoro Behar		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Matt Lewis		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
1	Muscatine Power and Water	Andrew Kurriger		Negative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Abstain	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	N/A
1	New York Power Authority	Daniel Valle		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Omaha Public Power District	Doug Peterchuck		Negative	N/A
1	Oncor Electric Delivery	Byron Booker	Gul Khan	Affirmative	N/A
1	Orlando Utilities Commission	Aaron Staley		Negative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Abstain	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		Affirmative	N/A
1	Platte River Power Authority	Marissa Archie		Negative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Negative	N/A
1	Puget Sound Energy, Inc.	Anna Lavik		Abstain	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Sarah Blankenship	Israel Perez	Affirmative	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	SaskPower	Wayne Guttormson		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Negative	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Negative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	David Plumb		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	Western Area Power Administration	Sean Erickson	Kimberly Bentley	None	N/A
1	Xcel Energy, Inc.	Eric Barry		Negative	N/A
2	California ISO	Darcy O'Connell	Val Neiberger	Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A
2	Independent Electricity System Operator	Helen Lainis		Affirmative	N/A
2	ISO New England, Inc.	John Pearson	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Negative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	Southwest Power Pool, Inc. (RTO)	Matthew Harward		Affirmative	N/A
3	AEP	Kent Feliks		Negative	N/A
3	Ameren - Ameren Services	David Jendras Sr		Negative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
3	BC Hydro and Power Authority	Alan Xu		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs	Rachel Schuldt	Affirmative	N/A
3	Bonneville Power Administration	Ron Sporseen		Negative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Negative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Bill Garvey		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		None	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Alan Kloster	Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Negative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	N/A
3	Florida Municipal Power Agency	Navid Nowakhtar	LaKenya Vannorman	None	N/A
3	Georgia System Operations Corporation	Scott McGough		Abstain	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
3	JEA	Marilyn Williams		None	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	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	Muscatine Power and Water	Seth Shoemaker		Negative	N/A
3	National Grid USA	Brian Shanahan		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney		Negative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Negative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Abstain	N/A
3	Platte River Power Authority	Richard Kiess		Negative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Santee Cooper	Vicky Budreau		Abstain	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		Negative	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Negative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Negative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		Negative	N/A
3	WEC Energy Group, Inc.	Christine Kane		Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Negative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Abstain	N/A
4	Austin Energy	Tony 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		Negative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
4	Northern California Power Agency	Marty Hostler		Negative	N/A
4	Oklahoma Municipal Power Authority	Michael Watt		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Negative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Seminole Electric Cooperative, Inc.	Ken Habgood		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Negative	N/A
4	Utility Services, Inc.	Tracy MacNicoll		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Negative	N/A
5	AES - AES Corporation	Ruchi Shah		None	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		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		None	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier	Carly Miller	Affirmative	N/A
5	Bonneville Power Administration	Christopher Siewert		Negative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Cogentrix Energy Power Management, LLC	Gerry Adamski		None	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Negative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Helen Wang		Affirmative	N/A
5	Constellation	Alison MacKellar		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Dairyland Power Cooperative	Tommy Drea		Abstain	N/A
5	Dominion - Dominion Resources, Inc.	Anna Salmon		None	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Enel Green Power	Natalie Johnson		Abstain	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	N/A
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Affirmative	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi		Abstain	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	JEA	John Babik		Negative	N/A
5	Lincoln Electric System	Brittany Millard		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
5	Manitoba Hydro	Kristy-Lee Young		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Negative	N/A
5	National Grid USA	Robin Berry		Abstain	N/A
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Eon Hiew		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Nebraska Public Power District	Ronald Bender		Negative	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	NextEra Energy	Richard Vendetti		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Affirmative	N/A
5	Northern California Power Agency	Jeremy Lawson		Negative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		None	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Dania Colon		Affirmative	N/A
5	Pattern Operators LP	George E Brown		Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Negative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG Nuclear LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Negative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Salt River Project	Jennifer Bennett	Israel Perez	Affirmative	N/A
5	Santee Cooper	Don Cribb		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Negative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Negative	N/A
5	Tennessee Valley Authority	Nehtisha Rollis		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		None	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		Negative	N/A
6	AEP	Justin Kuehne		Negative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Imane Mrini		Affirmative	N/A
6	Black Hills Corporation	Claudine Bates		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Cleco Corporation	Robert Hirchak		Negative	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
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Tiffany Lake	Alan Kloster	Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	N/A
6	Great River Energy	Brian Meloy		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	Kelly Bertholet		Affirmative	N/A
6	Muscatine Power and Water	Nicholas Burns		Negative	N/A
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Abstain	N/A
6	NiSource - Northern Indiana Public Service Co.	Joseph OBrien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Negative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Platte River Power Authority	Sabrina Martz		Negative	N/A
6	Portland General Electric Co.	Stefanie Burke		None	N/A
6	Powerex Corporation	Raj Hundal		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		None	N/A
6	Public Utility District No. 1 of Chelan County	Anne Kronshage		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	Mike Stussy		None	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Santee Cooper	Marty Watson		Abstain	N/A
6	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.	Kati Barr		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Negative	N/A
6	Tennessee Valley Authority	Armando Rodriguez		Affirmative	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Affirmative	N/A
6	Western Area Power Administration	Chrystal Dean		Affirmative	N/A
7	Oxy - Occidental Chemical	Venona Greaff		Affirmative	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	New York State Reliability Council	Wesley Yeomans		None	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Lindsey Mannion	Stephen Whaite	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Showing 1 to 280 of 280 entries

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BALLOT RESULTS

Ballot Name: 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 TOP-002-5 FN 3 ST
Voting Start Date: 9/29/2023 9:03:00 AM
Voting End Date: 10/6/2023 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 3
Total # Votes: 257
Total Ballot Pool: 279
Quorum: 92.11
Quorum Established Date: 9/29/2023 11:37:23 AM
Weighted Segment Value: 79.56

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	74	1	47	0.839	9	0.161	0	14	4
Segment: 2	8	0.8	4	0.4	4	0.4	0	0	0
Segment: 3	63	1	43	0.86	7	0.14	0	10	3
Segment: 4	14	1	10	0.769	3	0.231	0	0	1
Segment: 5	68	1	40	0.8	10	0.2	0	10	8
Segment: 6	44	1	28	0.824	6	0.176	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	7	0.5	5	0.5	0	0	0	1	1
Totals:	279	6.4	178	5.092	39	1.308	0	40	22

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	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Micah Runner		Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Abstain	N/A
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Affirmative	N/A
1	Duke Energy	Katherine Street		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Alan Kloster	Affirmative	N/A
1	Eversource Energy	Joshua London		Abstain	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	N/A
1	Georgia Transmission Corporation	Greg Davis		Abstain	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Joseph McClung		Negative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		None	N/A
1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
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
1	Muscatine Power and Water	Andrew Kurriger		Negative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Abstain	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	New York Power Authority	Daniel Valle		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Byron Booker	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	Abstain	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		Affirmative	N/A
1	Platte River Power Authority	Marissa Archie		Negative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Negative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Sarah Blankenship	Israel Perez	Affirmative	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	SaskPower	Wayne Guttormson		None	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Sempra - San Diego Gas and Electric	Mohamed 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	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	David Plumb		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	N/A
1	Western Area Power Administration	Sean Erickson	Kimberly Bentley	None	N/A
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
2	California ISO	Darcy O'Connell	Val Neiberger	Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	N/A
2	Independent Electricity System Operator	Helen Lainis		Affirmative	N/A
2	ISO New England, Inc.	John Pearson	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Negative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Negative	N/A
2	Southwest Power Pool, Inc. (RTO)	Matthew Harward		Negative	N/A
3	AEP	Kent Feliks		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Ameren - Ameren Services	David Jendras Sr		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
3	BC Hydro and Power Authority	Alan Xu		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs	Rachel Schuldt	Affirmative	N/A
3	Bonneville Power Administration	Ron Sporseen		Negative	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	Dominion - Dominion Virginia Power	Bill Garvey		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		None	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Alan Kloster	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Eversource Energy	Vicki O'Leary		Abstain	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	N/A
3	Florida Municipal Power Agency	Navid Nowakhtar	LaKenya Vannorman	None	N/A
3	Georgia System Operations Corporation	Scott McGough		Abstain	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
3	JEA	Marilyn Williams		None	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	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	Muscatine Power and Water	Seth Shoemaker		Negative	N/A
3	National Grid USA	Brian Shanahan		Abstain	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	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Northern California Power Agency	Michael Whitney		Negative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Abstain	N/A
3	Platte River Power Authority	Richard Kiess		Negative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Santee Cooper	Vicky Budreau		Abstain	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		Negative	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		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 Snyder		Affirmative	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.	Ryan Walter		Abstain	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	Austin Energy	Tony 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		Negative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
4	Northern California Power Agency	Marty Hostler		Negative	N/A
4	Oklahoma Municipal Power Authority	Michael Watt		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Negative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Ken Habgood		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	Utility Services, Inc.	Tracy MacNicoll		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	AES - AES Corporation	Ruchi Shah		None	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		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		None	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier	Carly Miller	Affirmative	N/A
5	Bonneville Power Administration	Christopher Siewert		Negative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Cogentrix Energy Power Management, LLC	Gerry Adamski		None	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Negative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Helen Wang		Affirmative	N/A
5	Constellation	Alison MacKellar		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Abstain	N/A
5	Dominion - Dominion Resources, Inc.	Anna Salmon		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	DTE Energy - Detroit Edison Company	Adrian Raducea		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Enel Green Power	Natalie Johnson		Abstain	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	N/A
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Affirmative	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi		Abstain	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
5	Manitoba Hydro	Kristy-Lee Young		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Negative	N/A
5	National Grid USA	Robin Berry		Abstain	N/A
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender		Negative	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	NextEra Energy	Richard Vendetti		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Affirmative	N/A
5	Northern California Power Agency	Jeremy Lawson		Negative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		None	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Dania Colon		Affirmative	N/A
5	Pattern Operators LP	George E Brown		Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Negative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG Nuclear LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Negative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Salt River Project	Jennifer Bennett	Israel Perez	Affirmative	N/A
5	Santee Cooper	Don Cribb		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Negative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Abstain	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		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	Tennessee Valley Authority	Nehtisha Rollis		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		None	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		Affirmative	N/A
6	AEP	Justin 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	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Imane Mrini		Affirmative	N/A
6	Black Hills Corporation	Claudine Bates		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Negative	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		None	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	John Sturgeon		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Tiffany Lake	Alan Kloster	Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	N/A
6	Great River Energy	Brian Meloy		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	Kelly Bertholet		Affirmative	N/A
6	Muscatine Power and Water	Nicholas Burns		Negative	N/A
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Abstain	N/A
6	NiSource - Northern Indiana Public Service Co.	Joseph OBrien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Negative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
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		Negative	N/A
6	Portland General Electric Co.	Stefanie Burke		None	N/A
6	Powerex Corporation	Raj Hundal		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		None	N/A
6	Public Utility District No. 1 of Chelan County	Anne Kronshage		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	Mike Stussy		None	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Santee Cooper	Marty Watson		Abstain	N/A
6	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.	Kati Barr		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	Western Area Power Administration	Chrystal Dean		Affirmative	N/A
7	Oxy - Occidental Chemical	Venona Greaff		Affirmative	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	New York State Reliability Council	Wesley Yeomans		None	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Lindsey Mannion	Stephen Whaite	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

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BALLOT RESULTS

Ballot Name: 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 Implementation Plan FN 3 OT
Voting Start Date: 9/29/2023 9:03:23 AM
Voting End Date: 10/6/2023 8:00:00 PM
Ballot Type: OT
Ballot Activity: FN
Ballot Series: 3
Total # Votes: 254
Total Ballot Pool: 278
Quorum: 91.37
Quorum Established Date: 9/29/2023 11:37:35 AM
Weighted Segment Value: 80.69

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	74	1	50	0.833	10	0.167	0	9	5
Segment: 2	7	0.7	6	0.6	1	0.1	0	0	0
Segment: 3	63	1	45	0.833	9	0.167	0	6	3
Segment: 4	14	1	9	0.692	4	0.308	0	0	1
Segment: 5	68	1	40	0.769	12	0.231	0	8	8
Segment: 6	44	1	27	0.794	7	0.206	0	4	6
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	7	0.3	3	0.3	0	0	0	3	1
Totals:	278	6.1	181	4.922	43	1.178	0	30	24

BALLOT POOL MEMBERS

Show All entries

Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Micah Runner		Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Abstain	N/A
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Affirmative	N/A
1	Duke Energy	Katherine Street		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Alan Kloster	Affirmative	N/A
1	Eversource Energy	Joshua London		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	N/A
1	Georgia Transmission Corporation	Greg Davis		Abstain	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Joseph McClung		Negative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		None	N/A
1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
1	Lower Colorado River Authority	Matt Lewis		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
1	Muscatine Power and Water	Andrew Kurriger		Negative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Abstain	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	N/A
1	New York Power Authority	Daniel Valle		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Byron Booker	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	Abstain	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		Affirmative	N/A
1	Platte River Power Authority	Marissa Archie		Negative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Negative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Sarah Blankenship	Israel Perez	Affirmative	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	SaskPower	Wayne Guttormson		None	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	David Plumb		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	Western Area Power Administration	Sean Erickson	Kimberly Bentley	None	N/A
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	N/A
2	Independent Electricity System Operator	Helen Lainis		Affirmative	N/A
2	ISO New England, Inc.	John Pearson	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Matthew Harward		Affirmative	N/A
3	AEP	Kent Feliks		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
3	BC Hydro and Power Authority	Alan Xu		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs	Rachel Schuldt	Affirmative	N/A
3	Bonneville Power Administration	Ron Sporseen		Negative	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	Dominion - Dominion Virginia Power	Bill Garvey		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		None	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Alan Kloster	Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	N/A
3	Florida Municipal Power Agency	Navid Nowakhtar	LaKenya Vannorman	None	N/A
3	Georgia System Operations Corporation	Scott McGough		Abstain	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
3	JEA	Marilyn Williams		None	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	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	Muscatine Power and Water	Seth Shoemaker		Negative	N/A
3	National Grid USA	Brian Shanahan		Abstain	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	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Abstain	N/A
3	Platte River Power Authority	Richard Kiess		Negative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Santee Cooper	Vicky Budreau		Abstain	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		Negative	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Negative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		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	Austin Energy	Tony 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		Negative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	N/A
4	Northern California Power Agency	Marty Hostler		Negative	N/A
4	Oklahoma Municipal Power Authority	Michael Watt		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Negative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Ken Habgood		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	Utility Services, Inc.	Tracy MacNicoll		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	AES - AES Corporation	Ruchi Shah		None	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		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		None	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier	Carly Miller	Affirmative	N/A
5	Bonneville Power Administration	Christopher Siewert		Negative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Cogentrix Energy Power Management, LLC	Gerry Adamski		None	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Negative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Helen Wang		Affirmative	N/A
5	Constellation	Alison MacKellar		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Abstain	N/A
5	Dominion - Dominion Resources, Inc.	Anna Salmon		None	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Enel Green Power	Natalie Johnson		Abstain	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	N/A
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Affirmative	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi		Abstain	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
5	Manitoba Hydro	Kristy-Lee Young		Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Negative	N/A
5	National Grid USA	Robin Berry		Abstain	N/A
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender		Negative	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	NextEra Energy	Richard Vendetti		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	N/A
5	Northern California Power Agency	Jeremy Lawson		Negative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		None	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Dania Colon		Affirmative	N/A
5	Pattern Operators LP	George E Brown		Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Negative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG Nuclear LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Negative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Salt River Project	Jennifer Bennett	Israel Perez	Affirmative	N/A
5	Santee Cooper	Don Cribb		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Negative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
5	Tennessee Valley Authority	Nehtisha Rollis		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		None	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		Affirmative	N/A
6	AEP	Justin 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	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Imane Mrini		Affirmative	N/A
6	Black Hills Corporation	Claudine Bates		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		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		None	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Tiffany Lake	Alan Kloster	Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	N/A
6	Great River Energy	Brian Meloy		None	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	Kelly Bertholet		Affirmative	N/A
6	Muscatine Power and Water	Nicholas Burns		Negative	N/A
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Abstain	N/A
6	NiSource - Northern Indiana Public Service Co.	Joseph OBrien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Negative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Negative	N/A
6	Portland General Electric Co.	Stefanie Burke		None	N/A
6	Powerex Corporation	Raj Hundal		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		None	N/A
6	Public Utility District No. 1 of Chelan County	Anne Kronshage		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	Mike Stussy		None	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Santee Cooper	Marty Watson		Abstain	N/A
6	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.	Kati Barr		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	Western Area Power Administration	Chrystal Dean		Affirmative	N/A
7	Oxy - Occidental Chemical	Venona Greaff		Affirmative	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		None	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Lindsey Mannion	Stephen Whaite	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A

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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 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.

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

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 ~~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			

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.

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

[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.

Requested information
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	
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

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

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Exhibit G

Standard Drafting Team Roster, Project 2021-07
Extreme Cold Weather Grid Operations, Preparedness, and Coordination

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

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